ACKNOWLEDGEMENTS

The publisher acknowledges and thanks the following law firms for their learned assistance throughout the preparation of this book:

ABOU JAOUDE & ASSOCIATES LAW FIRM
AFRIDI & ANGELL
ALC ADVOGADOS
ALFARO FERRER & RAMÍREZ
ANDERSON MÔRI & TOMOTSUNE
BRUUN & HJEJLE
CMS
COVINGTON & BURLING (PTY) LTD
DLA PIPER INTERNATIONAL
DUANE MORRIS & SELVAM LLP
G ELIAS & CO
HENRIQUES, ROCHA & ASSOCIADOS
HERBERT SMITH FREEHILLS LLP
HFW
HOLLAND & KNIGHT
HVG LAW LLP
KOLCUOĞLU DEMİRKAN KOÇAKLI ATTORNEYS AT LAW
LATHAM & WATKINS
LINKLATERS LLP
MORAIS LEITÃO, GALVÃO TELES, SOARES DA SILVA & ASSOCIADOS – SOCIEDADE DE ADVOGADOS, SP, RL
ORRICK
PINHEIRO NETO ADVOGADOS
Acknowledgements

PUYAT JACINTO SANTOS LAW OFFICE
SIDLEY AUSTIN LLP
SKRINE
SQUIRE PATTON BOGGS
STEPHENSON HARWOOD MIDDLE EAST LLP
STIBBE
STUDIO LEGALE VILLATA, DEGLI ESPOSTI E ASSOCIATI
TRILEGAL
WILMER CUTLER PICKERING HALE AND DORR LLP
YOON & YANG LLC
CONTENTS

PREFACE .......................................................................................................................................................... vii
   David L Schwartz

Chapter 1  EUROPEAN UNION OVERVIEW .......................................................................................... 1
   Charles Morrison, Nigel Drew and Andreas Gunst

Chapter 2  OVERVIEW OF CENTRAL AND WEST AFRICA .............................................................. 15
   Pascal Agboyibor, Doux Didier Boua, Gabin Gabas and Johana N’Dia

Chapter 3  GAS PRICE DISPUTES UNDER LONG-TERM GAS SALES AND PURCHASE
            AGREEMENTS .................................................................................................................. 33
   John A Trenor

Chapter 4  CLIMATE CHANGE: CLIMATE ACTIVISM THROUGH GOVERNMENT
            INVESTIGATIONS AND LITIGATION ............................................................................. 45
   Richard Alonso and Peter Whitfield

Chapter 5  ANGOLA ................................................................................................................................. 50
   Catarina Levy Osório and Helena Prata

Chapter 6  AUSTRALIA ............................................................................................................................ 65
   Simon Rear, Samantha Smart, Fiona Meaton and Connor McClymont

Chapter 7  BELGIUM .............................................................................................................................. 80
   Wouter Geldhof, Cedric Degreel and Marthe Matelii

Chapter 8  BRAZIL ................................................................................................................................... 89
   José Roberto Oliva Jr and Julia Batistella Machado

Chapter 9  CHINA ..................................................................................................................................... 102
   Monica Sun and James Zhang
<table>
<thead>
<tr>
<th>Chapter</th>
<th>Country</th>
<th>Authors</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>COLOMBIA</td>
<td>Jose V Zapata and Daniel Fajardo Villada</td>
<td>118</td>
</tr>
<tr>
<td>11</td>
<td>DENMARK</td>
<td>Nicolaj Kleist</td>
<td>132</td>
</tr>
<tr>
<td>12</td>
<td>FRANCE</td>
<td>Fabrice Fages and Myria Saarinen</td>
<td>141</td>
</tr>
<tr>
<td>13</td>
<td>GERMANY</td>
<td>Thomas Schulz, Henry Hoda and Ruth Losch</td>
<td>153</td>
</tr>
<tr>
<td>14</td>
<td>INDIA</td>
<td>Neeraj Menon and Akshita Amit</td>
<td>164</td>
</tr>
<tr>
<td>15</td>
<td>IRAN</td>
<td>Munir Hassan and Shaghayegh Smousavi</td>
<td>182</td>
</tr>
<tr>
<td>16</td>
<td>IRAQ</td>
<td>Salem Chalabi</td>
<td>194</td>
</tr>
<tr>
<td>17</td>
<td>ITALY</td>
<td>Andreina Degli Esposti</td>
<td>206</td>
</tr>
<tr>
<td>18</td>
<td>JAPAN</td>
<td>Reiji Takahashi, Norifumi Takeuchi, Wataru Higuchi, Kunihiro Yokoi, Kanitaro Yabuki and Kei Takada</td>
<td>218</td>
</tr>
<tr>
<td>19</td>
<td>KOREA</td>
<td>Soong-Ki Yi, Kwang-Wook Lee and Changwoo Lee</td>
<td>231</td>
</tr>
<tr>
<td>20</td>
<td>LEBANON</td>
<td>Souraya Machnouk, Hachem El Housseini, Rana Kateb and Chadi Stephan</td>
<td>249</td>
</tr>
<tr>
<td>21</td>
<td>MALAYSIA</td>
<td>Fariz Abdul Aziz and Karyn Khor</td>
<td>261</td>
</tr>
<tr>
<td>22</td>
<td>MOZAMBIQUE</td>
<td>Fabricia de Almeida Henriques and Paula Duarte Rocha</td>
<td>277</td>
</tr>
<tr>
<td>Chapter</td>
<td>Country</td>
<td>Authors</td>
<td></td>
</tr>
<tr>
<td>---------</td>
<td>---------</td>
<td>---------</td>
<td></td>
</tr>
<tr>
<td>23</td>
<td>MYANMAR</td>
<td>Krishna Ramachandra, Rory Lang and Bei Wang</td>
<td></td>
</tr>
<tr>
<td>24</td>
<td>NETHERLANDS</td>
<td>Dick Weiffenbach, Sander Simonetti, Nicolas Jans and Pieter Leopold</td>
<td></td>
</tr>
<tr>
<td>25</td>
<td>NIGERIA</td>
<td>Gbolahan Elias and Okechukwu J Okoro</td>
<td></td>
</tr>
<tr>
<td>26</td>
<td>PANAMA</td>
<td>Annette Bárcenas Olivardía and Luis Horacio Moreno IV</td>
<td></td>
</tr>
<tr>
<td>27</td>
<td>PHILIPPINES</td>
<td>Monalisa C Dimalanta, Sheryl F Balot and Jewelynn Gay B Zareno</td>
<td></td>
</tr>
<tr>
<td>28</td>
<td>PORTUGAL</td>
<td>Nuno Galvão Teles and Ricardo Andrade Amaro</td>
<td></td>
</tr>
<tr>
<td>29</td>
<td>SOUTH AFRICA</td>
<td>Lido Fontana and Sharon Wing</td>
<td></td>
</tr>
<tr>
<td>30</td>
<td>SPAIN</td>
<td>Antonio Morales</td>
<td></td>
</tr>
<tr>
<td>31</td>
<td>SWITZERLAND</td>
<td>Georges Racine</td>
<td></td>
</tr>
<tr>
<td>32</td>
<td>TURKEY</td>
<td>Okan Demirkan, Melis Öget Koç, Gökçe İldiri and Cihan Mercan</td>
<td></td>
</tr>
<tr>
<td>33</td>
<td>UNITED ARAB EMIRATES</td>
<td>Masood Afridi and Adite Alok</td>
<td></td>
</tr>
<tr>
<td>34</td>
<td>UNITED KINGDOM</td>
<td>Munir Hassan and Filip Radu</td>
<td></td>
</tr>
<tr>
<td>35</td>
<td>UNITED STATES</td>
<td>Eugene R Elrod, Michael J Gergen, Natasha Gianvecchio, J Patrick Nevins and David L Schwartz</td>
<td></td>
</tr>
<tr>
<td>Appendix 1</td>
<td>ABOUT THE AUTHORS</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Appendix 2</td>
<td>CONTRIBUTING LAW FIRMS' CONTACT DETAILS</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
PREFACE

In our seventh year of writing and publishing *The Energy Regulation and Markets Review*, we have seen dramatic changes in global energy policies. Europe has experienced a strong economic rebound, which has allowed many countries to dedicate increased resources to the infrastructure needs of the energy sector, including for renewables. While the United States commenced efforts to withdraw from the Paris Agreement, the signatories to the Paris Agreement countries have continued to make efforts to reduce greenhouse gases (GHGs). There is still a significant need to invest in infrastructure, and we have seen significant investment throughout the supply chains in the oil, gas and power sectors globally. The 2011 Fukushima nuclear incident continues to impact energy policy in many countries, and we continue to see extensive liberalisation of the energy sector. Oil prices have started to rebound somewhat, which presents some hope to those countries that remain dependent upon oil prices for national revenue.

I CLIMATE CHANGE DEVELOPMENTS

With respect to climate change efforts, the Paris Agreement was placed into effect on 4 November 2016, but President Trump announced last year that the United States would be withdrawing from the Paris Agreement. Nonetheless, we continue to see significant carbon reduction efforts, such as increased development of renewable resources, as well as energy efficiency and demand reduction measures, globally, including in the United States.

Following the Brexit vote, the United Kingdom closed its ‘renewable obligation’ programme to new generation, and limited new contracts for differences, which has significantly reduced new renewable construction this year. France has announced a plan to close all coal-fired power plants within five years, double the capacity of wind and solar renewable generation and prohibit shale gas production and all new searches for hydrocarbons. Denmark continues to seek to have renewable energy meet all of its electricity demands by 2050, and over the past year has initiated an effort to improve the output of solar and wind resources through technology improvements. The Netherlands has a goal of reducing GHGs by at least 25 per cent by 2020, and has announced its intent to close all coal plants by 2030. While Germany will likely miss its 2020 renewable energy goals, it has an ambitious goal to achieve 65 per cent renewable generation capacity by 2030. Belgium has continued its effort to develop offshore renewable wind resources (including the development of an offshore grid), but has reduced historical green certificate subsidies. Italy is seeking to reduce carbonisation by having a goal of relying on renewable resources for 28 per cent of its energy needs by 2030. Switzerland has continued to promote the development of renewables and is supporting the development of large-scale hydroelectric resources through state subsidies.
Spain is seeking to reach 20 per cent renewables by 2020, and has initiated new auctions for 6,000MW of new renewable installed capacity. Turkey seeks to have 30 per cent renewables by 2023.

China released a plan to have 15 per cent of its energy supplied by non-fossil fuels, 20 per cent from natural gas and no more than 58 per cent from coal by 2020. Korea's goal is to cut GHGs by 37 per cent by 2030, and it is seeking to have 95 per cent of all new installed capacity come from clean energy sources and to shut down coal power plants that are more than 30 years old. India's announced goal to have at least 40 per cent of its installed electric capacity powered by non-fossil fuels may be overshadowed by the fact that it is developing and constructing 50,000MW of new coal-fired generation capacity. Japan is looking at offshore wind and a variety of other new renewable energy sources to assist with the reduction of capacity following the shutdown of most of its nuclear generation capacity. Malaysia has been working hard to reduce its overdependence on coal and natural gas, and to encourage the production and use of renewable energy in an effort to meet its target of 50 per cent renewable resources by 2050. As of last year, 33 per cent of the installed capacity in the Philippines was from renewable resources, and 35 per cent was from coal generation. The United Arab Emirates continues its efforts to reduce its carbon footprint, announcing a goal of having 25 per cent of its capacity from renewables by 2030, and 75 per cent by 2050. South Africa relies upon coal generation for 85 per cent of its generation capacity but has taken steps to increase the development of renewable resources. Australia is adding significant new renewable resources to meet its 2020 renewable energy targets.

While the Trump Administration is seeking to reverse the Obama administration's Clean Power Plan, we are seeing continued significant investment in renewable energy development in the United States. Individual states are moving forward to achieve reduced reliance on fossil fuels and greater reliance on renewable energy, including California and New York, which are seeking a 50 per cent renewable portfolio standard goal by 2030, and Hawaii, which is seeking 100 per cent reliance on renewables by 2045.

II INFRASTRUCTURE DEVELOPMENT

For many countries, reliable energy supply is the primary concern, regardless of fuel source. Rural electrification and system reliability remain priorities in India, Indonesia, Myanmar, Mozambique, Angola, parts of Nigeria and Central and West Africa and we are seeing significant efforts to pursue electric generation and transmission projects in those regions. Turkey seeks to increase energy industry infrastructure in the power sector and the oil and gas sectors, in light of an estimated 6 per cent demand growth per year through 2023. Denmark has a new North Sea Agreement to secure future exploration and production of hydrocarbons from the North Sea. Panama continues to seek to attract foreign investment to assist with badly needed transmission and generation infrastructure needs. The 8 May 2018 announcement by President Trump that he intends to withdraw from the Iran nuclear deal and institute significant new sanctions is expected to present a significant roadblock to further foreign investment in the Iranian energy sector.

III NUCLEAR POWER GENERATION

Seven years after the Fukushima disaster, Japan has stopped operations for 43 out of its 48 nuclear power stations, and 14 nuclear power stations are in the process of complying
with new safety standards for possible restart. Germany continues to phase out all nuclear
generation by 2022. Belgium is seeking to dismantle all nuclear plants by 2025. France is
seeking a reduction of nuclear power generation to 50 per cent of total electricity production
within five years. Switzerland and Korea are planning to limit the life of their nuclear
generation units, with Korea abandoning the construction of six new nuclear power plants
and cancelling the extension of others.

On the other hand, Turkey is continuing with development of the Akkuyu nuclear
power plant (first unit estimated to be operational in 2023), and the United Arab Emirates
is almost finished with the construction of the Barakah nuclear power plant, both of which
are expected to be operational in 2020. South Africa is facing substantial resistance to its
efforts to develop 9,600MW of new nuclear generation capacity. India’s goal of 40 per cent
non-fossil fuel generation is expected to require a substantial ramp-up of nuclear generation
capacity.

In the United States, the early retirement of certain nuclear plants has been driven
by cost and power market considerations, rather than safety concerns. Some nuclear
owners in the United States have sought state subsidies in New York, Illinois, Ohio and
Pennsylvania, among others, in order to avert premature retirements. Illinois and New York
have implemented legislative and regulatory payment programmes for nuclear facilities in
those states, but they are currently being challenged on constitutional grounds and remain
pending before US federal circuit courts of appeal.

IV LIBERALISATION OF THE ENERGY SECTOR

We have seen significant energy sector regulatory reforms in many countries. Italy is
seeking to reduce the gap between price and cost of energy, compared to the rest of Europe.
Portugal continues to work on liberalising its electricity and gas markets. Japan has now
fully liberalised the retail electricity sector. And we are seeing continued efforts to encourage
further privatisation of the electricity sector in the United Arab Emirates and in certain
countries in Central and West Africa. Turkey is seeking to privatise its generation assets.
Brazil has seen significant privatisation, including the auction of four hydroelectric plants.
Given Switzerland’s interest in promoting the use of renewable resources, it has suspended
a planned 49 per cent divestiture of its state-owned hydroelectric fleet. China has made
moves to deregulate energy pricing. In a move away from privatisation, Colombia ordered
the liquidation of Electricaribe (owned primarily by Gas Natural Fenosa), which is now in
arbitration.

I would like to thank all the authors for their thoughtful consideration of the myriad of
interesting, yet challenging, issues that they have identified in their chapters in this seventh
edition of The Energy Regulation and Markets Review.

David L Schwartz
Latham & Watkins LLP
Washington, DC
May 2018
Chapter 1

EUROPEAN UNION OVERVIEW

Charles Morrison, Nigel Drew and Andreas Gunst

I OVERVIEW

The European energy markets are regulated primarily by a substantial body of European Union secondary legislation. Beyond the secondary legislation, which is comprised of regulations (directly applicable in Member States), directives (subject to transposition into domestic law), decisions (directly applicable and binding on the addressee), recommendations, opinions, and atypical acts (i.e., communications, guidelines, white and green papers), European energy market regulation needs to be understood in the greater context of a number of bilateral and multilateral treaties.

These include the European Union Treaties, namely the Treaty on European Union (TEU), the Treaty on the Functioning of the European Union, the Treaty establishing the European Atomic Energy Community (Euratom), and the Charter of Fundamental Rights of the European Union. Other treaties include the Energy Charter Treaty, the Energy Community Treaty, pending the Agreement establishing the World Trade Organization, the United Nations Framework Convention on Climate Change and the pending Paris Agreement, as well as bilateral investment treaties and bilateral project-specific agreements, such as pipeline or interconnector projects.

The 1994 European Charter Treaty, which builds on the 1991 European Energy Charter, is an unprecedented multilateral framework for international energy cooperation. The Treaty addresses four areas:

a non-discriminatory conditions for trade and provisions on reliable cross-border energy transit;

b protection of direct foreign investment and protection against key non-commercial risk;

c a dispute resolution system between participating states and between investors and host states; and

d the promotion of energy efficiency.

The Energy Community is an international organisation joining the European Union with a number of countries from the South East Europe and Black Sea regions, with the primary aim of extending the European acquis communautaire on energy, environment, competition and renewables to the parties. The Energy Community Treaty additionally sets up a regulatory mechanism for the regional network energy markets. It is worth noting that

1 Charles Morrison, Nigel Drew and Andreas Gunst are partners at DLA Piper International.
the implementation of the European internal energy market in contracting states is a measure that facilitates potential membership of the European Union, as demonstrated by Bulgaria and Romania in 2007 and Croatia in 2013.

The Paris Agreement has been ratified by 148 out of 197 parties to the United Nations Framework Convention on Climate Change, reaching its threshold to enter into force in October 2016. It sets ambitious targets for the parties to mitigate and adapt to climate change and contribute to the decarbonisation of the global economy, and imposes obligations upon all European Union Member States.

The cornerstone of the European energy policy is the internal energy market, which aims to achieve three primary objectives: affordable and competitively priced energy, environmental sustainability and energy security. In its achievement, European Union competition law plays an essential and complementary role, with free market provisions being enforced in coordination with energy regulators.

In its adoption of 'A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy' in February 2015, the Commission has set itself the priority of establishing the Energy Union, a grand strategy for European energy policy. It sets out five key 'dimensions':

a. energy security, solidarity and trust;
b. a fully integrated European energy market;
c. energy efficiency contributing to moderation of demand;
d. decarbonising the economy; and
e. research, innovation and competitiveness.

The Energy Union goes beyond the concept of the internal energy market in that it introduces an element of foreign policy, addressing security and supply risks in the European neighbourhood, and in doing so seeking to create a unified European approach to importing energy. This strategy develops the concept of solidarity in matters of energy supply as introduced by the Treaty of Lisbon.

The next step in the development of the Energy Union is covering the period of 2020 to 2030. In November 2016, the European Commission published the proposal for the Clean Energy for All Europeans package (formerly known as the Winter Package), a legislative package that largely proposes to update the Third Energy Package and other key EU environmental legislation. The proposals must, however, pass through the ordinary legislative procedure and may undergo material changes prior to their enactment. The Clean Energy for All Europeans package includes proposals on a recast Electricity Directive, a recast Electricity Access Regulation, a recast ACER Regulation and a recast Renewable Energy Directive, as well as an amendment to the Energy Efficiency Directive, a new Regulation on the Governance of the Energy Union and a new Regulation on Electricity Sector Risk-Preparedness.

It is clear that there is a substantial body of legislation regulating the European energy markets. For the purpose of this chapter, the main provisions of key secondary energy legislation will be presented.

II EUROPEAN ELECTRICITY AND GAS REGULATORY SYSTEM

The Third Energy Package is a legislative package comprised of three regulations and two directives designed to create the internal market for electricity and gas. These are the
ACER Regulation, the Electricity Directive and Gas Directive, and the Electricity Access Regulation and the Gas Access Regulation. The regulatory system for the European energy markets is effectively divided into the national and European Union level.

On the national level, the Electricity and Gas Directives require Member States to designate National Regulatory Authorities (NRAs), independent bodies that are primarily responsible for setting national transmission or distribution tariffs, cooperating with other NRAs on cross-border issues, monitoring the investment plans of national transmission system operators (TSOs), and ensuring the transparency of consumption data for consumers.

The ACER Regulation provides for the establishment and legal status of the Agency for the Cooperation of National Regulators (ACER), a European forum for the cooperation of NRAs. It defines its tasks, in particular those regarding NRAs, cross-border infrastructure access conditions and operational security, obligations on consultations and transparency, monitoring and reporting obligations on the electricity and natural gas sectors, organisational structure and its budget.

The Commission proposal for a recast ACER Regulation includes provisions on new tasks and restructuring to reflect the enhanced role ACER is to play in the Energy Union, as well as allowing ACER to establish local offices in Member States.

ACER and the NRAs form the core of the European electricity and gas regulation system and are supported by a number of other bodies as described below.

III ELECTRICITY

Electricity Directive

The Electricity Directive focuses specifically on establishing the European internal market for electricity. In particular, it sets out public service obligations for electricity undertakings and customer protection obligations, the monitoring of security of supply by Member States, technical rules and the promotion of regional cooperation of Member States and NRAs. As regards new generation capacity, it establishes an authorisation procedure and a tendering option.

Furthermore, transmission systems and TSOs must be unbundled; however, Member States may instead opt to designate an independent system operator. Unbundling provisions include the designation and certification of TSOs by NRAs, their tasks, ownership unbundling, dispatching and balancing, and confidentiality, as well as defining decision-making powers of TSOs regarding the connection of new power plants.

Distribution System Operators (DSOs) must additionally be unbundled, with the Directive providing for their designation by the Member States, their tasks and confidentiality obligations, as well as provisions on optional closed distribution systems. For both TSOs and DSOs, the unbundling process includes the transparency of their accounts to Member States or any designated authority.

---

5 Regulation (EC) No. 714/2009 on conditions for access to the network for cross-border exchanges in electricity.
The Directive further regulates transmission and distribution system access, notably on the freedom of third-party access, market opening and reciprocity, and direct lines to all eligible customers.

As discussed above, the Electricity Directive establishes NRAs, including their objectives, duties and organisational structure, and includes provisions on retail markets, as well as safeguard measures in response to a sudden energy market crisis, and the non-discriminatory nature of the Directive’s implementation.

The Commission proposal for the recast Electricity Directive includes provisions on further developing market-based pricing with an option for public intervention for vulnerable consumers, the expansion of consumer rights, the expansion of the tasks of NRAs regarding regional cooperation on cross-border matters, the clarification of the roles of TSOs regarding energy storage and regional coordination centres, and the clarification of the role of DSOs regarding energy storage and recharging points for electric vehicles.

ii Electricity Access Regulation

The Electricity Directive is coupled with the Electricity Access Regulation, which establishes the European Network of Transport System Operators for Electricity (ENTSO-E), a European forum for the cooperation of TSOs, which is tasked with monitoring national TSOs and their EU-wide network development plans. The Regulation designates tasks for ENTSO-E and monitoring obligations for ACER.

The Regulation furthermore establishes network codes (see Section III.iii, below), regulates network access charges, the provision of information by TSOs, general principles of congestion management and special provisions on new interconnectors.

The Commission proposal for the recast Energy Access Regulation includes provisions on core market principles, in particular that electricity prices are formed based on demand and supply and forbidding caps or floors on wholesale prices; the introduction of rules on balancing markets; the non-discriminatory and market basis of power generation and demand-response dispatching; the introduction of a definition of bidding zone borders; and the introduction of a European cooperation platform for DSOs.

iii Network codes

Network codes are technical rules designed to address key priorities specified by the European Commission. These aim to develop and harmonise specific aspects of the European energy networks, including capacity allocation, balancing supply and demand, requirements of generators and transmission networks, and security of supply.

Currently, 10 electricity network codes have been specified, which are grouped into three categories:

- connection codes, which set requirements for the connection of both generators and large customers to the transmission grids;

---

7 As established for the electricity market by the Electricity Access Regulation.
8 Network codes are initiated as non-binding ‘framework guidelines’ set out by ACER, outlining the aims and content to be achieved. Through consultation with stakeholders and the public, ENTSO-E drafts network codes based on these framework guidelines. These are subsequently evaluated by ACER to ensure their adherence to the framework guidelines. The draft network codes are then accepted through the process of comitology, and are finally published by the European Commission, commonly as binding regulations.
operational codes, designed to regulate the operation of the transmission systems and the security of supply, and to ensure that supply and demand of electricity within and between transmission systems is balanced; and market codes, which encourage a transparent and competitive pan-European marketplace for electricity and capacity in all timescales, and stimulate generator diversification and infrastructure optimisation.

At the time of writing, eight and thereby all of the originally planned electricity network codes have entered into force. The network code on Capacity Allocation and Congestion Management (CACM) sets out methods for allocating capacity in day-ahead and intra-day timescales, and designates Nominated Electricity Market Operators as coupling operators, and sets out their tasks as well as tasks for TSOs relating to single day-ahead and intraday coupling. CACM includes detailed provisions on terms, conditions and methodologies on capacity allocation and congestion income distribution.

The network code Forward Capacity Allocation sets out methods for allocating capacity in the forward markets, and aims to promote effective long-term cross-zonal trade with long-term cross-zonal hedging products for market participants, optimise the calculation and allocation of long-term cross-zonal capacity, provide non-discriminatory access to long-term cross-zonal capacity, ensure fair and non-discriminatory treatment of TSOs and market participants, and enhance the transparency and reliability of information.

The network code on Electricity Balancing (EB) sets out provisions on terms and conditions or methodologies of TSOs and their approval; roles and responsibilities of TSOs in the electricity balancing market; the establishment of European platforms for the exchange of balancing energy from (1) replacement reserves, frequency restoration reserves with manual activation and (2) frequency restoration reserves with automatic activation; the establishment of a European platform for the imbalance netting process; the procurement of balancing services; cross-zonal capacity for balancing services, balancing settlement and balancing algorithms; and reporting obligations.

The network code on Emergency and Restoration (ER) sets out provisions on regional coordination; the development of a system defence plan and a restoration plan; the development of rules and procedures for the suspension and restoration of market activities; information exchange between TSOs; and compliance testing with obligations under the ER.

The network code on Demand Connection sets out requirements for the grid connection of transmission-connected demand facilities, transmission-connected distribution facilities, distribution systems and demand units as used by a demand facility or closed distribution system to provide demand-response services.

The network code on High Voltage Direct Current Connections sets out requirements for long-distance direct current connections, links between different synchronous areas and

---

10 Commission Regulation (EU) 2016/1719 establishing a guideline on forward capacity allocation.
14 Commission Regulation (EU) 2016/1447 of 26 August 2016 establishing a network code on requirements for grid connection of high-voltage direct current systems and direct current-connected power park modules.
direct current-connected power park modules, such as offshore wind farms. The network code on Requirements for Generators\textsuperscript{15} provides requirements for newly constructed generators, as well as notification procedures and compliance provisions.

The network code on System Operation (SO)\textsuperscript{16} sets out provisions on operational security requirements; data exchange between different market participants; compliance with SO provisions; the development of training programmes on and certification of real-time system operation, operational planning, operational security analysis, outage coordination and control area adequacy analysis; the availability and provision of ancillary services; scheduling; the implementation and operation of an ENTSO-E operational planning data environment; and load-frequency control and reserves.

**IV NATURAL GAS**

\textbf{i Gas Directive}

The Gas Directive is the natural gas counterpart to the Electricity Directive, setting up a similar regulatory structure for the internal market for natural gas. In doing so, it sets out public service and customer protection obligations for gas undertakings, authorisation procedures, the monitoring of security of gas supply, regional solidarity, the promotion of regional cooperation, and technical rules.

The Directive includes provisions on the unbundling of transmission systems and TSOs, their designation and certification by NRAs, their certification in relation to third countries, the unbundling of transmission system owners and storage system operators, and the designation of storage and LNG system operators, as well as duties for these entities. As an alternative to unbundling, Member States may opt to establish independent system operators.

DSOs must be unbundled, with the Directive regulating the designation of DSOs, their tasks, and the option for Member States to designate closed distribution systems.

The Directive further regulates system access, specifically third-party access, access to storage, access to upstream pipeline networks, refusal of access, new infrastructure, market opening and reciprocity, and the possible designation of direct lines. It includes provisions on retail markets, safeguard measures and the level playing field.

The Directive requires Member States to establish NRAs, and sets out their objectives, duties and organisational structures.

\textbf{ii Gas Access Regulation}

The Gas Access Regulation establishes the European Network of Transmission System Operators for Gas (ENTSOG), the sister organisation of ENTSO-E, which cooperates in the same manner with ACER.

\textsuperscript{15} Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators.

\textsuperscript{16} Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation.
As with the Electricity Access Regulation, the Gas Access Regulation establishes network codes (see Section IV.iii, below). In addition, it establishes the free and non-discriminatory access of third parties to gas transmission networks on the European natural gas markets, thereby enforcing the principle of free competition.

The Regulation in particular provides for the transparency of tariffs and calculation methodologies for access to networks, third-party access services, the principles of capacity-allocation mechanisms and congestion management procedures, transparency requirements, balancing rules and imbalance charges, trading of capacity rights, guidelines on the minimum degree of harmonisation, compliance of regulatory authorities and reporting obligations from Member States to the Commission.

iii Network codes

Network codes for natural gas follow the same principles as those for electricity, and have near-identical key priorities. At the time of writing, five gas network codes have been adopted.

The network code on Capacity Allocation Mechanisms (CAM) was recast in March 2017, updating the previous regulation to include the offer of incremental capacity and removing provisions on tariffs that have been included in a separate network code. CAM regulates the principles of cooperation between TSOs in adjacent EU Member States, and the allocation of firm capacity. Allocation provisions are divided into allocation methodology, standard capacity products and capacity auction systems over different time frames. It furthermore regulates the bundling of cross-border capacity, incremental capacity, interruptible capacity and capacity booking platforms.

Gas Balancing in Transmission Networks sets out detailed provisions for a gas balancing system, trade notifications and allocations, operational balancing procedures, and on nomination and re-nomination procedures. The balancing procedures include provisions on short-term standardised products and the establishment of a trading platform for their procurement, as well as incentives for TSOs to undertake efficient balancing actions.

Congestion Management Procedures (CMP) are fundamentally guidelines addressing third-party access services concerning TSOs, the principles of capacity-allocation mechanisms and congestion management procedures, and their application in the event of contractual congestion, as well as setting out the technical information necessary for network users to gain effective access to the system.

Interoperability and Data Exchange (IO) regulates interconnection agreements, providing that adjacent TSOs mutually agree upon rules for flow control, measurement

17 As established for the gas market by the Gas Access Regulation.
18 The development process for natural gas network codes is identical to that for electricity; however, ENTSOG is tasked with performing the stakeholder consultations and drafting of the network code based on the framework guidelines.
principles for gas quantity and quality, rules for gas quantity allocation, and communication procedures in the case of exceptional events. It further provides for a dispute resolution system, and sets out a common set of units, as well as provisions for gas quality and odorisation.

Tariff Harmonisation\(^\text{23}\) aims to homogenise gas transmission tariffs within the European Union, promoting fair and objective tariffs, providing methodologies on reference prices, reserve prices, clearing price and payable price, provisions on reconciliation of revenue, pricing of bundled capacity and capacity at virtual interconnection points, consultation and publication requirements, and tariff principles for incremental capacity.

Remaining priority areas include network security and reliability rules, network connection rules, third-party access rules, data exchange and settlement rules, emergency operational procedures and transparency. These are currently under consideration by ACER.

**iv  Gas Security of Supply Regulation**

The recast Gas Security of Supply Regulation\(^\text{24}\) entered into force on and most of its provisions apply from 1 November 2017. It aims to prevent a disruption of natural gas supply to the European Union and to ensure a coordinated response if necessary. Its fundamental principle is that security of gas supply is the shared responsibility of natural gas undertakings, Member States and the Commission.

It provides for the establishment of a Gas Coordination Group; the development of a robust infrastructure network across the European Union; the development of a gas supply standard to ensure that vulnerable consumers have gas supply under certain extreme circumstances; the performance of a regular risk assessment by ENTSOG and coordinators of regional cooperation Member State groups; the establishment of preventive action plans and emergency plans, different supply crisis levels, regional and Union emergency responses; the solidarity principle whereby in a severe crisis neighbouring Member States are to help ensure that gas supplies to households and essential social services receive a continued supply of gas; information exchange, handling of confidential information by various market participants and authorities; and cooperation with the Energy Community Contracting Parties.

**V  PETROLEUM**

**i  Oil and Gas Licensing Directive**

The Oil and Gas Licensing Directive\(^\text{25}\) sets out common rules that aim to ensure competitive and non-discriminatory access to third parties to prospect, explore and produce hydrocarbons within the territories of the Member States.

Authorisations must be granted in a transparent and non-discriminatory manner to all interested parties. The evaluation of authorisations is based on criteria relating to the technical and financial capabilities of the applicant and the manner in which it proposes to exploit the area.

---

The boundaries of authorisation areas must be determined in such a way that the entity can act in the most efficient manner from an economic and technical point of view. This is intended to encourage the most efficient means of exploitation, as in some cases several entities can do so more effectively than single entities.

Member States are obliged to submit information pertaining to the authorisation to be published in the Official Journal of the European Union. This information includes the duration of the authorisation, the specific area, and selection criteria. Furthermore, Member States are obliged to submit an annual report on the areas opened, authorisations granted, details of entities holding the authorisations and information regarding the reserves available in their territory.

ii Oil Stockholding Directive
The stocks of crude oil and petroleum products directive26 sets out rules to mitigate an oil supply crisis in the European Union. The Directive sets out obligations for Member States to maintain emergency stocks, including a methodology for calculating stock levels, and the obligation to ensure the availability and accessibility of stocks. Member States must maintain a register of emergency stocks and submit an annual report to the Commission. Member States may set up a Central Stockholding Entity to support it in these obligations.

The Directive imposes regulations on economic operators, and permits Member States to maintain and manage a minimum level of specific oil stocks, providing methodologies to calculate summaries of stocks. Furthermore the Directive sets up a Coordination Group for oil and petroleum products, permits the Commission to review emergency preparedness and stockholding, and requires that Member States have emergency procedures in place in case of a major supply disruption.

VI TEN-E REGULATION
The trans-European energy infrastructure regulation (TEN-E)27 complements the aims of the Third Energy Package, establishing the concept of projects of common interest (PCIs). These are infrastructure projects that would significantly contribute to the development of the internal market and the achievement of the European Commission’s 2020 goals, namely a 20 per cent cut in greenhouse gas emissions (from 1990 levels), achieving 20 per cent of European Union energy from renewables, and a 20 per cent improvement in energy efficiency by 2020.

TEN-E regulates in particular the selection, implementation and monitoring of PCIs, as well as permit granting procedures, public participation, the regulatory treatment of PCIs, financing eligibility criteria and guidance for the awards criteria of financial assistance.

PCIs may benefit in a number of ways, including through accelerated and more efficient permit granting procedures; improved regulatory treatment on the national level; streamlined environmental assessment procedures; increased public participation via consultation; and access to grants from the Connecting Europe Facility.

26 Directive 2009/119/EC imposing an obligation on Member States to maintain minimum stocks of crude oil or petroleum products.
In November 2017, the third PCI list was published. It includes 173 projects, of which 110 are electricity and smart grids projects, 53 are gas projects and six are oil projects. A total of €1.6 billion is available in grants to PCI projects for works and studies, and receiving PCI status furthermore increases the attractiveness to external investors.

An applicant project must meet a series of criteria to be considered a PCI, in that it has to have significant benefits for at least two Member States; contribute to market integration and further competition; enhance security of supply for the European Union; and reduce CO2 emissions.

A list of PCIs is established by the European Commission every two years. TEN-E grants the Commission the ability to nominate PCIs by means of delegated acts, and sets out the conditions of its exercise. TEN-E further sets out obligations on reporting and evaluation of PCIs as well as information and publicity obligations.

VII RENEWABLE ENERGY DIRECTIVE

The Renewable Energy Directive is a key directive for the European Union’s commitment to renewable energy generation and consumption, setting out the specific aim of fulfilling at least 20 per cent of its total energy needs with renewable source energy by 2020, and a mandatory target of a 10 per cent share of energy from renewable sources in the transportation sectors of Member States by 2020.

The Directive requires Member States to set mandatory national overall targets and measures for the use of energy from renewable sources, as well as to adopt national renewable energy action plans. In order to achieve these targets, the Directive provides for statistical transfers, joint projects between Member States or third countries, and joint support schemes between Member States.

Member States are required to provide information and training on support measures and details on the benefits, cost and energy efficiency of renewable source energy to consumers, builders, architects and equipment suppliers.

One important aspect of the Directive is the establishment of guarantees of origin (GoOs), which is a system to ensure that the origin of electricity produced from renewable energy sources can be guaranteed.

The Directive furthermore regulates the access to and operation of the transmission and distribution grids, as well as sustainability criteria for biofuels and bioliquids and verification of their compliance, and specific provisions related to energy from renewable sources in transport. The Commission is additionally required to monitor and report the origin and impact of biofuels.

Member States are required to regularly report the progress of the promotion and use of renewable source energy, and the Commission is required to establish an online public transparency platform to facilitate and promote cooperation between Member States.

The Commission proposal for a recast Renewable Energy Directive as part of the Clean Energy for All Europeans package includes provisions on a Union-wide minimum target of 27 per cent share of renewable source energy in gross final consumption by 2030, the opening up of support schemes to projects in other Member States (increasing from an obligation of at least 10 per cent of newly-supported capacity in 2021–2025 to 15 per cent from 2026–2030),

28 Directive 2009/28/EC on the promotion of the use of energy from renewable sources.

© 2018 Law Business Research Ltd
a new auctioning system for GoOs and the use of GoOs for non-renewable projects, and the right of consumers generating their own electricity to sell any excess while retaining their rights as consumers.

VIII ENERGY EFFICIENCY DIRECTIVE

The Energy Efficiency Directive\(^\text{29}\) aims to promote energy efficiency across the European Union in order to meet the European Union 2020 goal of 20 per cent target on energy efficiency, thereby removing barriers that limit efficiency in the supply and use of energy.

The Directive requires Member States to set national energy efficiency targets and a strategy to mobilize investment for improving the energy efficiency of buildings, whereby public bodies are to set an exemplary role. It regulates public procurement with regard to energy efficiency, requires Member States to set up energy efficiency obligation schemes and sets out a number of consumer obligations.

Member States are required to encourage the use of energy audits and energy management systems for final consumers; provide final consumers with meters, cost-free access to metering and billing information and information on energy; and implement a consumer empowerment programme.

Member States are additionally required to perform a comprehensive assessment of the potential for the application of high-efficiency cogeneration and efficient district heating and cooling, and to ensure that, in the performance of their duties, NRAs take account of energy efficiency measures. The Directive provides for a system of qualification, accreditation and certification schemes for providers of energy services, energy audits, energy managers and installers of energy-related building elements should the Member State consider itself not to have the required technical competence.

Furthermore, Member States are required to promote energy services markets for SMEs, and are permitted to set up an energy efficiency national fund and other financing and technical support to increase energy efficiency in different sectors.

The Commission proposal for an amendment to the Energy Efficiency Directive is based upon the current Directive, and proposes a binding 30 per cent energy efficiency target for 2030, the extension of consumer rights in particular regarding billing and energy consumption information through smart metering systems.

IX DECARBONISATION

Emissions Trading Directive

The European greenhouse gas emissions allowance trading scheme (Emissions Trading Scheme) was established by the Emissions Trading Directive\(^\text{30}\) with the aim of significantly reducing greenhouse gas emissions through a cap-and-trade scheme.

The Emissions Trading Directive notably regulates greenhouse gas emissions permits and their application procedure; notification obligations for installation operators; the development of a national allocation plan; allocation methods for allowances; the transfer,

\(^{29}\) Directive 2012/27/EU on energy efficiency.

\(^{30}\) Directive 2003/87/EC establishing a scheme for greenhouse gas emission allowance trading within the Community.
surrender and cancellation of allowances throughout the European Union; the validity of allowances; guidelines for monitoring and reporting of emissions; and verification of reports submitted by operators. Allowance allocation decisions are to be made available to the public, and Member States must establish allowance registries, and they are further subject to reporting obligations. The Commission is required to designate a central administrator that is to maintain an independent transaction log, recording the issue, transfer and cancellation of allowances.

The Emissions Trading Directive is supported by additional legislation, such as the Registry Regulation, which sets up the registries system and regulates the creation, deletion and suspension of accounts, verification of emissions and compliance, the performance of transactions, permissible allowances, trading mechanisms, general technical requirements, and links with other greenhouse gas emission trading schemes.

### X  THE CARBON CAPTURE AND STORAGE (CCS) DIRECTIVE

The CCS Directive provides a legal framework for the environmentally safe geological storage of carbon dioxide, regulating the selection of storage sites, conditions on exploration permits and storage permits, and operation obligations. These operating obligations include the composition of carbon dioxide streams and their acceptance procedure; the monitoring of storage facilities; reporting obligations of the storage operator; inspections of the facilities; closure and post-closure obligations; the provision of financial security by operators for storage permits; and a financial mechanism for the competent authority.

This competent authority is to be designated by the Member State to fulfil its duties under the Directive, as well as to facilitate trans-boundary cooperation and maintain a registry of permits and closed storage sites.

The Directive further regulates third-party access to transport network and storage sites, and requires Member States to provide information to the public regarding storage operations as well as regular updates to the Commission on the implementation of the Directive.

---


XI ENERGY MARKETS

Following the global financial crisis of 2008/09, the European Union has adopted a number of legislative instruments to stabilise the financial markets, limit price volatility of commodities and ensure that markets have sufficient capital. It is not the aim of this chapter to discuss financial regulations; however, while not energy-specific, it should be kept in mind that the energy market is affected by European financial markets legislation.34

Along with the Third Energy Package and REMIT,35 this legislation has introduced additional obligations for energy markets including reporting obligations, transparency requirements, the treatment of certain types of energy or emissions allowances as financial instruments or derivatives, organisational requirements for markets, the introduction of new trading venues, the mandatory use of regulated markets for certain products and a clearing obligation for certain trades.

XII FURTHER PROPOSALS UNDER THE CLEAN ENERGY FOR ALL EUROPEANS PACKAGE

In addition to the above-listed legislative proposals, the Clean Energy for All Europeans package proposes the introduction of two new regulations. In effect, the Commission proposal for a Regulation on the Governance of the Energy Union centralises governance and reporting provisions for the entire EU energy sector, including provisions on integrated national energy and climate plans; long-term low emission strategies; Commission assessment of national plans and EU target achievement; national and EU systems on greenhouse gas emissions and removals by sinks; and cooperation and support between Member States and the EU.

The Commission proposal for a Regulation on Risk-Preparedness in the Electricity Sector proposes measures for risk assessments and risk preparedness, as well as the management of any electricity crisis situations in the Union, in particular setting out methodologies to assess electricity security of supply and to identify crisis situations on the level of both Member States and their regions.

XIII FUTURE DEVELOPMENTS

Two main external factors are likely to direct European Union energy policy in the future: the need to diversify and secure energy supply, and the Paris Agreement. The Juncker Commission has made significant commitments to the Energy Union, which promotes the diversification of energy sources and the tightening up of bilateral agreements between Member States and third states.


The European Union has already set mandatory targets to increase the share of renewable source energy in the European energy mix, which are in line with the target of the Paris Agreement. Following the ratification of the Paris Agreement, the Clean Energy for All Europeans package would appear to make an increased commitment from the European Union and its Member States to decarbonise the economy. Individual acts under the Clean Energy for All Europeans package are currently passing through the ordinary legislative procedure, and subject to further negotiation, the acts are expected to be enacted during the second half of 2018; however, the entry into force dates for these acts as well as the transposition deadlines of the directives remain unclear.

On 29 March 2017, the United Kingdom triggered Article 50 of the TEU following the result of the Brexit referendum in June 2016. This started a two-year negotiation window for the EU and UK to agree on the terms of UK withdrawal and potentially the EU–UK cooperation mechanism. On 19 March 2018, the European Union and UK made a significant step in the Brexit negotiations, agreeing upon the ‘Draft Agreement on the withdrawal of the United Kingdom of Great Britain and Northern Ireland from the European Union and the European Atomic Energy Community’ (the Draft Agreement). The Draft Agreement remains subject to negotiation; however, it does provide an understanding of the direction of the desired relationship between the UK and EU. Of note is that the Draft Agreement provides for a transition period after the withdrawal date of 29 March 2019 until 31 December 2020. While this is not yet binding, if passed the UK would remain subject to EU law and would remain part of the internal market; however, the UK would cease to be involved in the EU legislative procedure unless invited by the Member States.

Of possible relevance to the energy sector, the Draft Agreement provides on a high level for the movement of goods placed on the market prior to the end of the transition period, and on ongoing customs procedures. Neither the Draft Resolution nor the current status of negotiations, however, provide any clarity as to the impact of Brexit on the energy sector. It is unclear whether the UK government will continue with its intention of pursuing a ‘hard’ Brexit, whereby membership of the European Economic Area Agreement would be excluded. Notwithstanding the effects of Brexit on the UK energy sector, the regulatory landscape in the EU is likely to remain largely unchanged; however, certain issues may arise as part of the proceedings. These may include the adaptation of the ETS to account for the withdrawal of the EU’s second-largest emitter, as well as issues involving connection to the newly established UK energy sector. The Brexit negotiations will doubtless be complex, and the exact nature of any possible effects on the EU energy sector remains unclear; however, based on the Draft Agreement, it would appear that these effects may be delayed until 31 December 2020.

Chapter 2

OVERVIEW OF CENTRAL AND WEST AFRICA

Pascal Agboyibor, Doux Didier Boua, Gabin Gabas and Johana N’Dia

I OVERVIEW

i Electricity sector

As an overview, the electricity sector in each of the states has the following characteristics:

- the supply of electricity is among the weakest in the world, even compared with other states of the same income bracket;
- the cost of electricity is among the highest in the world as a result of the preponderance of thermal energy dependent on the price of oil;
- there is a precarious financial situation among public operators of electricity, who cannot pass on the increased costs of production to consumers;
- the power infrastructure is in a state of disrepair, which leads to significant energy losses; and
- growing demand colliding with a persistent shortfall in production and poor quality of services is causing chronic power cuts and slowing industrial development.

The current amount of investment only represents a small fraction of the sum needed to fill the gap between supply and demand. The use of private investment appears today to be the only way to significantly improve the performance of the electricity sector. Resources in the region (hydraulic, gas, solar, wind) remain largely underutilised and the question of their recovery is central.

In parallel with production capacity, the development of national transport networks and their interconnection is a key factor for both industrial (mining industry in particular) and remote rural community development.

---

1 Pascal Agboyibor is a partner, Doux Didier Boua is a senior associate and Gabin Gabas is an associate at Orrick, Herrington & Sutcliffe (Europe) LLP. Johana N’Dia is an associate at Orrick RCI.
2 This chapter covers the following countries: Benin, Burkina Faso, Cameroon, the Central African Republic, Chad, the Democratic Republic of the Congo, the Republic of the Congo, Gabon, Guinea, Ivory Coast, Mali, Niger, Senegal and Togo (individually referred to as the ‘state’ or collectively as ‘states’). This overview is not intended to present a detailed description of all applicable regulations relating to electricity and hydrocarbons of each state, but rather to highlight the common principles and main trends in each of the states concerning the rules and functioning of these industries. However, this overview will not present local practices that may deviate from the applicable law, and a deep analysis of the texts and practices in these states will thus be necessary to acquire a thorough understanding of these sectors.
3 For instance, the electrification rate of the Member States of the ECOWAS is 17 per cent, compared with a global average of 80 per cent.
African regional organisations have created a forum in which states agree to coordinate their national energy policies. Among the instruments of this coordination, the most relevant in the context of this study are:

- **a** the Convention dated 5 July 1996 governing the Economic Union of Central Africa (CAEU), adopted within the framework of the Economic and Monetary Community of Central Africa (CEMAC);[^4]
- **b** the Protocol dated 18 October 1983 on cooperation in energy between the members of the Economic Community of Central African States (ECCAS);[^5]
- **c** the A/P4/1/03 Energy Protocol, adopted by the Economic Community of West African States (ECOWAS) on 21 January 2003; and
- **d** the Additional Act No. 04/2001 dated 19 December 2001 on the adoption of a common energy policy of the West African Economic and Monetary Union (WAEMU).[^7]

The first reforms of the electricity sector, which were conducted to segment activities, introduce free competition and allow the participation of the private sector, appeared 20 years ago, primarily within the framework of these organisations.[^8] However, no French-speaking state seems yet to have fully completed the transition.

---

[^4]: The CEMAC is composed of six Member States: Cameroon, Chad, the Central African Republic, Equatorial Guinea, Gabon and the Republic of the Congo.
[^5]: The ECCAS is composed of 11 Member States: Angola, Burundi, Cameroon, the Central African Republic, Chad, the Republic of the Congo, the Democratic Republic of the Congo, Gabon, Equatorial Guinea and São Tomé and Príncipe. It can be noted that, through its Decision No. 15/CEEAC/CCEG/XIV/09 dated 24 October 2009, the ECCAS adopted the Central African Regional Electricity Market Code. This code, however, does not yet seem to have been implemented by the Member States.
[^6]: The ECOWAS is composed of 15 Member States: Benin, Burkina Faso, Cape Verde, Gambia, Ghana, Guinea, Guinea-Bissau, Ivory Coast, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leone and Togo.
[^7]: The WAEMU is composed of eight Member States: Benin, Burkina Faso, Ivory Coast, Guinea-Bissau, Mali, Niger, Senegal and Togo.
[^8]: The electricity sector is notably governed: in Benin, by the 2004 Agreement revising the Benin-Togo code of electricity and by Law No. 2006-16 dated 27 March 2007 establishing the code of electricity and complementing the Benin-Togo code of electricity; in Burkina Faso, by Law No. 14-2017 dated 20 April 2017 establishing regulation for the energy sector; in Cameroon, by Law No. 2011/022 dated 14 December 2011 governing the electricity sector and Decree of Implementation No. 2012/2806/PM dated 24 September 2012; in Chad, by Law No. 014/PR/99 dated 15 June 1999 concerning the production, transmission and distribution of electric energy and Decree No. 11/281/PR/PM dated 5 April 2011 electing the Société Nationale d’Électricité as public service concession holder for the electricity sector; in the Ivory Coast, by Law No. 2014/132 dated 24 March 2014 establishing the code of electricity, Decree No. 2016-782 dated 12 October 2016 relating to the terms and conditions for the execution of concession agreements for the performance of electricity production, transmission, dispatching, importation, exportation, distribution and marketing activities; Decree No. 2016-783 dated 12 October 2016 providing for the terms and conditions for the sale of electricity produced by an IPP or for the sale of the electricity produced in excess by an auto-producer; Decree No. 2016-786 dated 12 October 2016 providing for the rules governing the determination and revision of power sale and purchase tariffs and the rules governing access to the network; Decree No. 2016-787 dated 12 October 2016 providing for the terms and conditions for the performance of production associated with distribution and marketing of electric energy through mini-network or autonomous individual electric energy production systems; Decree No. 2016-785 dated 12 October 2016 pertaining to the organisation and functioning of the Côte d’Ivoire national energy sector regulator named ANARE-CI; in the Democratic Republic of the Congo, by Law No. 2014/011 dated 17 June 2014 concerning the electricity sector; in Gabon, by Law No. 08/93 setting the legal status of the production, transport and distribution
ii **Oil and gas sector**

The legal systems in each of the states are civil law based and reserve to the state the ownership of all natural resources located within its subsoil, including hydrocarbons.

These systems provide for concession agreements or production sharing contracts to be concluded between the state and hydrocarbons title holders, as well as the principles on which they will interact with the mining titles to which they relate.

The legislation also provides for detailed rules applicable to midstream and downstream sectors, which they regulate and generally subject to prior approval obligations.

Half of the states do not produce hydrocarbons and are dependent on imports from neighbouring countries. Some of these states are in the process of amending or creating legislation to foster the development of the hydrocarbons sector so as to generate revenues from the exploitation of their oil and gas resources.

Interconnected cross-border oil and gas infrastructure is being operated, and projects are being developed or extended between a growing number of states that are likely to attract producers and have a positive impact on states’ revenues and local development, through both production of oil and gas and, ultimately, power generation.

II **REGULATIONS**

i **National and regional regulators**

**Electricity sector**

**National regulatory authorities**

With the recent creation of a regulatory authority in Guinea, we can consider that all the reviewed states have legislation providing for the creation of a regulatory authority in the electricity sector. Some of these national authorities may have only been set up very recently, or may even not be effective yet.

---

9 In Guinea, Law No L/93/039/CTRN dated 13 September 1993 established a National Council for Power (Conseil National de l’Energie Electrique (CNEE)), a consultative body whose mission is to assist the minister in charge of energy on topics relating to energy policy. Law No. L/2017/050/AN dated 29 April 2017 established the Guinean Regulatory Authority for Water and Electricity (Autorité de Régulation des secteurs de l’Electricité et de l’Eau (AREE)) in charge of the regulation of both sectors.

10 It is common for the water sector to be under the supervision of the same authority.

11 For example, the regulation authority for the subsector of electricity in Benin has only been effective since July 2013.

12 As is the case in Chad.
Among the recurring missions of the various national regulation authorities, one may highlight the following:

- *a* monitoring that operators comply with the applicable regulations;
- *b* intervening in the setting or approval of electricity tariffs;
- *c* ensuring compliance with competition rules in relation to power production, transport and distribution;
- *d* preserving customers’ interests;
- *e* promoting competition and private sector participation according to objective, transparent and non-discriminatory (e.g., third-party access to transmission networks and customers’ access to the power supply) conditions;
- *f* taking part in the awarding of contracts via the setting up of tendering processes;
- *g* proposing amendments to the state relating to both the institutional and regulatory frameworks; and
- *h* implementing dispute resolution mechanisms (such as conciliation or arbitration) between the electricity sector’s participants (between operators or between operators and customers).

**Regional regulatory authorities**

Within the framework of the West African Power Pool (WAPP), in January 2008 the ECOWAS Conference of Heads of State established the ECOWAS Regional Electricity Regulatory Authority (RERA).\(^{13}\) This special body is in charge of setting up cross-border power exchange regulations as well as supporting the Member States’ national electricity regulators.

**Oil and gas sector**

**National regulatory authorities**

Contrary to the electricity sector and with some notable exceptions,\(^{14}\) the hydrocarbons sector is not characterised by the existence of specific regulators that are independent from the sector’s supervisory authority (in most cases, the ministry in charge of energy or hydrocarbons).

This obviously does not mean that this sector is not regulated.\(^ {15}\) The hydrocarbons sector is eminently strategic and constitutes one of the domains where the state fully exercises its sovereignty and the implementation and control of these regulations are often left to the central (ministry level) and local (prefecture level) authorities.

---

13 The RERA was created by Additional Act No. A/SA.2/01/08 and is governed by Regulation of the Council of Ministers No. C/REG.27/12/07 dated 15 December 2007 relating to the composition, organisation and functioning of the RERA.

14 For example, the Authority for the Downstream Petroleum Sector Regulation (Chad), the Regulation Agency of the Petroleum Downstream Sector (Republic of the Congo), the National Office of Petroleum Products (Mali), and the National Committee for Hydrocarbons (Senegal).

Regional regulatory authorities

With the exception of cross-border projects that are likely to exist mainly for the purpose of transporting hydrocarbons, there is currently no regional authority regulating the hydrocarbons sector in the states concerned.

Regulated activities

Electricity sector

Electricity production, transmission and distribution is typically considered a public service and placed under the state's authority. The electricity sector is, overall, open to the private sector, yet the above activities are regulated. Also, these activities are subject to obligations of regularity, continuity, permanence and equality of treatment, which are inherent in public service.

The public service of electricity can be delegated to private entities. Delegation occurs through a contract, the most usual form of which is, in the electricity sector, a concession contract (long-term lease contracts are also envisaged by some legislation). The public service concession holder is responsible for all operation and maintenance costs and, when acting as a concessionaire, also for the financing of the infrastructure. It is remunerated essentially through fees paid by users. Long-term lease contracts, under which the state bears the responsibility for the investment, are generally reserved for the country’s national company.

© 2018 Law Business Research Ltd
Generally, the public service concession holder must comply with the following obligations:

- guarantee a permanent and continuous supply of electricity under the best pricing conditions;
- comply with the principles of equality of treatment and electricity market access; and
- ensure a satisfactory coverage of power supply across the country.

The public service of electricity delegation is typically governed by a convention, including specifications, the purpose of which is to determine, in particular:

- the purpose, extent and duration of the relationship;
- the investment plan;
- the conditions relating to the maintenance of the infrastructure;
- the quality of the service;
- accounting and financial aspects;
- tariffs;
- the conditions of remuneration of the operator;
- the applicable tax regime; and
- termination events.

Legislation also allows private operators to access the sole power production sector. Independent power production by private operators is, therefore, possible in most of the states.

To carry out its activity, an independent producer must generally sign a concession contract with the state, as well as a power purchase agreement with the transmission or distribution network operator, as relevant. Legislation may also provide for the granting of licences or sometimes even mere authorisations, in particular when production facilities have a capacity below a certain threshold. The situation in Chad is, in fact, very specific, as the legislation provides that producing and selling electricity outside the framework of the public service is possible without formalities, other than a mere declaration.

**Oil and gas sector**

Of strategic importance to the economy and development policies, the oil and gas industries are particularly regulated. All the legislation indeed provides that the state is (and remains) the owner of the resources located in its subsoil (including liquid and gaseous hydrocarbons), together with the right for the state to grant (and renew and withdraw as the case may be) all titles necessary for prospecting, exploring and exploiting these resources and monitor, on the one hand, the rational exploitation of these resources and, on the other hand, the conditions for their marketing. This combines further with strict monitoring of the upstream and downstream subsectors. This also resulted in the setting up of a number of national players (controlled by the states or otherwise) intervening in the entire sector or certain subsectors of the industry.

---

20 This is the case in Benin, Burkina Faso (below a certain threshold), Cameroon (for independent production other than hydroelectricity), the Central African Republic, Mali (below a certain threshold), the Republic of the Congo, Senegal (for producing or selling electricity in general) and Togo.

21 For instance, in Benin, with the Société Nationale de Commercialisation des Produits Pétroliers (SONACOP), which is wholly owned by the state and acts in the procurement, storage, transport and
Overview of Central and West Africa

**Distinction based on the nature of the substance concerned**

Traditionally, liquid and gaseous hydrocarbons were treated like any other mineral substances and generally subject to the provisions of mining law.

Legislation has evolved, in particular based on international practice, the development of production sharing systems (replacing concessionary systems), and specific tax regimes applicable to hydrocarbons exploration and exploitation.

**Distinction based on the subsector concerned**

Regulations (upstream and downstream) relating to hydrocarbons in most of the states are generally provided for in a unique legislative instrument enacting the country’s ‘petroleum’ or ‘hydrocarbons’ code. If so, midstream and downstream activities, the principles of which are provided for in said code, are regulated by implementing regulatory instruments (such as presidential decrees or ministerial orders). Some states enacted special legislative instruments dedicated to midstream or downstream activities, which notably regulate the refining, transport, storage, transformation, distribution and marketing of hydrocarbons.

**Hydrocarbons rights and titles**

Hydrocarbons titles are either exploration or exploitation titles.

---

marketing of refined products sectors; in Cameroon, with the Société Nationale de Raffinage (SONARA), which is 82 per cent controlled by the state and acts in the domestic retailing and importation of petroleum products, and the Société Camerounaise des Dépôts Pétroliers (SCDP), which is 51 per cent owned by the state and acts in the storage of oil products sector; in Central African Republic, with the Société Pétrolière Centrafricaine (PETROCA) and the Société Centrafricaine de Stockage de Produits Pétroliers (SOCASP), which is 51 per cent owned by the state; in Chad, with the Société des Hydrocarbures du Tchad, which is wholly owned by the state; in Ivory Coast, with the Société Nationale des Opérations Pétrolières de Côte d’Ivoire (PETROCI), and the Société Ivoirienne de Raffinerie (SIR), which is 45.74 per cent owned by PETROCI and 1.54 per cent by the state and acts in the refining and importation of crude oil as well as the importation of refined products; and the Société de Gestion des Stocks de Sécurité (GESTOCI); in the Democratic Republic of the Congo, with the Congolaise des Hydrocarbures, which is wholly owned by the state; in Gabon, with the Gabon Oil Company (GOC), which is wholly owned by the state; and the Société Gabonaise de Raffinage (SOGARA), which is 25 per cent owned by the state, which acts in the refining sector; and the Société d’Entreposage de Produits Pétroliers (SGEPP), which is 25 per cent owned by the state, and acts in the storage sector; in Guinea, with the Société Guinéenne de Pétroles, which is 7 per cent owned by the state; in Niger, with the Société Nigérienne des Produits Pétroliers (SONIDEP), which is a state-owned company; in the Republic of the Congo, with notably the Société Nationale des Pétroles du Congo (SNPC), which is wholly owned by the state; and the Congolaise de Raffinage (CORAF), which is wholly owned by SNPC; and in Senegal, with the Société des Pétroles du Sénégal (PETROSEN), which is wholly owned by the state; and the Société Africaine de Raffinage, which is 46 per cent owned by PETROSEN; and with the Sénégalaise de Stockage (SENSTOCK), which is 66 per cent owned by PETROSEN.

In general, the word ‘petroleum’ may be misleading, as this legislation also governs natural gas exploration and exploitation. Therefore, and unless otherwise provided, the words ‘petroleum’ and ‘hydrocarbons’ used in this chapter shall refer to both liquid and gaseous hydrocarbons.


The term of exploitation titles ranges from 20 to 35 years depending on the applicable legislation. States also regulate prospecting activities, which are generally non-ground-disturbing and do not grant the
These titles are granted by the state\textsuperscript{25} through administrative acts (generally ministerial orders or presidential decrees) to companies that demonstrate the technical and financial capacities required to carry out the necessary petroleum operations.\textsuperscript{26}

In almost all the states, exploration permits and exploitation permits or concessions\textsuperscript{27} are granted within the context of concession agreements, while exclusive exploration and exploitation authorisations are granted within the context of production sharing contracts.

Remarkably, in almost all legislation the development of production sharing contracts has not resulted in the disappearance of exploration or exploitation administrative titles, and companies still have to apply for these to be authorised to carry out such activities.

Legislation provides that companies are prohibited to carry out exploration or exploitation works before being granted such titles. Equally, certain legislation may require that hydrocarbons titles (including exploration titles) be held by local companies. Other legislation will allow foreign companies to enter into petroleum contracts and hold hydrocarbons titles subject to creating a permanent establishment locally.

An exploration title holder is not allowed, \textit{per se}, to extract hydrocarbons. It will only be able to do so once granted an exploitation title. However, legislation often provides the possibility for the holder of an exploration title to apply for a temporary authorisation to exploit, which is limited in time and does not extend the term of validity of the exploration permit. This temporary authorisation aims to allow the holder of an exploration title to start the exploitation of wells it has discovered in exchange for pursuing the assessment and demarcation of these deposits.\textsuperscript{28}

Most of the states have legislation providing for common provisions to be stipulated in, or common principles to apply to, petroleum contracts (mainly concession agreements and production sharing contracts), and in particular that they:

\begin{itemize}
\item[a] cover the perimeter of the hydrocarbons titles to which they refer (exploration title and, as the case may be, exploitation title);
\item[b] are concluded for the term of the exploration title (and, as the case may be, exploitation title to which they apply);
\item[c] set the minimum work obligations of the holder during the various phases of the project, as well as the conditions in which exploration and exploitation will be carried out;
\item[d] provide for the stipulations relating to the transfer of rights and obligations deriving from the hydrocarbons titles;
\item[e] set the tax and customs regime applicable to the holder;
\end{itemize}

\begin{itemize}
\item[25] Authorities competent for granting these titles may vary from one country to another. Exploration titles are generally granted by the minister in charge of hydrocarbons, and exploitation titles are granted by the president.
\item[26] Remarkably, certain legislation (e.g., that of Niger and the Republic of the Congo) provides that exploration and exploitation titles can only be granted to companies specialising in the hydrocarbons sector. Other legislation sets forth additional capacity-related conditions with respect to companies acting as operators.
\item[27] Both exploration concessions and permits are exploitation titles, which derive from exploration permits. Exploitation concessions are not to be confused with the concession agreements that may attach to them.
\item[28] Temporary authorisations to exploit are, for example, provided in the legislation of Benin, Cameroon, the Central African Republic and Ivory Coast.
\end{itemize}
set the obligation for the holder in respect of local content;\textsuperscript{29} 
provide for the participation of the state or state-owned entities in all or part of the petroleum operations and, as the case may be, to the capital of the holder;\textsuperscript{30} and 
may stipulate dispute resolution, and, in particular, arbitration provisions.

Depending on the applicable legislation, these contracts are generally signed by the minister in charge of hydrocarbons before being approved by the President of the Republic by decree or ratified by an Act of Parliament.

Legislation also envisages – without necessarily regulating it in detail – the conclusion of joint operating agreements when referring to the possibility for the title holder to ‘partner’ with other companies (including all national companies) with a view to carrying out oil operations.\textsuperscript{31}

The states’ legislation further provides that petroleum operations must be carried out diligently and in accordance with high quality standards applicable in the international oil and gas industry.

A number of states’ legislation provides for hydrocarbons titles to be granted under certain conditions via tendering processes.\textsuperscript{32}

Lastly, almost all of the state’s hydrocarbons legislation provides that petroleum contracts may provide for the stabilisation of the contractual conditions entered into with the title holder.\textsuperscript{33}

iii Ownership, participation and restrictions

Ownership

Electricity sector

Facilities dedicated to the public service of electricity are generally part of the public domain, even when they are built by a private entity. Some states’ legislation provides, however, that facilities built by independent producers shall be governed by the private property regime.\textsuperscript{34}

Oil and gas sector

As most of the states have elected civil law systems, their legislation reserves to the state the ownership of the natural resources located in its subsoil, including its territorial sea and exclusive economic zone.\textsuperscript{35} As mentioned, this results in any entity (including the owner of the land containing the subsoil in which the deposit is located) wishing to carry out exploration or exploitation works being obliged to obtain all necessary approvals and titles.

\begin{itemize}
  \item \textsuperscript{29} Such as engaging by preference with local contractors or hiring local employees.
  \item \textsuperscript{30} Legislation generally allows states to participate in hydrocarbons projects (via the acquisition of interests in the title or acquisition of shares in the company holding the title).
  \item \textsuperscript{31} For instance, in Cameroon: Articles 7 and 8 of the petroleum code; in the Central African Republic: Article 7 of the petroleum code.
  \item \textsuperscript{32} This is the case in particular in Benin, Cameroon, the Central African Republic, Chad, Guinea and the Republic of the Congo.
  \item \textsuperscript{33} This is, for instance, the case in Cameroon in relation to economic and fiscal stabilisation; in Mali in relation to legal, economic and financial stabilisation; in Niger in relation to legal, economic and fiscal stabilisation; and in the Central African Republic in relation to ‘contractual conditions’.
  \item \textsuperscript{34} This is the case in the Republic of the Congo, Mali and Senegal.
  \item \textsuperscript{35} Some states also refer to the continental shelf (Ivory Coast, for instance).
\end{itemize}
The states’ legislation also provides for specific rules applicable to the access or occupation of land required for carrying out the project, as well as the related rights and obligations of the holder within or outside the perimeter of its title.

Technically, the transfer of ownership of the hydrocarbons extracted shall be made in accordance with the provisions of the petroleum contract (which generally provides that it occurs when passing the well head) and will result in either a transfer of ownership of the entire hydrocarbons production to the holder of the hydrocarbons title in a concessionary system, or the transfer of defined percentages of the production to the benefit of both the holder and the state in a production sharing system.

**Participation**

**Oil and gas sector**

States’ legislation generally provides that the state can directly, or through a national company, participate in all or part of the petroleum operations. Percentages of participation are either determined by the law or the agreement entered into between the state and the investor (concession agreements or production sharing contracts).

**Change of control and transfers**

**Electricity sector**

Regulations applicable to the electricity sector rarely address the possibility for a concessionaire, licensee or authorisation holder to assign its rights to a third party. The issues relating to indirect transfers occurring at the concessionaire’s shareholders’ level are taken into account even less frequently.\(^{36}\) This, however, does not mean that transfers of rights are completely free. Indeed, given the public service nature of the activities relating to the electricity sector, agreements between the state and private operators are concluded \textit{intuitu personae}, and the question of direct or indirect transfers is very likely to be addressed in said agreements.

**Oil and gas sector**

**Assignment of the hydrocarbons title**

States’ legislation provides rules relating to the transfer of hydrocarbons titles that vary depending on whether they relate to an exploration title or an exploitation title. The states provide for compulsory rules governing the transfer to third parties of hydrocarbons title held by the holder. Generally, such a transfer will have to be approved by the competent authority prior to the transfer. Legislation commonly provides that unapproved transfers are sanctioned (1) by the nullity of the act providing for such transfers; or (2) the possible withdrawal of the hydrocarbons title itself.

The transferee shall agree, without reservations or restrictions, to comply with the convention relating to the assigned title.

**Change of control of the holder of the hydrocarbons titles or transfer of petroleum interests**

Besides the assignment of hydrocarbons titles themselves, legislation generally provides for the possibility to transfer all or part of the rights and obligations deriving from the hydrocarbons

---

\(^{36}\) Cameroon is one of the only states that addresses this issue and it merely requires a declaration to the Regulation Agency in the event of changes in the concessionaire’s shareholding structure.
titles or oil agreements. Most of the time, these transfers are conditional on prior authorisation. In addition and similarly to what is provided for with regard to assignments of hydrocarbons titles, legislation generally provides that unapproved transfers of such rights and obligations may be sanctioned (1) by the nullity of the act providing for such transfers; and (2) the possible withdrawal of the hydrocarbons title, or the termination of the oil agreement from which these illegally transferred rights and obligations derive.

Lastly, states increasingly regulate the change of control of the hydrocarbons title holders and subject it to the prior approval of the competent authority.

**Market access restrictions**

**Electricity sector**

**Production**

Overall, access to the power production market is possible through a competitive tendering process. It is, however, common that, by way of exception, legislation relating to the electricity sector or public procurement authorises the implementation of a negotiated procedure. This exception is typically opened when urgency or general interest demand fast completion of a specific project. However, social conditions in Africa may easily constitute grounds of urgency and be likely to impede the full implementation of competition rules. This is particularly true in the field of power production, where concession agreements may often be granted without a prior tendering process.

**Transmission**

Transmission is generally reserved by law for a single concessionaire, whether or not wholly state-owned. When this segment is opened to the private sector, it is fairly common that the national or incumbent company’s monopoly will remain. It can be further noted that the opening of this segment to the private sector is sometimes partially allowed in areas that are not covered by the national or incumbent company.

**Distribution**

Access to the power distribution market varies from one state to another. However, even when legislation opens up this segment to the private sector (whether in whole or for areas that are

---

37 For example, the case with the Compagnie Électrique du Bénin (CEB) in Benin and Togo, the Société Nationale d’Électricité du Burkina (SONABEL) in Burkina Faso, the Société Nationale d’Électricité (SNE) in Chad, the Société d’Énergie et d’Eau du Gabon (SEEG) in Gabon or the Société Nationale d’Électricité (SENELEC) in Senegal.

38 This is, for instance, the case with the Compagnie Ivoirienne d’Électricité (CIE) in Ivory Coast, the Société Nationale d’Électricité (SNEL) in the Democratic Republic of the Congo, Électricité de Guinée (EDG) in Guinea, the Société Nigérienne d’Électricité (NIGELEC) in Niger or the Société Nationale d’Électricité (SNE) in the Republic of the Congo.

This used to be the case in Cameroon as well, with ENEO Cameroon (formerly AES SONEL), but electricity transport and transmission contracts in Cameroon are now granted to the national electricity transport company SONATREL and no longer to ENEO (see Decree No. 2015/454 of 8 October 2015 establishing the National Electricity Transport Company (SONATREL)).

39 This is, for instance, the case in Gabon, Benin and Togo, insofar as the perimeter concerned is not covered by the concession of the SEEG or the CEB.
not covered by the national or incumbent company), structural weaknesses of the market or exclusivity clauses in concession agreements do not always allow full implementation of such liberalisation. It is, therefore, common for *de facto* monopolies to survive the reforms.40

**Oil and gas sector**

Hydrocarbons law, like mining law, is a law of appropriation. States’ sovereignty over their resources prevents, by its nature, the implementation of any principle to allow third-party access to the resource. However, most of the applicable legislation imposes that non-discriminatory third-party access be granted to certain midstream or downstream oil and gas facilities and infrastructure (in particular in relation to transport, storage and distribution, etc.). Lastly, certain legislation provides that the company holding an exploitation title is required to give priority to satisfying the needs of domestic consumption.

### III TRANSPORT AND DISTRIBUTION

#### i Vertical integration

**Electricity sector**

To a large extent, states adopted regulations allowing either full or partial segmentation of production, transmission and distribution activities. Guinea remains a notable exception because it maintained full vertical integration of the electricity sector, which is fully operated by the company Electricité de Guinée.

The specific cases of Togo and Benin can also be mentioned, as they signed a treaty on 27 July 1968 for the purpose of creating a public international body, the Communauté Electrique du Bénin, which enjoys exclusivity for transmission41 and importation activities, as well as the purchase of electricity for both states.

#### ii Transmission, transport and distribution access

**Electricity sector**

Third-party access to the transmission grid is guaranteed in law in almost every state. As such, the grid operator cannot refuse power producers the right to transmit their electricity through the grid.

Under these circumstances, the power grid operator cannot discriminate between operators42 on matters such as access to transmission capacities, quality of service, tariffs and, in general, treatment of the operators. It is also very common that regulations provide that the price of a connection shall be based on costs borne by the grid operator and a reasonable profit margin.

Restrictions may, however, be allowed when justified by technical reasons or capacity limitations, and tariff discrepancies may only be implemented if objective differences exist between power producers.

---

40 This is, for example, the case with ENEO Cameroon in Cameroon, CIE in Ivory Coast, SNEL in the Democratic Republic of the Congo, EDG in Guinea or SNE in the Republic of the Congo.

41 Local and temporary delegation of the transmission activity is allowed, however.

42 Note that Cameroon does not have such an obligation provided in its regulation.
Oil and gas sector

Local activities for the transport and distribution of petroleum products are generally liberalised in the sense that private companies (the holder of the hydrocarbons title or a third party) can exercise them. These companies are, however, subject to obtaining approvals, which are generally granted for a limited period and likely to be renewed. However, exploitation titles typically confer on the title holder the right to transport its share of hydrocarbons. Lastly, and subject to excess capacity being available, third parties may be granted the right to access transport infrastructure on a non-discriminatory basis.

iii Terminalling, refining and processing

Oil and gas sector

Hydrocarbons terminalling, refining and processing operations are generally liberalised and can be exercised by private companies (the holder of the hydrocarbons titles or a third party), which shall also obtain approvals generally granted for a limited period and likely to be renewed.

iv Tariffs and rates

Electricity sector

In general, the tariffs set within the framework of a public electricity service are regulated. National laws provide for joint action of both the regulatory authority and the government to set a tariff that allows an acceptable financial balance for the public service delegation. However, to maintain a satisfactory level of access to electricity for the population, tariffs are greatly undervalued, to the point that electricity distributors fail to achieve a profit margin. For that matter, it is common for states to heavily subsidise the operators that suffer from these tariff policies.

On the other hand, independent power producers are generally allowed to freely negotiate their tariffs with the transmission or distribution operators within the framework of power purchase agreements. In such cases, the contract may be required to comply with specific instructions from the regulatory authority.

Oil and gas sector

In general, prices of hydrocarbons produced in each of the states are determined in accordance with complex regulation organising the setting of a reference pricing structure for petroleum and natural gas based on international market prices. A specific price structure can also apply in relation to the price of hydrocarbons designated for local market supply.

IV INTERCONNECTIONS AND REGIONAL POOLS

i Electricity sector

Within the states, electricity markets are underdeveloped. In Central and West Africa several bilateral or regional initiatives aim at developing a regional energy market supported by interconnections between states, and at implementing power pools.
Central Africa
Within the framework of the CEMAC, the Regional Economic Program (REP) implements various actions aimed at interconnecting electric grids between Member States and developing hydroelectric potential up to the total capacity of 25,000MW by the year 2025. This should enable the creation of an energy self-sufficient region with the additional opportunity to sell any excess production to Nigeria and other West African countries via a connection to the West African Power Pool (for more information about the WAPP, see below).

In parallel to the CEMAC initiative above, the Economic Community of Central African States (ECCAS) created a specialised body called the Central Africa Power Pool (CAPP). This body is in charge of implementing the community’s energy policy, following up studies and construction works relating to the community’s infrastructure, and organising the electricity exchange between Member States through the construction of a dozen regional projects.

West Africa
Within the framework of the ECOWAS and its REP, the Conference of Heads of State decided to implement the West African Power Pool. The objective is to reduce the region’s power production deficit by constructing interconnection infrastructure and developing electricity exchange between Member States. This system led to the implementation of a regional regulatory authority in 2008 (see above).43

Concerning the power grid, Mali is currently connected to Senegal, Ivory Coast is connected to Burkina Faso and Ghana, and the latter is also connected to Togo and Benin. Other interconnection projects exist within the region, such as between Ivory Coast, Liberia, Sierra Leone and Guinea; between Ghana, Burkina Faso and Mali; and between Guinea and Mali.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy
Although some states did adopt legislation promoting renewable energy sources,44 they generally do not have current practical implications as far as the energy sector is concerned.

VI THE YEAR IN REVIEW, CONCLUSIONS AND OUTLOOK

i Electricity sector

Current projects
The number of power plant projects has continued to rise in both Central Africa, among the CEMAC, and West Africa, among the WAEMU, including interstate organisations such as the Organisation for the Development of the Senegal River, the Organisation for the Development of the Gambia River, the WAPP and the Electrical Community of Benin.

43 See footnote 13.
44 As, for example, in Senegal, with Law No. 2010-21 dated 20 December 2010 relating to renewable energy and Law No. 2010-22 dated 15 December 2010 relating to the biofuel sector.
In 2017 and early 2018, ongoing and newly announced projects include:

a thermal plants in Benin (120MW in Maria Greta), Cameroon (345MW in Limbé), Ivory Coast (350MW in Ciprel V, 277MW in Azito, 46MW in Ayébo, 700MW in San Pedro Port and 372MW in Songon) and Niger (100MW in Gorou Banda);

b several hydroelectric dams in Benin (147MW in Adjarala), Cameroon (420MW in Nachtigal, 270MW in Song Dong, 1800MW in Dibang, and 72MW in Lagdo), the Democratic Republic of the Congo (240MW in Busanga, 105MW in Mbimbi Mayi ya Pembe), Gabon (73MW in Ngoulmendjim, 15MW in Dibwangui), Guinea (550MW in Souapiti), Ivory Coast (112MW in Gribi Popoli, 44MW in Singrobo, 150MW Tayabou in Duekoué and 150 MW Gao in Biankouma), Mali (140MW in Gouina), Niger (125MW in Kandadji) and Senegal (120MW in Sambangalou) and

c several hybrid solar-thermal power plants in Cameroon (186KW in Djoum), Burkina Faso (15MW in Essakane).

Although their impact is on a smaller scale, states’ appetite for solar power projects keeps growing every year. Many solar power projects were announced, including: in Burkina Faso (15MW in Dédougou, 10MW in Banfora, 20MW and 10MW in Ouagadougou, 10MW in Fada N’Gourma, 10MW in Orodara, 10MW in Ouahigouya and 15MW in Dori) and Senegal (20MW in Khaone, 20MW in Sakal and 30MW in Ten Marina).

**Rural electrification**

Populations’ access to power is a major concern shared by every state. Almost every state has implemented a national agency for rural electrification that is in charge of conducting the necessary technical and economic studies, preparing the tendering processes for delegating the management of the rural electric grid, promoting new technologies and seeking finance. Also, in the context of decentralisation, the management of power infrastructure in rural areas may be transferred to local authorities.

These agencies are typically supported by a rural electrification fund whose purpose is to help finance the connecting rural infrastructures. Such funds are financed by state allocations, lenders, gifts and bequests, loans, royalties, licence fees paid by operating companies and taxes paid by end users.

Regional initiatives for the electrification of rural areas also exist. For example, the CEMAC Energy Facility, which is part-financed by the EU-ACP Energy Facility, includes a ‘peri-urban electrification project’ component, which aims to reinforce the regional integration of energy policies in the context of the fight against poverty by improving access to electricity in peri-urban and rural areas within CEMAC countries.

**Regional electricity market**

The directive No. C/DIR/1/06/13 dated 21 June 2013 relating to the organisation of the regional electricity market provides a general framework for the regulation of the regional electricity market under the ECOWAS Energy Protocol.

---

45 The Energy Facility is a co-financing instrument that was established in 2005 to support projects aimed at increasing access to sustainable and affordable energy services for the poor living in rural and peri-urban areas in African, Caribbean and Pacific (ACP) countries.
The implementation of the West African electricity market aims to integrate the ECOWAS national power systems into a single market, for the purpose of stimulating electricity exchanges between the Member States.

ii Oil and gas sector

New legislation

Burkina Faso

On 20 April 2017, Burkina Faso adopted a new law establishing regulation of the electricity sector (Law No. 14-2017). It repeals all prior provisions contrary to those of this new Law, notably Law No. 053/2012/AN dated 17 December 2012 establishing the general regulation of the subsector of electricity. Pursuant to Section 2 of Law No. 14-2017, it does not apply to fossil fuels.

Law No. 14-2017 provides for the liberalisation of the energy sector. It therefore puts an end to the former monopoly of SONABEL and allows private companies to invest in electricity supply and sale. Section 8 of the Law creates an independent administrative authority named the Regulatory Authority for the Energy Sector (ARSE).

In addition, this new regulation aims at promoting energy efficiency and the diversification of the energy sources. It contains fiscal and custom incentives for renewable energies.

This new regulation allows independent power producers to operate in the whole national territory as well.

Several decrees of application of Law No. 14-2017 have been enacted, such as:

a Decree No. 2017-1016 on the powers, organisation and operation of the Regulatory Authority for the Energy Sector;

b Decree No. 2017-1014 establishing energy efficiency standards and requirements for devices and equipment as well as their implementation measures;

c Decree No. 2017-1013 establishing requirements specifications for electricity producers in Burkina Faso; and

d Decree No. 2017-1012 establishing terms and conditions for granting electricity generation licences and authorisations.

Gabon

A new petroleum code shall be adopted in Gabon. It shall be presented in June 2018.

Niger

In Niger, a bill establishing a new petroleum code was adopted by Parliament on 31 July 2017. At the time of writing, it appears that this new petroleum code still needs to be approved by the Constitutional Court so that it can be promulgated by the President of the Republic of Niger.
Republic of Congo

The Republic of Congo enacted a modern hydrocarbons code on 12 October 2016 (Law No. 28-2016), which was published in special edition No. 8 of the Official Journal dated 13 October 2016.\(^{46}\)

This code abrogates all previous legislation to the contrary, and notably Law No. 24-94 dated 23 August 1994.

The implementing decrees referred to in the code have not yet been enacted, which could give rise to certain interpretation issues.

Remarkably, the code prevails over any existing laws and regulations from which it derogates. While establishment conventions and production-sharing contracts entered into prior to the entry into force of the code remain subject to the former legislation, Article 212 of the code provides that amendments to these conventions and contracts entered into after the entry into force of the code must comply with its provisions.

In addition, pursuant to Article 213 of the code, its mandatory provisions, as well as any further amendments of general application to labour, health, safety, environment and local content, are applicable to all hydrocarbons-related activities as from the entry into force of the code.

Articles 212 and 213 of the code may, therefore, call into question the existence of implementation of stabilisation provisions.

Among the number of new provisions in the code, we note that:

\(a\) Whereas the former legislation gave production-sharing contracts a pivotal role (while suggesting that other types of contracts could have been used), the code expressly provides that petroleum contracts are comprised of both production sharing and service contracts.

\(b\) The code defines the contractor and regulates in detail its rights and obligations, as well as those attached to operatorship. It remarkably and consequently defines participating interests and provides for the legal regime thereof.

\(c\) The code also provides that the national oil company shall be part of the contractor in a production-sharing regime, but not in a service contract regime.

\(d\) Importantly, the code no longer allows for private companies to hold hydrocarbons titles and expressly provides that these must be exclusively granted to the national oil company, Société Nationale des Pétroles du Congo. As a result, hydrocarbons titles are no longer transferable in any way.

\(e\) The code further provides for the regime of public participation to be held by the state or the national oil company, which can comprise either participating interests or shares in the company holding the hydrocarbons title.

\(f\) Contrary to what is suggested in the code’s definitions section, the code, strictly speaking, does not regulate the change of control of the holder of a participating interest but more importantly provides that (1) transfers of participating interests by a member of the contractor must be prior approved by the Minister of Hydrocarbons; and (2) the Minister of Hydrocarbons must be informed of any transfers of shares in the share capital of a member of the contractor. Any instrument entered into in violation of such obligations will be unenforceable to the state and null and void. It may further result in the withdrawal of the hydrocarbons title itself.

---

\(^{46}\) The code is available on the website of the Secretary General to the Government at the following address: www.sgg.cg/imageProvider.asp?private_resource=2588&fn=jo_es2016_08.pdf.
Lastly, petroleum contracts are approved (no longer ratified) by Parliament, but the code expressly mentions that such approval does not allow the parties to derogate from the code or its implementing instruments.

Projects based on local and regional initiatives

On a local basis

It is notable that many of the countries under review are welcoming foreign investors interested in establishing oil terminals, oil storage facilities or oil transportation infrastructure (e.g., Benin, Cameroon, Guinea or Ivory Coast – the latter aiming at becoming the ‘Rotterdam of Africa’ – and where foreign investors could invest around US$900 million) as well as a number of infrastructure projects in the gas sector (LNG regasification plant in Ivory Coast).

On a regional basis

The Democratic Republic of Congo and Tanzania signed a memorandum of understanding to jointly explore and develop hydrocarbons from Lake Tanganyika.

Lastly, Senegal and Mauritania are to jointly develop natural gas deposits discovered by Kosmos Energy within the framework of an intergovernmental cooperation agreement.
Chapter 3

GAS PRICE DISPUTES UNDER LONG-TERM GAS SALES AND PURCHASE AGREEMENTS

John A Trenor

I  INTRODUCTION

Global production and consumption of natural gas has more than doubled since the early 1970s. A significant portion of this increased demand for natural gas is supplied pursuant to long-term gas sales and purchase agreements (GSPAs). Under these long-term contracts, gas is imported from gas exporting states into many countries in Europe, Asia, South America, and elsewhere, either transported via pipeline or shipped as liquefied natural gas (LNG).

Over the past decade, there have been a growing number of disputes between the parties to such agreements regarding the price to be paid for gas supplied thereunder. This increase in price disputes shows little sign of abatement.

In this chapter, we explain some of the key elements often seen in long-term GSPAs (including price review mechanisms), some of the recent market developments that may have contributed to the substantial increase in gas price disputes, and some of the issues of contention between parties that may arise in these disputes. Finally, we comment on the possible future of gas price dispute resolution.

II  LONG-TERM GAS SALES AND PURCHASE AGREEMENTS

Despite recent growth in hub trading of natural gas and shorter-term supply contracts in some markets, long-term GSPAs remain the principal mechanism for securing gas where demand exceeds domestic supply in many countries.

For more than 50 years, these long-term GSPAs have played a substantial role in enabling the transport of gas from its place of production to the major points of consumption. The long-term nature of these contracts provides significant benefits to both sellers (or exporters) and buyers (or importers). The long-term guaranteed revenue streams that such contracts provide to sellers help to facilitate the enormous costs of exploration, production, and development (as well as the construction of pipelines and other essential infrastructure such as liquefaction and regasification facilities, to the extent the seller bears such costs). The guaranteed supply of natural gas that such contracts provide to buyers helps to facilitate...
the onward sale of gas to end users and resellers in the buyers’ domestic markets and other
(frequently adjacent) markets to meet energy needs for heating, electricity generation,
industrial use and other consumption (as well as the buyers’ own consumption).

Long-term GSPAs have evolved substantially over the decades and today are often
lengthy contracts. The specific terms can vary widely from contract to contract. 4 Each
contract is negotiated in light of the parties’ particular needs, their relative bargaining power,
and the circumstances surrounding their contractual relationship and the relevant market.

Any given provision in a particular GSPA cannot be interpreted in the abstract. It must
instead be construed against the background of the parties’ whole agreement and the parties’
particular bargain struck therein regarding how the risks inherent in the production and sale
of gas are balanced between them. Although details vary, there are a number of provisions
that often appear in these contracts in some form or another.

i  Supply commitments and ‘take-or-pay’ obligations
The basic purpose of a long-term GSPA is to secure a commitment by the seller to supply
specified volumes of gas and a corresponding commitment by the buyer to take those volumes.
Parties can adopt a variety of approaches regarding the details of those basic commitments.

The contracts generally specify an annual contract quantity – the maximum amount
of gas that the seller will have to supply to the buyer, upon request, each year under the
contract, subject to detailed quality specifications. It is this obligation, sometimes coupled
with penalties for failure to deliver requested volumes up to the annual contract quantity, that
creates security of supply for the buyer.

In addition, parties may also specify a minimum annual quantity – the volume that
the buyer commits to take delivery of (or pay for if it does not take). This quantity is often
expressed as a percentage of the annual contract quantity and varies from contract to contract,
usually in the range of 80 to 95 per cent and often in excess of 90 per cent. The requirement
to take the minimum annual quantity, or otherwise pay for it, is called the ‘take-or-pay’
obligation.

Contracts often have ‘make-up rights’ for the buyer if it does not take its annual
take-or-pay volumes (for example, allowing the buyer in future years to take the volumes that
it previously failed to take, subject to specified conditions).

The volume of gas specified in the contract can vary greatly. Volumes may be as great as
30 billion cubic metres/year and as small as 1 billion cubic metres/year or even less. 5

ii  Flexibility rights
Sometimes parties agree to provide the buyer with a degree of flexibility regarding when it
may elect to take gas and how much it elects to take at any given time. Flexibility can offer
a buyer considerable advantages, including enabling the buyer to align its supply with the
demands of its own customers (whether end users or resellers) or with its own use.

4 Although there is no commonly adopted standard-form long-term GSPA, several organisations such as the
Association of International Petroleum Negotiators offer a number of model contracts, including model gas
supply agreements with price review clauses, that are influential in the oil and gas industry.
5 See Anne Neumann, Sophia Rüester, and Christian von Hirschhausen, ‘Long-Term Contracts in the
Natural Gas Industry – Literature Survey and Data on 426 Contracts (1965–2014)’, DIW Berlin Data
The flexibility terms – if any – can vary considerably by contract and whether the gas is supplied by pipeline or by LNG tankers, also known as LNG carriers. Where gas is supplied via pipeline, parties can agree to provide for yearly, seasonal, quarterly, monthly, daily or even hourly flexibility (or any combination thereof). Parties may also agree to provide buyers with the limited ability to reduce their take-or-pay volumes in a particular year (i.e., to reduce the minimum annual quantity). Other contracts offer the buyer no flexibility, requiring the buyer to take delivery of the same volume of gas each hour of every day of every year and providing no option to vary the minimum annual quantity. With respect to long-term LNG contracts, parties typically agree on a scheduled volume per shipment but may negotiate upward or downward flexibility, subject to logistical constraints such as cargo capacity, storage and capacity at the reliquefaction facility. The parties can also agree to other flexibility regarding scheduling or destination, again depending on logistical constraints.

Parties also sometimes agree to provide varying levels of discretion to the seller as well or in the alternative. In particular, in some contracts, parties may provide the seller with a certain amount of ‘optionality’ (e.g., the ability to choose not to deliver requested volumes in certain circumstances, or to deliver at the times that it chooses, without any contractual penalty).

iii Contractual term

The term (i.e., the duration) of a long-term GSPA can vary widely. Many contracts provide for a term falling somewhere in the range of 10 to 30 years, with contractual terms of 20 or 25 years perhaps the most prevalent. Some contracts that have been agreed more recently have somewhat shorter terms, with 10 to 15 years becoming more common, and even shorter terms becoming prevalent for LNG sales. Some contracts may contain an express provision for incremental limited extension of the term for a number of years (either by agreement, or at the election of one party).

iv Pricing provisions

The price that the buyer must pay for gas under a GSPA is heavily tied to the terms of the contract more generally and is part of the overall bargain reached between the parties.

Given their duration, long-term GSPAs often do not set a fixed price but instead use a pricing formula pursuant to which the price may vary over time. One type of price formula commonly agreed sets forth a negotiated base price (\(P_0\)), which is indexed to the prices for a basket of competing alternative fuels (often including oil products such as gasoil or heavy fuel oil, although some contracts have been priced by reference to wholesale electricity prices, coal and other indices). Under these formulae, the contract price varies as the prices of these alternative fuels vary.

---

Over the past decade, following the emergence of gas trading at physical or virtual hubs in certain markets (like the NBP in the United Kingdom and the TTF in the Netherlands), the parties to some contracts have agreed to include (to varying degrees) hub pricing in the price formulae (e.g., by indexing the contract price (or a portion of it) to a specified price on a specified hub).

Other possible variations include the adoption of a ‘price corridor’ or ‘price bands’ or ‘s-curve pricing’, which act in various ways to address potential variation between the oil-indexed contract price and a designated hub price or other benchmark.

Changes in price formulae can often be negotiated in connection with other amendments to the contracts, such as revisions in the flexibility terms or volume, or in connection with other contracts.

v Price review clauses

Given the long-term duration of these GSPAs, most have price review clauses – also variously called price revision clauses, price reopener clauses, price adjustment clauses, etc. – to permit the parties to periodically revise the contract price formulae. These clauses balance the certainty of long-term guaranteed supply with the recognition that circumstances may change over the duration of these contracts and therefore that the price formulae may need to be revised to restore the parties’ agreed bargain.

The terms of these price review clauses can vary. Some early clauses provided little more than an obligation to periodically reconsider the applicable price in good faith. Most price review clauses, however, now provide a more detailed mechanism setting forth a right to some revision of the contract price formula in defined circumstances, either by agreement of the parties or through mandatory dispute resolution procedures such as arbitration, if the parties are unable to agree.

Price review clauses may include a number of elements, including provisions stipulating how frequently a request for a price review can be made, what must occur to ‘trigger’ a price review, what standards or requirements any revision to the price must meet, what procedures must be followed to obtain a price review, and what process follows in the event the parties are unable to reach agreement (normally, the dispute can be referred to arbitration).

Because GSPAs and disputes relating to them are almost always confidential, there is little publicly available information regarding the exact language that parties have adopted in their price review clauses. One exception is the text of the clause used in the 1995 contract for the sale of LNG between Atlantic LNG Company of Trinidad and Tobago and Gas Natural Aprovisionamientos, SDG, SA, made public in 2008 in conjunction with an action in a US federal court seeking to confirm an arbitral award (and a related motion to vacate). Again, although clauses vary widely, this clause contains elements sometimes seen in gas review clauses in other GSPAs. Although somewhat long, the full text of the price review clause in the Atlantic LNG case is set forth below, both to understand how a complete clause functions and to contrast the language there with other formulations discussed in the remainder of this chapter:

9 A physical hub is a distribution point located on a natural gas pipeline system – and a virtual hub is a virtual trading point – at which gas is bought and sold in spot and forward trades for standardised gas products without flexibility.
(a) If at any time either Party considers that economic circumstances in Spain beyond the control of the Parties, while exercising due diligence, have substantially changed as compared to what it reasonably expected when entering into this Contract or, after the first Contract Price revision under this Article 8.5, at the time of the latest Contract Price revision under this Article 8.5, and the Contract Price resulting from application of the formula set forth in Article 8.1 does not reflect the value of Natural Gas in the Buyer's end user market, then such Party may, by notifying the other Party in writing and giving with such notice information supporting its belief, request that the Parties should forthwith enter into negotiations to determine whether or not such changed circumstances exist and justify a revision of the Contract Price provisions and, if so, to seek agreement on a fair and equitable revision of the above-mentioned Contract Price provisions in accordance with the remaining provisions of this Article 8.5.

(b) In reviewing the Contract Price in accordance with a request pursuant to sub-Article 8.5(a) above the Parties shall take into account levels and trends in price of supplies of LNG and Natural Gas (redacted) such supplies being sold under commercial contracts currently in force on arm's length terms, and having due regard to all characteristics of such supplies (including, but not limited to quality, quantity, interruptability, flexibility of deliveries and term of supply).

(c) The Contract Price as revised in accordance with this Article, shall in any event, allow the Buyer to market the LNG supplied hereunder in competition with all competing sources or forms of energy . . . in the market of the Buyer at the point of consumption, taking into account, inter alia, all appropriate operations, services and risks which are usual in the Natural Gas industry from the points of import for handling and marketing the Natural Gas in all market segments when due regard is given to all characteristics of the LNG supplied under this agreement . . . and on the basis that sound marketing practices and efficient operations on the part of the Buyer are assumed and such Contract Price Shall allow the Buyer to achieve a reasonable rate of return on the LNG delivered hereunder.

(d) Neither Party shall request a Contract Price revision to be effective as of the date which is earlier than twelve (12) Months following the Date of First Commercial Supply and no Party shall request any further revision to be effective as of a date which is earlier than three (3) Calendar Years after the date as of which such Party has last requested a revision to be effective.

(e) Unless the Parties agree otherwise, no price revision shall be effective:

(i) earlier than provided for in (d) above;

(ii) retroactively before the date of notification of the request of such revision; or

(iii) earlier than six (6) months before the date on which agreement is reached or arbitration proceedings are initiated on such revision, whichever is the latest.

(f) If agreement is not reached within six (6) months from the date of notifying the request for Contract Price revision, either Party may submit the matter to arbitration for decision in accordance with the criteria set out in sub-Articles (b) and (c) above.

(g) While, and notwithstanding, the Parties have not reached agreement and no arbitration award is effective, this Contract shall remain in full force and effect and the rights and obligations of the Parties, including, without limitation, the obligations of the Seller to sell and deliver and the obligations of the Buyer to take and/or pay for LNG at the Contract Price shall remain in effect.

(h) Each Party shall provide all necessary information to substantiate its own claim. No Party shall be required to disclose any business secrets or breach any confidentiality undertaking nor to provide such information as the other Party may need to substantiate its claim.10

---

10 Gas Natural Aprovisionamientos, SDG, S.A. v. Atlantic LNG Company of Trinidad and Tobago (2008 WL 4344525, at *1 (S.D.N.Y.)), and also Exhibits A and B to the declaration of George von Mehren in support of motion to confirm arbitration (petition), filed with the S.D.N.Y. in the same case (available on
The elements of price review clauses and the various issues that can often arise in gas pricing disputes are discussed in more detail in Section IV, below.

vi Dispute resolution

As noted above, long-term GSPAs often specify that disputes are to be referred to arbitration (although in a few instances they may specify alternative dispute resolution mechanisms, such as expert determination). In some contracts, parties may agree on a dedicated dispute resolution mechanism specifically for disputes under the price revision clause. Otherwise, the general dispute resolution clause applicable to the GSPA as a whole will typically apply in the case of a price revision dispute. Arbitration clauses in these contracts frequently specify institutional arbitration such as ICC (although other institutions are also agreed), but *ad hoc* arbitration, whether adopting the UNCITRAL Rules or purely *ad hoc*, is also not uncommon.

III THE RECENT INCREASE IN GAS PRICING DISPUTES

As noted above, the price for gas being bought and sold under these long-term GSPAs has often been set via a price formula in which an agreed base price (P0) is indexed to the published market prices for a basket of competing alternative fuels (often including oil-based fuels). This approach to pricing is said to reflect the relationship between natural gas and oil products, including the fact that natural gas prices in end-user markets have traditionally been priced by reference to the price of competing oil-based fuels.

Over time, many countries have made efforts to liberalise their natural gas markets, although the results of these efforts vary by country. For example, the European Union has taken a variety of steps to liberalise gas markets in the Member States and across the EU, commencing with the First EU Gas Directive in 1998 and continuing through the Third EU Gas Directive in 2009. These liberalisation efforts coupled with other factors facilitated the emergence and increased liquidity of gas trading hubs, noted above, on which buyers can purchase certain volumes of gas at a market price. This ‘gas-to-gas’ competition has led a number of buyers to argue for the introduction of hub pricing in the contract price formulae of their long-term GSPAs.

In addition, in some markets in the late 2000s, a divergence (or ‘decoupling’) occurred between hub prices for natural gas and the price of oil (and hence between hub prices and the prices payable under some oil-indexed contracts). A number of factors have been said to have contributed to this, including additional volumes of LNG entering the international LNG market as a consequence of increased North American shale gas production and other increased imports. At the same time, the global financial crisis in 2008 contributed to a reduction in demand for gas in a number of markets. These shifts in supply and demand for natural gas had an impact on the price of gas available for purchase at hubs.

Buyers reacted in a number of ways. Some sought to minimise their offtake under their existing contracts to the extent permissible under their take-or-pay obligations. And some commenced price reviews, seeking a variety of revisions to reduce the contract

Westlaw). Other published language of price dispute clauses is seen in ICC Final Award No. 9812 (extract), dated August 1999, ICC International Court of Arbitration Bulletin Vol. 20 No. 2 (2009), and ICC Case No. 13504 (2007), 20(2) ICC Bull. 93 (2009), at p. 94.

Gas Price Disputes under Long-Term Gas Sales and Purchase Agreements

Price. The revisions sought have reportedly ranged from basic price discounts to revisions that would modify the contract price formulae to achieve a contract price that includes hub-based elements or, in some instances, is entirely hub-based. Sellers also responded in a variety of ways, with some proposing reductions in flexibility terms or introduction of seller's optionality.

In light of these and other events, including the upheaval in Asian gas markets stemming from the increased demand for LNG in the wake of the Fukushima nuclear power plant disaster, the past decade has seen a proliferation in price review requests. Moreover, many parties have been unable to resolve these price review requests during the contractually specified pre-arbitration stage, and the number of price review disputes that have moved to arbitration for resolution has increased significantly.

IV THE ANATOMY OF A GAS PRICING DISPUTE

Although the provisions of any given price review clause must be construed on their own terms and against the background of the other provisions of the contract in question, there are certain features common to many price review disputes.

i Process and procedure

As noted above, many price review clauses will spell out the procedure to be followed to initiate a price review. Many clauses stipulate that contractual price revisions can occur only periodically; for example, every three years from a party's prior request, as provided in the clause in the Atlantic LNG contract quoted above. Under many such clauses, parties may also be entitled to bring exceptional 'joker' or 'wild card' price revision requests earlier than otherwise provided for under the contract. The clause typically specifies a limited number of such joker price revision requests that can be made; for example, two over the lifetime of the contract or one during a specified period and a second during a later period.

Price review clauses may also require that the party seeking a price revision first send a notice for a request for a revision to its contractual counterparty pursuant to stipulated notice provisions. The parties may then be required to seek in good faith to resolve the revision request between themselves for a prescribed period (for example, six months). If no agreement is reached within that period, the price review clause will often provide that the dispute can be submitted by either party to arbitration (or, less commonly, expert determination) pursuant to the terms of the contract's dispute resolution clause.

Once an arbitration has been commenced, the parties may seek agreement on the timetable for the arbitration, subject to any contractual limitations they may previously have agreed. Of course, such limitations can often be modified by further agreement of the parties.

ii Triggering a revision

Price review clauses will generally stipulate what must be established to trigger a revision of the contract price provisions. This can vary considerably from contract to contract.

Some price review clauses require that a change in circumstances of a specified nature or level of seriousness has occurred during a specified period, often referred to as the 'reference period' or 'review period'. Some clauses explicitly require that the change affects the balance of the parties' agreement in a certain way. Some clauses specify the market in which such a change in circumstances must occur or contain other language specifying the nature of the necessary change. Not uncommonly, price review clauses will expressly require that the
change in circumstances be beyond the control of the parties, or not foreseeable or reasonably expected, or both, at the time of the most recent contract price revision. Where such clauses do not expressly provide for such requirements, disputes may arise as to whether the clauses implicitly include such requirements or they are otherwise applicable as a matter of industry practice.

Many of these elements are present in the Atlantic LNG clause quoted above. Under that clause, a revision is triggered where ‘either Party considers that economic circumstances in Spain beyond the control of the Parties, while exercising due diligence, have substantially changed as compared to what it reasonably expected . . . at the time of the latest Contract Price revision . . . and the Contract Price . . . does not reflect the value of Natural Gas in the Buyer’s end user market’.12

Some clauses identify specific changes (for example, amendments to certain regulations or laws, or changes in taxes) that will be deemed to satisfy the trigger requirements. Less commonly, some clauses specify that a revision will be triggered if the delta between the contract price and a specified comparator exceeds a stated threshold.

In addition, some clauses explicitly spell out mandatory considerations or benchmarks that the parties must take into account in assessing a price revision request. For example, in the clause in the Atlantic LNG case, the parties are expressly required to take into account ‘levels and trends in price of supplies of LNG and Natural Gas . . . being sold under commercial contracts currently in force on arm’s length terms’.13

Whether the trigger requirements have been satisfied is a matter that can lead to disagreement between the parties. Among other things, it is possible for parties to disagree on:

a whether the asserted change in circumstances occurred within the reference period (for example, in some price review clauses, the reference period is the period between the date of the most recent revision and the date that the price review in question was requested, although the parameters of the reference period can themselves be a source for dispute);

b whether the asserted change meets the degree of gravity explicitly or implicitly required (for example, some clauses may stipulate that the changes must be ‘significant’, ‘substantial’, or ‘serious’ but provide no explicit guidance as to when the specified threshold will be satisfied; other clauses may not expressly stipulate the degree of gravity required, leading some parties to argue for standards implicit in the contract, imposed as a matter of industry practice, or indicated through the parties’ prior practice);

c whether the asserted change is of the nature contemplated by the price review clause (for example, some clauses expressly require that the changes must be changes in economic circumstances; even where there is no express stipulation as to the nature of the changes required, parties may raise arguments regarding what types of changes can qualify to trigger a price revision, including arguments regarding the extent to which the change must impact the parties’ bargain);

d whether the asserted change was ‘reasonably expected’ or ‘foreseeable’, etc. at the time the contract was entered into or at the time of the most recent price revision (this may be disputed where one party argues that the changes in circumstances were a continuation of a pre-existing trend);

---

12 See Section II.v, above.
13 See Section II.v, above.
whether the asserted change in circumstances was within the control of one or both of the parties (such an argument may potentially arise where a party arguably is in a position to bring about or to act to prevent the change);

what weight should be given to any mandatory considerations or benchmarks that the parties must take into account, and how those mandatory considerations or benchmarks are to be assessed in practice;

what market (e.g., the gas markets in which country or countries) and what market level (e.g., the import level, wholesale level or end-user level) should be considered when assessing the asserted change in circumstances;

whether the asserted change in circumstances is in fact already reflected in the existing price; and

whether the asserted change in circumstances ‘justifies’ a revision of the contract price.

If the parties agree that a price revision has been triggered – or an arbitral tribunal determines this to be the case – the question then turns to determining what revision to the contract price, if any, is warranted.

iii Determining the scope and nature of any revision of the contract price

Often price review clauses stipulate a specific standard or requirement regarding what revision, if any, should be made to the existing contract price formula if the trigger has been met. The specified standard varies among contracts. Some clauses simply state that the revision to the contract price formula must be fair or reasonable. For example, the clause at issue in the Atlantic LNG case provides that, if a revision is triggered, the parties are required to reach agreement on – or in the absence of agreement, a tribunal is required to determine – ‘a fair and equitable revision’ of the contract price. Some other clauses provide that the contract price provisions must be revised to reflect the change in circumstances that was established at the trigger phase or to reflect the value of gas in a defined market or market segment. Other standards also exist.

Some price review clauses require that specified benchmarks or other factors be considered in determining what revision should be made. Such benchmarks can include import prices and whether the gas can be economically marketed under specified conditions, assuming prudent and efficient operations and marketing practices on the part of the buyer.

Again, for example, the clause in the Atlantic LNG case provides that the revised contract price shall ‘allow the Buyer to market the LNG supplied hereunder in competition with all competing sources or forms of energy’. Such clauses – often referred to as ‘in any case’ clauses because they begin with those words – vary considerably by contract and require close review.

The adjustment phase can potentially give rise to a number of disputes between the parties, including:

what the stipulated standard actually means (for example, what is required for a proposed revision to be considered fair and equitable, as in the clause in the Atlantic LNG case);

how any specified benchmarks or other mandatory considerations should be taken into account (for example, what market indices or other sources of data relating to import prices should be considered), what weight should be given to these factors and in which market or at which market levels these considerations should be assessed;
what the permissible scope of revision is and what limitations there are regarding the revision (for example, some price review clauses state that only revisions to the contract price provisions are permitted in a price review, whereas some occasionally provide that other provisions of the contract may also be revised; parties may also disagree as to whether the particular contract permits a complete replacement of the existing price formula or only adjustments);

to what extent other provisions of the contract (for example, regarding volume, flexibility, security of supply and term of the contract) must be taken into account in determining what adjustment to the contract price provisions should be made; and

whether, taking into account the determinations made with respect to the issues identified above, the proposed revision actually satisfies the stipulated standard and appropriately restores the balance of the parties’ bargain.

iv Consequences of gas price disputes progressing to arbitration

As noted above, the number of price review disputes that have proceeded to arbitration has increased significantly in recent years. There are a number of consequences for contracting parties that arise when a gas price dispute proceeds to formal dispute resolution, including consequences for the time frame within which the arbitration will be resolved, the nature and scope of the issues to be arbitrated and the nature of the resolution ultimately reached through an arbitral award.

First, the time frame for resolving the dispute is likely to expand significantly. Unless the parties are able to agree up front (or have previously agreed) to some sort of fast-track arbitration (which is not necessarily feasible in practice), an arbitration may take many months, if not years, to finally resolve the dispute. Of course, the parties’ efforts to settle their dispute may continue in parallel during the arbitration and, if successful, may shorten this time.

Second, the arbitral process may lead to a much more detailed and formal airing of the issues between the parties than might occur in negotiations between the parties. There are a number of reasons for this. For example, when parties turn from negotiations to more formal dispute resolution, the number of legal issues that must be addressed often expands. Moreover, parties – with much at stake – typically retain the services of large international law firms with experience in gas price disputes and one (or more) experts experienced in gas pricing and other aspects of the gas industry. These legal and industry experts will be able to identify potentially favourable arguments for their clients that the commercial parties may not themselves have focused on, which can significantly expand the scope of issues in dispute.

In addition, in an arbitration, substantial volumes of material (including submissions, witness statements, and expert reports) may be exchanged between the parties far in excess of the volume of material likely to be exchanged in negotiations, providing further opportunity for the parties to litigate a large number of issues. The document disclosure process that often forms part of an arbitration may also lead to orders requiring disclosure of documents that the parties would not otherwise have exchanged in negotiations, further exacerbating the potential for an expansive set of issues requiring determination by the arbitral tribunal.

Third, an arbitration that proceeds to a final award results in a determination by a third party or parties to the contract – namely, the arbitrator or arbitrators – to revise the contract price or contract pricing mechanism applicable between the parties for a number of years. This determination can have significant commercial consequences, which may not be fully anticipated by the tribunal. Although there is a growing set of arbitrators well-versed in
international gas markets and gas pricing disputes, there is no guarantee that the tribunal in a particular case will be so qualified. In any event, even well-versed arbitrators are not experts in the creation and modification of price formulae, and they will not be fully familiar with the particular nuances of the wider commercial relationship between the parties.

Nevertheless, a growing number of parties have in recent years pursued arbitration through to a final award (although others have settled their disputes commercially after the commencement of the arbitration but before the tribunal has issued an award). This suggests that the many benefits that arbitration can bring to commercial dispute resolution (including procedural fairness, party autonomy in the selection of arbitrators and applicable procedural rules, confidentiality of proceedings, finality and enforceability) are significant in the eyes of the parties to long-term GSPAs. Even where disputes settle before an award is rendered, the additional clarity regarding the strengths and weaknesses of each party’s position that the exchange of extensive pleadings and related documents brings may also help to facilitate negotiated solutions to the parties’ dispute.

V THE FUTURE OF GAS PRICE DISPUTE RESOLUTION

It is not clear what the future holds for gas pricing. However, an end to the recent growth of gas price review disputes and resulting arbitrations does not appear imminent. Indeed, as the number of gas price disputes under existing long-term contracts proceeding to arbitration has increased and parties have become more familiar with the arbitral process and procedure, some parties may now consider arbitration as a well-established step in the price renegotiation process.

In addition, as these gas price disputes and arbitrations under existing long-term contracts continue to occur, it is possible that parties may also reconsider the terms of their gas price review clauses and specifically reconsider how disputes regarding gas pricing are to be finally resolved.

Among the alternatives to traditional arbitration, other gas price dispute resolution mechanisms sometimes discussed include the use of expert determinations, mediation or the use of modified arbitration clauses that substantially constrain the arbitrators’ jurisdiction to narrow questions (for example, limiting the arbitrators’ jurisdiction to determining only how the base price should be modified or, where the price formula provides for weightings of different elements, limiting jurisdiction to determining what such weightings should be, etc.).

Other modified forms of arbitration have also been proposed. For example, some propose the use of high-low (or ‘bounded’) arbitration, in which the parties privately agree to a range within which the final price must fall. In the event that the tribunal’s decision fixes a price falling outside that range, the price will, by virtue of the parties’ prior agreement, be set at the upper or lower boundary of the agreed range. Another possibility is ‘baseball’ arbitration (also sometimes called ‘either/or’ or ‘final-offer’ or ‘pendulum’ arbitration). In the context of a gas price dispute, this mechanism generally provides that, if the trigger has been met, each party proposes a revision and the arbitrators must then choose one of the two proposals without modification (a process intended to discourage each party from making an unreasonable proposal, because doing so would likely lead to the tribunal choosing the other side’s proposal).

None of these alternative mechanisms seems to have found much favour in the industry to date. Although it remains uncertain whether any of these (or other) alternative dispute mechanisms will gain much traction in the future, at present, they seem unlikely to
significantly displace traditional arbitration of gas price review disputes. This suggests that many parties to long-term GSPAs continue to be attracted to the benefits of traditional arbitration over these potential alternatives. And, while traditional arbitration continues to play a central role, it remains for the participants in that process to focus on ways to ensure that it results in the most effective, efficient, and satisfactory means possible to resolve the inevitable price disputes that continue to arise under long-term GSPAs.
By the start of 2017, a majority of the world’s countries signed the Paris Agreement in an effort to address climate change and reduce global greenhouse gas (GHG) emissions. This action suggested alignment of the international community on approaches to addressing climate change. The United States, however, reversed course on the commitments to addressing climate change issues following the 2016 presidential election and initiated the process for withdrawing from the Paris Agreement on 1 June 2017. The impact of the United States’ change in policy on international efforts to address climate change remains uncertain.

Nonetheless, the developments of 2017 and beyond have the potential more directly and significantly to impact energy development and production around the world. On the heels of the Paris Agreement, which entered into force in 2016, advocates for addressing climate change are reinventing their playbook by seeking remedies beyond what the diplomats and world leaders agreed in Paris, and beyond what courts have been willing to endorse. For these groups, commitments and regulations to reduce GHGs, while a step in the right direction, do not go far enough. They also see a need to fill the void left by the United States’ planned withdrawal from the Paris Agreement.

Increasingly, advocates for climate change are pursuing economic damages, compensation and other remedies directly against energy producers, not only for current and future GHG emissions, but also for an historic accounting of emissions spanning decades, and in some cases centuries. This new wave of climate change initiatives takes several forms, which are described below. However, all these efforts share certain commonalities and challenges in their pursuit of what these groups label ‘climate change justice’ and constitute the beginning of a new era of climate change advocacy in which remedies are sought from energy companies directly. Ultimately, these actions face numerous legal challenges and likely insurmountable hurdles before courts and other bodies, but at the same time various groups have indicated that they are not deterred or discouraged from advancing new push-the-envelope arguments in pursuit of such claims, which will be an increasing focus in 2018 and beyond.

I FROM EARLY EFFORTS TO REGULATE GHG EMISSIONS TO THE PARIS AGREEMENT

For more than a generation, proponents of climate change action have advocated for limiting emissions of GHGs in order to prevent the rise of the global average temperature by a certain
amount (usually 2°C or less). Such groups have focused their efforts to reduce GHG emissions primarily on influencing regulators to take action: specifically, pursuing various government agencies at national, provincial and local levels to enact regulations and laws to reduce GHG emissions by either imposing energy efficiency requirements on certain sectors (and thus reducing GHG emissions) or capping GHGs by source or region. The best examples of such programmes are various fuel efficiency standards for motor vehicles in the US and elsewhere, Europe’s EU ETS cap-and-trade system, California’s AB 32 cap-and-trade programme and a cap-and-trade programme in the northeast United States called the Regional Greenhouse Gas Initiative.

These programmes differ widely in form, scope and origin. Several of them arose from either environmental advocate intervention or court decisions, while some arose organically from regulators. What they share in common, however, is a reliance on regulators to determine how to reduce GHG emissions, and then to translate those decisions to regulations and standards imposed on industry.

The Paris Agreement fits the mould. Negotiated in 2015, the Paris Agreement is likely the most significant milestone for international consensus on addressing climate change by reducing GHG emissions. It also signalled the culmination of the efforts of climate change advocates over the past two decades to develop limits and caps on GHG emissions with the goal of stabilising global temperature rise and other climate change impacts. The Paris Agreement entered into force on 4 November 2016, with over 190 signatories. Parties are required to sign ‘intended nationally determined contribution’ (INDC) pledges to reduce or address GHGs through regulatory mechanisms. These pledges will likely be achieved through centralised regulatory programmes. The INDC submitted by the EU, for example, has a 40 per cent reduction target by 2030 (compared with 1990).

The election of Donald Trump in the US, however, will likely have significant repercussions for the implementation of the Paris Agreement. Under President Obama, the US took aggressive regulatory action to address climate change, including programmes to reduce GHG emissions from motor vehicles, power plants and the oil and gas sector. In particular, the ‘Clean Power Plan’, which required significant emissions reductions from fossil fuel-fired power plants, is viewed as a key component of any US plan to implement the Paris Agreement. The INDC submitted by the US calls for a 26–28 per cent reduction by 2025. After taking office, President Trump is taking steps potentially to rescind the Clean Power Plan. Furthermore, the US Environmental Protection Agency has announced its intention to withdraw the GHG emissions standards for motor vehicles put in place by President Obama. The Trump administration has also reversed course on a number of other climate change regulations issued by the Obama administration. Further, President Trump announced his intent to withdraw from the Paris Agreement. Such actions would impose a significant roadblock on the successful implementation of the Paris Agreement’s GHG emission reduction goals.

International agreements and national regulatory reforms have not been the sole means that climate regulation advocates have used to advance their agenda. Private citizens and non-governmental organisations such as activist environmental groups have also been using litigation as a means to press for reductions in GHG emissions, either through direct actions against emitters or, more commonly, through actions against governmental entities to compel regulatory controls. For example, in a decision captioned ‘Urgenda’, which is being cited as precedent for a wave of new judicial actions on climate change, a court in The Hague issued an order requiring the Dutch government to pursue more aggressive GHG reductions.
nationally of at least 25 per cent by 2020 (compared with 1990). Similar litigation is under way in the United States, Switzerland, New Zealand and Belgium. A report co-sponsored by the London School of Economics and Political Science found that in 2017 there were over 250 court cases outside of the US in which climate change was a relevant factor. More are on file in the US. If successful, these lawsuits could result in binding legal obligations for nations to reduce GHG emissions.

During this generation-long effort to pursue global commitments to GHG reductions, courts have developed a line of case law that simultaneously has, on the one hand (as in the Urgenda decision), deferred to requests generally to push regulators to pursue GHG reductions; and, on the other hand, cast significant scepticism on efforts to leapfrog the regulators and seek remedies directly against companies. On the latter point, the courts have established significant limitations on the reach of GHG accountability even when they have shown support for regulatory efforts generally. For example, the US Supreme Court initially ruled in favour of climate change regulations in the landmark 2008 decision Massachusetts v. EPA, but in recent years has limited recovery directly against parties that emit GHGs (in AEP v. Connecticut); has limited the scope of regulations that could reach beyond industrial sources of GHGs (in UARG v. EPA); and has intervened – for the first time in the history of the Court – to stay the implementation of the Clean Power Plan after challengers argued that the broad regulation of the energy sector exceeded the regulator’s authority and would cause irreparable harm to the nation’s energy grid. Beyond the US Supreme Court, other courts – including courts in Germany and Australia – have refused to endorse remedies against private parties as opposed to regulators and have consistently declined requests to serve as ‘special masters’ of the climate and GHG allocations, deferring to regulators to make such determinations. It is with this backdrop of judicial decisions, however, that groups are looking to move beyond the Paris Agreement in the next stage of climate change activism.

II THE EVOLVING FOCUS ON ACCOUNTABILITY FOR CLIMATE CHANGE

In upcoming years, the efforts to reduce GHG emissions globally will intensify. The impact of the US withdrawal from the Paris Agreement is difficult to predict and will take several years to accomplish. With or without the US, however, governments around the world will work to implement their commitments in the Paris Agreement through regulations and laws at home. These efforts will translate to increasingly stringent requirements that will likely require GHG controls and limits on power generation and other sources, with increasing efforts to ‘decarbonise’ economies around the world. However, beyond the national governments focused on commitments to implement the Paris Agreement, local governments and activist groups will continue to pursue even greater reductions than the Paris Agreement commitments through additional programmes and lawsuits that aim to achieve separate and additional goals.

In the post-Paris Agreement stage of climate change issues, these groups – activist environmental groups and some local, state and provincial governments – are seeking to become the drivers for implementing new climate change policies. At the same time, these groups, which to date have focused on seeking government accountability to enact programmes to address GHGs, are increasingly shifting their targets. The emerging efforts
are aimed beyond just reducing GHG emissions and now include seeking remedies against individual emitters of GHG emissions for their alleged historic contributions to climate change. These actions take several different forms but share many attributes.

At the outset, core to all these various efforts is a common goal: the pursuit of injunctive relief or financial compensation from companies based on an accounting of GHG emissions. The source of such an accounting, however, is not limited to current or future emissions. Instead, many of these groups look to a single study, referred to as the Heede study (published in 2014 with an update in 2017), that purports to present a historical carbon accounting for 90 investor and state-owned companies back to the early 19th century. The Heede study, however, departs significantly from every established GHG reporting methodology employed in the world by pursuing an outcome-oriented approach that seeks to lay blame for the majority of the world’s historic anthropogenic emissions upon a small list of energy producers as opposed to the world’s nearly infinite GHG emitters in every sector that are directly responsible for releasing GHGs to the atmosphere. By choosing a methodology that first and foremost seeks to assign the significant majority of the world’s GHG emissions to a limited universe of a relatively small number of parties associated with some percentage of the world’s fossil fuel producers, regardless of who or what consumed such fuels or actually emitted GHGs, the study presents a significant credibility challenge at the outset for those groups who seek to tout it in various policy and judicial fora.

Despite these issues, armed with the Heede study, various groups have indicated they are preparing a new wave of legal challenges and policy campaigns against the identified companies. Groups initiated the first of these efforts in September 2015, when they petitioned the Philippines Commission on Human Rights to investigate companies identified in the Heede report under human rights law for harms from typhoons the groups allege are linked to climate change. The Commission accepted the petition and opened the investigation in December at the close of the Paris negotiations and invited the companies named in the petition to respond. Only a handful of companies submitted responses, many of which questioned the Commission’s jurisdiction over them. Whether the Commission pursues an investigation regarding any companies or offers any recommendations is yet to be seen.

Beyond the Philippines test case, various groups also have indicated that they are preparing actions against companies identified in the Heede report under a wide range of legal theories, including common law nuisance cases, drawing analogies to laws that were used to litigate against tobacco companies in the US, unjust enrichment, other human rights regimes and advertising and consumer protection laws.

In the US, several state attorneys general have begun aggressively investigating fossil fuel producers with respect to their historical knowledge of potential climate change risks and the degree to which those risks were adequately disclosed to the public. Structurally, the approach taken by the state attorneys general is similar to that taken against tobacco companies in the 1990s, which resulted in multibillion dollar settlements. At this stage in the investigations, it is not clear whether the states will find sufficient evidence to pursue climate change-based claims against energy producers in court.

Local governments in the US also have instituted litigation against fossil fuel companies. The cities of San Francisco and Oakland, California, for example, have pursued nuisance claims against the five largest oil companies. The City of Richmond, California also filed suit against 29 fossil fuel companies. Additionally, New York City has filed suit against the five largest investor-owned fossil fuel companies. The cities have sought damages to pay for costs of adapting to climate change.
In addition to state and local governments, private citizens are also trying to address climate change through the courts. In 2015, 21 youths filed a lawsuit against the US government alleging a violation of their constitutional rights given the government’s failure to address climate change and for its subsidies to fossil fuels. The case is *Juliana v. United States* and was filed in the US District Court in Oregon. The US government and industry groups have tried to have the case dismissed, but the case continues and the courts seem willing to hear the case.

Although groups have indicated that they plan to continue to pursue climate-related claims in the upcoming years, the courts are likely to present significant challenges to their pursuit of these remedies. Climate change litigation has been active for more than 15 years around the world. While in many cases courts have expressed deference and sympathy for efforts to spur governments to take action to address climate change, courts at the same time have taken a fundamentally different approach in expressing scepticism regarding efforts to seek remedies directly from companies. In other words, courts generally have rejected efforts to allow parties to leapfrog properly enacted regulations and seek additional remedies directly against the emitters of GHGs for emissions that are not otherwise unlawful or prohibited, whether past, present or future. This scepticism is partly policy – the reluctance of courts to step beyond their bounds and serve as either lawmakers or regulators deciding whether and which companies should be accountable for climate change and to what extent. However, even more fundamentally, this scepticism is the result of centuries-old legal concepts and defences that are likely to bar remedies against individual companies in climate change contexts. Just as climate change presents unprecedented complex policy issues for the world’s leaders to address, it similarly presents challenges to the courts, which must confront bedrock issues such as causation, redressability and legal standing, which, given the nearly infinite number of GHG emission sources in the world, provide obstacles to such claims that are likely to be insurmountable.
Chapter 5

ANGOLA

Catarina Levy Osório and Helena Prata

I OVERVIEW

Angola’s energy sector is characterised by strong public activity, with state companies acting throughout the value chain of the oil, natural gas and electricity industries.

Despite the prominent public presence in the energy industry, the country is progressively widening entry to private players, creating the necessary mechanisms to allow private companies to take part in the industry’s activities alongside and in close cooperation with the relevant state-owned companies.

The electricity industry is the one that requires the most significant investment, undergoing transformation and expansion plans that amount to US$13 billion, between 2009 and 2025, to meet growing demand.

In accordance with the measures set out by the National Energy Security Policy and Strategy, the Angolan government is committed to reforming the energy industry. With this intention, among other measures, in the electricity industry the government is mainly focusing on:

a restructuring state-owned companies;
b developing a strategic and regulatory framework for renewable energies;
c reinforcing powers of the Regulatory Institute of the Electrical and Water Sectors (IRSEA);
d revising the legal framework for the electricity sector;
e defining an attractive model for private investment and development of its legal framework; and
f progressively eliminating electricity price subsidies.

In the oil and natural gas industry, the focus is on:

a ensuring the ‘Angolanisation’ of upstream activities;
b implementing the liberalisation of the market and creating a new legal and regulatory framework;
c enacting a natural gas regulatory framework;
d reinforcing existing refining capacity;
e finishing short-term projects such as pipelines and railways; and
f defining a new tariff model and removing fuel price subsidies.

1 Catarina Levy Osório and Helena Prata are partners at ALC Advogados.
2 Put into force by Presidential Decree No. 256/11 of 29 September.
The Angolan electricity system is divided into two separate segments:

a. the Public Electricity System (PES), which encompasses the Electricity National Transmission Network (NTN) and all generation and distribution infrastructures tied to the NTN; and

b. the Non-Tied Electricity System (NTES), which encompasses non-tied producers, self-producers and non-tied customers (collectively, non-tied agents).

The commercial relations between the aforementioned agents is governed by the General Electricity Law and the Commercial Relationships Regulation.

The producers tied to the PES are public service concessionaires or licence holders who have the obligation to sell electricity to the NTN concessionaire. Under its capacity as a 'single buyer', the NTN concessionaire is required to acquire all power generated by tied producers. To do so, tied producers and the NTN concessionaire must enter into power purchase agreements (PPAs), which set out the terms and conditions of their commercial relations.

Subsequently, the NTN concessionaire (in which the Angolan state must have a majority equity participation or a veto right) must sell the electricity acquired under the PPAs to the high-voltage (HV) distribution network operators, at a single price, including those who operate in isolated systems.

In turn, HV distributors sell electricity to medium-voltage (MV) distributors who then sell electricity to low-voltage (LV) distributors, who in turn sell the electric power to the customers, therefore acting as suppliers.

Without prejudice to the necessities of the PES, the non-tied agents are committed to the role of strengthening the competitive regime on the supply and consumer markets of the Angolan electric system. Hence, non-tied producers and customers are entitled to establish bilateral agreements, freely negotiated between the parties, governing the terms and conditions of the supply of electricity. Nonetheless, the terms and conditions of such agreements must comply with the Regulation for the Licensing and Security of Electric Facilities and the Networks Access Regulation, as well as the rules and procedures put into force by the IRSEA. With the reform of the General Electricity Law, non-tied producers who wish to sell their electricity to the PES are no longer required to enter into generation concession agreements or request the award of a power generation licence.

The commercial relationships established under the regime of the PES are therefore regulated, with contractual terms and sale prices administratively set, as opposed to relations with non-tied agents, whose contractual terms and prices can be freely established by the parties. It should be noted that any tied customer who wishes to migrate to the non-tied electric system is allowed to do so.

---

3 Mainly composed of ultra-high-voltage networks, which operate at a voltage greater than 60kV.
4 Put into force by Law No. 14-A/96 of 31 May and amended by Law No. 27/2015 of 14 December.
5 Put into force by the Presidential Decree No. 2/11 of 5 January.
6 The HV networks operate at a voltage of between 35kV and 60kV, the MV networks between 35kV and 1kV and the LV networks below 1kV.
II REGULATION

i The regulators

The IRSEA was created by Decree No. 59/16 of 16 March, which extinguished the former IRSE, which was replaced by IRSEA. IRSEA is the Angolan regulatory authority for electricity and water, a public institute with management, administrative and financial independence, responsible, *inter alia*, for regulating the activities of generation, transmission, distribution and sale of electricity in the PES.

The IRSEA is also in charge of regulating the business relationship between agents included in the PES and between the PES and non-tied agents, and the specification of tariffs and of revenue transfer models between different players in the electricity industry, as well as the performance of duties related to national arbitration and the composition of interests of different stakeholders of the industry.

The Oil Derivatives Regulating Institute (IRDP), created by Presidential Decree No. 133/13 of 5 September, is the Angolan regulatory authority, with management, administrative and financial independence, responsible for regulating the activities of the oil-derived products sector.

The IRDP is, *inter alia*, responsible for defending the consumers’ rights and interests in matters of price, services and quality of service, fostering competition among industry players, ensuring fairness and transparency of commercial relations, monitoring compliance with public service obligations, performing duties related to national arbitration and proposing public policies to the executive power regarding the oil-derived products industry.

ii Regulated activities

*Exploration for and production of oil and gas*

Exploration and production activities related to oil and natural gas in Angola are governed by Law No. 10/04 of 12 November.

The right to produce and explore for oil or natural gas is granted by concession agreement, generally preceded by a public tender procedure.7

The concession for exploration and production, after the public tender procedure, is granted by concession decree, issued by the Angolan government, awarding the national concessionaire Sonangol8 the right to develop a specific oil concession.

All successful companies that wish to explore for and produce oil or natural gas in Angola have to form an association with Sonangol in one of three possible ways: incorporation of a joint company, a consortium agreement or a production-sharing agreement9. The concession agreement must subsequently be signed by the parties within 30 days of the publication of the concession decree.

7 Decree No. 48/04 of 1 September governs the Rules and Procedures for Public Tenders in the Oil Sector.
8 Sociedade Nacional de Combustíveis de Angola, EP, the exclusive concessionaire for mining rights in Angola.
9 With the restructuring of the oil and gas sector enacted by Presidential Decree No. 109/16, Sonangol’s equity holdings in the oil and gas and other sectors shall be transferred out of the company and supervised by a new government agency (yet to be incorporated).
Companies that wish to undertake preliminary exploration and prospection works may do so by applying to the Ministry responsible for oil exploration and production matters for the grant of a prospection licence. After hearing the national concessionaire, the said Minister decides on the request and grants the licence by executive decree.

**Refining, storage, transportation and markets of oil-derived products**

The construction, exploration, capacity transformation, licence renewal and any activity that affects the safety condition of (1) oil refining facilities, (2) storage structures, (3) transportation via pipelines, (4) oversight of the oil-derived products system, or the (5) functioning of the oil-derived products wholesale and retail markets are subject to licensing procedures set out in accordance with Presidential Decree No. 132/13 of 5 November.

The activities mentioned in (2), (3) and (4) above are classified as activities of strategic interest for the country and are subject to public service concession agreements, which are granted after completion of a tender procedure, except when such concessions are awarded to entities controlled by the state.

Oil refining is authorised by the grant of a licence and is developed under market conditions, except for the case of the Luanda Refinery, which is a refinery that operates under a special regime.

**Construction of electric facilities**

The construction of electric facilities\(^{10}\) is subject to the licensing procedures prescribed in Decree No. 41/04 of 2 July, the Regulation for the Licensing and Security of Electric Facilities.

Under this Regulation, any entity interested in developing new electric facilities is required to obtain an establishment licence (which grants the authorisation for the construction of the facility) and, subsequently, an exploration licence, which grants the necessary authorisation to start operating the facility.

The request for these licences is made to the licensing entity (the entity within the energy sector\(^{11}\) Ministry that is competent to conduct the licensing process), with full details of the project and all other elements necessary to understand the project as a whole.

The licensing entity may impose any modifications it deems essential to ensure the safety of the population and assets as well as complying with the applicable security regulations. In certain situations, the project may be subject to various consultation procedures, namely with affected populations or official departments in charge of activities that are affected by the project in question.

After all the foregoing formalities are successfully concluded, an establishment licence is granted after the payment of the fee, allowing the commencement of construction. Usually, the project developer is obliged to finish the construction works within two years of the establishment licence being granted, although this may be extended depending on the circumstances.

Following the completion of the construction works, the project developer should request an inspection to ensure compliance of the facility with all applicable rules. If it complies, the exploration licence is granted (no later than 15 days after the inspection) and the facility may enter into operation.

---

\(^{10}\) Meaning generation, transmission or distribution facilities.

\(^{11}\) At present, the Ministry of Energy and Water.
In certain cases – mostly construction of small facilities that do not interfere with public domain terrains or assets – there may be an exemption from obtaining the establishment licence, or both the establishment and exploration licences.

**Authorisation to develop generation, transmission or distribution activities**

The authorisation to develop generation (without prejudice to the exemption applicable to non-tied producers), transmission or distribution activities is granted through concession agreements,\(^\text{12}\) entered into with the Angolan government, or through licences granted by the local authority, depending on the circumstances.

**Concession agreements**

The award of concession agreements is made after a public tender procedure and the concession is awarded for a maximum term of 50 years, determined on a case-by-case basis. At the request of the concessionaire, the concession agreement may be renewed, if the renewal is in the public interest. At the end of the term of the concession agreement, all of the related assets of the concession become the property of the state.

**Licences**

Licences regulate the activities of public supply to isolated localities (not included in the concession areas), of self-generation and of private supply. Licences are awarded by the local authorities within their jurisdiction areas, authorising the generation, transmission and distribution under a public service regime. Licences are awarded for each facility and any entity may hold several licences, regardless of its category or nature.

**Generation**

As previously noted, the right to develop generation activities is granted either by concession agreement or the award of a generation licence, depending on the circumstances, without prejudice to the obtainment of the aforementioned establishment and exploration licences for the corresponding facilities.

The producers tied to the PES hold concession agreements or licences for power generation and must comply with public service obligations. Thus, the electric power generated by the tied producers is earmarked to supply the PES. As compensation for this obligation, these producers are entitled to receive a fair price\(^\text{13}\) for the sale of the electric power they generate, established in the PPAs entered into with the NTN concessionaire.

Alternatively, non-tied producers are not required to hold administrative rights to pursue generation activities and are free to dispose of their electric power solely by entering into bilateral agreements, with terms and conditions set by the parties (even if the electricity is sold to the PES).

---

\(^\text{12}\) The concession agreements are signed and approved by the Council of Ministers. Although the law grants the Council of Ministers the power to approve the concession agreements, as a result of the governmental structure established by the Constitution of 2010, the Council of Ministers ceased to develop executive functions, becoming merely an advisory body. As such, given the concentration of executive power in 2010, it is presumed that this competence now rests with the holder of executive power.

\(^\text{13}\) Considering an adequate return on the investment made.
The integration of new generation plants by tied producers into the PES depends upon the generation needs of the country, provided in the Electric System Expansion Director Plan, in accordance with the National Energetic Plan. If the generation plant uses public domain water resources, the project developer must also obtain the correct authorisation for the use of public domain resources.

The granting of the right to explore a generation plant via concession agreement is made through a public tender process.

The contractual position on a concession agreement may be assigned to third parties, but it is subject to the IRSEA’s opinion and dependent upon authorisation by the Ministers’ Council.

Licences for the development of generation activities are granted by local authorities to entities who ensure supply to isolated localities whose power needs are equal to or under 1MW. These licences are valid for a minimum of 15 years.

To obtain a generation licence, a request must be submitted to the local authority, which shall request the opinion of the Energy and Water Ministry. In turn, the Energy and Water Ministry must request the opinion of several official bodies that may be involved or affected by the project. These opinions must be submitted to the local authorities within 90 days. Upon receipt of the opinions, within 60 days, the local authority must award a provisional generation licence, and the project developer then has 180 days in which to obtain the establishment licence from the Energy and Water Ministry.

**Distribution**

As with the generation of electric power, distribution activities are authorised via concession agreements, entered into with the state, or through a licence, granted by local authorities.

In general terms, the authorisation to operate HV and MV distribution networks is granted via concession agreements, and distribution in LV or closed networks is authorised by the granting of a licence.

**Supply**

Pursuant to the reform of the General Electricity Law, supply of electricity is authorised through a licence, in terms to be regulated by the government.

iii **Ownership and market access restrictions**

**Oil and gas**

As previously mentioned, companies who wish to develop exploration and production activities must do so in association with Sonangol in one of three ways: incorporation of a joint company, consortium agreement or production-sharing agreement. Only commercial

---

14 Or 120 days, in the case of a hydropower generation unit.

15 Except for settlements with more than 50,000 inhabitants or networks with a maximum peak power required by the system equal or greater than 4MW, in which case the right is awarded via concession agreement, under the terms of Article 5 of the Electric Power Distribution Regulation (Decree No. 45/01 of 13 July).
companies may become associates of Sonangol, and if the association is made via incorporation of a joint company, or via consortium agreement, Sonangol is legally required to hold an equity participation greater than 50 per cent.¹⁶

Companies that intend to dedicate their activities to oil refining, storage and transportation of oil-derived products, oversight of the oil-derived products system, or that wish to operate in the wholesale or retail markets of oil-derived products must be controlled¹⁷ by Angolan citizens. Furthermore, oil refining, storage and transportation of oil-derived products (activities subject to the award of concession agreements) must be developed by companies with management and headquarters effectively established in Angola; the said activities must be their primary scope of business; and they must demonstrate that they possess the technical and financial capacity to develop these activities.

**Electricity**

Concessions and licences for generation, transmission and distribution activities may only be granted to legal persons, private or public, and the development of new electric facilities is dependent upon the award of the aforementioned establishment and exploration licences.

Companies that develop generation, transmission or distribution activities authorised by licence are allowed to hold several licences, regardless of their category or nature. Consequently, there are no impediments to the development of such activities by vertically integrated companies.

The Angolan state is legally required to hold a majority equity participation in the share capital of the concessionaire of the NTN, or a veto right.

**iv Transfers of control and assignments**

**Oil and gas**

The assignment of a contractual position in the exploration and production concession agreement requires the prior authorisation of the Minister responsible for the exploration and production of oil matters, provided that the transferee is of proven competence, and technical and financial capability, unless the assignment is made between subsidiary companies of the transferor.

If the assignment is authorised, Sonangol has a right of pre-emption. If Sonangol does not exercise this right, Angolan companies that are party to other concession agreements at the time of the transfer are entitled to exercise this pre-emption right.

The concessionaires of oil refining, storage and transportation of oil-derived products activities cannot transfer or encumber the assets pertaining to the concession, as these acts are subject to the prior authorisation of the grantor.

**Electricity**

Subject to prior authorisation by the Council of Ministers, concessionaires for generation, transmission or distribution activities may assign, sell or encumber their contractual positions

---

¹⁶ In duly justified situations, the government may authorise Sonangol to hold a smaller equity participation.

¹⁷ In accordance with Presidential Decree No. 132/13 of 5 September, ‘control’ means owning at least 51 per cent of the company’s share capital, holding more than half the voting rights, being able to appoint more than half the members of the board of directors and having the power to set operational and strategic policies of the company.
to third parties. Licensees may also transfer their licences to third parties, provided that the licensing entity agrees to the transfer and the requirements that determined its award are fulfilled at the time of the transfer.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

As previously noted, the energy industry in Angola is strongly dominated by the presence of state-owned companies.

Oil and gas

In the oil and gas industries Sonangol is party to every exploration and production agreement made with foreign companies, being responsible for the technical management of these agreements to maximise both the state and the company’s interests.

Sonangol Group, through its multiple subsidiaries, operates as a vertically integrated company that has its main activities concentrated in all phases of the oil value chain. Its activities include exploration, production, development, marketing, transportation and refining of hydrocarbons and their derivatives. Those activities can be performed independently or in association with other companies, national or foreign.

The activity of oil-derived products’ storage and transportation is now subject to a functional and accounting unbundling regime.

The activity of overseeing the oil-derived products system is subject to a legal unbundling regime.

The exploration, evaluation and development of natural gas reserves are the responsibility of Sonagas, a subsidiary of Sonangol Group. Sonagas create joint ventures with partners with financial capability, expertise and willingness to contribute to the development of the natural gas industry in Angola.

In 2007, an agreement was made to develop the Angola LNG Project, where Sonagas is a partner. Angola LNG operates one of the world’s most advanced liquefied natural gas (LNG) processing facilities in Soyo, in Zaire province, under a consortium of companies that includes Sonangol (22.8 per cent), and subsidiaries of Chevron (36.4 per cent), Total (13.6 per cent), BP (13.6 per cent) and ENI (13.6 per cent).

At the end of 2017, Angola LNG started to supply the Soyo Combined Cycle Power Plant, which will receive gas via pipeline and generate electricity. The total public investment channelled to the Soyo Combined Cycle Power Plant is estimated to be around US$900 million, and is expected to be a major turning point in meeting the country’s energy demand.

Electricity

In the electricity industry, the main public players are, after the formal unbundling of the public entities of the electricity sector effected by Presidential Decree No. 305/14 of 20 November, Rede Nacional de Transporte de Electricidade, EP (RNT) (which is responsible for managing the NTN, for the global management of the system, offtake and acting as market operator),

18 Currently developed by Sonangol Logística, EP.
19 More information about this project can be found at www.angolalng.com.
Empresa Pública de Produção de Electricidade, EP (PRODEL) (which is responsible for the operation, under a public service regime, of publicly owned power generation facilities) and Empresa Nacional de Distribuição de Electricidade, EP (ENDE), whose sole purpose is the distribution and supply of electricity in the PES.

This reorganisation stemmed from the National Energy Security Policy and Strategy, whereby the government has approved an ambitious reform plan for the electricity sector, which foresees provision of access to electricity for between 50 and 60 per cent of the population by 2025.\footnote{Today, only around 30 per cent of the Angolan population has access to electricity.} As part of the reform, the government envisaged:

\begin{itemize}
\item[a] a state-owned company exclusively dedicated to the management of generation assets, resulting from the merger of ENE and GAMEK, resulting in the incorporation of PRODEL;
\item[b] a state-owned company dedicated to the transmission of electricity in ultra-high and HV networks and to the management of the national electricity system, resulting in the incorporation of RNT; and
\item[c] a state-owned company dedicated to the distribution of electricity, resulting from the merger of the distribution assets of ENE EP, EDEL EP and the municipalities, resulting in the incorporation of ENDE (which was, however, incorporated without the assets of the aforementioned municipal distribution networks).
\end{itemize}

This restructuring model accommodates the creation of a national holding company, owning the aforementioned three companies.

The government estimates that the execution of the restructuring programme for the electricity industry in Angola will require an investment of US$13 billion by 2025. Consequently, the electricity sector will gradually open up to competition, and private investors will be welcomed.

\section*{ii Transmission/transportation and distribution access}

\subsection*{Oil and gas}

Under the Law for the Transport and Storage of Oil and Natural Gas,\footnote{Enacted by Law No. 26/12 of 22 August.} operators of oil and gas pipelines have an exclusive right to develop these infrastructures.

The operators are prohibited from adopting discriminatory behaviour, unless such discrimination is justified by technical conditions.

\subsection*{Electricity}

Concession agreements and licences grant the concessionaires or the licensees the exclusive right to explore and operate the transmission and distribution networks.

Under the Networks Access Regulation, the NTN concessionaire and the tied distribution operators of HV and MV networks are obliged to provide equal access conditions to third parties.

The Networks Access Regulation acknowledges the network access rights of:

\begin{itemize}
\item[a] entities that are tied to the PES and hold concession agreements or licences to generate electric power under the terms of the Electric Power Generation Regulation;
\end{itemize}
entities that are not tied to the PES and hold a concession agreement or a licence to generate electric power;

tied customers under the terms of the Electric Power Supply Regulation;

non-tied customers who are recognised as such under the Commercial Relations Regulation; and

self-producers or producers for private supply who intend to exercise their right of providing electric power through access to PES networks, as well as the entities that are supplied by these.

The commercial relations regarding networks access are governed by written agreements, valid for a period of one year, and its general terms are approved by the IRSEA.

According to the Commercial Relations Regulation, the NTN concessionaire is responsible for operating and maintaining the NTN, managing the national electric system and acting as a commercial agent. Also, the commercial relations between non-tied agents and the PES are centralised in the NTN concessionaire.

For the purpose of avoiding discriminatory behaviours and ensuring transparency, the NTN concessionaire must separate, in terms of organisation and accounting, the three aforementioned activities.

iii Terminalling, processing and treatment

Angola has great potential for natural gas production, with proven reserves of 270,000 million cubic metres (with some estimates indicating resources of over 1.2 billion cubic metres), and intends to develop this industry aiming for the exportation markets.

Investment, however, has been limited (the main investment in the industry is the Angola LNG project), mainly because of great legal and regulatory uncertainty. To address these uncertainties, Presidential Decree No. 256/11 of 29 September sets the development of the legal and regulatory framework for these activities as a primary goal for the strategic orientation of the oil and natural gas industries.

The entry into force of the Law for the Transport and Storage of Oil and Natural Gas in 2012 was a pivotal first step, but the natural gas industry is in great need of regulatory progress to provide certainty and clarity to the development of activities such as terminalling, processing and treatment of natural gas, as well as access conditions by third parties to LNG facilities.

Nevertheless, and despite these shortcomings, 2017 was a remarkable year for the gas sector in Angola. Besides the opening of the Soyo Combined Cycle Power Plant, Angola LNG is collecting, processing and trading an annual average of 5.2 million tonnes of LNG and also entered into a significant supply agreement with a major global distributor.

---

22 The commercial agent is the part of the NTN concessionaire that ensures supply and the optimisation of the PES, managing the PPAs with tied producers and distributors, among other duties.


24 An example is the fact that there is as yet no concession model specific to natural gas exploration and production.
iv Rates

Rates for transmission and distribution of electricity are established in accordance with the Tariffs Regulation, put into force by the IRSEA. Rates are uniform for the entire country, the application of different tariffs being prohibited for customers in the same tariff category. The IRSEA sets the maximum tariffs and hence the maximum prices for the provision of transmission or distribution services.

Tariffs are based upon the provider’s costs plus a reasonable rate of return, resulting in the allowed revenues of the network operators. The rate of return of the transmission and distribution companies is calculated using the weighted average capital cost/capital asset pricing model methodology.

The calculation of the allowed revenues of NTN transmission concessionaires includes:

a. efficient investment costs;
b. efficient operation and maintenance costs;
c. other costs necessary to efficiently develop the transmission activity; and
d. a fair rate of return over the investments.

Investments made on network expansion projects are remunerated in accordance with the aforementioned methodology.

For distribution services, remuneration is set through a distinction between the rate of return of the distributor’s activity, via the HV, MV and LV networks, and the rate of return of the investment costs and the costs for the connection of consumers’ facilities to the grid. The first is called the aggregated value of standard distribution (AVSD), while the second is called the connection fee.

The AVSD is set for a certain number of standard distribution areas, distinguished by several variables such as consumption per unit area, consumption per capita, number of consumers per unit area or the facilities’ age, which justify differences on the efficient costs of the distribution activity.

The AVSD is composed of operational costs, calculated in respect of a reference company for each standard distribution area, and a fair rate of return on efficient investments. Operational costs should consider, inter alia, commercial, distribution, administrative, financial and management activities.

The unitary cost of investment in the distribution network is calculated from the annuity of the capital cost corresponding to the new value of replacement of the existing network. The annuity is calculated considering a useful lifetime of the distribution facilities of 30 years.

The tariffs set for activities authorised by concessions are defined in the corresponding concession agreements, taking into account the rules to be set in a separate regulation (the latter to be approved by the Minister of Energy and Water).

v Security and technology restrictions

The NTN concessionaire, in its capacity as system operator and manager, is responsible for ensuring the continuous and safe operation of the NES. As such, it is responsible for constantly evaluating the security level of the grid and declaring, in extreme situations,
a ‘situation of absolute shortage of power’. The NTN concessionaire is also tasked with the responsibility of elaborating a security plan, establishing the necessary preventive measures to avoid incidents that may disrupt the provision of electric power to customers.

Under Article 6 of the General Electricity Law, concessionaires or licensees of generation, transmission or distribution activities must ensure, at their own expense, that their facilities are protected against sabotage or acts of war.

In a state of emergency, the state assumes the responsibility for the supply of electricity to the PES. In addition, in these situations the state may tie independent producers to the PES, without prejudice to the right of compensation of the affected entities.

Retail suppliers of oil-derived products are obliged to maintain safety reserves in accordance with the law.

IV ENERGY MARKETS

i Contracts for sale of energy

As previously mentioned, only non-tied agents use a market-based approach. Accordingly, the Commercial Relations Regulation allows for the establishment of physical bilateral agreements for the sale and purchase of electric power, with their terms and conditions freely defined by the parties.

These agreements may be for long or short-term periods, with short-term meaning less than one year.

ii Energy market rules and regulation

Only the entity in charge of overseeing the oil-derived products market (Sonangol Logística) is entitled to import oil-derived products to the Angolan market. This entity preferentially buys its oil-derived products from the Luanda Refinery (a refinery operating under a special regime). Throughout 2017, Sonangol Logística supplied the domestic market with oil-derived products, 70 per cent of which came from abroad. The Luanda Refinery supplied 26 per cent while the remaining 4 per cent was supplied by Cabinda-based CABGOC.

In addition, the entity in charge of overseeing the oil-derived products market is committed to the role of last-resort supplier of oil-derived products, thus having the obligation to provide oil-derived products to retail suppliers at the price set administratively by the IRDP.

The retail suppliers of oil-derived products must ensure their supply by entering into bilateral agreements either with the oil refineries’ operators under the market regime, or with the entity in charge of overseeing the oil-derived products market.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

The Angolan government considers renewable energies to be a key element in the development of the country’s electric system, particularly in rural areas. The country has high potential in terms of renewable resources, mainly in terms of hydro and solar power. Solar power will play an important role in providing electricity to rural areas, while large hydropower projects are intended to be connected to the NTN supplying the PES. The country is also undertaking a wind power study to ascertain the potential of this energy source.
The electric power industry in Angola is urgently in need of major financial investment in the area of power generation. As a result, Angola is now seeking to create attractive conditions for private investors to participate in the development of the electric power industry. This goal is now expressly set out in the reformed General Electricity Law, which states that ‘temporary economic advantages’ may be granted to renewable energy promoters.

To ensure attractive remuneration to private investors (without compromising the cost-efficiency for the government and customers) the government is taking into account the utilisation of PPAs as a privileged instrument to capture investment into new large-scale generation units (over 10MW), and as a mechanism that guarantees an adequate return on the investment made and ensures its long-term amortisation.

In addition, Angola is ever more inclined towards establishing public–private partnerships (PPPs) with interested investors, allowing state-owned companies to improve their skills and expertise, and favouring the creation of long-lasting commercial relationships with such investors.

For smaller projects, the use of feed-in tariffs will be the main mechanism of remuneration for generation capacity in isolated systems (under 10MW).

Presidential Decree No. 88/13 of 14 June recently established the Strategic Plan for New Environmental Technologies, which is divided into two perspectives, a transversal and a sectoral perspective. The governmental body in charge of implementing this project is the General Directorate for Environmental Technologies.

The transversal perspective aims essentially to promote, disseminate, foster and raise the population’s awareness regarding the use of environmental technologies in Angola, mainly by:

\( a \) developing information campaigns using social media;
\( b \) implementing information campaigns in schools and local communities;
\( c \) creating a platform to share information between entities related to the environmental technologies industries; and
\( d \) promoting the country’s adherence to an international sustainability index.

The sectoral perspective focuses on promoting and implementing tailored measures and actions according to economic sector, including specific programmes for the following sectors:

\( a \) real estate and construction;
\( b \) agriculture and forestry;
\( c \) industry;
\( d \) energy and water;
\( e \) oil; and
\( f \) transportation.

The government has allocated around 224 million kwanzas to complete the Strategic Plan for New Environmental Technologies.

**ii  Technological developments**

During 2013, the government committed to successfully complete a pilot project for solar power villages – the Aldeia Solar de Cabiri. This project is being financed by Sonangol, which invested around US$30 million, and aims to test a solar village concept that could be implemented throughout the country, especially in rural areas. The project was inaugurated in 2014.
By the end of 2013, the Angolan authorities had foreseen that the construction of the first wind farm in Angola would begin in the near future, after the wind studies were completed. Located in the municipality of Tômbwa, the wind farm will be developed under a PPP regime and will add 100MW to the country’s installed capacity.

The government approved a series of agreements regarding the construction and development of generation, transportation and distribution of electric power, namely a generation project in the city of Malanje\textsuperscript{26} and the construction of transportation grids between Cambambe and Catete, and Cambambe and Gabela\textsuperscript{27}.

ZTE Corporation, a Chinese company, will provide smart meter solutions to EDEL EP (currently ENDE), the distribution network operator in Luanda, including equipment, construction, personnel training, and operations and maintenance.

This project is intended to solve difficulties such as bill arrears, inefficient manual meter reading and electricity theft, and to improve ENDE’s management efficiency, while reducing its operation and maintenance costs.

The Laúca Dam is also expected to be concluded in 2018 after an investment of US$4.5 billion. The project is expected to supply energy to the vast majority of the nation’s industrial sectors, thus significantly reducing the importation of fossil fuels.

VI THE YEAR IN REVIEW

Presidential elections were held in Angola during August 2017, with a new president being elected. The current President João Lourenço succeeded José Eduardo dos Santos, who was in power for the past 38 years. Consequently, major developments are expected to follow the election, as the new President seems to be eager to change the status quo and has already replaced numerous public officials, including the Chairman of the Board of Directors of the National Concessionaire. The following months will thus be crucial to figure out if these political and administrative reforms bring about palpable changes in the energy and petroleum sectors.

The legislative momentum thus followed through in 2017, and in the wake of Presidential Decree No. 109/16 (a legislative approach aimed at the improvement of the efficiency of the petroleum sector) came Presidential Decree 222/17, which approved Sonangol’s new framework statute. Among other reforms, under the new statute the role of non-executive director ceases to exist.

Concerning oil prices, the year of 2017 registered the lowest production rates of the past four years, although the year ended on a very positive note, with a significant increase in production and revenue.

A public tender was also launched in 2017 for the audit of the individual and consolidated accounts of Sonangol and its subsidiaries, another indication that the new government and public officials seem focused on enforcing standard international business practices.

The recently elected President also nominated a work group to submit proposals for improving the performance of the oil and gas industry. The work group was composed of the Finance Minister, the Petroleum Minister, two representatives of the National Concessionaire and, remarkably, one representative of the major IOCs operating in the country: BP.

\textsuperscript{26} Approved by Presidential Order No. 57/13 of 26 June.
\textsuperscript{27} Approved by Presidential Order No. 49/13 of 15 May.
CABGOC, ENI, Esso, Statoil and Total. The work group pointed out issues such as: excessive bureaucracy and consequent inefficiency in the National Concessionaire’s internal procedures, negative institutional relations between Sonangol and the IOCs and the absence of exploration activities. More developments may therefore be expected in this respect.

VII CONCLUSIONS AND OUTLOOK

Angola is struggling to rebuild its infrastructure, and rise from the wreckage of its civil war. Since 2002, it has managed to increase generation capacity, improve operational capability and progressively rehabilitate and maintain the country’s electric power grids. Nonetheless, productive ability is still unable to sustain existing demand and the service is generally unreliable. Poor access and unpredictable power is also a consequence of the fragmented nature of Angola’s power system. The three main Angolan grids – the north, south and central systems – are not interconnected (which would free up excess power from the north to the central and south systems).

The electricity tariffs structure also needs revising. The current tariffs structure does not allow state-owned companies to cover their costs and finance the necessary investments, but subsidies need to start being cut from supply prices.

The problem is exacerbated by the high level of commercial losses due to the inefficiency of the transmission and distribution networks, unbilled consumption or fraudulent connections, which lead to serious financial constraints from these companies.

In this context, Angola has committed to reforming the legal framework for energy-related activities and restructuring of the companies in these industries, welcoming new private players that may provide valuable expertise, along with a new financial stimulus.

Despite recent economic headwinds, the country has all the conditions to create a sustainable and prosperous energy industry. Its economy is steadily growing and the country is rich in natural resources. Now, it needs to create attractive conditions for new investors, and a business environment that inspires trust and security in its players.
I OVERVIEW

The South West Interconnected System (SWIS) and the North West Interconnected System (NWIS) are the electricity grids that service large portions of Western Australia (WA). However, WA’s extreme geographical spread coupled with its relatively small population necessitates the use of off-grid stand-alone generation power supplies to isolated customers.

Similarly, the remainder of Australia is serviced by large-scale electricity grids (including a very large interconnected electricity grid across the eastern seaboard of Australia connecting Queensland, New South Wales, Victoria, Tasmania and South Australia, known as the National Electricity Market or the NEM) and supported by off-grid power supplies. The regulation of these grids is not the subject of this chapter.

Within WA, the ‘on-grid’ energy market has three main regulators, which seek to ensure the energy market operates in a competitive, efficient, fair and commercial manner. These regulators are: the Independent Market Operator (IMO), which is performed by the Australian Energy Market Operator (AEMO); the Economic Regulation Authority (ERA); and the Clean Energy Regulator (CER).

Stand-alone generation facilities that provide electricity directly to customers, rather than through the NWIS or SWIS, are exempt from some regulatory measures (particularly those relating to market regulation) but are still subject to certain licensing regulations overseen by the ERA.

While it is the state government that sets the retail price of electricity, it is the ERA that plays a major role in the electricity supply chain in WA, including:

a. approving access arrangements for the SWIS, which set out the price, terms and conditions on which Western Power (as network owner) can charge generators and customers to access the SWIS transmission and distribution services;

b. administering the licensing regime, which involves issuing licences to entities generating, transmitting, distributing or retailing electricity, monitoring and enforcing compliance with licence conditions and approving customer protection measures; and

c. monitoring the effectiveness of the market and reporting to the Minister for Energy about the behaviour of participants in the wholesale energy market (WEM) (the market where retailers buy electricity from generators) to make sure that they are complying with market rules.2

1 Simon Rear is a partner, Samantha Smart is of counsel, Fiona Meaton is a senior associate and Connor McClymont is an associate at Squire Patton Boggs.

In 2014, the Minister for Energy oversaw the Electricity Market Review (the 2014 Review), which was designed to assess the current industry structure, regulatory arrangements and options for reform. The overarching objectives of the 2014 Review were to reduce the cost of production and supply of electricity (without compromising safe and reliable supply) as well as to reduce government exposure to energy market risks. Following the outcome of the 2014 Review, the government has set out to facilitate long-term stability in the electricity industry and encourage continued investment from large private-sector participants.3

Natural gas and coal-fired power stations remain the major source of electricity generation capacity in WA; however, the abundance of solar and wind energy throughout WA, and the continued improvement in the technological efficiency of renewable energy as well as the increase in providers of battery storage to support the reliability of renewable energy, provides the perfect platform for expanding the utilisation of alternative forms of energy. In fact, by 2016, WA had over 200,000 solar arrays installed, the sheer volume of which means that solar power already comprises the state’s de facto largest power station.4 WA’s rooftop solar capacity is only set to increase, with predictions from Energy Networks Australia stating that up to 44 per cent of WA’s energy could come from renewable energy sources by 2030.5 As such, this chapter will focus on the energy regulation of renewable electricity generation facilities including solar, wind and battery storage.

II REGULATION

i The regulators

The AEMO is an industry-funded organisation that oversees the functioning of the WEM and was created by the Council of Australian Governments and governed by the National Electricity Rules. It monitors participant compliance with the WEM rules, investigates potential breaches and initiates enforcement action where appropriate pursuant to the National Electricity Rules. The AEMO also sets the capacity price that uncontracted generators will receive for making their capacity available to the market.6

The ERA is established under the Economic Regulation Authority Act 2003 (WA) as an independent statutory authority designed to oversee the energy industry in WA and ensure that all parties abide by the relevant regulations. It issues licences to providers of various sources of energy, including electricity. In addition, the ERA monitors and publicly reports on industry performance, including the WEM; taking enforcement action when required. It also has authority through various codes7 to approve contracts and service standards that protect residential and small business electricity, gas and water customers and assess the performance of utilities in relation to the treatment of customers experiencing financial hardship.

5 Energy Networks Australia, Electricity Network Transformation Roadmap: Final Report (April 2017), Figure 29.
The Clean Energy Regulator Act 2011 (Cth) established the CER, a non-corporate Commonwealth entity for the purposes of the Public Governance, Performance and Accountability Act 2013 (Cth). As an independent statutory authority, the CER is comprised of the chair and members, who set the ‘strategic direction’ for the agency’s administration of its regulatory schemes. The role of the CER is to administer climate change law legislated by the Australian government to measure, manage, reduce or offset Australia’s carbon emissions. Accordingly, the CER has administrative responsibilities for the National Greenhouse and Energy Reporting Scheme (NGERS) under the National Greenhouse and Energy Reporting Act 2007, the Emissions Reduction Fund (ERF) under the Carbon Credits (Carbon Farming Initiative) Act 2011, the Renewable Energy Target (RET) under the Renewable Energy (Electricity) Act 2000, and the Australian National Registry of Emissions Units under the Australian National Registry of Emissions Units Act 2011.

ii Regulated activities

Pursuant to the Electricity Industry Act 2004 (WA) (the EI Act), there is a legal requirement to obtain different classifications of electricity licences from the ERA where you intend to:

- construct or operate generating works;
- construct or operate a transmission system of a voltage of 66kV or higher;
- construct or operate a distribution system of a voltage of less than 66kV;
- sell electricity to customers; or
- construct or operate any combination of generation, transmission, distribution and retail activities for the purpose of supplying electricity to customers other than through the SWIS.

However, there are also certain activities in the electricity industry that fall outside the scope of the licensing requirements under the EI Act and do not require a licence; these include:

- self-supply: where the generating works, transmission system or distribution system is to be used solely for the supply of electricity for consumption by the person who owns, controls or operates the works or system or a related body corporate of that person; and
- where the sale of electricity is to a person who is not the end-use customer; for example, a generator who sells electricity solely to retailers is not required to hold an electricity retail licence.

Where a licence application is made to the ERA in the form prescribed by the EI Act, the ERA must, within 90 days, grant or renew the licence or approve the transfer of a licence if it is satisfied that the applicant has, and is likely to retain, the financial and technical resources to undertake the activities authorised by the licence. When exercising this power, the ERA is...
required to consider the overall public interest, including but not limited to considerations involving the environment, social welfare and equity, economic and regional development, and the interests of customers generally.\(^\text{12}\)

iii  Ownership and market access restrictions

The Electricity Networks Access Code 2004 (the Access Code) is established under the EI Act and provides the framework for the independent regulation of certain electricity networks in WA.\(^\text{13}\) The objective of the Access Code is to promote efficient investment in, and operation and use of, networks and services of networks in WA and to promote competition in electricity retail and wholesale markets.\(^\text{14}\) The Access Code allows a 'coverage application' to be made to the Minister for Energy requesting that the whole or any part of an electricity network be covered. If a network is covered, it is deemed to be regulated and must have an approved access arrangement in place that sets out the terms of access to the network, including the conditions and prices that apply to the covered services of the network.

Service providers of a regulated network must submit their own access arrangement information to the ERA, which allows:

- the ERA, users and applicants to understand how the service provider established the proposed arrangement; and
- the ERA to form an opinion as to whether the proposed access arrangement complies with the Access Code.\(^\text{15}\)

Currently, the SWIS is the only regulated network in WA and Western Power is the service provider.

iv  Transfers of control and assignments

Where a proposed acquisition may have the actual or likely effect of substantially lessening competition in the market, approval of the proposed transaction may be required under the Competition and Consumer Act 2010 (Cth) from the Australian Competition and Consumer Commission (ACCC). The ACCC may provide either formal or informal clearance, with clearance typically taking up to three months. Alternatively, the Australian Competition Tribunal may grant authorisation based on a 'net public benefit test' where satisfied that the proposal is likely to result in such a benefit to the public that it should be allowed to occur, even if it is likely to substantially lessen competition in the market.

The ACCC has previously expressed concerns about the accumulation of market power through merger activity in the electricity sector, as well as the potential for anticompetitive conduct to ensue from vertically integrated structures.\(^\text{16}\)

Those investors who are either based overseas or owned by a foreign entity must apply to the Foreign Investment Review Board (FIRB) for approval from the Federal Treasurer where they are seeking to acquire a 'substantial interest' in an Australian company (i.e., 20 per cent or more), assets of an Australian business or Australian land. The acquisition

\(^{12}\) Ibid. Section 8(5).

\(^{13}\) Economic Regulation Authority, Guidelines for Access Arrangement Information (06 December 2010), 1.

\(^{14}\) Electricity Networks Access Code 2004 (WA) Section 2.1.

\(^{15}\) Electricity Networks Access Code 2004 (WA) Section 4.1, Section 4.48.

of electricity generation or distribution assets in WA by foreign persons and companies is likely to trigger a requirement for FIRB approval. Once FIRB is notified, the board will consider the proposed transaction and assess whether it is against the ‘national interest’. New requirements introduced in 2016 allow FIRB to consult with other government departments to determine whether the proposed transaction is within the national interest. The Australian Taxation Office and the ACCC are among the departments that have been actively assessing foreign investment proposals.\(^\text{17}\)

On the recommendation of FIRB, the federal Treasury may then issue a notice of no objection or, where the transaction is against the national interest, disallow the proposed transaction, or impose conditions on how it may be conducted.\(^\text{18}\) The FIRB approval process generally takes 40 days from the time the application is made; however, FIRB may extend this period for complex applications.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

\begin{itemize}
  \item[i] Vertical integration and unbundling
  
  There is a significant degree of vertical integration in WA with Synergy, a state-owned corporation, owning or controlling the majority of generating plants on the SWIS while also supplying over half of the state’s consumable load.\(^\text{19}\) Western Power, as another state-owned entity, then owns and operates the distribution network.

  Similarly, the NWIS operates through a vertically integrated model, with Horizon Power (also a state-owned entity) being responsible for the generation, procurement, distribution and retail of electricity to customers in the NWIS. The NWIS is owned by significant users of the electricity network: Horizon Power, Alinta Energy, BHP Billiton, Pilbara Iron (Rio Tinto) and ATCO Australia.

  \item[ii] Transmission/transportation and distribution access
  
  Pursuant to Chapter 12 of the Access Code, Western Power sets the technical rules for the SWIS in terms of transmission and distribution. These rules establish various performance and technical requirements relating to the power transmission and distribution systems.\(^\text{20}\) As a network provider, Western Power is responsible for approving the connection of new ‘embedded’ generation systems to the SWIS. A system can only be connected once all of the applicable connection eligibility criteria have been met, as a means of ensuring that the quality and reliability of supply is of an appropriate standard. The connection of new generation systems may also be subject to the completion of overall network upgrades or the installation of new infrastructure to ensure network capacity is large enough to service the additional generation capacity and community and industrial demand. Therefore, the approval process depends on the size of the system to be embedded and the capacity of

\end{itemize}

\(^{17}\) Australian Financial Review, ‘ATO to test national interest’ (1 April 2016).

\(^{18}\) Foreign Acquisitions and Takeovers Act 1975 (Cth) Section 17.


the network in the region where it will be installed. In 2016, Western Power amended its technical rules, making it easier for commercial solar photovoltaic systems to be installed both onto rooftops and into its network by removing the requirement for a technical review where certain criteria are met. These changes are expected to significantly reduce the cost of commercial-scale rooftop solar installations and are intended to enable the next phase of the solar revolution.

Similarly, Horizon Power sets the technical rules for the NWIS and non-interconnected systems in the north of WA. Renewable electricity generators seeking to distribute their electricity through the NWIS are required to complete a Renewable Energy Electrical System Connection Application Form. This application allows Horizon Power to assess whether the facilities meet the technical requirements and provides an opportunity for electricity generators to participate in Horizon Power’s Renewable Energy Buyback Offer (discussed below). If the application is accepted, it forms the basis of the contractual relationship between Horizon Power and the generator.

### Rates

Pursuant to the Electricity Industry (Licensing Conditions) 2005 (the Electricity Licensing Conditions), WA government-owned retailers must offer eligible customers a buy-back scheme. This ensures that residents, schools and non-profit organisations with renewable energy systems can sell their excess energy to Synergy (a state-owned enterprise that sells electricity to retail customers in the SWIS) and Horizon Power. Subject to specific requirements, the retailers establish their own terms and conditions (including rates) for buying excess energy and are responsible for running the Renewable Energy Buyback Scheme (REBS). The objective of the REBS is to provide eligible customers who own renewable ‘systems’ with a framework to sell the energy that their systems export and to ensure owners receive ‘fair and reasonable’ terms, conditions and rates for exported energy.

The Electricity Licensing Conditions define an eligible customer as:

- a residential customer who consumes not more than 50MWh of electricity per annum;
- a customer that is a school, university or other educational institution; or
- a customer that is a non-profit-making organisation.

Retailers may also, at their discretion, choose to accept customers into the REBS who do not ordinarily meet the minimum requirements of the regulations. For example, Horizon Power offers REBS to its commercial customers.

The terms and conditions, as well as buy-back rates, vary between retailers and are subject to change as a consequence of ordinary market pressures. Accordingly, the Public Utilities Office is required to conduct reviews of all terms and conditions to ensure that all contracts, including the buy-back rates, are ‘fair and reasonable’, by weighing up:

- the wholesale cost of electricity for the retailer;
- line-loss reductions provided by distributed renewable energy;

---


peak reductions provided by distributed renewable energy;
capacity benefits provided by renewable energy; and
costs to retailers in running REBS.24

Ultimately, this formalised process is designed to protect customers who are dealing with retailers that operate in a traditionally monopolised market. That said, the general consensus among the public is that the buy-back price is very low and does not incentivise the installation of larger-scale private renewable energy systems. The challenge going forward is to improve the desirability of renewable energy when considering the factors noted above so that the network providers are driven to seek out and support renewable energy generation to meet their capacity requirements and thus increase the buy-back price they are willing to offer.

iv Security and technology restrictions

As a general principle, all primary equipment on the transmission and distribution system must be protected so that if an equipment fault occurs, the faulted item is automatically removed from service by circuit breakers or fuses. Protection systems must be designed so that, if there is a fault, unnecessary equipment damage is avoided and any reduction in terms of power transfer capability or level of service to users is minimised.25

The scale and changing nature of electricity networks now dictates that security is of greater significance. The roles of key electricity sector stakeholders are changing with a gradual shift toward a shared responsibility for network security, with customers becoming generators that use distributed generation technologies, and vendors assuming new responsibilities to provide advanced technologies as well as their own security mechanisms. With these changes, all stakeholders are becoming responsible for ensuring the continued overall security and resilience of the broader grid, including through:

- facilitating public–private partnerships to accelerate cybersecurity initiatives for the grid of the 21st century;
- funding research and development of advanced technology to create a secure and resilient electricity infrastructure;
- supporting the development of cybersecurity standards to protect against vulnerabilities;
- facilitating timely sharing of actionable and relevant threat information;
- advancing risk management strategies to improve decision-making;
- supporting sector incident management and response; and
- enhancing and augmenting the cybersecurity workforce within the electric sector.26

With the growth of renewable technologies, the AEMO will be undertaking further studies designed to investigate how the integration of such technologies is likely to affect market operation in the future.

24 Ibid.
25 Note 21, above, at 2.9.1.
IV ENERGY MARKETS

i Development of energy markets

The WEM is a capacity market, with each retailer required to acquire capacity credits from the AEMO, or generators directly, to match their individual capacity requirements. These capacity requirements are based on estimates made by the AEMO in relation to the overall capacity requirement of the SWIS for the next 10 years, in accordance with provisions specified in the Western Australian Market Rules. As well as supplying capacity credits to retailers, the AEMO is also responsible for assigning capacity credits to generation facilities.27

After determining the amount of reserve capacity required, the AEMO places obligations on market customers (i.e., retailers) to purchase capacity credits equivalent to their forecast contribution to peak demand. Those supplying electricity into the network earn ‘capacity credits’ by providing capacity to the system and, where that generation arises from renewable sources, can also earn Renewable Energy Certificates (RECs), which is the general term used to cover small-scale technology certificates and large-scale generation certificates. These are created in the CER’s REC Registry to be bought, sold, traded or surrendered. Commonly referred to as ‘green products’, they can be bought by customers along with the electricity as part of a bundled power purchase arrangement so that customers can use them to meet their own obligations to surrender RECs or sell to the AEMO through a capacity auction.28

In the WEM, only the electricity volume that is not already covered by bilateral contracts is traded. For example, market customers (typically electricity retailers) may need to purchase additional electricity over and above their contracted position because of fluctuations in the weather or unanticipated increases in demand. In this scenario, the market customer bids into the market for the volume of electricity required to balance its contract position and pays market price for that balancing amount of electricity. The WEM’s bilateral net settlement system for uncontracted energy is overseen and facilitated by the AEMO.

ii Energy market rules and regulation

The structure and processes that constitute the WEM in WA are established through the WEM Rules. The WEM Rules were developed by the Office of Energy (which has since become the Public Utilities Office), with substantial support from a number of expert teams comprising representatives from industry and government. The WEM Rules detail the roles and functions of the AEMO (in its role as the IMO), System Management and other governance bodies, and guide the operation of the market including the trading and dispatch of energy and settlement.29 The WEM Rules are administrated and interpreted by the independent Rule Change Panel, which commenced operations in April 2017.30

The WEM Rules establish the broader objectives of the WEM, which are to:

a promote the economically efficient, safe and reliable production and supply of electricity-related services in the SWIS;

b encourage competition among generators and retailers;
c avoid market discrimination against particular energy options and technologies;
d minimise the long-term cost of electricity supplied to customers from the SWIS; and
e encourage the taking of measures to manage the amount of electricity used and when it is used.31

iii Contracts for sale of energy

Bilateral trades of energy and capacity occur between market participants, with the AEMO taking no interest in the formation of these trades. However, market participants are subsequently required to submit bilateral schedule data relating to the energy transactions to the AEMO each day so that the transactions can be scheduled.

Bilateral contracts are agreements formed between wholesale market suppliers and wholesale market consumers (i.e., retailers and directly connected loads) for the provision of energy and serve to provide the holders with certainty over their settlement position with respect to that transaction. Once a bilateral contract submission is accepted, the energy is ‘scheduled’ and the ensuing demand forecast. The AEMO report allows market participants to revise their bilateral contract positions.32

To the extent that one of the parties cannot meet their contractual requirements, whether that be because of (1) an outage of a generator, (2) transmission or network security constraints, (3) maintenance operations on the generator or (4) some other situation, then those parties will be individually liable to settle their deviations from the contract position. This places discipline on the market to only form contracts that reflect a reasonable expectation of the ability of the network to facilitate the delivery of that energy.

iv Market developments

A number of market developments are currently being considered and implemented via the Electricity Market Review, which was launched by the former Minister for Energy on 24 March 2015.

The key proposed reforms include:

a Network regulation: this will look at transferring regulation of the Western Power network, including: price, connection and access, from the WA regime to be regulated under the National Electricity Law and National Electricity Rules. This will mean that WA operates under the same rules and regulations as the NEM. The proposed time frame to transfer regulation has not been achieved and, as a result, Western Power continues to be subject to the state-based regulatory framework and further implementation of the transfer time frame is unclear at this time.

b Institutional arrangements: this involves seven broad projects including investigating the merits of replacing the five Market Objectives with the singular National Electricity Objective, replacing the Western Australian Energy Disputes Arbitrator and Western Australian Energy Disputes Board with more cost-efficient dispute resolution bodies and procedures, and establishing a WA reliability panel, which is expected to formally commence in 2018. System management functions and market operation functions

have already been transferred to the Australian Energy Market Operator and the independent Rule Change Committee has been established, with the appointment of the first initial panel members in January 2017.

c Market competition: this will include reforms to enhance market competitive outcomes through full retail contestability and the removal of barriers to entry in the retail and wholesale market.

d Wholesale electricity market improvements: this involves two broad projects: reform to the Reserve Capacity Mechanism to address the manner in which the capacity price and volume is determined; and reforms to existing energy market operations and processes, which were announced in July 2016. The reforms to energy market operations and processes include introducing security-constrained dispatch, a later gate closure period and a shorter dispatch cycle, facility bidding and the development of co-optimised energy ancillary services.33

The long-term success of these reforms, measured by their ability to reduce energy prices, as well as the viability of these reforms long-term, is something that will be closely scrutinised in the years to come.

In April 2016, the former state government also announced further changes to WA’s electricity market, pursuant to the Electricity Market Review. These changes are expected to reduce the cost of supplying electricity by up to A$130 million every year.

The reforms included:

a transitional arrangements to reduce capacity payments to power stations and demand-side management (DSM) providers because of current levels of excess capacity;

b the introduction of an ‘auction’ by 2021, at the latest, to achieve efficient levels of electricity capacity in the market;

c updated requirements for DSM providers so that services are more readily able to be called upon, and therefore more effective for the market; and

d improved incentives to maintain power stations to ensure they are ready to supply electricity immediately, as required.

The reforms that will be implemented, together with significant reductions in costs of the electricity businesses over the coming years, will go towards fixing the problem of surplus energy within the SWIS going to waste. Accordingly, in the interests of removing excess capacity, it is proposed that Synergy will also reduce its plant generation capacity by 380MW by 1 October 2018.34

In the lead-up to the most recent Western Australian state government election in March 2017, the privatisation of Western Power was a key election issue, with the Liberal Party advocating its partial sale as a means of reducing government debt. The coalition government, a combination of the Liberal Party and the National Party, were firmly beaten in the election, and the Labor Party campaigned heavily against the full or partial privatisation of Western Power. As such, it seems that any privatisation of Western Power is unlikely to happen in the foreseeable future.


V  RENEWABLE ENERGY AND CONSERVATION

i  Development of renewable energy

Western Australia has some of the best solar energy resources in Australia, particularly in the Pilbara and North West regions, which are home to Australia’s first large grid-connected, photovoltaic 20kW tracking system, which was commissioned in 1995. This trend has continued with two recent proposals to build large-scale solar farms in WA’s regional areas. In March 2017, Carnegie Clean Energy announced plans to develop a 10MW solar farm in Northam. This solar farm, which has been 100 per cent privately funded to date, is strategically located to enable it to deliver electricity to the WA grid when it is most needed. It has also been designed with the capacity to accommodate battery storage when the costs of energy storage decline. Sun Brilliance Group has also announced plans to build a 100MW solar farm in the middle of the state’s wheat belt. This project will be the largest solar farm in WA and is expected to be the largest energy producing solar farm in Australia.

Given the geographic isolation of certain areas of the state, there is demand for small-scale solar power in remote communities where transport and fuel costs make diesel power generators more expensive. Consequently, in 2010, Marble Bar and Nullagine in WA became the first towns in the world to use solar-hybrid generation technology, which combines photovoltaic technology and diesel. This trend has continued with around half of the current major pastoral stations in WA utilising solar power to contribute to their power generation; with solar technology also being used in remote telecommunications infrastructure and water pumping stations. In 2015, a leading French renewable energy firm Neoen began construction on the DeGrussa solar hybrid project. This 10.6MW solar photovoltaic farm, which is coupled with a 6MW battery facility, will be the world’s largest integrated off-grid solar power system in use by the mining industry. This project, which combines solar and battery storage, offers the opportunity to reduce the reliance on diesel-powered energy for mining in remote areas and demonstrates the significant potential for off-grid renewables in regional and remote Australia.

The RET is overseen by the CER and mandates that 20 per cent of Australian electricity should come from accredited renewable sources by 2020. Subsequent reforms, agreed to by Parliament in 2015, were designed to have the effect of:

a  protecting Australian jobs and helping industries remain competitive by increasing assistance for all emissions-intensive trade-exposed industries to 100 per cent exemptions from all RET costs; and

b  removing the requirement for biennial reviews of the scheme and replacing them with regular status updates by the CER to provide more certainty to industry and transparency to consumers.

The government will also work to progress reforms to improve the scientific understanding of wind turbine noise and the monitoring and transparency of information relating to the operation of wind turbines. The government is also considering options to enhance the uptake of large-scale solar technology, other renewable energy technologies and energy efficiency.


36  Ibid.
The RET has already been largely responsible for a growth in large-scale wind and solar photovoltaic projects. Similarly, the Australian Renewable Energy Agency (ARENA), established by the federal government in 2012, and the Clean Energy Finance Corporation (CEFC), function to improve the competitiveness of renewable energy technologies and increase the supply of renewable energy in Australia. ARENA is fully funded from an initial A$2 billion funding pool provided in 2012 to invest in supporting renewable energy projects until the year 2022 to:

- fund renewable energy projects;
- support research and development activities; and
- support activities that facilitate the capture and sharing of knowledge.

In September 2016, ARENA announced funding to construct 12 new large-scale solar photovoltaic plants across Australia. Similarly, the CEFC intends to mobilise capital investment in renewable energy in Australia by investing in organisations and projects using clean energy technologies. In 2015, CEFC committed up to A$15 million in finance to the DeGrussa solar-hybrid project in WA. ARENA continues to support projects that advance renewable energy technologies from early research to later stage demonstration projects in the field.

ii Energy efficiency and conservation

As part of the implementation of an alternative climate change policy, the ERF was enacted as a voluntary scheme with three components relating to crediting, purchasing and safeguarding emissions reductions. The ERF aims to provide incentives for a range of organisations and individuals to adopt new practices and technologies to reduce their emissions. Eligible participants are able to earn Australian carbon credit units (ACCUs) for emissions reductions (with one ACCU being equivalent to one tonne of carbon dioxide equivalent stored or avoided by a project). ACCUs can be sold to generate income, either to the government through a carbon abatement contract, or in the secondary market to emitters who fall under the safeguard mechanism and have exceeded their emissions cap.37 While the crediting and purchasing elements provide incentives for businesses to reduce their emissions, the safeguard mechanism, which came into effect on 1 July 2016, is designed to ensure that emissions reductions purchased by the government are not offset by a significant rise in emissions elsewhere in the economy.38 This mechanism allows the CER to create a baseline under which businesses that already report under the NGERS, and have direct emissions of more than 100,000 tonnes of carbon dioxide per year, are required to keep their emissions.

iii Technological developments

Owing to rising electricity costs, environmental awareness and emerging technology, consumers are demanding a more reliable, sustainable and economically efficient electricity network.39 In March 2015, ARENA contributed A$3.3 million to a four-year trial of a Synergy

---

pilot project that combines rooftop solar photovoltaic with battery storage at a new housing development north of Perth. This trial, which is currently under way, includes a new tariff option for consumers and has the potential to be replicated in future residential developments across Australia because of its centralised lithium ion battery storage capabilities. Western Australia is also set to construct its first thermal energy to waste facility and Australia’s largest distributed energy resource microgrid. The A$400 million energy-to-waste project aims to reduce the amount of landfill by using revolutionary thermal technology to incinerate waste and convert it into energy. The facility will aim to generate approximately 35MW of electricity, which is the equivalent of powering around 35,000 homes.40

The former state government also announced the development of Australia’s largest energy resource microgrid, which combines traditional energy sources with wind and solar power and battery storage. It is expected to deliver more than 50 per cent of Onslow’s electricity needs with renewable energy and will be closely monitored to assess the viability of replicating the project across WA.41 Similar pioneer projects are also under way throughout the state, including those utilising wave energy technologies that convert ocean swell into zero-emission renewable power and desalinated fresh water.42 In 2013, the WA government approved plans to build a 40MW tidal power station in the west Kimberley, which would be the state’s first utility-scale ocean energy plant. These projects are indicative of the demand for alternative sources of energy, as well as the need for energy storage to become more cost-effective so as to promote more renewables being included in local electricity grids. They also demonstrate a gradual psychological shift towards prioritising the use of renewable energy.43

The SWIS uses a conventional electricity network consisting of ageing infrastructure that is struggling to meet the changing demands of a growing population and is due for upgrading. This provides an opportunity to take advantage of new and emerging smart grid technologies.44 Building a smarter electricity grid system in WA is integral to meeting consumers’ needs and has become the core architectural component of the energy network, enabling distributed low-carbon systems, advanced metering infrastructure and meters, renewable energy and even electric vehicles to be integrated with the grid. Western Power has likened the smart grid to the internet of today’s electricity system; allowing for a two-way flow of information and electricity. Smart grids use electronic sensors to monitor its performance and feed information back to consumers and network operators, allowing consumers to monitor their energy consumption and make better-informed choices. It also gives providers

---

44 Note 40, above.
real-time information on network performance and consumption, which can be used to make sustainable and commercial decisions on infrastructure development, thereby enhancing reliability and power quality.45

If appropriately implemented, smart grids will better utilise low-emission sources of energy, such as that generated by wind and solar projects. In addition, increased flexibility and control means it will be able to account for the intermittency of renewable generation. The integration of communications infrastructure and intelligent control systems will also enable detection and mitigation of threats and support a wide variety of generation options in case of an incident at any one point on the network.

VI THE YEAR IN REVIEW

Throughout 2016 and 2017, the Western Australian government intended to introduce a set of key reforms and implementation arrangements pursuant to the Electricity Market Review launched in March 2014. Notable developments of this review included the completion of the transfer of system management functions and market operation functions to the Australian Energy Market Operator and the creation of a new market rule-change committee. One of the central aims of the reforms was the introduction of a choice of electricity retailers for households and small business customers, with the gas services industry providing an example of how a competitive market could benefit consumers (this is known as full retail contestability). The government had also intended to transfer the regulation of the Western Power electricity network to the national regulator; however, the expected time frame for this transfer to the AER was not achieved. As a result, Western Power will continue to be subject to the current state-based regulatory framework in accordance with the Access Code for the immediate future. A transition to the AER will provide the benchmarks and incentives for Western Power to meet national best-practice standards in operations, efficiency and cost. However, at the same time, the former government announced that it would not split the state-owned electricity business Synergy and that WA would not join the national electricity market.46 Accordingly, further reform implementation is seemingly on hold in WA.

Western Australia continues to meet major milestones regarding the 2020 renewable energy target set by the RET. The CER announced on 23 January 2018 that record levels of investment in renewable energy throughout 2017 meant that WA is well on the way to meeting its renewable targets.47 The growth of renewable energy production in WA, coupled with positive news that every greenhouse gas emitter under the National Greenhouse and Energy Reporting scheme in WA met its compliance target in 2017,48 is evidence of a genuine shift in the industry on behalf of producers and consumers to greener, cleaner energy production.

45 Note 40, above.
47 Clean Energy Regulator, Record year of investment means Australia’s 2020 Renewable Energy Target will be met (23 January 2018), www.cleanenergyregulator.gov.au/Infohub/Media-Centre/Pages/Media%20updates/NewsItem.aspx?ListId=19b4efbb-6f5d-4637-94c4-121c1f96f6fe&ItemIds=468.
In October 2017, the Australian government announced a new energy policy that proposed to implement a National Energy Guarantee (NEG) designed to ensure power supply meets consumer demands and reduce the likelihood of power outages in the NEM system. The NEG comprises an electricity reliability guarantee, requiring retailers to maintain certain load requirements, and incorporates an emissions guarantee. Notably, the NEG policy indicates an exception from the shift towards renewable energy, as base-level power guarantees are expected to stifle the growth of renewable energy markets that cannot, at this stage, offer the same reliability of energy production as traditional power sources. The Australian government is intending to roll out a comprehensive set of reforms to implement the NEG in the eastern seaboard’s NEM over the coming years.

One of the most publicised recent developments in the renewable energy industry in Australia was the deal struck between the South Australian government and technology company Tesla to deliver up to 50,000 solar power systems for domestic use, utilising Tesla’s domestic lithium-ion batteries. This project is in addition to the Tesla Powerpack battery system, coined the ‘world’s largest lithium-ion battery’, a 100MW battery that is connected to the Hornsdale wind farm. The development of lithium ion battery systems is expected to increase the viability of renewable energy power generation on a commercial and domestic scale in the coming years.

VII CONCLUSIONS AND OUTLOOK

The continued transformation of Australia’s electricity market in recent years has, along with the growth of the renewables sector, brought about considerable policy and regulatory changes. Notwithstanding these changes, the energy market in WA still faces major challenges, the first of which being the geographical isolation that restricts certain areas from being serviced by the existing electricity network. The second is the status of the existing grids’ current regulations and technology, which do not support the optimisation of renewable energy generation. Wind and solar electricity generation offers a clean, green and, potentially, cost-effective means of meeting the peak electricity demand of WA’s growing metropolitan population and can also service WA’s remote off-grid communities through stand-alone facilities. Therefore, it is imperative that WA invest in the technological research and development, infrastructure upgrades and legislative reforms required to ensure WA builds on this natural advantage to reduce the cost of electricity for families and businesses while also securing efficient and reliable electricity supplies for future generations.

51 Nick Harmsen, Elon Musk’s giant lithium ion battery completed by Tesla in SA’s Mid North (24 Nov 2017), www.abc.net.au/news/2017-11-23/worlds-most-powerful-lithium-ion-battery-finished-in-sa/9183868.
Chapter 7

BELGIUM

†Wouter Geldhof, Cedric Degroef and Marthe Maselis†

I OVERVIEW

As an EU Member State, Belgium has implemented EU energy legislation and organised liberalised electricity and natural gas markets where (unbundled) grid operators are obliged to grant non-discriminatory third-party access to producers, suppliers and off-takers, and which are overseen by a regulating authority.

Belgium is also a federal country where legislative powers over energy matters and policy are distributed among the federal and regional governments. The federal government is responsible for legislation regarding large energy production, large energy storage capacities, nuclear energy, offshore energy, transmission of electricity and gas, including transmission tariffs, retail energy prices and competition in the energy market. The regional governments enact legislation for renewable energy, energy efficiency, distribution of electricity and natural gas, and distribution tariffs. All governments ought to cooperate on the implementation of Belgium’s long-term energy policy and the shift to a clean energy economy.

In 2003, Belgium decided to phase out its nuclear energy by dismantling all seven nuclear power plants after 40 years of operation. This means the last nuclear power plants will stop producing power in 2025. Despite this decision, nuclear power plants still account for roughly half of Belgium’s power production, and little efforts have been made so far by the market or the government to construct alternative power-generating plants. All of the different Belgian governments are currently negotiating an ‘energy pact’, which would (finally) result in a long-term energy policy for Belgium and facilitate the construction of gas-fired power plants and renewable energy installations (including offshore wind farms) to replace nuclear energy. As a transitory measure, extending the lifetime of the two youngest nuclear power plants is considered – yet heavily debated.

II REGULATION

i The regulating authorities

The regulatory structure in Belgium is rather complex. This is most likely because of its federal government structure whereby one single national regulatory authority does not exist. Instead, regulatory responsibilities are distributed among the federal regulating authority, the Commission for Electricity and Gas Regulation (CREG), and the three regional energy

†Wouter Geldhof was a partner at Stibbe. Cedric Degroef and Marthe Maselis are associates at Stibbe.
regulating authorities: the Flemish Regulator of the Electricity and Gas Market (VREG) for Flanders, the Brussels Energy Regulator (BRUGEL) for the Brussels Capital Region and the Walloon Commission for Energy (CWaPE) for Wallonia.

These authorities are all independent: they are independent from all market players and policymakers, from which they may not receive any direct instructions. Despite this independence, they do, however, have to comply with general policy choices.

The core competence of these regulators is grid tariffs. They set the tariff methodologies and approve the grid tariff proposals from the grid operators. In doing so, they must consult stakeholders.

The regulators can also impose administrative fines on market players that do not comply with energy legislation. Energy regulators principally have an ex ante market regulation function; while ex post market regulation (such as actions against cartels or abuse of dominant market positions) is done by the competition authorities.

ii Regulated activities

Building and operating new power or gas plants requires environmental and planning permits. In Flanders and Wallonia, these two permits are now integrated into a single permit (from recent legislation). Furthermore, large new onshore power plants (more than 25MW) require a federal production permit. This permit is issued by the federal Minister for Energy after he or she has obtained advice from the CREG. Smaller power units, such as solar panels or wind turbines, do not require such permit.

Offshore wind farms require an offshore domain concession (granted by the federal Minister for Energy after he or she has obtained advice from the CREG, among others), a marine protection permit and, as the case may be, a submarine cable licence.

A supply licence is required to engage in retail electricity or gas supply. Depending on the voltage level and the regional location of the consumer, a federal or a regional supply licence is required. The federal supply licence is limited in time to five years, but it can be renewed indefinitely. The regional supply licences have no time limit. Licensed suppliers must also comply with the criteria laid down by law, such as having sufficient technical and financial capacities.

Energy traders do not require any licences to operate on the Belgian market. However, they must communicate certain information to the regulators and the authorities for purposes of market monitoring.

Grid operators must be appointed and must receive an unbundling certification proving that they are operationally and legally independent from other market players such as producers and suppliers. To develop their grid, grid operators benefit from easements and can use areas that are public property. If more drastic grid development needs to take place, there are specific expropriation procedures in place.

iii Ownership and market access restrictions

Grid operators must be ownership-unbundled. Furthermore, most grid operators are largely owned by public authorities with the ultimate shareholders being Belgian municipalities. The electricity transmission system operator is a listed company, but almost half of its shares are owned (indirectly) by public authorities. As for the distribution system operators, it is a legal requirement that the distribution grid be fully or mostly owned and operated directly by municipalities or indirectly by inter-municipal cooperative entities.
Suppliers are required to have a corporate seat in the European Economic Area (EEA). Producers must have their corporate seat, central administration or main office in the EEA also.

iv Transfers of control and assignments

The transfer or assignment of a supply permit or licence, or the merger, acquisition or change of control of the holder of such permit or licence, usually requires a prior notification to the authority that has issued the permit in question.

For an electricity production permit, the federal Minister of Energy must decide within 60 business days whether the permit can be kept or whether a new permit must be applied for. Before deciding on this, he or she will seek the CREG’s advice on the matter. If a new permit must be applied for, the standard procedure applies (approximately three to four months). However, the transfer, assignment, merger, acquisition or change of control can be implemented already.

For an intention to transfer, assign or lease an offshore domain concession, a stand-still period of 50 business days applies during which the Minister for Energy’s representative will assess whether the transaction is compatible with the retention of the concession.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Grid operators are ownership-unbundled, meaning that they may not have any participation in or control over any supplier or producer, or vice versa. This model has been implemented gradually since the 90s, with full ownership occurring since the beginning of the millennium. The structure of the industry has therefore not changed significantly over the past few years (except for some mergers and new players on the supplier and producer sides – see below).

ii Access to transmission, transportation, and distribution

Grid operators have not only a natural but also a legal monopoly on the grid operation. The reverse side of this monopoly is the obligation for them to grant non-discriminatory third-party access to producers, suppliers and off-takers who meet the necessary legal and technical requirements. The grid codes set out which technical and legal requirements (e.g., signing of an access responsible party (ARP) contract) must be met by grid users to have access to the grid. The grid codes are being revised to comply with the netcodes (EU regulations jointly developed by the European Network of Transmission System Operators for Electricity, the European Network of Transmission System Operators for Gas and the Agency for the Cooperation of European Regulators).

iii Rates

Grid tariffs must be approved by the regulator. The transmission grid tariffs are approved by the CREG, while the distribution grid tariffs are approved by the regional energy regulators. The grid operators have to draft a tariff proposal based on the tariff methodology (general framework) developed by the regulator. The grid tariffs are set for four to five years (the regulatory period), except for the grid tariffs for the LNG terminal, which are set for 20 years. The tariffs of the transmission system operator are principally based on a cost-plus model, while the distribution grid tariffs are more incentive-based; for example, in Flanders there is a
specific stimulant to preserve the quality of the services by the Distribution system operators (DSOs). The costs that the grid operators can influence (such as public service obligations) may be integrated fully into the grid tariffs.

### iv Security and technology restrictions

There is no specific regulation concerning the protection of critical energy infrastructure. However, after an attempt by China State Grid to obtain a participation in the Flemish DSO Eandis, and related transactions, Flanders is considering introducing a legal basis for ministerial approval of participations in critical energy infrastructure by non-EU companies.

With regard to cyber security, it is up to each player to implement adequate software and hardware systems. This is monitored by the energy regulators. Data exchanges between grid operators, suppliers and ARPs happen by means of the data management system MIG.

Access to and import of goods into the nuclear power plants is monitored by the Nuclear Safety Agency and the Belgian State Security Service.

### IV ENERGY MARKETS

#### i Development of energy markets

The opening up of EU electricity markets has led to the introduction of a power stock exchange in Belgium: BELPEx, in short, is the physical power exchange for electricity supply and off-take on the Belgian hub and was established in Brussels in 2006. BELPEx facilitates anonymous, cleared trading in two different market segments, namely a day-ahead market segment (DAM) and a continuous intraday market segment (CIM). BELPEx’s day-ahead market segment is coupled with the APX in the Netherlands and the United Kingdom, the EPEX Spot in France and Germany, and the Nord Pool Spot in the Nordic region. The intraday market segment is coupled with the APX in the Netherlands and the Nord Pool Spot in the Nordic region.

The futures market is organised by the ICE Endex through the ‘ICE Endex Belgian Power Baseload Futures’ module.

The futures market for gas is organised on the ICE Endex (under the ‘ICE Endex ZTP Natural Gas Futures’ module in monthly, quarterly and annual nominations) and on the PEGAS (the ‘SEA’ module in monthly, quarterly, season- and yearly-nominations and the ‘ZTP’ module in monthly nominations). ICE Endex uses ‘MW’ as a unit, PEGAS uses ‘MWh’ for ZTP and ZEE ‘therms’. The gas spot market is organised on the ICE Endex (the ‘ICE Endex ZTP Natural Gas Daily Futures’ module for the H zone) and on the PEGAS (the ‘PEGAS Spot ZTP’, ‘PEGAS Spot ZTP L’ and ‘PEGAS Spot ZEE’ modules).

On the power market, the ARP is responsible for maintaining a quarter-hourly balance between total injections and total withdrawals of the grid users in its portfolio. The ARP can be a producer, a major customer, an energy supplier or a trader. Each ARP is able to exchange energy (import or export) with a view to maintaining a balanced portfolio. Annual, monthly, daily and intraday capacities are allocated by means of different allocation mechanisms. The annual and monthly capacities are allocated by means of explicit auctions. At such auctions, the ARP can acquire the right to import or export a certain volume (in MW) of power for each hour of the year, month or day in question. The transmission system operators (TSOs) in 17 countries of the European Union have created shared rules governing these explicit auctions. The auctions are organised through a jointly created entity called Joint Allocation Office.
Daily capacity is allocated to market players through an implicit allocation mechanism (whereby energy and interconnector capacity are seen as bundled products).

Since October 2016, the intraday capacity is allocated via an implicit mechanism based on continuous trading on the intraday markets of EPEX by means of the M7 trading platform.

When the ARP has acquired capacity through the explicit allocation mechanism, it must nominate or schedule the volumes it wishes to import and export: it must submit a nomination to the TSO of the exporting country and one to the TSO of the importing country. The system operators check to see that the details of the two nominations match. For implicit capacity allocation, the ARP does not have to nominate its import or export by itself. The clearing house of the power exchanges organises the cross-border shipping.

Capacity obtained by a participant can be resold or transferred via the secondary capacity market.

ii Energy market rules and regulation

Energy market rules are set out in the respective regulation. Market monitoring is done by the regulator. To have access to trading activities, traders must enter into some kind of participation agreement with the hub operator and usually also provide some kind of financial guarantee. Gas traders must also enter into the standard transport contract with Fluxys. Depending on the nature of their activities, electricity traders might have to conclude an ARP agreement with Elia.

iii Contracts for sale of energy

Electricity generators can either enter into direct, private contracts with suppliers and traders or sell their electricity on the wholesale market (over the counter or on the stock exchange).

There are three Belgian gas hubs: Zeebrugge Beach, ZPT (H) and ZTP (L). Trading on these gas hubs previously required the signing of a HUB Services Agreement. However, the HUB services have recently become part of the standard transport contract of Fluxys. The user can submit nominations for ZTP Notional Trading Services, ZTPL Notional Trading Services or Zeebrugge Beach Physical Trading Services. There are regulated tariffs for the use of these HUB services.

Following the liberalisation of the energy market, end consumers are free to choose their electricity and gas suppliers. To protect the consumer from any negative effects as a result of the liberalisation, the federal minister for consumer goods, a majority of the suppliers and the consumer organisation entered into an agreement setting out good practices and consumer protection measures. This agreement is regularly updated.

Furthermore, the regional governments set up a system of social obligations, of which the most important one pertains to maximum pricing, obliging electricity and gas suppliers to supply energy at a fixed price to certain consumers. This price is set by the regulator and adjusted every six months according to the lowest commercial tariff on the electricity market. Only protected and low-income residential consumers or those in a vulnerable situation benefit from this lowest commercial tariff. These protected consumers are placed on the social tariff automatically, regardless of the supplier they choose.

To ensure that every person can live in a dignified way, a DSO must always provide a minimal supply of electricity and gas to consumers, even if the bills are not paid or if the budget meter credits are exhausted. However, the consumer must still pay the cost of this minimal supply. DSOs are only allowed to terminate this minimal supply of electricity and
gas in very restricted circumstances. These circumstances are set out in more detail in the respective legislative decrees relating to the sector. In Flanders and Wallonia, the installation of a budget meter is expected in certain circumstances. A budget meter is a device that can limit the supply of electricity and gas, and that is paid for in advance.

iv Market developments
Demand side management and energy flexibility are expected to become more and more important, hence increasing the role of aggregators. In the summer of 2017, a legal framework for commercial energy flexibility was introduced. Each end-consumer has a right to valorise his or her own energy flexibility. To this end, he or she can enter into a contract with an electricity supplier or with a flexible service provider, who in turn must have an ARP or similar contract with the grid operator. Each end-consumer is also the holder of its grid data.

In the draft EU Winter Package, demand-side management also has a prominent role. Smart meters and dynamic electricity price contracts should foster the development of demand-side management, allowing consumers to adapt their consumption to real-time price signals.

The different regions are also developing their own legal framework for technical flexibility.

V RENEWABLE ENERGY AND CONSERVATION
i Development of renewable energy
The Renewable Energy Directive imposes on Belgium a target of 13 per cent of renewable energy consumption by 2020. This target has been further broken down into separate targets, because renewable energy (except for offshore energy) falls under the individual regions’ legislative powers. Furthermore, in 2015, Belgium signed the United Nations 2030 Sustainable Development Goals, which set a target of 18 per cent of renewable energy consumption by 2030. Reaching this target can be feasible, despite unfavourable geographic and weather conditions in Belgium, but this will require political cooperation between all of the different Belgian entities.

The principal legal instrument for the promotion of investment in renewable energy sources is the green certificate. Each Belgian region has established its own green certificates system. In Flanders they are called green power certificates and CHP (combined heat and power) certificates; and in the Brussels Capital Region and Wallonia they are called green power certificates. There are also federal green power certificates that are awarded to offshore wind parks and offshore hydro-plants. For the production of geothermal green heat, subsidies are granted through a half yearly call-system.

While the Flemish green power certificates and CHP certificates are awarded on the basis of the green electricity generated (corrected by a banding factor), the Brussels and the Walloon green power certificates are awarded on the basis of CO2 savings.

Each licensed supplier must submit a certain number of green power certificates, depending on the amount of electricity supplied through the quota obligation. Suppliers can meet their quota obligation by either producing renewable energy (for which they are granted green power certificates) or acquiring green power certificates on the market. Producers of green electricity are granted green power certificates, which they can in turn sell on the
market. However, green electricity producers in Flanders and Wallonia can also sell their
green certificates to the DSOs (Flanders) or the TSO (Wallonia) at a fixed price. Hence, a
minimum price is guaranteed to the renewable energy producers in these two regions.

By Decree of 10 March 2017, the Flemish government adopted a (limited) legal
framework on district heating networks. The date of entry into force of this Decree has still
to be determined by the government.

ii Energy efficiency and conservation
Rational Energy Use (or energy efficiency) falls under the legislative powers of the regions, but
the federal government provides the regions with supporting measures on this. The allocation
of legislative powers in the field of energy has made it necessary to organise a consultation
between the regions and the federal government. This consultation takes place as part of the
Interministerial Conference for Economy and Energy.

EU countries must report annually the progress they have achieved towards their
national energy efficiency targets. According to a survey performed by the Energy Efficiency
Watch (2015), Belgium is among the EU Member States that have made medium progress in
energy efficiency policies since the implementation of the Second Flemish Energy Efficiency
Action Plan. A fourth action plan was transmitted to the European Commission in 2017.²

The Buildings Directive 2010/31/EU has been transposed into law by all three Belgian
regions. Increased energy performance for buildings is promoted by the regions through
energy premium schemes and through certain fiscal measures. Each region has its own variety
of schemes and measures for energy efficiency.

Besides, several investment funds and banks are experimenting more and more
with energy-saving contracts in the private market. The use of energy saving contracts is
couraged by the European Union, the Belgian federal government and Belgium’s regional
governments.

iii Technological developments
The value of the green certificates depends on the technology that is used to generate the
renewable energy. Technologies that have become common, such as onshore wind turbines
and solar panels, receive fewer euros per MW than more advanced technologies. Innovations
may, under certain circumstances and conditions, also benefit from premiums and investment
subsidies.

Following the potential from the geothermal energy projects in the northeast of
Belgium, the Flemish legislature has amended the Decree of 8 May 2009 on Deep Subsoil.
More particularly, a licencing system has been introduced for prospecting and extracting
geothermal energy. The licence holder is given real rights, including expropriation rights, if
necessary, for building the necessary infrastructure for its geothermal activities. Although the
text of the amended decree has been ratified by the Flemish parliament, this amended decree
has not yet entered into force. The Flemish legislature has also introduced a guarantee to
cover the geothermal risk, which should foster the development of geothermal energy.

Smart metering technology is expected to be gradually rolled out in Flanders as from
2019. No regional initiatives are currently undertaken for Wallonia or the Brussels Capital
Region.

² See www.energiesparen.be/EErichtlijn.
VI THE YEAR IN REVIEW

In 2003, Belgium decided to phase out nuclear energy and dismantle all seven nuclear power plants after 40 years of operation. This means the last nuclear power plants would be dismantled in 2025. The different Belgian governments are currently negotiating an Energy Pact, which would (finally) result in a long-term energy policy for Belgium.

On the gas market, the gradual depletion of the Groningen natural gas field has prompted the Dutch government to completely phase out low calorific natural gas exports to Belgium and France between 2024 and 2030 and to Germany between 2020 and 2030. In view of this situation, Belgium is preparing to switch to natural gas from other sources (high calorific natural gas, or H-gas). Synergrid, the federation of electricity and gas system operators, has drawn up a technical methodology and a road map for this, which were discussed with the federal authorities, the CREG and the regions in early 2016. Fluxys Belgium has elaborated the Synergrid roadmap in its 10-year investment plan and is on track for completing the conversion on schedule in 2029.

Within its territorial sea and EEZ, Belgium is further developing offshore energy activities. Offshore wind farms used to be heavily subsidised by means of green certificates. Following the examples of offshore wind farms in the Netherlands and Germany that operated without any support by the tax payers, a deal was struck with the three youngest offshore wind farms, Mermaid, Seastar and Northwester 2 (offshore domain concession granted, but not yet operational), to reduce the amount of offshore green certificates that would be granted to them.

In the summer of 2017, the Belgian legislature also approved the legal framework of the Modular Offshore Grid. This is an offshore part of the electricity transmission grid to which the latest offshore wind farms would be connected.

On the M&A market, the most notable deal of 2017 was the sale of Eni Belgium to Eneco. Following this deal, Eneco became the third largest electricity and gas supplier of Belgium, ranked under Engie and EDF Luminus, and has a market share of about 12 per cent.

VII CONCLUSIONS AND OUTLOOK

The Belgian energy market is the result of the implementation of the EU energy liberalisation packages. This has resulted in liberalised energy markets that are gradually evolving into one EU internal energy market. The EU Winter Package (draft legislation) is to further foster such internal energy market.

The liberalised energy market, in combination with zero-marginal-cost technologies, has lowered commodity prices for electricity and gas significantly. However, the shift to a carbon-free economy and the decentralisation of the energy system (owing to decentralised renewable energy generation) has led to increased grid tariffs and taxes to be paid for renewable support schemes. This has led to an overall higher invoice for the end-consumer. To protect the energy intensive industry, the Belgian legislature has created exceptions for large energy consumers. These exceptions are under increased scrutiny, however, by the European Commission for alleged illegal state aid.

Energy storage, geothermal energy and hydrogen are expected to likely be the biggest game changers in the coming years.

From a contractual point of view, corporate power purchase agreements are becoming increasingly frequent on the Belgian energy market.
The NEMO interconnector, linking the United Kingdom with Belgium, is expected to become operational in early 2019. With Brexit following soon thereafter, specific technical and legal issues could arise.
I OVERVIEW

The Brazilian electricity sector, which operates under an integrated and hydrothermal system and with a strongly established free market, is founded on a regulatory framework that provides investors with considerable safety. The market underwent a major restructuring process in the 1990s when it was opened for private investments, and was submitted to further regulatory reform in 2004. Security of supply, regulatory stability and competitiveness provide the basis for the regulatory framework.¹

The main power source used in Brazil is hydropower (60 per cent of the electricity mix, excluding small plants), while thermal power plants play an important role in complementing the mix and assuring security of supply (26 per cent of the mix).² In addition, alternative power sources, notably wind, biomass and solar, have gradually increased their share and gained additional importance in the electricity portfolio. Renewable energy has more recently been encouraged by net metering policies, and has become more competitive over the past few years, as evidenced by the latest power auctions.

The electrical system is interconnected by transmission facilities that enable electricity produced in remote areas of a continent-sized country like Brazil to be transported to major consumers’ markets, mainly located in the south-east. The grid has its operation centrally coordinated and controlled, to reduce global costs and enhance security of supply, especially during dry seasons.

II REGULATION

i The regulators

The Brazilian federal government is empowered by the Constitution to provide services and facilities within the power sector. Private companies are entitled to enter the market through government delegation by concession, permission or authorisation.

---

¹ José Roberto Oliva Jr is a partner and Julia Batistella Machado is an associate at Pinheiro Neto Advogados.
² At the time of writing, a new reform is under discussion in the Congress, comprising topics such as the Generation Scaling Factor (GSF), short-term models (DESSEM) for the generation schedule of hydro and thermal plants and the separation of energy purchase and energy production in new auctions.
The main governmental body responsible for formulating public policies within the energy and mines sectors is the Ministry of Mines and Energy (MME). There are currently other arms of the federal government that play an important role in this sector, namely:

a. the National Council on Energy Policy (CNPE), presidential cabinet for energy policy affairs created by Law 9,478/1997; and

b. the Committee for Monitoring of the Electricity Sector, part of the MME, mainly created as a response to 2001’s rationing (by Law 10,848/2004), and responsible for monitoring security of supply and suggesting correction measures.

Since the market’s liberalisation, the industry’s participants have been regulated by ANEEL, granted with autonomy from central government but attached to the MME. ANEEL, created by Law 9,427/1996, regulates and supervises power generation, transmission, distribution and trading activities to assure the correct balance between the interests of companies and consumers.

The agency is responsible for implementing the policies and guidelines outlined by the MME, and for monitoring the activities developed in the sector, by verifying the compliance with its rules and regulations, and supervising contract performance. Some of ANEEL’s activities are undertaken by delegation from the MME, such as the conduction of power auctions and the granting of regulatory licences. It is important to note that the performance of complementary supervision activities may be decentralised to state regulatory authorities, under the terms established by law.

ANEEL is managed by an executive board composed of a managing director and two other directors, is organised into technical divisions and is charged with performance of administrative functions in different areas such as economic regulation, market studies, supervision, mediation and the granting of concessions and authorisations.

The restructuring processes undergone by the power sector involved the creation of new institutional authorities. The National Electric System Operator (ONS) was created by Law 9,648/1998 as a non-profit association to coordinate and control the operations of the electrical grid, and had its governance system granted even more independence within the 2004 reform. Under the previous regulatory framework, an operational institution was created to manage the wholesale market, which was succeeded by the Electricity Trading Chamber (CCEE) following 2004’s regulatory reform. The CCEE, introduced by Law 10,848/2004, is mainly responsible for the registration of power purchase agreements (PPAs), and for the accounting and financial settlement of electricity trading operations. Within 2004’s reform, another institutional entity was created: the Energy Research Company (EPE), a public company responsible for studies and research on the energy industry with a view to enabling the sector’s planning, as foreseen in Law 10,847/2004.

ii Regulated activities

Since the federal government has the authority to provide electricity services and facilities, private companies need government delegation to enter the market. The regulatory licence required for entrepreneurs to operate in the power sector depends mainly on the segment

---

4 In a way, the companies were already subject to regulation before the creation of ANEEL, but the previous governmental bodies lacked effectiveness since they were not granted with autonomy and were part of the central government, which also controlled the state-owned companies that were the main service providers within the sector at the time.
(generation, transmission, distribution or trading) to be joined, and the extent to which regulation is exercised in each of them. Under the provisions of the legislation currently in force, the MME is the granting authority and may delegate its powers to ANEEL.

Power generation may be operated by means of a concession of use of public assets, a public service concession (former concessions fall within this regime), an authorisation, or even a communication. The regulatory licence required and the applicable regime depend on the plant’s installed capacity, the power source and the reservoir’s size (a requirement for hydropower plants).

As for large hydropower plants (HPPs) that have an installed capacity in excess of 50MW, the entrepreneur must participate in power auctions to be granted a concession to operate new generation projects (new-project auctions), and is required to sell a minimum percentage of the plant’s output on the regulated market (the remainder may be sold on the free market). The bid entitles the winning bidder (selected by lowest price criteria) not only to operate the new project (by being granted with a concession of use of public asset), but also to sell electricity to the distribution companies participating in the auction. Companies with hydropower plants in operation may participate in power auctions conducted specifically for purchasing electricity from existing projects (existing-project auctions), or may sell their output on the free market.

On the other hand, authorisation is required from companies willing to operate small hydropower plants (SHPPs) – which have an installed capacity of up to 30MW and a small reservoir – and plants with a capacity not higher than 50MW that do not have SHPP characteristics. Although the granting of authorisation does not require an auction, the existence of more than one interested company in the same hydroelectric potential triggers a competitive process by which ANEEL selects the entrepreneur, under the provisions of ANEEL’s regulations.

Other energy sources such as thermal, wind and solar are subject to an authorisation regime, whose process is conducted by ANEEL. All of them, including hydropower plants subject to authorisation, may participate in power auctions (either new-project, existing-project, or back-up energy auctions) to sell their production in the regulated market, or may sell it in the free market.

When it comes to new projects, plants subject to an authorisation regime may choose to participate in a power auction to be granted the correspondent authorisation and sell electricity in the regulated market. Should they decide to sell their production in the free market, they need to undergo the authorisation process with ANEEL to operate the power plant and freely trade the plant’s output.

Small plants – with an installed capacity of up to 5MW for thermal and renewable energy, including hydropower plants – do not need authorisation, but require a communication to ANEEL in light of their reduced impact on the system.

The regulatory licences mentioned (except for new hydropower concessions, currently only operated by independent producers) can be granted either under an independent power production regime or under a self-production regime. Former concessions are also operated under public service regimes.

---

5 In this case, the auction usually requires that a minimum percentage be allocated to the regulated market.

6 The importance of the difference between the two regimes has diminished since independent producers are entitled to consume part of their production and self-producers are allowed to sell the unused portion of their own output under the conditions set forth by rules and regulations.
Please refer to the table below for a general summary of the regulatory licences required from private investors to enter the Brazilian power generation segment.

<table>
<thead>
<tr>
<th>Power source</th>
<th>Installed capacity</th>
<th>Regulatory licence</th>
<th>Regimes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydropower</td>
<td>Greater than 50MW</td>
<td>Concession for use of public asset (preceded by a public auction)</td>
<td>Independent power producer</td>
</tr>
<tr>
<td></td>
<td>Greater than 5MW and not greater than 50MW (certain plants may be characterised as SHPPs)</td>
<td>Authorisation</td>
<td>Independent power producer or self-producer</td>
</tr>
<tr>
<td></td>
<td>Up to 5MW</td>
<td>Communication</td>
<td></td>
</tr>
<tr>
<td>Thermal power plants and renewable energy (except for hydropower)</td>
<td>Greater than 5MW</td>
<td>Authorisation</td>
<td>Independent power producer or self-producer</td>
</tr>
<tr>
<td></td>
<td>Up to 5MW</td>
<td>Communication</td>
<td></td>
</tr>
</tbody>
</table>

Private investors are forbidden to provide nuclear power on account of the federal government’s operation monopoly, foreseen in the Constitution. For that purpose, the state-owned company Eletrobrás has a subsidiary, Eletronuclear, which operates two nuclear power plants currently in operation.

Power transmission and distribution activities are considered natural monopolies, given their dependence on the electrical grid. In addition, in light of their importance to a continent-sized country like Brazil, operation thereof requires a public service concession, mandatorily preceded by a public bid.

Power trading companies wishing to operate in the power market need authorisation, under the provisions established by ANEEL’s regulations.

### Ownership and market access restrictions

The Brazilian Constitution establishes that hydropower generation activities must be carried out by Brazilian citizens or companies organised under Brazilian laws, with headquarters and managing offices located in Brazil. The bidding rules of electricity auctions usually do not forbid the participation of foreign companies, but normally establish that:

- a foreign companies shall organise a special purpose company under Brazilian laws to have the regulatory licence granted; and
- if foreign companies bid jointly with a Brazilian company in a consortium, the leadership shall always be exercised by the Brazilian company.

In addition, the bid notice usually establishes that foreign companies shall have a legal representative in Brazil with powers to receive service of process and provide answers in the judicial and administrative spheres, as well as represent them in all phases of the proceedings.

The legislation does not forbid electricity companies, organised under Brazilian laws, from being controlled by foreign companies or private equity investment funds organised under foreign legislation (except for nuclear power plants). ANEEL requires, however, that such companies have a legal representative in Brazil, duly vested with powers to receive service of process and provide answers in the judicial and administrative spheres.

In addition, there are specific restrictions for the organisation of power companies in the economic group. Unbundling, adopted by the sector since its restructuring in the 1990s and further deepened in the 2004 regulatory reform, restricted the activities of distribution
companies in the regulated market, limiting their participation in other activities of the supply chain. As such, generation and distribution companies operating in the interconnected system are required to maintain separate legal entities and individual accounting, although they may be part of the same corporate group or share infrastructure and human resources when authorised by ANEEL.

iv Transfers of control and assignments
As a rule, the transfer of the regulatory licence or of the controlling interest of the industry's participants is subject to ANEEL's prior consent, mainly to adhere to the bidding process and transparency principles.

In general terms, the regulation in force (ANEEL Resolution 484/12) sets forth that the prior consent of the regulatory agency is required for transfer of controlling interests of public service providers, hydropower companies and nuclear-fuelled energy companies, as well as in any companies, regardless of the power source, whose intended controlling company makes up the corporate group holding or which, with the intended transaction, become the holder of 'a significant share of the power generation market for the safety of the regulated market' – a concept yet to be tested by the regulatory agency. Some transactions are exempt from consent, under the terms established by ANEEL's regulations. Nonetheless, the exempt agent has a deadline to inform ANEEL of the implemented transaction.

The rules currently in force may be further amended after upcoming regulation by the regulatory agency on how 'a significant share of the power generation market for the safety of the regulated market' is enacted. This matter has been under discussion at the regulatory agency for a while, without any formal pronouncement yet.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling
The segregation of the different levels of the production chain was implemented mainly to promote efficiency and competitiveness, given that in the 1990s it became apparent that the vertically integrated industry had proven to be unable to provide services efficiently. The unbundling was formally adopted by the restructuring undertaken in the 1990s, and further enhanced under the 2004 regulatory framework.

The primary purpose of the unbundling in the sector was to encourage competition in the generation and trading segments (which may be provided under competitive regimes), whereas transmission and distribution segments remain natural monopolies. Since the 1990s restructuring, the separation between the contracting of the grid's access and the purchase of electricity had already been adopted as an unbundling measure.

The current regulatory framework also requires that generation, transmission and distribution activities be undertaken by separate legal entities, with specific restrictions on the corporate structure of their economic groups (see Section II.iii, supra).

The 2004 regulatory reform imposed restrictions on the distribution companies within the interconnected system by forbidding them to undertake any activities in connection with: a generation;

7 The concept of controlling interest adopted by ANEEL is the same as provided in Brazilian corporate law and is associated with prevalence in the company's corporate and managerial decisions.
Brazil

(b) transmission;

c) sale to non-captive consumers;

d) direct or indirect participation in other companies, except for the funding, implementation and management of financial funds for the provision of service; and

e) activities unrelated to the purpose of the concession, except for the cases provided by law or in the concession contract.

The legislation has not imposed, however, the unbundling between the segments of generation and transmission, which has remained bundled up in some economic groups.

ii Transmission/transportation and distribution access

Distribution and transmission companies are subject to regulation of access to their respective grids to avoid discrimination and eliminate barriers to entry. The regulatory framework requires that network companies share and provide access to ‘essential facilities’ to segregate the service provision from the corresponding infrastructure management. For this reason, the electricity sector is governed by the principle of open access to the electrical grid, upon reimbursement of the cost incurred with transportation.

Both ANEEL and the Brazilian Telecommunications Agency (ANATEL) have issued regulations on the reference price applicable to infrastructure sharing (Joint Resolution 04/2014 from ANEEL and ANATEL), because of several disputes over the subject.

iii Rates

Power transmission and distribution companies are subject to price regulation, and thus have their revenues calculated by ANEEL, which aims at setting prices to promote economic efficiency as if these segments were competitive and not characterised as natural monopolies.

Rates are based on the price-cap mechanism (revenue-cap for transmission companies), and thus are subject to adjustment by an inflation rate; and a productivity factor called the X factor is also applicable. The initial rates or revenues are established in the concession contract resulting from either the auction’s competitive process (applicable to new transmission assets), or the privatisation process.

After the initial rates or revenues have been set, they are submitted to annual adjustments for inflation, periodic reviews (every four or five years, depending on the concession contract), and even to further extraordinary reviews to restore the concession’s balance upon ANEEL’s approval.

Therefore, in the periods between periodic reviews, rates are annually adjusted for inflation (and the X factor is subtracted therefrom). Under this regime, concessionaires are encouraged to be more efficient by reducing costs up to the following price review, when new pricing levels are defined by ANEEL. The price control review process basically aims at setting new efficiency standards to operational costs and to the return of the investments, to ensure that private companies receive an adequate remuneration and that consumers pay fair electricity bills. The new standards established will be valid for the new period up to the following price review.
IV ENERGY MARKETS

i Development of power markets

The 2004 restructuring process that established the current regulatory framework for the Brazilian power sector has envisaged two markets in which participants are able to sell power: the regulated market, and the free market.

Within the regulated market, generation companies sell power to distribution companies participating as buyers in public auctions conducted by the government. Generation companies compete against themselves according to the rules of each auction by the lowest bid price (reais/MWh) to sell power to the distribution companies. As mentioned above, new-project auctions also involve the granting of concessions or authorisations to enable the winning bidders to operate new power plants.

The regulated market aims at serving the captive market. In other words, the power bought by distribution companies in the auctions is purchased by captive consumers (defined as not having the choice to select their power supplier). As a rule, distribution companies are under obligation to buy power in the regulated market (aside from a few legal exceptions), and to ensure that 100 per cent of their consumers’ demand is met.

There are three types of auctions in the regulated market:

a new-project auctions, conducted to promote power generation expansion soon enough to enable plant construction, to meet the market consumption growth;

b existing-project auctions, conducted to contract power produced by existing projects, to reduce the financial risks for distribution companies in their demand projections; and

c back-up energy auctions, conducted to increase security of power supply.

The auctions for new projects usually include HPPs designated by the government, but companies may also participate with their own projects (SHPPs, thermal, wind, biomass, and solar projects), which need prior technical qualification before the EPE to be entitled to participate in the auctions. Traditionally, new-project auctions have been:

a A-5 (A minus five), conducted five years before the beginning of supply;

b A-3 (A minus three), conducted three years before the beginning of supply; and

c auctions for structuring projects, conducted to contract strategic projects designated by CNPE.

Recently, new legislation has been enacted to allow new-project auctions to be conducted as from the third until the seventh year after the bid. Accordingly, most recent auctions were launched as A-4 and A-6.

The auctions for existing projects, in which generation companies with projects in operation decide to sell power within the regulated market, typically are:

a A-2 (A minus two), conducted two years before the beginning of supply;

b A-1 (A minus one), conducted one year before the beginning of supply;

c A, conducted in the same year as the beginning of supply; and

d adjustment auctions, conducted to adjust the demand projections of distribution companies.

Recently, new legislation has been enacted to allow auctions for existing projects to be conducted in the same year or up to the fifth year after the bid.
Note that ‘A’ is the year in which the plant must enter operation and start delivering power to the grid.

There are also renewable energy auctions, conducted between years A-1 and A-6 exclusively for contracting new or existing projects that rely on renewable sources. In the last bids, this type of auction has contracted power originated from SHPPs, wind and biomass plants.

In the free market, power is freely traded between the parties entitled to participate in it: generation and trading companies, as well as free and special consumers. Free consumers, who may choose their power generation supplier, need to have a demand higher than 3MW. Former consumers also need to comply with a voltage requirement, which will be waived as from 1 January 2019. Special consumers, which may constitute a consumer or group of consumers that share the same interests, are required to have a demand higher than 500kW and may only choose their supplier when buying from specific renewable sources.

ii Energy market rules and regulations

Sector participants that carry out power trading transactions are under obligation to comply with all of its rules and regulations. As a result of the 2004 regulatory reform, participants must prove that 100 per cent of the power sold in PPAs is associated with generation plants of their own, or belonging to third parties (by means of PPAs to purchase from them), according to the terms set forth by Decree 5,163/2004. While distribution companies need to serve 100 per cent of their market’s demand, sellers need to produce or purchase the same amount sold under PPAs, and consumers need to consume the same amount purchased under PPAs.

If they are not able to produce or purchase the total amount of power traded or consumed, participants will be exposed to the short-term market, proportionally to the amount not produced or purchased, to cover their original PPAs. Financially exposed participants are:

a under the obligation to pay the amount equivalent to the difference between the power contracted and the power delivered or consumed (not covered in additional PPAs), multiplied by the price of financial settlement of differences (PLD);\(^8\) and

b also subject to penalties imposed by the CCEE.\(^9\)

The amount of power allocated to each generation plant is determined by its assured capacity, defined as the maximum amount of power that the plant is allowed to sell and is committed to deliver under PPAs.\(^10\) This calculation is very important as it sets the limit on the power (originating from the plants’ own power generation) available for sale.\(^11\)

The operation of the Brazilian interconnected system may cause the dissociation of the participants’ contractual commitments from the actual physical delivery of the power

---

\(^8\) The CCEE calculates the PLD based on the Operation’s Marginal Cost (CMO) and on a variety of criteria established by legislation (e.g., hydrologic conditions) for each submarket and for each demand level.

\(^9\) The CCEE has responsibility for the processes described – the accounting of the market’s traded power amounts and the financial settlement of the values involved in short-term market transactions.

\(^10\) The assured capacity considers the plant’s expected production and excludes events of unavailability, and may be lower than the installed capacity of the power plant.

\(^11\) While in the regulated market the assured capacity represents the limit available for sale, participants in the free market are able to sell an amount above the assured capacity if they have executed PPAs to cover the total amount sold.
traded. Power production mainly depends on operational decisions made by the ONS, since a number of power plants are subject to centralised dispatch, which reduces the control that companies have over their own plants’ output. A few regulatory mechanisms have been established to mitigate this risk and avoid financial exposure of these participants for reasons they cannot manage, such as the Energy Reallocation Mechanism, applicable to hydropower plants.

iii Contracts for sale of energy

Within the regulated market, as a result of the auction, long-term power purchase agreements are executed among each of the generation companies that have won the bid and the distribution companies buying at the auction. In back-up energy auctions, a back-up energy agreement is executed among, the sellers, and the CCEE, as a representative of all consumers. All contractual conditions – including supply period, rates (set by the low-bid award criteria), and amounts – are defined within the bid process and are not subject to negotiation.

The contracts’ effective terms depend on each type of auction and power source, and may vary from 15 years to 35 years for new-project auctions, from 1 year to 15 years for existing-project auctions, and for up to 35 years in back-up energy auctions. The PPAs may be executed under two modalities: quantity or availability. Under quantity contracts, sellers assume hydrological risks (variations between the amounts contracted and effectively produced) and deliver the power sold at the submarket where the plant is located. Under availability contracts, buyers assume the risks deriving from the plant’s unavailability resulting in a production lower than the amount contracted.

In the free market, participants execute PPAs in which they freely establish conditions, supply period (short, medium or long term), price and amounts, provided that the contractual terms comply with the sector’s rules and regulations, particularly the CCEE’s trading rules and procedures.

iv Market developments

Some developments have been attained recently. Free and special consumers and small generation participants are eligible for representation in their transactions before the CCEE by a ‘retail trading company’, under the terms established by ANEEL’s regulations. Free-market consumers have also been granted the possibility of assigning power to other participants under the conditions set forth in the applicable regulations, despite not being authorised to sell it. Because of concerns raised about over-contracted distribution companies (to serve the relevant market demand) and about the struggle of generation companies to comply with their construction schedules, ANEEL has issued new regulations on mechanisms for contracting-level adjustments by way of bilateral agreements, and on new mechanisms to reduce the distribution companies’ contractual surpluses by assignment of amounts related to new-project PPAs among themselves and by competitive bids to terminate agreements. In addition, more recently, Decree 9,019/2017 was enacted to enable the termination of back-up energy agreements under the conditions established therein, and Law 13,360/2016 allowed the sale of the excess energy by distribution companies to free consumers, under the provisions of ANEEL’s regulations.

---

12 Under availability contracts, the remuneration consists of a fixed amount for the plant to be available, and an additional value that varies according to the plant’s effective production.
V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

One of the most important regulatory policies adopted to encourage the development of renewable power was Proinfa, an incentive programme to encourage the use of alternative power sources, created by Law 10,438/2002. This programme was based on feed-in mechanisms to contract wind, biomass and SHPP projects for a 20-year period. According to the programme regulations, a total of 3,300MW was expected to be contracted under the first phase of Proinfa. The second phase aims to achieve 10 per cent of the annual energy consumption deriving from renewable sources until 2022.

Recent information provided by the EPE, in its 2026 Energy Plan,\(^\text{13}\) shows growth in installed capacity of wind and solar plants of 2,653MW since 2009, and that wind power is the source whose participation through auctions has most grown. The EPE has also stated in the referred plan that, while wind power has become more competitive in price, competitiveness of SHPPs has decreased particularly because of environmental and construction risks. As for solar energy, its installed capacity is still not significant but is expected to grow.

Renewable energy sources are entitled to some regulatory benefits (such as a discount on fees for use of the electrical grid, and the option of selling power to special consumers, under the terms established by law), and also to some special credit lines from the Brazilian public bank BNDES, the National Bank for Economic and Social Development.

The Special Incentives Regime for Infrastructure Development, known as REIDI, is a federal tax-incentive scheme for the development of infrastructure, applicable to the purchase of equipment related to power generation and transmission projects, including renewable energy ones, under conditions established by legislation. At the federal level, a tax incentive is granted for ‘infrastructure debentures’ as well. There are also some local incentives granted by states to encourage the development of renewable sources.

ii Energy efficiency and conservation

The Brazilian power market gained a lot in terms of power efficiency during 2001’s rationing, when the market learned how to make the reduction in consumption required by the government. As the market has suffered rather unfavourable hydrological conditions in recent years, broad awareness campaigns on the country’s exposure to water-shortage conditions have been conducted, possibly as a way of encouraging energy-efficiency measures without recourse to stricter rationing control.

In addition, since January 2015 power rates have been subject to a band pricing scheme, which, by allowing customers to be charged more when the system incurs higher generation costs, represents an important incentive for demand reduction.\(^\text{14}\) Moreover, a new pricing scheme is expected to be available for certain consumers as from January 2019 (others will have the option at later dates), allowing them to pay different rates according to the time and the day of the week of their consumption.

---


14 Green, yellow and red flags indicate lower, medium and higher generation costs. As a result of the recent water shortages, the ONS has continuously dispatched high-cost thermal power plants since the end of 2012, and consumers have had red flags in their bills for some time.
iii Technological developments

In terms of technological developments, the Brazilian market has taken some important steps towards the implementation of smart grid technologies. In addition to regulations on the band pricing scheme, ANEEL has established a net metering policy for renewable micro and mini distributed generation, and has issued regulations imposing a future obligation for distribution companies to install electronic metering for Group B consumers. These measures, taken to allow the integration between power supply and communications technology, aim at improving the quality of service provision and reducing operational costs and technical losses in power supply.

VI THE YEAR IN REVIEW

In 2017, the market experienced a price scenario considerably higher than 2016. Between August and October 2017, the PLD has been subject to fluctuations, particularly because of some periods of rather scarce rainfall, which have put upward pressure on prices, but prices have fallen again as from November 2017. Simultaneously, self-production alternatives have been in fast expansion; for example, net metering, whose installed capacity increased by 440 per cent in 2016 and continued to grow in 2017.

The avalanche of lawsuits, filed by the market’s players not only to prevent losses deriving from the recent major drought, but also to deal with several intervening governmental acts, are still pending. At the same time, distribution companies have been struggling with their over-contracting levels, mainly caused by the current economic projections for the following years and the continual migration of consumers to the free market, which has had more attractive prices lately. A competitive mechanism for the termination of these power purchase agreements with the distribution companies was carried out by ANEEL in August 2017.

The auction of four hydropower plants formerly held by Cemig, which were not renewed under the terms of Provisional Measure 579/2012 (later converted into Law 12,783/2013), was conducted in September 2017. The Chinese company SPIC made the acquisition of...
HPP São Simão for 7.180 billion reais; the French group Engie made the acquisition of HPP Jaguaru and HPP Miranda for 2.171 and 1.360 billion reais; and the Italian company Enel made the acquisition of HPP Volta Grande for 1.419 billion.  

In addition, two new-project auctions A-4 and A-6 were conducted in December 2017 – the first, winning 24 power plants and a total install capacity of 674 MW, was successfully contracted at the average price of 144.51 reais/MWh (mostly solar power); and the second, winning 63 power plants and a total install capacity of 3,841MW, was successfully contracted at the average price of 189.45 reais/MWh (mostly wind power).  

Two existing-project auctions (A-1 and A-2) were also conducted in December 2017, and eight and 13 projects were successfully contracted at the average price of 177.46 and 174.52 reais/MWh, respectively.

During the period in review, two transmission auctions were successfully conducted, marking the entrance and consolidation of foreign companies, in particular the Indian Sterlite Power Grid:

a. on 24 April 2017, the bid contracted 7,068km of transmission lines and substations (investment of 12.7 billion reais); and

b. in December 2017, the bid contracted 4,918km of transmission lines and substations (an investment of 8.7 billion reais).

Mergers and acquisitions transactions were also successfully carried out during the year, such as:

a. the acquisition of the controlling interest in CPFL Energia by State Grid;

b. the acquisition, by Brookfield, of the interest held by Renova Energia SA in TerraForm Global;

c. the acquisition, by CTEEP, of the transmission concessionaire Ienne held by Isolux and Cymi;

d. the acquisition, by Iberdrola Group, of the controlling interest in Neoenergia, by means of the incorporation of Elektro Holding; and

e. the acquisition, by Equatorial Energia, of the controlling interest of the transmission concessionaire Intesa.

VII CONCLUSIONS AND OUTLOOK

The coming years are likely to be a continuation of what has already been an eventful period for the Brazilian market. Although there are issues yet to be addressed, the sector has been adjusting well to the new economic and political scenario, and important transactions can be expected in the near future.

---

20 Information provided by ANEEL. Available at: www2.aneel.gov.br/aplicacoes/editais_geracao/documentos/1%C2%BA%20Relat%C3%B3rio%20Habil.%20final%20-%20Leil%C3%A3o%2001-2017.pdf. Accessed on 26 March 2018.


Following the privatisation of Celg Distribuição in 2016, the privatisation of another six distribution companies belonging to state-owned Eletrobras are projected to have their controlling interests auctioned in May 2018. A different auction is expected by the market for the privatisation of the Eletrobras holding, which is not the same as the privatisation of the distribution companies and currently depends on a bill of law under discussion in the Congress. In addition, the government of the State of São Paulo is studying the privatisation of Cesp, which owns the HPP Porto Primavera.

The market is already responding to the positive signals sent by the government to investors. Increased competition and the entrance of new foreign bidders, in particular Indian and Chinese companies, is likely both in transmission auctions and in mergers and acquisitions. From a financial perspective, investors should be able to adopt original alternatives for financing (e.g., infrastructure debentures), given that the government has been increasing interest rates for loans and will most likely significantly reduce its participation in the sector by either reducing funds made available for certain types of investments or restricting investments from state-owned companies.

The strength of the Brazilian market’s institutions will certainly play an important role in its gradual recovery and stability. EPE estimates that investments in power generation in the years 2017–2026 will amount to 242 billion reais, and another 119 billion reais in power transmission and substation.24 In sum, the Brazilian power sector should be viewed as a target for long-term investments, to the extent that investors are knowledgeable of the characteristics inherent in each type of investment and accurately assess the risks involved.

---
Chapter 9

CHINA

Monica Sun and James Zhang

I OVERVIEW

Energy regulation in China involves a number of stakeholders including various governmental authorities that heavily regulate the energy sector, monopolistic state-owned enterprises (SOEs), private companies that are trying to catch up, foreign companies that have had varying degrees of success, and a vast number of consumers. Currently, and for the foreseeable future, energy regulation in China is anchored in China’s ambitious economic restructuring agenda. Top priority is being placed on environmental goals and the deployment of cleaner energy in China’s economic reform plan. The ‘energy revolution’ proposed in the 13th Five Year Plan for National Economic and Social Development (2016 to 2020) is divided into three main sections, namely the upgrade of the energy structure, the development of energy transmission network, and the establishment of a smart energy internet.

China, as one of the largest economies globally, is deeply embedded in the global energy value chain. The effects of China’s energy consumption and production extend well beyond its borders.

China’s prominent role in the global energy market underlines the importance of understanding China’s domestic energy regulation regime and its market structure. This chapter aims to provide an overview of China’s energy market and regulatory regime with a focus on oil and gas, power, and renewable energy from a foreign investment perspective. We have endeavoured to state China’s energy regulation and practice on the basis of the materials available to us as of March 2018.

II REGULATORY REGIME

In March 2018, a grand government restructuring plan was submitted and approved at the 13th National People’s Congress meeting, which reshuffled the set-up and functions of various ministries and commissions at the State Council (the March 2018 Restructuring Plan). It is expected that similar restructuring will be rolled out to local government in due course. The implementation details of the restructuring plan, such as steps and transition arrangements, are currently not available in the public domain. In this chapter, we will refer to the regulatory bodies and their roles immediately prior to this restructuring, and note any intended shift as set out in the restructuring plan as applicable.

---

1 Monica Sun is a partner and James Zhang is a senior associate at Herbert Smith Freehills LLP.
Regulators

*Oil and gas*

The Ministry of Land and Resources (MLR)\(^2\) is responsible for the supervision and administration of the exploration and exploitation of mineral resources throughout China. It has the authority to grant the licences required for the exploration and production of crude oil and natural gas in China. It also plays a role in examination and approval of blocks open to private and foreign investment.

The National Development and Reform Commission (NDRC) is in charge of setting out and implementing policies in respect of the oil and gas sector. It is also responsible for approving certain investment projects. The National Energy Administration (NEA) is established under the NDRC, with broad duties ranging from drafting energy strategies, proposing reform advice, implementing the management of energy sectors to overseeing overall development plans (ODP) for individual oil projects, or for oil and gas projects.

The Ministry of Commerce (MOFCOM) was previously in charge of review and approval of making, and amendments of, all production sharing contracts (PSCs). This approval is no longer required, and has been replaced with a record filing requirement at MOFCOM.

*Power*

The NDRC also has the authority to approve certain investment projects in the power industry.

The Market Regulatory Department of the NEA (which took over from the State Electricity Regulatory Commission) regulates the power industry. It is responsible for the enactment and enforcement of regulations in this industry, and also for granting power business permits to power companies.

*Other regulators*

Other regulators include:

\(a\) the Ministry of Environmental Protection (MEP);\(^3\) in charge of administering and enforcing environmental protection matters in China;

\(b\) the National Nuclear Safety Administration;\(^4\) an authority under the MEP that acts as the central government agency responsible for regulating nuclear safety, supervising all civilian nuclear infrastructure in China. It also inspects nuclear safety activities and regulates the approval mechanism; and

\(c\) the State Administration of Work Safety;\(^5\) responsible for overseeing and administering work safety nationwide.

---

\(2\) According to the March 2018 Restructuring Plan, the Ministry of Land and Resources will be dissolved and its functions will be taken over by the newly established Ministry of Natural Resources.

\(3\) According to the March 2018 Restructuring Plan, the Ministry of Environmental Protection will be dissolved and its functions will be taken over by the newly established Ministry of Ecological Environment.

\(4\) According to the March 2018 Restructuring Plan, the National Nuclear Safety Administration will be shifted to be under the newly established Ministry of Ecological Environment.

\(5\) According to the March 2018 Restructuring Plan, the State Administration of Work Safety will be dissolved and its functions will be taken over by the newly established Ministry of Emergency.
ii Laws and regulations

China has many laws and regulations governing its energy sector, including the following.

**Oil and gas**

a The Mineral Resources Law (1986, amended 1996 and 2009) and its Implementation Rules (1994) establish the basic legal framework under which exploration and production activities (including oil and gas development) are to be carried out.

b The Oil and Natural Gas Pipeline Protection Law (2010) provides for the security requirements for the construction and operation of pipelines.

c The Regulation on Registration of Exploitation of Mineral Resources (1998, amended 2014) provides detailed requirements on the registration of mineral resources exploitation and the issuance of exploitation licences.


f The Regulation on Sino-foreign Cooperation in the Exploitation of Offshore Petroleum Resources (1982, amended 2001, 2011 and 2013) is the basis for foreign companies to participate in the exploration and exploitation of offshore blocks in China through PSCs.

g The Measures for Regulation of Fair and Open Access to Oil and Gas Pipeline Facilities (for Trial Implementation) (2014) (Third-party Access Measures) provide the third-party access regime, allowing third parties to use the surplus capacity of pipeline facilities.

h The Measures for the Administration of Natural Gas Pipeline Transportation Prices (for Trial Implementation) (2016) provide that the pipeline transportation price is determined by the price administration department under the State Council following the principle of ‘allowed cost plus reasonable profits’.

i The Measures for the Supervision and Review of Natural Gas Pipeline Transportation Pricing Costs (for Trial Implementation) (2016) provide that the price administration department under the State Council shall be in charge of the supervision and review of pipeline transportation pricing cost following the principle of legality, the principle of relevance and the principle of rationality.

j The Guiding Opinions on Strengthening Regulations over the Gas Distribution Price (2017) provide that gas distribution price shall be determined and reviewed separately, following the principle of ‘allowed cost plus reasonable profits’.

k The Opinions regarding Further Reform of Oil and Gas Regime (2017). This ‘Opinions’ document was issued by CCP Central Committee and the State Council, and was long expected to set out roadmap for next phase reform in the oil and gas sectors. However, the full text of the document is not yet available in the public domain.
**Power**

- The Electric Power Law (1996, amended 2009 and 2015) is the main legislation governing the electricity sector.
- The Circular on the Reform Plan for Power Prices (2003) sets out the targets for the power price reform and is followed by the Regulation on Feed-in Tariffs (2005), the Regulation on Power Sales Price (2005) and the Regulation on Transmission and Distribution Price (2005).
- The Regulations on Electricity Regulation were issued in 2005 to strengthen and improve electricity regulation, focusing on maintaining the order of electricity markets and promoting the development of the electric power industry.
- The Administrative Regulations on Permits for the Power Industry (2005) focus on maintaining the order of the electricity markets and promoting the development of the electric power industry.
- The Opinions regarding Further Reform of the Electric Power Regime (2015) set out the plan for further reform.
- The NDRC and NEA Circular on Issuing Administrative Measures on Electricity Companies’ Entrance and Exit and Administrative Measures on Orderly Derestricting the Electricity Distribution Network Business (2016) provide opportunities for social capital to enter into the electricity distribution industry.
- The NDRC and NEA Circular on Orderly Derestricting the Power Generation and Consumption Plans (2017) provides plans for promoting electricity traded through market-based transactions.

In addition, there are numerous regulations and rules enacted by various administrative authorities, to define specific procedures or particular issues with respect to the electricity sector under the framework of the main law and regulations.

**Renewables**

- The NEA Notice on Facilitating the Development of Geothermal Power (2013) is aimed at promoting the development and utilisation of geothermal power.
- The NDRC Notice on Adjustment of Feed-in Tariffs for Onshore Wind Power and Photovoltaic Power Generation Projects (2017) provides for the feed-in tariff for onshore and offshore wind farms and solar energy projects.
- The Administrative Regulation on Guaranteed Purchase of Renewable Energy-generated Power in Full Amount (2016) sets out detailed rules to guarantee the purchase of renewable energy generated power (excluding hydropower).
China


iii Regulated activities

Oil and gas

As mentioned above, exploration and production activities are subject to exploration and exploitation licences issued by the MLR.

In upstream oil and gas exploration and exploitation, foreign companies should partner with and enter into PSCs with legally designated national oil companies (for details, see Section II.iv, below).

Pipeline design and construction are subject to review based on criteria related to safety, environmental protection, optimal land use and economic feasibility. The construction of oil and gas pipeline networks must be approved by the NDRC or its local branches. The qualifications of the enterprises and personnel engaged in the design, installation, use and inspection of pipelines must be accredited by the General Administration for Quality Supervision, Inspection and Quarantine or its local counterpart as the case may be.

A specific business permit is required to engage in crude oil storage or trading; or refined oil wholesale, retail or storage.

Power

Power companies are required to obtain electric power business permits issued by the NEA. Electric power business permits are divided into three categories depending on the type of business:

a. a power generation permit for power generation companies;
b. a power transmission permit for power transmission companies; and
c. a power supply permit for power supply companies (power supply business is defined to cover both distribution and sale of power).

A company applying for an electric power business licence must demonstrate that it has the financial capability and personnel with the required experience. In addition, power companies must obtain approval for each specific power project from relevant authorities and comply with environmental regulations to be issued with the electric power business licence.

Through an NEA notice issued in April 2014 and further amended in December 2016, the following type of generation projects enjoy a general exemption to apply for a power generation licence:

a. distributed generation projects registered or approved by the NEA;
b. small hydropower stations with single-station generating capacity below 6MW;

According to the March 2018 Restructuring Plan, the General Administration for Quality Supervision, Inspection and Quarantine will be dissolved and its functions will be taken over by the newly established General Administration for Market Regulatory.
new-energy generation projects such as solar, wind, biomass, ocean power and geothermal power with generating capacity below 6MW;

power projects with comprehensive use of heat and pressure by-products; and
captive power plants without direct combustion of fossil fuel and that are dispatched by dispatching organisations at city level or below.

iv Ownership and market access restrictions

Oil and gas

The state has ownership over all mineral resources within the territory of China. Pursuant to the Mineral Resources Law, a licensing regime has been adopted and the MLR has the authority to grant exploration licences and production licences. Applicants for exploration licences or exploitation licences must be approved by the State Council to engage in oil and gas exploration and production activities. The approved companies are national oil companies (NOCs) and include China National Petroleum Corporation (CNPC), China Petrochemical Corporation (Sinopec) and China National Offshore Oil Corporation (CNOOC). However, the state has been piloting energy reform in Xinjiang province since November 2016, which includes reducing market access restriction. In particular under the pilot programme, the state further encourages diversified entities to enter into oil and gas exploration and production activities. In early 2018, a private-controlled listed company successfully bid for exploration rights of Wensu Block in Tarim Basin, Xinjiang province.

Foreign companies can partner with designated Chinese oil companies (usually CNPC, Sinopec or CNOOC) through the PSC regime to invest in onshore and offshore exploration and production in China.

Regarding unconventional oil and gas, exploration and exploitation of coalbed gas generally follows the regime for conventional oil and gas – exploration licences and exploitation licences are granted to designated companies and foreign companies can invest through the PSC regime. There is, however, more flexibility in shale gas for foreign investors. Under the current regime, foreign companies can either partner with Chinese companies holding an exploration licence of a shale gas block under a PSC, or establish a joint venture with a Chinese partner to bid for the licences directly. Owing to the continuing efforts of de-regulation as explained below, future opportunities are expected to be available for wholly owned foreign companies.

The Foreign Investment Industrial Guidance Catalogue issued jointly by the NDRC and MOFCOM sets out encouraged, restricted and prohibited activities and sectors. The latest version was issued in 2017 (the 2017 Catalogue). Any activity or sector not included in the Catalogue is permitted. Projects that are ‘encouraged’ benefit from simpler approval procedures and customs and tax incentives. ‘Restricted’ activities and sectors must generally be approved at higher levels of government, which means that approvals can be harder to obtain.

Oil and gas exploration and production are ‘encouraged’ activities in the 2017 Catalogue. Other than specific types of unconventional resources (namely oil shale, oil sands and shale gas), upstream oil and gas requires sino-foreign joint venture or cooperation. A PSC is a well-recognised type of ‘cooperation’ for this purpose. Specific unconventional resources are now, strictly speaking, open to wholly foreign owned investors; however, in most recent shale gas bidding rounds (MLR second tender in 2012 and Guizhou tender in 2017), the tender still required sino-foreign joint venture to bid.
The midstream oil and gas industry, however, is dominated by NOCs. CNPC controls nearly all the long-distance pipelines in China, including the West-East Pipelines. The CNPC website states that the CNPC owns and controls 70 per cent of the nation's crude oil pipeline and 76 per cent natural gas pipelines by the end of 2016. In December 2015, CNPC consolidated a sprawl of pipeline operations in a single company with a registered capital of 80 billion yuan, aiming to improve efficiency and boost the value of the businesses. It is considered a step towards potential divestment in future, as well as a prologue to the government's bigger plan to reform the energy regime in China, including to strip oil companies of their pipeline assets and set up an independent national pipeline company or regional pipeline companies that would own and operate oil and gas pipelines.

Construction of new imported LNG receiving terminals of capacity of 3 million tonnes and above is subject to central government approval. Most of the LNG terminals are owned and operated by the three NOCs (i.e., CNOOC, CNPC and Sinopec). In recent years, private entities as well as foreign entities have started to participate in this sector as well. As of February 2018, there are three small-scale LNG terminals in operation that have been established by private investment, and several in construction. See Section III.ii, below, for details of third-party access to infrastructure.

The downstream oil and gas sector is still dominated by NOCs. Sinopec has focused on downstream activities, such as refining and distribution, with these sectors making up over 70 per cent of the company’s revenues in recent years.

**Power**

The main market players in the power industry include power companies (among which the five large state-owned generators are China Huaneng Group, China Datang Corporation, China Huadian Corporation, State Energy Investment Corporation (through the recent merger of China Guodian Corporation and China Shenhua Group) and State Power Investment Corporation (through the recent merger of China Power Investment and State Nuclear Power Technology Corporation), two grid companies (namely, State Grid Corporation of China and China Southern Power Grid Co.) and companies engaged in power engineering and construction business (such as China Energy Engineering Group Co. and Power Construction Corporation of China).

The main opportunities for foreign investors in the power industry lie in the construction and operation of power stations with certain technologies and renewable energy. Specifically, the following types of business in the power industry are ‘encouraged’ in the 2017 Catalogue:

- **a** construction and operation of ultra-supercritical power stations with single unit power of 600,000kW or more;
- **b** construction and operation of power stations for heat-power co-generation units of back-pressure (extraction-back) type, heat-power-cool multi-generation units, and heat-power co-generation units of 300,000kW or more;
- **c** construction and operation of power stations with large air-cooled generation units with single unit power of 600,000kW or more in regions suffering from water shortage;
- **d** construction and operation of projects of power generation via integrated gasification combined cycle and other clean coal power generation projects;
- **e** construction and operation of power generation projects with single unit power of 300,000kW or more that use fluidised bed boilers and coal gangue, middling, and coal slurry.
construction and operation of hydropower stations for the primary purpose of power generation;

construction and operation of nuclear power stations (the Chinese party must hold a controlling interest);

construction and operation of new-energy power stations (including solar energy, wind energy, geothermal energy, tidal energy, wave energy and biomass energy); and

construction and operation of a power grid (the Chinese party must hold a controlling interest). This was previously a ‘restricted’ item under the 2011 Catalogue.

It is worth noting that, although they are not specifically addressed in the 2017 Catalogue, the following types of projects are generally restricted, which applies to all (foreign or domestic) investors, pursuant to Interim Provisions on Construction Management of Small Thermal Power Units (1997) and the NDRC Guiding Catalogue for Industrial Structure Adjustments (2011):

- power plants utilising coal-fired and steam condensation thermal generator sets whose single generator capacity is 300,000kW or less and connected to small grids;
- thermoelectric power stations utilising coal-fired steam condensation and extraction thermal generator sets whose single generator capacity is 100,000kW or less and connected to small grids; and
- the above types of power plants (in the case of thermoelectric power stations, the capacity threshold is 200,000kW) connected to large grids.

Transfers of control and assignments

The transfer of exploration rights and exploitation rights for mineral resources (including oil and gas) is allowed provided that the following conditions are met:

- two full years have passed since the issue of the exploration licence, or the discovery of the mineral resources available for further exploration or exploitation in the exploration zone; or one full year has passed since the exploitation enterprise began exploitation;

- the specified minimum input for exploration has been fulfilled;

- no disputes have arisen regarding the ownership of the exploration rights and exploitation rights;

- the exploration right usage fees, exploitation fees or any price for the exploration and exploitation rights have been paid; and

- a transferee of mineral exploration rights or exploitation rights should meet the qualifications of a mineral exploration right applicant or exploitation right applicant prescribed in the Measures for Area Registration Administration of Mineral Resources Exploration and Survey or the Measures for the Registration Administration of Mineral Resources Exploitation.

The MLR will decide whether to approve the transfer within 40 days of receipt of the application. The transfer will take effect as of the day of approval.

As mentioned above, in most cases, the rights for exploration and exploitation of oil and gas are held by the three NOCs, with whom the foreign investors would enter into a PSC. There is no regulatory requirement for transfer of participating interest under a PSC. Previously, any amendments to the PSC were required to be approved by MOFCOM. This requirement was abolished in 2013 and now only record filing with MOFCOM is required. In practice, Chinese PSCs often provide that the consent of a foreign investor is required if
the NOCs propose to take over the production operations before foreign contractors’ full recovery of the development costs. After the full recovery of the development costs incurred in accordance with the ODP of any oil or gas field within the contract area, the NOCs may, at any time, have the right to take over the production operations by giving a written notice to the foreign contractor.

Transfer of power generation units in operation requires a change to the power business licence, which needs to be approved by the NEA. The NEA will review if the requirements for granting the relevant licences are still satisfied.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

The State Grid and China Southern Grid control the electricity transmission and distribution networks in China, and are used to monopolise the supply of electricity by purchasing power from power generators at regulated feed-in tariff, and sell power at the regulated power sales prices.

The ongoing power price reform, however, aims to separate the sale of power from grid companies. The Opinions regarding Further Reform of the Electric Power Regime (2015) and the NDRC and NEA Circular on Issuing Supporting Documents for Electric Power System Reforms (2015) provide that power generators will enter into agreements directly with retailers or users with term contracts or spot trades, with the power price being freely negotiated between the parties. The transmission and distribution tariff will be regulated by the government on a ‘cost plus reasonable profits’ basis. According to the Notice by the NDRC regarding Comprehensive Promotion of Pilot Reform of Transmission and Distribution Tariff (2016), this reform is now carried out in most provinces.

Since 2009, the user-generator direct trading system has been put on trial in more than 20 provinces. Companies with high electricity consumption (such as aluminium electrolysis and steel plants) can purchase electricity directly from generators. The price paid by such consumers is composed of the power purchase price negotiated between the generator and the consumer (under a power purchase contract), the transmission and distribution price paid to the grid company (under a service contract) and government surcharges. The Opinions regarding Further Reform of the Electric Power Regime (2015) also set out further goals for the development of this user–generator direct trading system.

ii Transmission/transportation and distribution access

Oil and gas

China established the third-party access scheme in the Third-party Access Measures for a trial period of five years. In addition, The Regulation on Construction and Operation of Natural Gas Infrastructure (2014) encourages investment into natural gas facilities.

Under the Third-party Access Measures, pipeline and facility operators should grant third parties access to pipeline networks and associated facilities if operators have surplus capacity and, in the case of multiple third-party users, non-discrimination principles should apply, but priority should be given to contracts already in place. The facilities to be opened to third parties include not only trunk pipelines and branch pipelines for crude oil, refined oil and natural gas, but also the relevant associated facilities including ports, receiving terminals, and liquefaction, compression and storage facilities.
Power

A grid operator must ensure non-discriminatory and fair access of its grid to qualified power plants and disclose the following information to power plants within its network:

a) grid structure and line layouts;

b) amount and status of transformation facilities;

c) total installed capacity;

d) power supply and demand and transmission capacity of major lines and outgoing lines; and

e) tariffs and prices for inter-provincial power transactions and direct trading.

An interconnection agreement will be entered into by the grid operator and the power generator, specifying terms and conditions including capacity and feed-in tariff.

Grid companies must ensure non-discriminatory and fair access to their grid to qualified power plants.

For renewable power generation (RPG) enterprises, the grid operators are required to:

a) build and manage the interconnection system for qualified RPG projects;

b) enter into grid connection agreements with qualified RPG enterprises; and

c) purchase all the on-grid power generated by these RPG projects at a higher feed-in tariff.

iii Rates

Oil and gas

According to Measures for the Administration of Natural Gas Pipeline Transportation Prices (for Trial Implementation) (2016) and Measures for the Supervision and Review of Natural Gas Pipeline Transportation Pricing Costs (for Trial Implementation) (2016), inter-provincial pipeline transportation tariffs are regulated by the NDRC on the 'allowed cost plus reasonable profits' basis. The NDRC completed the costs assessment of 13 interprovincial pipeline systems in August 2017 and published reduced tariffs effective from September 2017. Intra-province pipeline transportation tariffs are regulated by local development and reform commission and are reported to the NDRC annually.

According to the NDRC Circular on Issuing the Guiding Opinions on Strengthening Regulations over the Gas Distribution Price (2017), gas distribution price shall be determined and reviewed separately, following the principle of ‘allowed cost plus reasonable profits’. This marks a further big step by the state to achieve the goal of ‘regulating middle while liberalising the front and end’.

Power

In theory, the rates that the grid companies charge end users seek to recover power purchase costs and fees for transportation, distribution and sale services, power losses and the like. However, in practice, the rates are set by the government and vary depending on the type of user and the region.

iv Security and technology restrictions

Oil and gas pipeline owners and operators have obligations under the Oil and Natural Gas Pipeline Protection Law, including those to patrol, inspect and maintain the pipelines; to
upgrade, transform or stop using those pipelines that do not satisfy the safe use requirements in a timely manner; to post, repair or change signs related to the pipeline; and to take effective safety protection measures for a pipeline not in operation.

As gas pipelines are considered to be ‘specialised equipment’ under the specialised equipment regulatory regime, a pipeline operator is required to hold a Specialised Equipment Registration Certificate. In addition, both natural gas and gas pipelines are considered to be ‘hazardous material’ under the hazardous material regulatory regime. The ‘producer’ of hazardous material is required to hold a Production Safety Permit and the ‘trader’ of hazardous material is required to hold a Hazardous Material Operation Permit. However, it is not clear whether the pipeline owner and operators will be considered producer or trader of hazardous material.

Power grid operators also have security obligations under the Electricity Law. The power grids shall be operated in accordance with the principles of safety, high quality and economy. Power grid operations must be maintained in an uninterrupted and stable way, with a stable supply of electricity guaranteed.

IV ENERGY MARKETS

i Development of energy markets

The price of refined oil products is regulated by the NDRC. Gas (including LNG) price used to be heavily regulated by the NDRC, but there has been a steady progress of deregulation. According to an NDRC press release, as of October 2017, the price for 50 per cent of all gas consumption in China is completely deregulated, and 30 per cent is regulated on base-price basis. The remaining 20 per cent is for residential use and the price for this portion is still regulated.

In August 2016, the State Council clearly pointed out in its notice regarding lowering real economic business costs, one of the essential plans is to liberalise the prices in competitive sections (in particular, to speed up market-oriented reform in oil and natural gas). In addition, in the Opinions regarding Further Reform of Oil and Gas Regime (2017), the CCP Central Committee and the State Council further instruct on the market-oriented reform in oil and natural gas, and more supporting policies are expect to be issued in 2018.

As mentioned above, under the current regime, grid companies purchase power from power generation companies at regulated fixed prices and sell power to the customers at regulated fixed prices. Generation is dispatched on a fair and equal basis.

Under the ongoing power price reform, the Chinese government is exploring the possibility of opening up electricity markets. The aim at this stage is to establish a mid-to-long-term market and a spot market.

ii Energy market rules and regulation

Oil and gas

To engage in crude oil storage or trading, or refined oil wholesale or retail, a specific business permit issued by MOFCOM is required. There are certain requirements for applicants to obtain a business permit, including a certain amount of registered capital, long-term supply agreements, and stable sales channels and facilities. Foreign-invested enterprises may also apply for permits.
State trading enterprises and non-state trading enterprises may engage in the importation of crude oil and refined oil. MOFCOM publishes a list of state trading enterprises, and companies outside that list may become a non-state trading enterprise if they:

a. have a foreign trade business qualification;
b. satisfy the requirements published by MOFCOM; and
c. register with MOFCOM.

Both state trading enterprises and non-state trading enterprises must obtain an import licence issued by MOFCOM. However, non-state trading enterprises shall be subject to import quotas. This quota for the year 2018 is 142.42 million tonnes. In 2015, MOFCOM also issued a notice setting out the detailed requirements for refineries to import crude oil, including requirements regarding equipment, product quality, safety management and personnel.

Use of imported crude oil was previously limited to NOCs. In February 2015, however, the NDRC issued a notice breaking the monopoly. Local refineries can now apply to use imported crude oil if they meet certain requirements, including requirements regarding equipment, product quality and safety management. Thirty-two refineries have obtained a permit from the NDRC to use imported crude oil as of December 2017.

There is no market entry restriction on the import or export of gas or LNG.

In addition, trading of oil and gas requires safety permits under, for example, the hazardous material regulatory regime.

**Power**

Sale of power to customers has been largely controlled by the State Grid and China Southern Grid through their subsidiaries. Under the power sector reform, however, we expect to see more participants in the market. Apart from the user–generator direct trading system, the NDRC and NEA Circular on Issuing Supporting Documents for Electric Power System Reforms (2015) also allows independent power supply companies to participate in the market provided that certain conditions, including on total assets, equipment and expertise, and the electric power business licence issued by NEA, are met.

**iii Contracts for sale of energy**

**Oil and gas**

There are two types of government regulated prices:

a. government fixed price; and
b. government guidance price.

The former is fixed and there is no flexibility, while the latter is more flexible. Government guidance price can be in the form of:

a. a benchmark price with a float range;
b. maximum price;
c. minimum price;
d. the rate of price difference; and
e. the profit rate.

When a foreign company invests in upstream oil and gas through the PSC regime, parties would normally agree in the PSC that the NOC will sell the foreign investor’s share of oil...
and gas on its behalf. Usually the price is determined by reference to the prevailing price in an arm’s-length transaction for a long-term sales contract of similar quality of crude oil in the main world oil markets with adjustment to be made for quality, delivery, transportation, payment and other terms, and expressed as ‘free on board’ price at the delivery point in China.

Upstream crude oil prices and gas prices are not regulated, while refined oil prices and natural gas prices at city gate are subject to government regulation:

a. the retail and wholesale of gasoline and diesel, as well as sale of gasoline and diesel to wholesale business, railway customers and transportation customers are subject to the governmental guidance price; and

b. the supply of gasoline and diesel for state reserves or Xinjiang Production and Construction Corps as well as the factory price of aviation gasoline are subject to government (fixed) pricing.

The price of gasoline and diesel will be adjusted every 10 business days based on international crude oil price, processing cost, taxes, transmission fees and reasonable profits.

The government provides for base price of natural gas at the city gate (which means parties may negotiate the city gate price and such price shall not exceed 120 per cent of base price) while the ex-factory price can be negotiated between parties. The prices of gas produced from shale gas, coalbed gas, coal gas and imported LNG are deregulated and can be determined by parties. The price for direct sale arrangement between CNPC/Sinopec and industrial users under ‘direct supply arrangement’ is also deregulated. In order to accelerate the gas price reform, the state started a pilot programme in Fujian province in November 2016, whereby the city gate prices will be determined freely based on negotiation between the supplier (CNPC) and consumers (utilities), and not subject to government regulation.

**Power**

To a large extent, the power prices are set by the government, taking into account the power purchasing cost, the loss from power transmission and distribution, power transmission and distribution price and government funds. The prices vary depending on a number of factors including season, peak hour, region and type of user (namely, residential user, agricultural user and industrial and commercial user).

Customers are allowed to participate in the power market if certain criteria are met, and may choose to enter into power purchase agreements with (1) power supply companies, or (2) directly with power generators. The terms and conditions of these agreements can be freely negotiated between two parties.

The Opinions regarding Further Reform of the Electric Power Regime (2015) and the NDRC and NEA Circular on Issuing Supporting Documents for Electric Power System Reforms (2015) set out future steps to further facilitate the reform, including determining qualified generators based on energy conservation and environment protection requirements; expanding the direct trading to power supply companies; and encouraging long-term agreements between generators and customers.

**V RENEWABLE ENERGY AND CONSERVATION**

As part of government policies in response to climate change and in line with China’s commitments to the international community, the State Council set an objective to
control energy consumption to 5 billion tonnes of standard coal in the 13th Five-Year Plan period (2016 to 2020). The NDRC also set Mid-to-Long Term Plans for renewable energy development: 10 per cent of the total energy consumption should be sourced from renewable energy by 2010, and 15 per cent by 2020. The midterm target (10 per cent by 2010) has been achieved. In July 2017, the NEA issued Guidelines of the National Energy Administration on the Implementation of the 13th Five-Year Development Plan for Renewable Energy, listing the overall development plan for wind power, biomass and solar plants for 2017–2020.

In addition, the Chinese government has established a clean development mechanism fund to support construction and industrial activities that are beneficial to strengthen proper responses to climate change since 2010. The construction and operation of power stations using renewable energy is ‘encouraged’ under the 2017 Catalogue.

Under the current power regime, the government sets higher feed-in tariffs (FITs) to encourage power generation from renewable energy. The table below sets out the feed-in tariffs for wind, biomass and solar power.

<table>
<thead>
<tr>
<th>Electricity source</th>
<th>FITs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>Onshore project: four tiers ranging from 0.4 yuan/kWh to 0.57 yuan/kWh, depending on project locations (for projects approved after 1 January 2018 and projects approved before 1 January 2018 but not in construction at the end of 2019). Offshore projects: 0.85 yuan/kWh or 0.75 yuan/kWh depending on the distance to shore.</td>
</tr>
<tr>
<td>Biomass</td>
<td>0.75 yuan/kWh</td>
</tr>
<tr>
<td>Solar</td>
<td>Three tiers ranging from 0.65 yuan/kWh to 0.85 yuan/kWh, depending on project locations, for projects initiating operation from January 2017. For projects initiating operation from January 2018, the FITs range from 0.55 yuan/kWh to 0.75 yuan/kWh.</td>
</tr>
</tbody>
</table>

**Other incentives include:**

- **a** surcharges collected from end users, which are used to subsidise the difference between feed-in tariffs and the benchmark price for desulphurised coal generators, operations and maintenance for independent public power systems, and costs for connecting renewable energy generators to power grids;
- **b** favourable loans with financial discounts for renewable energy projects listed in the guidance catalogue for renewable energy industry development;
- **c** subsidies for renewable energy development in areas such as new-energy vehicles, building-integrated solar photovoltaic systems, wind turbines and biomass power generation; and
- **d** tax incentives.

Also, the NDRC approved a nuclear project in March 2015 marking the official relaunch of nuclear projects in China. The Mid-to-Long Development Plan of Nuclear Power by the State Council sets the target for nuclear power at installed capacity of 58 million kW and 30 million kW under construction by 2020, which means a shortfall of 39 million kW. The industry is expecting a large wave of investment into nuclear power in the near future. In March 2016, Shenhua, China’s largest coal producer (now part of the State Energy Investment Corporation) was reported to be in talks with leading Chinese nuclear developers China National Nuclear Corporation and China General Nuclear Power Corporation on taking stakes in domestic nuclear projects, as part of its efforts to diversify into cleaner forms of energy. Despite the NEA’s earlier plan to promote eight new projects in 2017, no new nuclear projects were actually approved by the State Council during 2016 and 2017.
In order to help reduce government subsidies to the renewables sector, the NDRC, together with the Ministry of Finance and the NEA, issued a Circular on the Trial Implementation of the Renewable Energy Green Power Certificate Issuance and Voluntary Subscription Transaction System (the Green Power Certificate Circular) in January 2017. According to the Green Power Certificate Circular, solar and wind power producers would apply for and be issued tradeable certificates for the renewable electricity generated by them. End users are encouraged to buy such certificates at an agreed price through negotiation or a bidding process. Solar and wind power producers will not receive a direct subsidy (higher FITs) for the electricity corresponding to the certificates sold. The NDRC indicated that the state may launch a mandatory green certificate scheme in 2018. In July 2017, an official website for trading of the Green Power Certificate was launched. As of October 2017, while over 8 million certificates were issued, only around 20,000 certificates were traded.

Also aiming to promote clean energy, a carbon emissions trading system has been operated on a pilot basis in parallel. In December 2017, the NDRC announced the plan to roll it out to the national level. The interaction and reconciliation between the green certificate regime and the carbon emissions trading system are to be further observed in the future.

VI THE YEAR IN REVIEW

In February 2017, the State Council released the 13th Five Year Plan for Energy Development (2016 to 2020), listing future energy strategies for an efficient, clean and safe energy system. According to the Plan, the annual primary energy consumption will be capped at an amount equivalent to 5 billion tonnes of standard coal by 2020. The Plan sets goals on future energy structure, with at least 15 per cent of energy supplied from non-fossil fuels, 20 per cent supplied from natural gas and at most 58 per cent from coal by 2020.

China also continues towards achieving the marketisation of its energy supply. Gas price deregulation is the most advanced in progress compared to other subsectors. As of October 2017, the price for 50 per cent of all gas consumption in China is completely deregulated, and 30 per cent is soft-regulated on base-price basis. The remaining 20 per cent are for residential use and only the price for this portion is still regulated. Meanwhile, reform on gas pipeline infrastructures (most notably the third-party access regulations and tariff regulations) secures the foundations of large-scale trading to be emerged. Shanghai Petroleum and Natural Gas Exchange started commercial operation in November 2016, and a second exchange of similar nature was launched in Chongqing in January 2017 and is expected to start trading in early 2018. The deregulation of gas price coincides with a jump in gas demand. In 2017, the total gas consumption increased 15.3 per cent from 2016, to 237.3 billion cubic meters. This shooting demand, coupled with an insufficient capacity of gas storage and LNG importation infrastructure, caused a severe gas shortage during winter 2017–2018 in China, which pushed up the entire northern Asia LNG spot market. The gas shortage has drawn further attention to the need of further development of, and third-party access to, gas infrastructures.

In 2017, the Chinese coal mine industry continued to focus on reducing excessive industrial capacity by closing small local coal mine companies and reorganising big coal mine SOEs. The NDRC also emphasised that its goal in the near future is to promote industry
upgrading and transformation by reorganising big coal mine SOEs. Such an industry goal is consistent with the 13th Five Year Plan for Energy Development (2016 to 2020), pursuing a more efficient, clean and safe energy system in China.

The year 2017 also saw major players in the power sector consolidating, underscored by the Chinese government’s grand plan to improve the efficiency and competitiveness of SOEs. Most notably, Shenhua and Guodian merged into the State Energy Investment Corporation, creating a giant with the largest amount of coal-fire installed capacity and the largest renewable installed capacity in the world. China Power Investment and SNPTC merged into the State Power Investment Corporation, becoming the only energy group in China operating all types of hydro, coal-fire, nuclear and renewable power plants. On the nuclear side, China National Nuclear Corporation (CNNC) acquired and absorbed China Nuclear Engineering and Construction Group Corporation (CNECC), consolidating the resources to push forward with the going-out of China’s nuclear technology.

VII CONCLUSIONS AND OUTLOOK

The regulatory environment is changing fast in China, and the energy sector is no exception. Both the economic restructuring plan and the development of green-energy technology have had a profound influence on the energy industry. Various stakeholders and their demands contribute to innovation in the industry, while also adding complexity to the reform process. With reforms taking place in the regulatory regime and the restructuring of the market ongoing, it is vital to keep a close eye on energy regulations in China.
Chapter 10

COLOMBIA

Jose V Zapata and Daniel Fajardo Villada

I OVERVIEW

In past decades, the energy sector in Colombia has been one of the main pillars of development and growth of the country’s economy while contributing significantly to the national budget, which is devoted to infrastructure and social development, as result of the collection of royalties, taxes and dividends.

Although nowadays the country is a target for international investment, having extensive trade relations and an attractive business environment,² it is undeniable that there is currently an environment of uncertainty in Colombia, which has had adverse effects on international investment and on the country’s credit rating. However, some elements should be highlighted as providing a positive boost for the economy and investment: the ongoing implementation of the peace process with the Armed Revolutionary Forces of Colombia (FARC) ending an armed conflict of over 50 years and the reactivation of the peace talks between the National Liberation Army (ELN) and the government have made Colombia more attractive to foreign investors.³

As result of the issuance of the Colombian Constitution in 1991, the Colombian electricity sector has been transformed from a sector with total governmental ownership into a clearly separate sector in terms of the roles of service providers or utilities and regulation, policymakers and control and oversight agencies. Since then, this sector has existed on three main levels. First the Ministry of Mines and Energy (MME), which governs policy and establishes the long-term plans for the whole sector. Second, the Energy and Gas Regulation Commission (CREG), which sets out the rules and roles of each of the participating agents, while also focusing on quality and price for the end user. And third, the Superintendence of Domiciliary Public Utilities (SSPD) an inspection, monitoring and surveillance body that oversees operators and guarantees supply to the end user.

¹ Jose V Zapata is a partner and Daniel Fajardo Villada is an associate at Holland & Knight.

© 2018 Law Business Research Ltd
The main power source used in Colombia is hydropower, which represents 70 per cent of the installed capacity, followed by thermal power stations operating with coal and gas with a share of 20 per cent. The remaining energy is obtained and supported by other sources such as cogeneration, with a share of 1.03 per cent; and wind, which only adds 0.11 per cent.\(^4\)

In terms of connectivity, the Colombian electricity sector is divided as follows: on the one hand, the National Interconnected System (SIN), which comprises generation plants, the interconnection network, the regional and interregional transmission networks and distribution networks, all connected to each other; and on the other hand, the non-interconnected zones, where electric service is not provided by the national network but by independent small-scale systems.

## II REGULATION

### i Regulators

The Colombian Constitution, issued in 1991, conferred legislative power on Congress and granted regulatory power to the national government, which in turn exercises such power through the regulatory entities that serve the energy sector via decrees and resolutions.

Specifically, the determination of policies and issuance of regulation is undertaken by several government entities, as follows.

On the one hand, the MME is the government entity responsible for formulating, adopting, directing and coordinating the policies, plans and programmes of the mining and energy sector in Colombia as well as the supervision of the electricity sector. The MME regulates generation, interconnection, transmission and distribution activities and is in charge of generation and transmission programmes.

On the other hand, the administration and issuance of particular regulations in the electricity sector is dealt with by the following technical entities:

\(a\) CREG, a special administrative body created in 1994, is in charge of the regulation and promotion of competition between the entities involved in the electricity sector and the regulation of electricity and gas utilities. Pursuant to Laws 142 and 143 of 1994, the following specific functions are assigned to CREG:

- promoting fair market competition;
- setting out the conditions for deregulation of the electricity sector regarding a competitive market;
- determining and approving interconnection and usage charges and tariffs for the transmission and distribution of electricity;
- defining the regulated and unregulated end-user markets;
- setting out the regulations for the operation, planning and coordination of the national transmission system; and
- issuing the technical regulations with respect to quality, reliability and security of electricity;

\(b\) the UPME is a special administrative unit attached to the MME in charge of planning the energy mining sector in coordination with other agents in the sector and supporting the MME in achieving its goals and objectives;

---

c the Institute for Planning and Promotion of Energy Solutions for Non-Interconnected Areas is responsible for the promotion, development and implementation of energy efficient, viable and sustainable solutions that meet the needs of non-interconnected zones; and

d the SSPD is a government agency that oversees public utilities companies that operate within the Colombian territory. Among other functions, the SSPD is in charge of:

- supervising the quality and efficiency of all public service companies;
- taking over public utilities companies when the companies are financially non-viable or when the service rendered is at risk; and
- imposing sanctions on the companies subject to surveillance, and in particular with respect to electricity companies as result of a violation of the code of operations of the electricity sector.

In addition to the above-mentioned entities, the following entities provide consultation and technical assistance in the electricity sector:

a The National Operation Council, responsible for determining the technical standards for the efficient operation and integration of the SIN; and

b the Commercialisation Advisory Board, created by CREG as an advisory entity for the monitoring and review of the commercial aspects of the wholesale energy market (MEM).

The Superintendence of Industry and Commerce (SIC) is the authority in charge of investigating and sanctioning commercial restrictive practices, as well as authorising the mergers of companies operating within a single sector and market.

ii Regulated activities

Environmental permits

From an environmental perspective, the development of works and activities related to electricity or nuclear energy requires a prior licence or environmental permit to be granted by the National Environmental Licensing Authority (ANLA) or regional entities, depending on the sector, type of project and area where it is developed.

Furthermore, the main regulation in relation to environmental authorisations is Decree 1076 of 2015, which, among other things, defines the environmental authority in charge of granting the environmental licence, depending on the type of project and the installed capacity (MW) of the specific project.\(^5\)

Pursuant to Decree 1076 of 2015, an environmental licence is the authorisation granted by the competent environmental authority for the execution of a project, work or activity, which can cause serious deterioration of natural resources or the environment or introduce significant modifications to the landscape. Environmental licences include all permits, authorisations and concessions for the use of renewable natural resources throughout the duration of the project, work or activity, and any requisites for the initiation of the work, project or activity subject to an environmental licence.

\(^5\) Article 2.2.2.3.2.1, Decree No. 1076 of 2015.
Pursuant to the ILO Convention 169 and Colombian regulations, should ethnic communities be located within the area of influence of the project, a prior consultation process with such communities must be undertaken prior to the issuance of the environmental licence. Prior consultation suspends the proceeding with respect to the environmental licence.

**Electricity: regulated activities**

It is of utmost importance to note that, pursuant to the Colombian Constitution, electricity generation, interconnection, transmission and commercialisation activities are considered public utilities to be provided under Colombia’s authority and supervision and governed by the constitutional principles of free economic activity, free private initiative, free competition and private ownership.

The primary electricity regulation is contained in Laws 142 and 143 of 1994, which were enacted in a context of severe energy insufficiency and outages. Until 1995, electricity services were provided by the state through the company Interconexión Eléctrica SA (ISA) and other government-owned entities, with minor participation of the private sector. The power sector was reformed to introduce market economy principles, assigning the state the role of regulator. ISA was spun off into two companies: ISA the transmission company with system and market operating functions, and ISAGEN, a new company for electricity generation.

Law 142 regulates all aspects related to energy as a public service, and Law 143 sets out the legal regime applicable to the generation, interconnection, transmission, distribution and commercialisation as well as the Wholesale Electricity Market, which came into operation in July 1995. Furthermore, Law 143 of 1994 states that all the activities that involve the supply chain of electricity, from generation to commercialisation, are intended to satisfy primary collective needs on a permanent basis and thus considered as mandatory public utilities, essential in nature.

In relation to projects, free private initiative is the general rule and thus, private and public–private partnerships may get involved in the generation, transmission, distribution and commercialisation of electricity without requiring a concession. In other words, this means that Colombia will only get involved in the development of electricity generation projects when no private entity is willing to assume such activity.6

### iii Ownership and market access restrictions

In Colombia, there are no limitations or prohibitions for foreign participation or investment in the electricity sector. The only sectors in which foreign investment is prohibited are national security and defence and processing and disposal of toxic, hazardous or radioactive waste, as specified by Article 6 of Decree 2080 of 2000, further amended by Decree 2466 of 2007.7

Nevertheless, pursuant to Article 471 of the Code of Commerce, foreign companies willing to undertake permanent business in the country are required to constitute a branch with local address in Colombia. Moreover, according to Law 142 of 1994, enterprises providing public utilities, such as companies participating in the electricity sector, must be constituted as public utilities companies.

---

6 See Article 56 of Law 143 of 1994.
7 Compiled in Article 2.17.2.2.3.1 of Decree 1068 of 2015.
Regarding the electricity sector, as of the issuance of Laws 142 and 143 of 1994, generation, transmission, distribution and commercialisation of energy are considered as isolated activities. Furthermore, Article 74 of Law 143 of 1994 expressly prohibits companies involved in the electricity sector to engage in more than one activity except for commercialisation, which can be developed along with other activities of the electricity sector.

In addition, CREG regulations have set out specific restrictions as follows:

\(a\) electricity generators are not allowed to have an equity participation of more than 25 per cent in distribution companies;

\(b\) no company can have market participation above 25 per cent in the generation activity;\(^8\) and

\(c\) no company is allowed to directly or indirectly own more than 25 per cent of the equity of a company involved in commercialisation of electricity.\(^9\)

iv Transfers of control and assignments

With respect to mergers and acquisitions, it is important to note that all companies involved in the electricity sector are subject to the general competition and antitrust regime provided for in Law 1340 of 2009.

Pursuant to Article 9 of Law 1340 of 2009 and Resolution 10930 of 2015 issued by the SIC, certain mergers, consolidations or integrations require either to be approved or to be notified to the SIC.

Mergers require notice to the SIC when they meet the following conditions:

\(a\) whenever the transaction creates any form of integration. Any transaction to acquire ‘control’ over assets or shares of other companies leading to the creation or reinforcement of market power constitutes a merger;

\(b\) the parties of the transaction in Colombia jointly or individually have, in the year prior to the transaction, a level of total assets or operational income equal to or above 60,000 minimum monthly Colombian legal wages (approximately US$16,401 million);\(^10\)

\(c\) whenever the companies involved in the transaction are dedicated to the same activity or participate in the same vertical value chain; and

\(d\) whenever at the time of notice companies have

- 20 per cent or less market participation; or
- 20 per cent or less participation in the same vertical value chain.

Notice must be submitted as a pre-completion requirement of the transaction. However, this filing does not constitute a merger clearance by any means. Mergers will require approval of the SIC when they meet the first three above-mentioned conditions and the market participation of the companies individually or jointly equals or exceeds 20 per cent of the relevant market under Colombian jurisdiction.

Approval has to be submitted as a pre-completion requirement of the transaction; the SIC’s clearance is therefore a mandatory condition in order to proceed with completion of the transaction.

In addition to the above, Article 34 of Law 142 of 1994 mandates that companies involved in public utilities must avoid unjustified privileges and discriminatory acts and must

\(^8\) See CREG Resolution 60 of 2007.


\(^10\) COP: 46,874,520,000. Conversion rate: US$1 = 2,857.88 Colombian pesos.
Colombia

refrain from undertaking any act or transaction that has the capacity, purpose or effect of generating unfair trade, restricting competition or abuse of dominant position. The SSPD is the entity in charge of monitoring compliance of the aforementioned obligation and imposing sanctions.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

As indicated above, the electricity Law 143 of 1994 and CREG regulation establish unbundling rules restricting horizontal and vertical integration of utility companies that provide electricity services. Integration rules indicate the following:

a utility companies incorporated before Laws 142 and 143 of 1994 can develop more than one activity under separate accounts for each business; and

b utility companies constituted after the enactment of Laws 142 and 143 of 1994 can only undertake, at the same time, complementary activities such as generation-retailing or distribution retailing, and are prohibited to simultaneously perform activities of generation transmission, generation-distribution, transmission-distribution and transmission-retailing.

With respect to horizontal integrations, as it was previously stated, pursuant to Resolution 128 of 1996 of the CREG, a single company may not own more than 25 per cent of country’s generation, retailing and distribution activities.

ii Transmission/transportation and distribution access

The electric power system consists of an interconnected grid – the SIN – that supplies about 95 per cent of the overall demand. The remaining demand (non-interconnected zones) is typically supplied by local small electricity generation plants that operate on fossil fuels (gasoline and diesel).

The SIN has a total length of 24,981.73 kilometres comprising the following:

a the SIN;

b the regional transmission system; and

c the local distribution system.

The National Transmission System is a multi-owner network that has the unique characteristics of a natural monopoly, with ISA holding the largest share.

The grid system supply, provided by the National Transmission System, enables the coordination of the generators while reducing the amount of backup generating capacity and reserves. Pursuant to applicable regulations, transmission is defined as the transportation of electricity at a tension level equal to or greater than 220kV. Networks operating at less than 220kV are part of the distribution activity, the main function of which is to transport the electric energy to the end user. Moreover, the electric distribution system is integrated by networks, substations that operate at voltages lower than 220kV and do not belong to the National Transmission System.

With respect to third-party participation, it is important to note that the National Transmission System operates on an open market basis, and thus transmission operators must
provide open access to customers on a non-discriminatory basis, while receiving regulated revenues through the use of transmission system charges. These charges are regulated by CREG, paid by electricity consumers and further collected by retailers.

In addition to the above, Colombia is interconnected with both Ecuador and Venezuela, which has fostered the development of energy security standards while allowing these electricity markets to operate in a coordinated manner.

iii Rates
Pursuant to Article 23 of Law 143 of 1994, CREG:

c) Defines the methodology for the calculation of rates for access and use of electric grids as well as the rates for services related to connection and coordination which are carried out by regional dispatch centres and the national dispatch centre.

d) Approves the rates to be paid in relation to access and use of electric grids as well as the rates for services related to connection and coordination which are carried out by regional dispatch centres and the national dispatch centre.

Further, Article 88, numeral 1 of Law 142 of 1994 provides that:

Companies should adhere to the formulas that CREG periodically defines to fix their rates, except in the exceptional cases listed below. According to cost studies, the regulatory commission may establish maximum and minimum tariff caps which are mandatory for companies; while it may also define methodologies for determining rates and whether it is appropriate to apply the regime of regulated or supervised rates.

In relation to the regime of regulated and supervised rates, Article 11 of Law 143 of 1994 establishes a regulated liberty regime according to which rates for generation, interconnection, transmission, distribution and commercialisation of electricity within the national territory is set and limited by the criteria and methodology of CREG.

While each company negotiates its own rate, as mentioned above, rates are capped at the maximum rate established by CREG. Generally speaking, for affixing rates to be charged for utilities, CREG establishes the methodology and procedure for the calculation of the rate including costs associated to such rate. Thus, resolutions that set rates include the costs assumed by the provider of such service as well as the methodology used for regulating such cost.

Furthermore, Article 87 No. 9 of Law 142 of 1994 provides that the rates and formulas to calculate such rates fixed by the CREG may be modified by the CREG every five years and when the law so provides. However, Article 126 of Law 142 of 1994 indicates that the formulas to calculate the rates will be valid for five years, unless otherwise agreed between the CREG and the utility companies. The current rates are those set by way of Resolution 097 of 2008 issued by CREG. While it is evident that such Resolution 097 of 2008 was issued more than five years ago, it should be noted that a modification and adjustment proposal has already been drafted and has not yet been approved.
iv Security and technology restrictions
The main concern in terms of security of the electricity sector in Colombia is related to physical security of the oil and energy infrastructure. For several decades, infrastructure was a common target for guerrilla groups related to the armed conflict within the country. Attacks to pipelines as well as energy towers were frequent; they implied serious damages, paralysis of some parts of the system and impacted production levels gravely, affecting vulnerable populations. A decrease and eventual halt in attacks to oil and energy infrastructure is expected as a result of the implementation of the peace process with FARC, and as a result of ongoing negotiations with the National Liberation Army.

While recent developments in terms of peace have substantially diminished attacks to oil platforms, pipelines and energy towers, in 2014, before the negotiation and subsequent implementation of the peace process with FARC, the Colombian government created a task force for the protection of infrastructure including pipelines, energy towers, oil platforms and infrastructure in general, which was named COPEI. Among the various outcomes of the implementation of such task force were the creation of a special operation centre and the distribution of a daily report including possible threats and events.

IV ENERGY MARKETS
i Development of energy markets
The Colombian energy market is based on a competitive market model that is basically open to access through the MEM. The MEM is a market in which generators, transmitters and wholesale energy consumers and unregulated users participate with the main purpose of trading energy blocks through the SIN.

The MEM is divided into long-term and short-term transactions, depending on the needs of those participating in the MEM and the terms for such negotiations. For example, long-term participants opt for bilateral agreements while short term agreements usually refer to next-day purchases between all of the generators of the market, which are subject to explicit regulations. These kind of transactions usually cover the spot market.

Oversight of the MEM is led by the SSPD, which created the Oversight Committee of the MEM in 2006.

A substantial amount of electricity that is generated in Colombia is traded through the MEM via wholesale transactions, as all of the generation companies are obliged to participate in the MEM with all of their generation plants and units that are connected to the SIN.

Retail companies that sell directly to end users are also required to carry out their electricity transactions through the MEM.

ii Contracts for sale of energy
As explained above, the MEM is divided into long-term and short-term transactions. While long-term transactions usually involve bilateral agreements, short-term transactions (referred to as ‘on spot transactions’) usually involve negotiations of daily price offers along with hourly availability. The prices at which electricity is offered reflect the variable costs of generation as well as opportunity costs.
Firm energy obligation (OEF) auctions

Allocation of OEF between the different generators and investors is effectuated through dynamic auctions. OEFs are the resulting links from the auctions, according to which generators must generate a daily amount of electricity, as long as the obligation is in force. When the stock market price exceeds the price of shortage, the OEF price is determined by descending clock auctions.11 The purpose of such auctions is to allocate firm energy obligations (between the generators and investors), thus ensuring reliability in long-term firm energy supply at efficient prices.12 Auctions are held three years prior to the date when the firm energy is required. The time between the announcement of the auction date and the end of the obligation term consists of three stages: (1) the prequalifying period; (2) the planning period; and (3) the obligation effectiveness period, the total of which varies from one to 20 years.13

Bilateral contracts

The bilateral contracts market is primarily a financial market, as its function is to reduce exposure of the generator and end user to short-term price volatility. Such contracts are freely agreed commitments acquired by generators and commercialisation companies to sell and buy electricity. Energy is delivered though the spot market by the generator indicated in the contract, or by another generator as determined by the ideal dispatch (see below). The only requirement in such agreements is that the contract specifies the amount of energy that will be used on an hourly basis. Aside from that requirement, there are no restrictions on the electricity that a generator or commercialisation company may specify in the contracts, or the time frame covered by such agreements. Energy purchases made through such contracts, intended for regulated users, are governed by rules that guarantee competition among generators, while the prices and conditions on such contracts intended for non-regulated users are freely negotiated and agreed by the parties.14

Spot market

In the spot market the transmission network is neutral, thus implying that the generator makes its price offer for each day and its availability declaration for each hour, without considering the state of the transmission network. The resources that will be dispatched in order to comply with the hour-by-hour demand are selected according to the most economic offers. This dispatch is known as the ideal dispatch, as it diverges from the real dispatch, which considers the restrictions that may affect the transmission network. The ideal dispatch is determined once finalised by the National Dispatch Centre. It considers real demand and availability, not taking into account physical and technical restrictions imposed by the transmission network. Price offers presented by the generators must reflect the variable costs of generation and opportunity costs. The spot price is the price of the last resource used to meet the total energy demand every hour, which establishes the price at which all

11 Article 2, CREG Resolution 071/2006.
submarginal resources in the same hour will be remunerated. The part of the energy demand from commercialisation companies not covered by bilateral contracts must be paid at this spot price.\textsuperscript{15}

\section*{RENEWABLE ENERGY AND CONSERVATION}

\subsection*{Development of renewable energy}

Most of the developments in terms of renewable energy have been a result of the issuance of Law 1715 of 2014, which aims, \textit{inter alia}, to promote the development and use of unconventional sources of energy, mainly renewable energy, in the national energy system, as a means to achieve sustainable development, reduce greenhouse gas emissions, ensure the country’s energy supply and promote efficient energy management. This law establishes the legal framework and instruments required to take advantage of unconventional sources of energy and renewable energy, while promoting investment, research and development of clean technologies for energy production, energy efficiency and demand response.

The law defines unconventional sources of energy as environmentally sustainable energy resources that are globally recognised but in Colombia are not widely used or are not widely marketed, such as nuclear or atomic energy, unconventional sources of renewable energy and those determined by UPME. Further, it defines as unconventional sources of renewable energy as sources of energy that meet the above characteristics and are also renewable energy resources, such as biomass, small hydroelectric, wind, geothermal, solar, sea and solid waste that is not susceptible to being reused and recycled and which UPME has deemed to be environmentally sustainable.

Law 1715 of 2014 classifies activities related to the production and use of non-conventional energy sources (mainly non-renewable energy) as matters of public utility and social interest, with the purpose of facilitating certain requirements, processes and access to benefits in urban planning, territorial planning, environmental planning, economic development and the right to compulsory expropriation, etc. It also assigns competence to entities such as the ANLA and regional autonomous corporations to implement rapid evaluation cycles for projects related to non-conventional sources of energy, and for matters pertaining to this Law.

This Law is especially relevant as it authorises small and large-scale energy self-generators to surrender their surplus to the distribution and transport network, in accordance with the regulations of CREG, and the allocation of energy credits to small-scale energy self-generators using non-conventional sources of renewable energy. Such credits may be negotiated with third parties, in accordance with the regulations issued by CREG. The fund for non-conventional renewable energies and the efficient management of energy (FENOGE) has also been established to finance programmes and projects in this area.

In relation to the above, in February 2018 a change was introduced to the energy sector with regard to the generation and distribution of energy: CREG ruled that users of the electric power service in the country could produce energy and sell it to the SIN.\textsuperscript{16} This refers


\textsuperscript{16} See CREG Resolution 30 of 2018.
to small-scale self-generation, up to 1MW, and distributed generation, by means of which all residential users, as well as commercial and small industrial users, who produce energy mainly to meet their own needs, can sell the surplus to the interconnected system.

Law 1715 of 2014 sets out important fiscal, customs and accounting incentives for companies investing in projects of non-conventional sources of energy.

In fiscal matters, it offers an annual reduction in the income tax, for five years after the taxable year in which it makes the investment: 50 per cent of the total value of the investment made, without exceeding 50 per cent of the net income of the taxpayer determined before subtracting the value of the investment.

For these purposes, the taxpayer must obtain a certification of environmental benefit issued by the Ministry of Environment and Sustainable Development. In addition, national or imported equipment, elements, machinery and services that are intended for the pre-investment and investment for the production and use of energy from unconventional sources and for the measurement and evaluation of potential resources will be excluded from the VAT. For these purposes, a certification from the Ministry of the Environment must be provided stating the equipment and services that will benefit from this award, according to the list established by the UPME.

With respect to custom incentives, Law 1715 provides that those who import machinery, equipment, materials and supplies destined exclusively for pre-investment and investment in projects from non-conventional sources of energy are entitled to obtain an exemption with respect to tariff duties.

Finally, as an accounting incentive, companies participating in generation activities with non-conventional energy sources can enjoy the accelerated depreciation benefit, at a depreciation rate of no more than 20 per cent per annum, applicable to machinery, equipment and civil works necessary for pre-investment, investment and operation of such sources, provided that they have been acquired or constructed exclusively for that purpose, and after the validity of this law.

For its full implementation, Law 1715 requires regulation in different governmental entities affected by the measures of the law. Thus, to date, the following aspects have already been regulated, according to the information published by the Ministry of Mines and Energy on its website www.minminas.gov.co:

a) Decree 0570 of 23 March 2018 of the Ministry of Mines and Energy, which establishes the public policy guidelines to define and implement a mechanism that promotes long-term contracting for electric power generation projects and that is complementary to the existing mechanisms in the MEM. Additionally, it indicates that the aforementioned mechanism shall endeavour to comply with the following objectives:
  • through the diversification of risk, it will strengthen the resilience of the electric power generation matrix during events of variability and climate change;
  • it will promote competition and increase efficiency in the creation of prices through long-term contracting of new or existing electric power generation projects;
  • it will mitigate the effects of variability and climate change through the use of the potential and complementarity of available renewable energy resources that manage the risk of supplying for future electricity demand;
  • it will promote sustainable economic development and strengthen regional energy security; and
• reduce greenhouse gas emissions of the electricity generation sector, to comply with the commitments made by Colombia at the 2015 Paris Climate Change World Summit.

b Decree 1543 of 16 September 2017 of the Ministry of Mines and Energy, which regulates the FENOGÉ;

c Resolution 1670 of 15 August 2017 of the Ministry of Environment and Sustainable Development, which adopted the terms of reference for the preparation of the environmental impact study in projects for electric power transmission systems;

d Resolution 1312 of 11 August 2016 of the Ministry of Environment and Sustainable Development, which adopted the terms of reference for the preparation of the environmental impact study in projects for the use of wind energy sources and other aspects;

e Resolution 1283 of 8 August 2016 of the Ministry of the Environment and Sustainable Development, which establishes the procedure and the requirements of the certification of environmental benefit to obtain the tax benefits granted by law;

f Resolution UPME 045 of 3 February 2016, which establishes the procedures and requirements for issuing certification and endorsing projects from non-conventional energy sources in order to obtain the benefit of VAT exclusion and exemption from the tariff levy; and

g Decree 2143 of 4 November 2015, issued by the Ministry of Mines and Energy in relation to the definition of the guidelines for the application of incentives established in Chapter III of the law.

In addition, a Decree that intends to develop Law 1715 of 2014, by regulating and providing the guidelines for defining a mechanism for the long-term contracting of generation projects with non-conventional sources of energy (FNCER), in relation to the promotion, development and use of FNCER is yet to be issued.

ii Energy efficiency and conservation

The energy efficiency area of the MME developed the Programme for the Rational Use of Energy and the Use of Renewable Sources of Energy, which aims for energy efficiency and establishes targets for unconventional renewable energies in the SIN, as stated in Law 697 of 2001.

The most recent regulatory advance can also be found in Law 1715 of 2014, which, among other things, orders the MME, together with the Ministry of Environment and Sustainable Development and the Ministry of Finance, to jointly develop an action plan for the development of technical regulations with respect to renewable energies; consumer information on the energy efficiency of processes; facilities, services, products and manufactured products; and information; as well as to promote campaigns on the use of renewable energy sources.

In addition to the above, Law 1715 provides that the national government and public administrations should establish energy efficiency objectives in public buildings and plans and actions of efficient energy management.

iii Technological developments

In addition to the tax and customs incentives created by way of regulation issued in response to Law 1715 of 2014, and certain programmes to provide electricity and the
use of unconventional renewable resources in remote areas, no significant regulatory additional developments have been made in the areas of renewable energy and conservation. Nevertheless, it cannot be ignored that Colombia is considered one of the most promising markets for foreign investment in terms of non-conventional renewable energy matters.\textsuperscript{17} Therefore, large projects in this area are being planned in the Colombia, and there are even some in implementation stages.

VI THE YEAR IN REVIEW

For the Colombian energy sector, 2017 will be strongly determined by an event between the state and one of the main players in the electrical energy service. In November 2016, the SSPD temporarily took control of the foreign company Electricaribe, supplier of the electric power public utility to millions of people in the Colombian Caribbean coast, as a result of irregularities in the service and particularly as a result of constant power outages and energy shortages that affected end users. Subsequently, in March 2017, the SSPD decided and ordered the liquidation of Electricaribe, considering that ‘the company is not in a position to provide the energy service with the adequate quality and continuity’.\textsuperscript{18}

As a result of the liquidation decision order by the SSPD, Gas Natural Fenosa, owner of the 86 per cent of Electricaribe, decided to submit the matter to international arbitration before the United Nations Commission on International Trade Law (UNCITRAL), claiming compensation of more than US$1 billion.

In terms of innovation, 2017 also gave glimpses of the first projects of non-conventional renewable energies, which have prompted or pressured the government to issue specific regulation for such projects.

VII CONCLUSIONS AND OUTLOOK

The Colombian electricity sector has come a long way since its power outages during the 1990s. Privatisation, promotion of investment as well as implementation of regulations have made the Colombian electricity sector into an attractive and competitive market in the region.

However, the rapid expansion of the electricity sector and the ongoing dependence on resource-driven sources of energy such as hydroelectric power still have the capacity to force the system to a halt, as El Niño showed in early 2016.

In addition to the foregoing, foreign investment has adopted a more cautious attitude towards the country, owing to the environment of legal uncertainty generated by certain decisions, both governmental and judicial – especially the Constitutional Court – together with elections to be held in the middle of 2018, where there is a strong division between right-wing candidates and left-wing candidates.

\textsuperscript{17} El Tiempo, ’Solar and wind energy boom attracts firms from Portugal and Germany’. Available at: www.eltiempo.com/economia/sectores/portugueses-y-alemanes-entran-a-proyectos-de-energias-renovables-en-colombia-194304, accessed 22 March 2018.

\textsuperscript{18} Superintendencia de Servicios Públicos Domiciliarios, ’SSPD orders the liquidation of ELECTRICARIBE SA ESP. Available at: https://imgcdn.larepublica.co/cms/2017/03/14144450/Superintendencia%20de%20Servicios%20Domiciliarios%20ordena%20la%20liquidacion%20Electricular%20de%20SA%20ESP%20ELECTRICARIBE%20SA%20ESP.pdf?w=auto, accessed 23 March 2018.
The main objectives and challenges faced by the Colombian electricity sector to develop and secure the Colombian market include:

a. providing greater legal security to investors;
b. attracting greater investment in the electricity sector;
c. promoting unconventional renewable resources, aiming to achieve self-sustainable and permanent energy sources;
d. advancing regional electric integration;
e. increasing the installed capacity and effective generation and reliability; and
f. drafting and issuing the necessary regulations for supplies and projects of non-conventional renewable energy.
Chapter 11

DENMARK

Nicolaj Kleist

I OVERVIEW

The Danish energy demand is met by domestic natural gas resources and oil, coal imports, and domestic renewable energy sources such as waste, woodchips, wind and biogas. There is no large hydropower or nuclear power production in Denmark.

The first oil and gas exploration licence was granted in 1935, and since then oil and gas have been exploited in Denmark. In 1966, hydrocarbons were discovered in the North Sea, and in 1972 the first oil was produced. During the first 50 years, exploration of oil was carried out under sole-right concessions, but in 1983 competitive licensing rounds were introduced and the first licences with more than one concession holder were awarded in 1984 – the latest in 2016. Oil and gas activities are governed by the Subsoil Act, which lays down the basic framework for oil and gas exploration and production.

The first comprehensive legislation governing electricity supply entered into force on 1 January 1977. Electricity activities are mainly governed by the Electricity Supply Act, which lays down the basic framework for electricity production and supply. The aim has been to ensure electricity supply in accordance with the principles of security of supply, economics, and environmental and consumer protection. Access to cheap electricity and consumer influence on the administration of electricity sector assets; promoting sustainable energy use, including in connection with energy savings and use of combined power and heating; lasting and environmentally compatible energy sources, as well as securing effective use of financial resources; and creating competition on the markets for production and trade in electricity are essential elements in the legislation.

The long-term goal of Danish energy and climate policy is to have the total energy demand covered by renewable energy by 2050. The total share of renewable energy in electricity consumption is expected to be approximately 80–85 per cent in 2020 and for district heating consumption approximately 95 per cent. Wind power alone is expected to cover up to 53–59 per cent of electricity consumption in 2020, compared with approximately 43 per cent in 2017.

---

1 Nicolaj Kleist is partner at Bruun & Hjejle.
2 Act No. 960 of 13 September 2011 on the Use of Danish Subsoil.
3 Consolidated Act No. 114 of 9 February 2018 on the Supply of Electricity.
II REGULATION

i The regulators

The overall administrative responsibility for the energy sector lies with the Danish Minister for Energy, Utilities and Climate (the Minister). Part of the Minister’s authority has been delegated to the Danish Energy Agency (DEA). The DEA is responsible for the entire chain of tasks linked to energy production and supply, transportation and consumption, including energy efficiency and savings as well as national carbon dioxide targets and initiatives to limit emissions of greenhouse gases. In cooperation with the Minister, the DEA prepares the majority of the bills and other political proposals. The DEA carries out analyses and estimates of the development in the energy sector and represents Denmark in international forums.

The Danish Energy Regulatory Authority (DERA) controls prices and conditions in the energy sector. DERA’s purpose is to ensure an efficient and transparent energy market in Denmark. Transmission, storage and distribution undertakings and supply-committed undertakings are under the supervision of the DERA. Decisions of DERA may be appealed to the Energy Board of Appeal. Decisions by the Energy Board of Appeal cannot be brought before any other administrative body, but may be challenged before the courts.

Energinet, a state-owned undertaking, owns, operates and develops the Danish transmission network for electricity and gas and is responsible for effective and safe supply and for a competitive energy market. Energinet must ensure open and equal access to the transmission networks for all users. It also issues rules on gas transport and coordinates the general planning of emergency supply for the natural gas sector.

The city councils in the municipalities are responsible for the planning of local heat supply. In each municipality, the city council must carry out planning in cooperation with the supply undertakings and other stakeholders. The heat planning procedure ensures public participation, and as part of the heat supply planning, the city council may decide that connection to a collective heat supply system should be mandatory.

The Energy Supplies Complaints Board is a private board established by the energy industry and the Consumers’ Council. The Energy Supplies Complaints Board handles complaints about the purchase and delivery of energy from supply undertakings. As a principal rule, the board only accepts complaints from consumers. Decisions of the Board cannot be appealed to any administrative authority, but can be brought before the courts.

---

4 www.efkm.dk.
5 www.ens.dk.
6 www.energitilsynet.dk.
7 www.ekn.dk.
8 Established by Act No. 1097 of 8 November 2011.
The main legislation for energy regulation is the Continental Shelf Act, the Act on Raw Materials, the Subsoil Act, the Pipeline Act, the Natural Gas Supply Act, the Heat Supply Act and the Electricity Supply Act.

ii Regulated activities

A licence issued by the DEA is necessary for exploration, production, transmission, distribution and storage activities. A permit is required for the establishment of plants and for expansion or changes to such plants causing increased pollution. Permits are issued by the relevant city council or regional council depending on the size of the plant. Permits for major plants require a prior public hearing, and for major plants there may be a duty to complete an environment impact assessment under the Planning Act. Offshore plants are primarily subject to approval under the Subsoil Act and Continental Shelf Act. Offshore installations are subject to approvals and permits issued by the DEA. These include operation permit, manning and organisation plan approval and approval for the contingency plan. To obtain an operation permit, there must be an evaluation of safety and health conditions for the installation and the operational conditions (health and safety review/safety case) and other relevant information regarding health and safety conditions (e.g., certificates). Offshore installations operating in Denmark must have a workplace assessment system.

iii Ownership and market access restrictions

The Danish state has a general right to all hydrocarbons in the subsoil of the Danish territorial jurisdiction area. The state can grant licences for preliminary investigation, exploration and production of hydrocarbons. Licences are granted through tender procedures or under the ‘open door’ procedure.

The main part of the natural gas on the Danish market is produced in the Danish North Sea. Through the Danish North Sea Fund, the Danish state participates in concessions for exploration and production of hydrocarbons. Licences are granted through tender procedures or under the ‘open door’ procedure. The Danish state’s oil and gas company, which contributes to the decision-making processes in connection with exploration, production and development activities with respect to Danish licences. The aim is to use existing knowledge across licences and support the development of new technologies that can enhance the recovery rate of oil and gas resources in the subsoil.

Partly state-owned Ørsted A/S (previously DONG Energy) owns upstream pipelines and operates the gas treatment plant at Nybro. The establishment and operation of upstream pipeline networks require a licence issued by the DEA. Any interested party is entitled to

10 Act No. 1101 of 18 November 2005.
12 See footnote 2, above.
14 Act No. 1157 of 6 September 2016.
15 See footnote 9, above.
16 See footnote 3, above.
17 See also Section III.iii, below.
18 Act No. 966 of 23 June 2017.
19 Act No. 50 of 19 January 2018.
Denmark

access an upstream pipeline network subject to payment. The physical planning of the system for supply of natural gas is governed by the Heat Supply Act. Establishment of new distribution network facilities for natural gas and major alterations to existing facilities requires approval from the relevant city council and, in certain cases, the DEA. A storage undertaking is obliged to place storage capacity at the disposal of Energinet, but only to the extent necessary to enable Energinet to maintain physical balance in the network and to ensure security of supply. A storage undertaking must grant access to the storage facilities on the basis of objective, transparent and non-discriminatory criteria. The Danish market for natural gas was fully liberalised on 1 January 2004, and since then customers have had a right to choose a natural gas supplier. Anybody may in principle establish a natural gas supply undertaking.

Electricity grid undertakings have a monopoly on the distribution in their areas and are governed by the Electricity Supply Act. The transmission system operator (Energinet) is responsible for the general security of supply in Denmark and must ensure the overall balance and quality of the electricity supply system. Also, the operator must ensure players have access to the transmission system on objective, fair and transparent terms. Electricity supply undertakings supplying electricity on commercial terms are generally not governed by the Electricity Supply Act.

iv Transfers of control and assignments

Natural gas and electricity licences, where applicable, can only be issued to applicants with the necessary expertise and economic capacity. The licence can neither directly nor indirectly be transferred to others without approval by the DEA. A gas distribution network or shares in companies that own distribution networks are generally only allowed to be transferred to the state. The state, on the other hand, has a duty to buy. The state must exercise its duty to buy within three months of the date of notification of the owner’s wish to dispose of the distribution network or the shares. If the parties cannot reach an agreement on the conditions of the transfer, the prices and terms of the transfer will be fixed by a valuation commission in accordance with the procedure that applies to compulsory sale to the state. In 2016 and 2018 the Danish state purchased two out of the three large gas distribution networks in Denmark. The state is in negotiations with the owner of the third and largest gas distribution network regarding a purchase to finalise a consolidation of the sector.

Since 1998, Danish competition legislation has been strongly influenced by EU competition law, but the Danish rules are generally stricter than those of the EU in terms of support for free competition.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

The level of unbundling in Denmark generally exceeds the requirements of the Electricity and Gas Directives. Through the establishment of Energinet, Denmark has secured ownership unbundling of the main transmission grid.

---

20 There are 98 municipalities (city councils).
21 Act No. 1161 of 20 November 2008 on the Procedure for Compulsory Sale of Real Property.
In the electricity and natural gas industries, there is a requirement for legal unbundling in relation to the parts of the value chain of monopolistic character. The Natural Gas Supply Act requires a company with a licence for transmission, distribution, storage, LNG business or universal service obligations to conduct only activities allowed under the licence.

As a general rule, the Electricity Supply Act does not allow grid and transmission licences to be issued to the same company. Undertakings producing electricity by means of waste incineration are not allowed to carry out other types of electricity production or trading activities. The requirement for unbundling of activities does, however, not preclude the use in combined waste incineration plants of other types of fuel (e.g., straw, chipped wood or natural gas) together with waste suitable for incineration.

The requirements are supplemented by demands for managerial unbundling in the Electricity Supply Act and in the Natural Gas Supply Act. To prevent conflicts of interest, executives and managers of a distribution undertaking must not directly or indirectly participate in the operation or management of an associated undertaking selling or producing natural gas or electricity, or participate in an associated undertaking that indirectly owns such an undertaking. Members of the board of directors of distribution undertakings must not directly or indirectly participate in the operation or management of associated undertakings selling or producing natural gas or electricity.

ii Transmission/transportation and distribution access

Danish law allows full access on a non-discriminatory basis to the transmission and distribution systems in both the natural gas and electricity sectors.

Natural gas

The transmission network for natural gas is connected to the natural gas transmission networks in Germany and Sweden. The transmission network is connected to the distribution network to which the end users are connected. There is a general right to use the transmission network against payment of applicable fees. Access can be denied if the transmission undertaking cannot meet the capacity requirements, cannot ensure the quality of the natural gas, cannot ensure security of supply, cannot ensure sufficient quantities of natural gas, or if a natural gas undertaking has severe economic and financial difficulties with fulfilling contracts (including take-or-pay commitments). Access can also be denied if a natural gas undertaking does not comply with the access requirements laid down by the transmission undertaking. Reasons must be given for denial of access, and a denial of access can be brought before the DERA.

Electricity

The transmission grid for electricity is the part of the electricity grid that transports electricity to local grid undertakings, which then distribute the electricity to end users. The transmission grid also transports electricity to and from other countries. The transmission grid is owned and operated by Energinet, which is responsible for the security of supply and the overall balance and quality of the electricity supply system. Energinet is also responsible for the overall planning and development of the transmission system. Energinet must ensure that players have access to the transmission system on objective, fair and transparent terms. The grid undertakings deliver electricity from the transmission grid to individual end-users. Each

22 See footnote 8, above.
owns and operates a distribution grid within a local supply area. Grid undertakings have a monopoly on the distribution within their area. However, the grid undertakings must ensure that players have access to the grid on objective, fair and transparent terms.

iii Terminalling, processing and treatment

The storage facilities for natural gas are currently situated at two locations in Denmark: Stenlille and Lille Torup. The two gas storage facilities are owned and run by Energinet.

iv Rates

It is a general rule that access to transmission and distribution grids must be provided on the basis of objective, transparent and non-discriminatory criteria. When setting prices, grid undertakings must not discriminate between users. Transmission and grid undertakings must prepare a plan for internal supervision and describing the undertaking’s measures to prevent discriminatory practices. Prices must be based on the undertaking’s costs and a reasonable return on capital invested by the undertaking.

v Security and technology restrictions

Undertakings that sell oil in Denmark must keep oil reserves in storage ready for emergency use by the Danish state. Denmark’s obligations to maintain such oil storage follow from an EU directive and from rules laid down by the International Energy Authority. The Danish Act on Emergency Oil Supplies\(^{23}\) ensures emergency supply in the event of disruptions or threats in the oil sector, including keeping reserves of crude oil and petroleum products, and collecting data on the oil conditions in Denmark. The Danish emergency oil management system is primarily handled by the Danish Central Stockholding Entity, which is an independent organisation set up by the oil companies and appointed by the DEA.

IV ENERGY MARKETS

i Development of energy markets

Nord Pool Spot runs a power market in northern Europe and offers both day-ahead and intraday markets; 380 companies from 20 countries trade on the market. Nord Pool Spot is owned by the Nordic and Baltic transmission systems operators (in Denmark, Energinet). In 2017, the group had a total turnover of 512TWh. The power price is determined by the balance between supply and demand. Factors such as the weather or power plants not producing to their full capacity may have an impact on how much power can be transported through the grid and may therefore influence the price of power.

ii Energy market rules and regulation

The Minister can decide that oil undertakings must submit information on the conditions of import, export, production, sale, storage and transport, and on other general matters. The Minister can stipulate that undertakings producing or importing oil must sell oil in accordance with international distribution schemes.

\(^{23}\) Act No. 354 of 24 April 2012 on Emergency Oil Supplies.
The liberalisation of the gas market on 1 January 2004 meant that all natural gas customers would have a free choice of supplier. Any party can establish a natural gas undertaking supplying natural gas, provided that it enters into agreements with the relevant transmission, storage (if needed) and distribution undertakings. An undertaking trading in natural gas can sell its products on market terms. Natural gas suppliers may be licensed as a supply-committed undertaking in areas designated for natural gas pursuant to the Heat Supply Act, with the effect that the undertaking has the right and duty to supply natural gas to all customers within the area that have not used their right to choose an alternative gas supplier. The undertaking may deny supply of natural gas to a customer that does not pay for the deliveries.

Sale and delivery of electricity to end-users are made by electricity suppliers, which are either supply-committed undertakings or undertakings supplying electricity on commercial terms. Supply-committed undertakings deliver electricity to consumers who have not exercised their right to choose an alternative supplier.

iii Contracts for sale of energy
Most power in the Nordic and Baltic region is traded on Nord Pool Spot. Natural gas, on the other hand, is still primarily traded through bilateral contracts, although an increasing quantity is traded at the market exchange Gaspoint Nordic. Danish energy legislation generally only regulates end-user contracts.

iv Market developments
There are a large number of new energy policy initiatives seeking to accelerate the transition to green energy. The four critical focus areas are: energy efficiency, electrification, expansion of renewable energy and research, and development and demonstration.

V RENEWABLE ENERGY AND CONSERVATION
i Development of renewable energy
Denmark has a long tradition of active energy policy, initiated by the first oil crisis in 1973. When oil prices accelerated in 1973, Denmark was among the OECD countries most dependent on oil in its energy supply, with more than 90 per cent of all energy supply deriving from imported oil. Denmark launched an active energy policy to ensure the supply and enable Denmark to reduce its dependency on imported oil. In combination with oil and gas production from the North Sea, Denmark went from being a net importer of oil in 1973 to being more than self-sufficient in energy from 1997 and beyond.

In the Kyoto period 2008–2012, Denmark committed itself to a greenhouse gas reduction target of 21 per cent. Today, renewables account for more than 40 per cent of Danish electricity consumption and, through expanded offshore wind production and use of biomass, the government expects that renewables will reach almost 70 per cent of Danish electricity production in 2020. A new political agreement between the government and all the major opposition parties was reached in March 2012. The agreement covers the period 2012–2020 and sets out the following goals: more than 35 per cent renewable energy in final energy consumption, approximately 50 per cent of electricity consumption to be supplied by wind power, 7.6 per cent reduction in gross energy consumption in relation to the 2010 level and 35 per cent reduction in greenhouse gas emissions in relation to the 1990 level.
Energy taxes on electricity and oil were introduced in 1977, and since then taxes have been increased several times and have also been extended to coal and natural gas. In 1992, the taxes were supplemented by carbon taxes.

Other means of achieving renewable energy are heat-savings initiatives in buildings, use of renewable energy in buildings, municipal heat planning, energy-efficient electricity and district heat production, and use of renewable energy in electricity and district heat production, plus energy savings and use of renewable energy in industry and transportation.

Wind turbines have been supported politically for many years, including through state subsidies, feed-in tariffs, orders to the electricity utilities to build wind turbines, tenders for offshore wind farms and orders to the municipalities to allocate suitable areas for new onshore wind turbines. Approximately 40–45 per cent of electricity is currently produced by wind turbines (and this is expected to exceed to 50 per cent in 2020).

In 2009, the Promotion of Renewable Energy Act24 was launched to promote the production of energy through the use of renewable energy sources, in accordance with climate, environment and macroeconomic considerations, to reduce dependence on fossil fuels, ensure security of supply and reduce carbon emissions and other greenhouse gases.

ii Energy efficiency and conservation

Denmark has long supported energy efficiency and conservation initiatives, which played an important role in the efforts to free Denmark from dependence on fossil fuels. In the 1976 Energy Plan, energy efficiency was one of two main targets. During the 1970s, a number of acts and initiatives were implemented to support energy efficiency, with a focus on three main areas:

a heat consumption in buildings;
b industrial and process – covering industrial and production-related consumption; and
c appliance and components – covering electrical appliances and components not directly related to industrial use.

A number of schemes have also been implemented, designed to promote energy savings in buildings and industry. Major current initiatives include:

a energy and carbon taxes on domestic and public sector energy consumption;
b carbon taxes on industrial consumption;
c carbon emission allowance trading scheme;
d voluntary agreements for industry;
e energy labelling for large and small buildings;
f energy labelling of appliances and lighting;
g norms for energy efficiency and voluntary agreements; and
h reduction of standby consumption.

iii Technological developments

The Danish strategy for energy-efficient technologies provides a framework for prioritisation and development of research and development efforts to achieve the greatest possible impact by public funds used in the field.

---

VI  THE YEAR IN REVIEW

i  New subsidy scheme for wind and solar power 2018–2019
The government introduced a new scheme where solar and wind power projects compete through tenders for state subsidies in 2018 and 2019. The total pool under the scheme is 1.165 billion kroner, of which 1.015 billion kroner has been allocated towards a technology-neutral call for a wind and solar power tender and 150 million kroner for new test windmills on land. The aim is to achieve the highest possible capacity for the allocated amounts by increasing competition between the technologies. It is expected that the 1.015 billion kroner will result in approximately 190MW of sustainable energy, which corresponds to the annual power consumption of approximately 140,000 households. It is also expected that approximately 130MW test windmills will be built in 2018 and 2019.

ii  New revenue framework for electrical grid companies
Amendments to the Energy Supply Act per 1 January 2018 introduced changes to the financial regulation of grid companies. The new rules govern the prices that electrical grid companies can charge consumers in order to cover the costs of running the grid, including return on investments and depreciations. A five-year regulation period with annually updated revenue frameworks has been introduced, aiming to provide better regulatory security than the previous regulation.

iii  Consolidation of gas distribution networks
In June 2017, the government entered into an agreement in principle with the owners of two of the three natural gas distribution networks in Denmark, HMN Naturgas and NGF Nature Energy, on the framework for a consolidation of the gas networks in Denmark under a state-owned entity. The state had (through Energinet) already purchased the third part of the distribution network from DONG Energy in 2016. Following the agreement, the state entered into a purchase agreement in March 2018 concerning NGF Nature Energy’s distribution network. Negotiations regarding the purchase of HMN Naturgas’ distribution network is ongoing.

iv  Danish energy giants sell oil and gas activities
Both Ørsted (DONG Energy) and Maersk sold their oil and gas activities during 2017. In May 2017, Ørsted announced that it had agreed to sell its oil and gas business to petrochemicals firm Ineos in order to focus its activities on renewables, and in August 2017 Maersk Oil announced that they were selling their activities in the Danish part of the North Sea to French Total, which thereby became the leading operator in the Danish North Sea.

VII  CONCLUSIONS AND OUTLOOK
Denmark is continuously increasing its focus on renewable energy with the aim of being an international leader in the area and ensuring self-sufficiency. There is a large focus on cost-effectiveness and ensuring cheap energy for consumers while maintaining incentives for new investments in the sector.
Chapter 12

FRANCE

Fabrice Fages and Myria Saarinen

I OVERVIEW

In France, the energy market has undergone a progressive liberalisation as a result of the European plan to establish a unique energy market that would end national monopolies. This has naturally led to an important legislative and regulatory change, which was codified by an Order dated 9 May 2011 and which created the legislative part of the French Energy Code. This Code sets out provisions relating to electricity, gas, renewable energy, hydropower, oil and both heating and cooling networks.

This chapter will focus mainly on electricity and gas markets since they have been the main energy markets affected by such changes. It should, however, be underlined that the other sources of energy are also subject to specific regulation.

As a matter of history, after the Second World War, to rebuild the infrastructure and the network, the French authorities decided to grant a state monopoly to Electricité de France (EDF) and Gaz de France (GDF, now Engie) with regard to the production, transportation and distribution of electricity and gas respectively. This situation remained substantially unchanged for half a century until France had to implement into its national law two Directives dated 1996 and 1998 adopted by the European Commission to promote an effective and efficient internal energy market, open to competition. These directives were progressively transposed into French law as of 2000 and initiated the beginning of the liberalisation, although initially only large industrial consumers could benefit from this system.

Further opening of the energy market occurred several years later with the transposition into French law of new Directives dated 2003, which aimed to make this opening available to all professional consumers by 1 July 2004, and to all consumers, including residential or customers, by 1 July 2007.

1 Fabrice Fages and Myria Saarinen are partners at Latham & Watkins AARPI. This chapter was written with the assistance of Julie Ladousse, an associate at the firm, and Alexandre Bay, law clerk.
3 Law No. 46-628 of 8 April 1946 concerning the nationalisation of electricity and gas, repealed by Law No. 2004-803.
Although significant progress had been made, the European Commission adopted the Third Energy Package to further liberalise the energy market, which included two new directives\(^5\) replacing the former electricity and gas directives. These directives were transposed into French law on 7 December 2010 by a new law commonly referred to as ‘Law NOMEx\(^6\), which led to the removal of several obstacles to the development of competition in the French electricity market. Greater price liberalisation for industrial and residential customers has been achieved, notably by requiring EDF to sell a substantial part of its existing nuclear facilities to alternative suppliers at a regulated price, from January 2011 to 2025, so as to allow alternative suppliers to compete fairly with the historical supplier. Finally, France launched an energy transition with the adoption of Law No. 2015-992 on 17 August 2015. This law established new rules supporting renewable energy production and stated ambitious objectives that were specified by the multi-annual energy programming for the period 2016–2023.

II REGULATION

i The regulators

Compliance with the new energy market regulations is mainly controlled by the Commission of Regulation of Energy (CRE), the sectoral regulator, which was created by the Law dated 10 February 2000.\(^7\) Its overall mission is to ‘contribute to the proper operation of the electricity and natural gas markets, to the benefit of final customers’.

The CRE is principally in charge of:

- powers of decision, approval or authorisation (system operators, contributions to the public electricity sector, etc.);
- dispute settlement and sanctions relative to access to the electricity and gas networks;
- powers of proposal (tariffs for the use of public electricity grids, contributions to public electricity services, etc.);
- information and investigative powers with stakeholders;
- advisory powers (tariffs, regulated access to incumbent nuclear electricity, etc.); and
- additional powers (processing of tenders for electricity generation, etc.).

The CoRDIs committee, which is an independent body of the CRE, acts in matters where the CRE has competence with regard to sanctions, and settles disputes related to the access and use of public electricity grids and natural gas networks.

Further, an energy ombudsman has been put in place whose role is to provide consumers with all necessary information concerning their rights, current legislation and the means of dispute settlement available to them in the event of a dispute.

In addition, the French Competition Authority (FCA) has the power to prevent and sanction anticompetitive practices in any economic sector, including electricity and

---


\(^6\) Law No. 2010-1488 of 7 December 2010 establishing a new organisation of the electricity market.

\(^7\) Articles L131-1 to L135-16 of the French Energy Code.
gas. It must inform the CRE when seized of any matter that would fall under the CRE’s jurisdiction. The FCA must also notify the CRE of any abuse of a dominant position or any anticompetitive practice in the gas or electricity sector.8

Finally, the Higher Energy Council is a body established by the Ministry of Energy that is composed of several members including Members of Parliament. Its main purpose is to advise on national energy policy. The Council is consulted on regulatory acts relative to such policy and on electricity and gas market-related decisions.

ii Regulated activities

The energy market is composed of four main areas of activity: production (generation), transmission, distribution and supply (commercialisation). Under the previous regime, which was applicable until 2000, these four activities were carried out by EDF and GDF, which self-regulated the monopoly.

There have now been greater strides towards liberalisation as production and supply are open to competition. Transmission and distribution are still, however, public service activities supervised by the CRE. Where, to guarantee this public service mandate, a legal and financial separation between such activities has taken place,9 transmission is performed by GRT (gas) and RTE (electricity), and distribution is performed by GRDF (gas) and ERDF (electricity) or local distribution companies.10

More generally, some activities, such as the exploitation of electricity production facilities, require an administrative authorisation when the installed power of the facility exceeds a certain threshold, with different thresholds for different types of facilities. Decree No. 2016-687 of 27 May 2016, for example, provides that the installation of an electricity generating facility using renewable energy will require an administrative authorisation if its installed power exceeds 50MW.11 The previous threshold ranged from 12–30MW. The authorisation is delivered by the Minister of Energy according to specific considerations such as security, energy efficiency, technical and economic capacities of the applicant.12 Similarly, gas exploration also requires an administrative authorisation or a concession, which is granted subject to a public enquiry and a tender procedure.13

iii Ownership and market access restrictions

Although the French Energy Code does not provide for any restriction or requirement in relation to the acquisition of assets in the energy sector by foreign companies or individuals, it clearly states that the French state must hold at least 70 per cent of the capital and voting rights of EDF and one third of Engie14 (to protect the French national interest, the state may benefit from specific shares within the capital of Engie).15

9 Law No. 2004-803 of 9 August 2004 concerning the electricity and gas public service; Law NOME.
10 Local distribution companies are defined by Article L111-54 of the French Energy Code.
11 Articles R311-1 et seq. of the French Energy Code.
13 Articles L131-1, L132-3 and L132-4 of the French Mining Code.
iv Transfers of control and assignments

Any merger or any change in control over businesses in the energy sector, or any acquisition of utility assets, must be notified and supervised by the FCA if the following three cumulative conditions are met:¹⁶

a. worldwide aggregate turnover of all the parties to the concentration exceeds €150 million;

b. turnover in France of each or at least two parties concerned exceeds €50 million; and

c. the transaction does not meet the EC Merger Regulation thresholds.

The examination process by the FCA is twofold. In Stage I (which takes up to 40 working days), the FCA has 25 working days to examine the transaction starting from the date when a complete notification is received. When remedies are proposed to the FCA, this period is extended by up to 15 working days. At the end of this period, the FCA can clear the transaction, with or without remedies or proceed to an in-depth investigation. In the absence of any decision, the transaction is tacitly cleared.

Stage II takes between 65 and 85 working days. If serious doubts remain as to the competitive impact of the transaction, the FCA proceeds with an in-depth investigation. During Stage II, if the transaction relates to a regulated area, the FCA may request a non-binding opinion from the relevant regulator (e.g., the CRE). At the end of Stage II, the FCA can either clear the transaction with or without remedies or prohibit the transaction.

The FCA’s authorisations for acquisitions may be subject to conditions.¹⁷

In addition, the French government issued Decree No. 2014-479 dated 14 May 2014 expanding the list of strategic sectors, including the energy sector, in which foreign investments in France require the prior authorisation of the French Minister of the Economy.¹⁸

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Vertical integration is the process in which different aspects of the market are controlled by a common company or entity. Prior to the deregulation of the energy industry, French energy companies were largely vertically integrated, which created potential conflicts of interest and monopoly situations.

The European Commission issued Directives 2003/54/EC and 2003/55/EC principally to ensure efficient and non-discriminatory network access, ensure free choice of suppliers by consumers, and encourage investment. This legislation was transposed into the French system by a Law dated 9 August 2004, which provided for a legal unbundling of regulated activities (distribution and transmission) from non-regulated activities (production


¹⁷ See, for example, the decision of the FCA dated 7 February 2012: the FCA made its authorisation of the acquisition of Enerest by Electricité de Strasbourg conditional on a number of commitments designed to resolve competitions concerns, such as the commitment not to make offers for two energies that include at least one component at a regulated tariff. This commitment, the effectiveness of which is to be guaranteed by separating the sales teams responsible for electricity and gas at Electricité de Strasbourg, notably eliminates any risk of the company using its business of supplying energy at regulated tariffs as a tactic to win customers on the open market.

¹⁸ Article L151-3 of the French Monetary Code.
and supply). After an inquiry launched in 2005 by the European Commission, however, serious shortcomings in the electricity and gas markets were identified, including an inadequate current level of unbundling between network and supply interests deemed to have negative effects on the market and investment.19 Consequently, under Directives 2009/72/EC and 2009/73/EC, priority was given to achieving effective unbundling of network and supply activities.

As explained above, these directives were transposed into French law so that the transmission and distribution system operators would be legally and fully unbundled companies. Accordingly, transmission and distribution system operators must be equipped with all the necessary human, technical, physical and financial resources to fulfil their obligations under French law and, in particular, they must own the assets necessary for their activity.

ii Transmission/transportation and distribution access

Non-discriminatory and fair access to transmission and distribution networks for gas and electricity are at the core of the free market approach.20 Any discrimination, prevention of new participants from entering the market, and restriction to fair competition in favour of the consumer, is subject to sanctions issued by the CoRDiS committee.21

Among the measures guaranteeing such non-discriminatory and fair access, it should be noted that any refusal to enter into an agreement must be justified and notified to the applicant, as well as to the CRE, specifying that any refusal is justified by objective, transparent and non-discriminatory reasons.22 Furthermore, any transport or distribution system operator serving more than 100,000 clients must draw up a code of conduct to ensure compliance with the non-discrimination principle.23

Finally, the CRE must publish an annual report concerning compliance with the code of conduct and a summary of its assessment of the independence of the transport or distribution system operators.24

iii Terminalling, processing and treatment

There are currently three natural gas terminals in France: Fos Tonkin and Fos Cavanou, both near Marseille, and Montoir-de-Bretagne, near Saint-Nazaire. Tariffs for the use of natural gas terminals, which are regulated, are set by the CRE.

The operation of storage facilities is subject to a concession.25 The storage of natural gas must ensure (1) the proper operation and balancing of systems connected to underground natural gas storage facilities, (2) the direct or indirect meeting of domestic clients’ needs, and (3) compliance with public service obligations. Access to storage is guaranteed; the operators

---

20 Articles L111-91 et seq. of the French Energy Code.
22 Articles L111-93 (for electricity) and L111-102 et seq. (for gas) of the French Energy Code.
25 Articles L211-2 and L 231-1 of the French Mining Code.
of underground storage facilities are free to negotiate the terms of their offers with their customers, with the latter being able to rely on objective, transparent and non-discriminatory criteria.26

iv Rates
Access tariffs to networks aim at guaranteeing transparent and non-discriminatory access to public networks. These fees are calculated in a way that cover all costs supported by the system operators (costs arising from their public service duties, the research and development needed to increase the transmission capacity, and the grid connection).

The methodology used to establish access tariffs to the network is set up by the CRE. In addition to fixing the rates, the CRE grants appropriate incentives for transmission and distribution system operators over both the short and long term to increase efficiency, foster market integration and security of supply and support related research activities.27

v Security and technology restrictions
Security of electricity and gas supply is an essential public service obligation.28 The Ministers of Energy and Economy must ensure the fulfilment of this public service mission mainly by EDF, GDF, RTE, GRT, ERDF, GRDF and local distribution companies. In the event of a serious energy shortage, the government may subject energy resources to control and allocation.29 Such measures mainly concern production, imports, exports, storage, acquisition, and transportation. In the event of a serious energy market crisis, or threat to the safety or security of the networks and of people, the Minister of Energy may take protective measures to grant or suspend licences for the operation of power generating facilities.30 In times of war or serious international tension, the government may regulate or even suspend oil import or export completely.31

In addition, in order to ensure energy autonomy, France has put in place a capacity market that entered into force on 1 January 2017. The capacity mechanism aims at encouraging demand management, especially during peak hours, via the purchase or sale of certificates depending on whether energy consumption needs are met.

IV ENERGY MARKETS
i Development of energy markets
The sale of energy takes place within either the wholesale market or the retail market. The wholesale market is the market in which electricity and gas are traded (bought and sold) before delivery in the network to final customers (individuals or companies), whereas the retail market concerns the final clients who may freely choose their suppliers (eligible customers).32

The participants of the wholesale market are:

a producers who trade and sell their production;

---

27 Articles L341-3 (electricity), L452-2 and L452-3 (gas) of the French Energy Code.
28 Articles L121-1 (electricity) and L121-32 (gas) of the French Energy Code.
29 Article L143-1 of the French Energy Code.
30 Article L143-6 of the French Energy Code.
31 Article L143-7 of the French Energy Code.
32 Article L331-1 of the French Energy Code.
b suppliers who trade and supply gas or electricity before selling gas or electricity to the final client; and

c brokers or traders who purchase gas or electricity for resale and thus favour market liquidity.

As most of the activity in the wholesale gas market and wholesale electricity market takes place over the counter, through direct transactions or through intermediaries (brokers and trading platforms), the opening of these markets to competition has led to the emergence of organised markets, namely trading platforms (such as Epex Spot France or EEX Power Derivatives France).

ii Energy market rules and regulation

Even if the supply of energy is open to competition, it is still subject to certain requirements and monitoring.

First, the sale of electricity or gas is subject to governmental approval. Indeed, suppliers willing to purchase electricity or gas to sell them to consumers need an administrative authorisation that is delivered subject to their technical, economic and financial capacities, and according to their project’s compatibility with the security of supply obligation.

Second, each transaction performed on the French market that would involve the participation of a producer, broker or energy supplier, must be monitored by the CRE, regardless of the trading method (two-way trades, with or without a broker or transactions within organised markets).

Third, free competition is limited with respect to pricing practices since, in certain circumstances, ‘regulated tariffs’ may be chosen within the electricity market by customers having contracted for less than 36kVA. However, because of the European Commission’s unhappiness, especially with the electricity retail market and the dominant position exercised by EDF, Law NOMÉ ended ‘regulated tariffs’ for customers having contracted for more than 36kVA by 31 December 2015. Furthermore, in the gas market, the suppression of gas-regulated tariffs for all non-domestic consumers entered into force on 1 January 2016. The removal of these tariffs has induced more competition, with new participants entering the wholesale market, even though price differences remain small.

Finally, the Contribution to the Public Electricity Service, which has been funded since 2016 by the domestic consumption tax on electricity for end users, has been created to compensate public service charges assigned mainly to EDF, such as support schemes for renewable energy or social electricity tariffs.

iii Contracts for sale of energy

The legal unbundling between the production and the distribution activities imposed by the energy market creates several inconveniences for the consumer who, as a result, gets an increasing number of contractors, the responsibilities of which are diminished.

33 CRE, Electricity and gas market report, fourth quarter of 2011.
34 Articles L333-1 (electricity), L443-1 and L443-2 (gas) of the French Energy Code.
36 Article L337-7 of the French Energy Code.
To prevent this, the Law dated 7 December 2006, completed by the Law NOME, created a new section in the French Consumer Code entitled ‘electricity supply or natural gas contracts’, the provisions of which apply to contracts concluded by consumers and professionals for less than 36kVA (electricity) or less than 30,000kW (gas).

The energy supplier ‘must give the client an opportunity to sign a single contract dealing with both the supply and the distribution of electricity or natural gas’. This contract, which should at least last for one year, thus creates a tripartite relationship between the supplier, the distributor and the consumer, even though the supplier often remains the consumer’s main interlocutor.

The supplier must mention several specific provisions both in the offer and the contract. Failure to do so is subject to sanctions. The consumer can rescind the energy supply contract at any time if it plans on changing supplier. Professionals are not entitled to ask the consumer for any other costs than those incurred by the rescission, provided that these costs were mentioned in the offer.

iv Market developments
Market developments have taken place in different areas, and in particular on the cost of electricity with the Law NOME and on renewable energies with the Law on energy transition. Moreover, the renewal procedure of hydraulic concessions has been launched and is ongoing, while the regime of hydraulic concessions has been reformed, notably regarding the procedure applicable to the granting of such concessions.

Finally, the implementation of legal frameworks for the self-consumption of electricity and for closed energy distribution systems, such as the one set up by Order No. 2016-1725 of 15 December 2016 subjecting the operation of these systems to the issuance of an administrative licence, might enhance the development of local energy markets for the upcoming years.

V RENEWABLE ENERGY AND CONSERVATION
i Development of renewable energy
In July 2007, the French government launched the Grenelle Environment Forum, a major national consultation that led to the emergence of priority targets in terms of controlling energy consumption and promoting renewable energies. This forum led to the enactment of two ‘Grenelle Laws’, on 3 August 2009 (Grenelle I) and 12 July 2010 (Grenelle II) respectively, aiming at promoting environmental objectives such as the increase of the share of renewable energy to at least 23 per cent of final energy consumption before 2020, in accordance with European Union Directive 2009/28/EC. These laws were codified in...
a separate section dedicated to renewable energy in the French Energy Code. More recently, Law No. 2015-992 of 17 August 2015 on energy transition and its several implementing decrees substantially modified the applicable legal framework on renewable energy.

To enhance the development of renewable energies, public authorities can use two economic instruments: (1) the purchase obligation,\(^\text{45}\) requiring EDF to buy electricity produced from renewable sources, for a regulated tariff over a long period, which can be changed and is slightly higher than the market price; and (2) the supplementary remuneration,\(^\text{46}\) which provides that EDF is obliged to enter into a contract for the purchase of electricity – whose duration shall not exceed 20 years – with renewable energy producers, according to which an additional remuneration shall be paid to them.

The regime, eligibility for and articulation of these two schemes were later substantially reformed by three Decrees:

a. Decree No. 2016-691 of 28 May 2016 defining the list and characteristics of the installations eligible to one or the other of the support mechanisms;

b. Decree No. 2016-690 of 28 May 2016 setting out the terms and conditions of the assignment of the purchase obligation contract; and

c. Decree No. 2016-682 of 27 May 2016 on the purchase obligation and on the supplementary remuneration.

### ii Energy efficiency and conservation

To achieve a 20 per cent increase in energy efficiency, in accordance with the climate and energy package, on 25 October 2012 the European Union adopted Directive 2012/27/EU on energy efficiency. It lays down rules designed to remove barriers in the energy market and to overcome market failures that impede efficiency in the supply and use of energy, and provides for the establishment of indicative national energy-efficiency targets for 2020.

The transposition of this directive into French law led to the adoption of several measures intended to improve energy efficiency, such as:

a. the creation of an obligation for companies to be subject to an energy audit every four years;\(^\text{47}\)

b. the submission by France of its report on its efficiency energy target to the European Commission on 24 April 2014; and

c. the establishment of a requirement for public purchasers to buy products and services and to buy or rent buildings that have a high energy efficiency.\(^\text{48}\)

### iii Technological developments

Directive 2012/27/EU also includes several provisions related to the development of smart grids and smart meters, the aim of which is to reduce bills by paying what was really consumed and by understanding consumption patterns better. The development of smart grids is based on the idea that it improves energy efficiency and better integrates renewable energy resources in the network.

---


\(^{47}\) Article L233-1 of the French Energy Code.

\(^{48}\) Article R234-1 of the French Energy Code.
The development of smart grids has also been decided in France. Indeed, a Decree dated 31 August 2010 provided that new connection points must be equipped with smart meters from 1 January 2012 and provided for a test run or pilot for such equipment.

Following the governmental announcement that 35 million smart meters will be provided to electricity customers throughout the country by 2020, the deployment started in December 2015.

VI THE YEAR IN REVIEW

2017 and the beginning of 2018 were characterised by several developments in the energy sector.

i The Conferences of the Parties to the United Nations Framework Convention on Climate Change (UNFCCC)

Withdrawal of the United States from the Paris Agreement

In spite of the COP22’s\textsuperscript{49} final plea to the US President-elect, President Donald Trump announced on 1 June 2017 that the United States would withdraw from the Paris Agreement,\textsuperscript{50} stating that it would ‘undermine [the US] economy’ and ‘put [the US] at a permanent disadvantage’. This withdrawal process will not conclude until the 2020 US election.

Bonn Climate Conference (COP23)

Held in Bonn from 6 November to 17 November 2017, the 23rd session of the Conference of the Parties to the UNFCCC, presided over by the government of Fiji, mainly led to discussions on the implementation methods of the Paris Agreement. Special focus was set on the coal phase-out, with the launch of the ‘Powering Past Coal Alliance’ led by the United Kingdom and Canada. Joined by more than 20 countries, including France, the Alliance’s signatories committed to the progressive shutdown of their coal-fired power plants.

ii Clarification of the legal framework for the self-consumption of electricity

Following Order No. 2016-1019, dated 27 July 2016, ratified by Law No. 2017-227 of 24 February 2017, and in a context of strong development of self-consumption of electricity, on 28 April 2017 the French government issued Decree No. 2017-676. This Decree notably specifies the obligations of the public electricity distribution system operators in the implementation of collective self-consumption operations.

iii Further regulatory provisions regarding mediation in the energy sector

Decree No. 2017-1113, dated 27 June 2017, provided additional details in relation to the mediation process that can be undertaken before the energy ombudsman, coordinating the

\textsuperscript{49} From 7 November to 18 November 2016, Marrakech hosted and presided over the 22nd session of the Conference of the Parties to the UNFCCC, which mainly led to discussions on the implementation methods of the Paris Agreement. The commitments of the signatory countries (such as reducing greenhouse gas emissions) will only enter into force in 2020.

\textsuperscript{50} The Paris Agreement entered into force on 4 November 2016, after 55 countries that account for at least 55 per cent of global emissions had ratified it. The aim of such Agreement is ‘to strengthen the global response to the threat of climate change’.
mediation procedure of the French Energy Code with the provisions of the French Consumer Code. This alignment enables the application to the mediation of the energy sector of certain general rules such as the gratuitousness of the mediation for the consumer, as well as the specific deadline granted to the ombudsman to communicate his or her solution to the dispute.

iv Amendment of the provisions relating to energy efficiency certificates

The French government issued two decrees amending the regulatory provisions of the French Energy Code relating to energy efficiency. Decree No. 2017-690, dated 2 May 2017, implemented a fourth period of energy efficiency obligations, extending from 1 January 2018 to 31 December 2020, and set the level of obligations for said time period. Decree No. 2017-1848, dated 29 December 2017, laid out new conditions regarding the possibility to delegate part of one’s obligation of energy efficiency to one or more third parties. Both decrees came into force on 1 January 2018.

v Public debate on the Multi-annual energy programming

The French National Public Debate Commission (CNDP) decided on 6 September 2017 that the objectives and priorities set out in the multi-annual energy programming had to be the subject of a public debate. Pursuant to Article 176 of the Law on energy transition, Decree No. 2016-1442, dated 27 October 2016, had set out a list of medium-term objectives about the priorities of action of the public authorities for the period 2016–2023, including notably:

a the reduction of final energy consumption by 12.6 per cent in 2023;

b the increase of renewable energy production;

c the establishment of a strategic plan by EDF on how to reduce the part of the nuclear industry to 50 per cent of electricity production by 2025 within a maximum period of six months; and

d the prohibition of installation of any new coal plant that is not equipped with a system of gas capture or storage.

The debate organised by the CNDP began on 19 March 2018, and will come to an end on 30 June 2018.

vi Cancellation of Order No. 2013-400 dated 16 May 2013

In a decision dated 19 July 2017, the French Council of State, France’s highest administrative court, repealed the Order of 16 May 2013 concerning regulated tariffs for the sale of natural gas, considering that the legal framework regulating the setting of these tariffs, provided for in Articles L445-1 to L455-4 of the French Energy Code, was contrary to European law. The court’s decision did not have an immediate impact on regulated gas prices in France, as it neither questioned existing contracts, nor did it request the French government to organise the extinction of said tariffs. However, the ruling was much anticipated.

51 Decision No. 2017/41/PPE/1.
By contrast, regarding the electricity market, the French Council of State has just rendered a decision on 18 May 2018\(^5\) in which it confirms the principle of regulated tariffs for non-professionals and other similar consumers. France’s highest administrative court explains its decision by insisting on the specificity of electricity and its high market volatility.

vii France’s Climate Plan to accelerate the energy and climate transition

On 6 July 2017, Environment Minister Nicolas Hulot unveiled the details of France’s climate action plan, showcasing France’s commitment to speeding up the operational implementation of the Paris Agreement, the plan aiming for such goals as carbon neutrality by 2050 and the end of sales of fossil fuel-powered cars by 2040.

viii Law No. 2017-1839, dated 30 December 2017

Law No. 2017-1839, adopted on 30 December 2017, brought to a definite end the search and exploitation of hydrocarbons. The government’s principal aim being the progressive phase-out of the hydrocarbon production on the French territory by 2040, the law provides that no new research permit for hydrocarbons will be granted by the government. Moreover, the existing exploitation concessions will not be able to be renewed past 2040. Shale gas exploration will also remain prohibited in France.

Law No. 2017-1839 also contains a reform regarding access to underground natural-gas storage. The reform abandons the negotiated access system for a new regulated access of third parties, with new rules of commercialisation and a regulated tariff, the key purpose being better guaranteeing to the consumers of natural gas the security of supply.

VII CONCLUSIONS AND OUTLOOK

Since 2007, the liberalisation of the energy market and the energy transition continue together step by step. While historically France is strongly committed to a public energy service, a huge step towards liberalisation and energy transition has been achieved in the past few years, notably so with the end of regulated tariffs and the adoption of the Law on Energy Transition on 17 August 2015, which aims at developing the role of renewable energies.

Furthermore, the implementation of President Emmanuel Macron’s energy programme will have to be followed. Emmanuel Macron thus notably intends to maintain the objective of reducing the part of nuclear energy to 50 per cent of electricity production, to close all coal-fired power plants within five years, to fix a bottom carbon price for the European Union, to double the capacity of wind and solar energy production and to maintain the prohibition of shale gas exploration.

Finally, the amendment and the adoption by the European Parliament and Council of the European Commission’s Fourth Energy Package and its transposition and implementation by France will have to be closely monitored. Containing proposals for no less than four Regulations and four Directives, the EC’s Fourth Energy Package may well have an impact on the French regulation of the energy market.

---

\(^5\) French Council of State, 18 May 2018, Nos. 413688, 414656.

© 2018 Law Business Research Ltd
I  OVERVIEW

The German energy sector continues to evolve dynamically. As Germany will probably miss its 2020 carbon dioxide emission reduction goals, the new government plans to intensify its efforts to pursue the reform of the German energy market (the ‘energy transition’), meaning a shift of electricity generation to renewable energies, a substantial reduction of carbon dioxide emissions and a phase-out of nuclear energy. In particular, the share of renewable energy sources in the power generation mix shall be increased to 65 per cent by 2030. However, the side effects of these ambitious targets have resulted in rising costs for the support of renewable energies, the need for considerable network expansion and unintended effects on the viability of conventional generation capacities. At the same time, the large German utilities are adapting their business models to the changing market conditions.

II  REGULATION

i  The regulators

The responsibility for the energy transition and all aspects related to it, including climate change, are concentrated at the Federal Ministry for Economic Affairs and Energy (BMWi). The main national regulatory authority is the Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway (BNetzA) under the authority of the BMWi. BNetzA is responsible for the regulation of gas and electricity networks with at least 100,000 grid customers or networks that extend beyond the territory of an individual state. BNetzA also plays a key role in planning and approving large energy network extension measures according to the Grid Extension Acceleration Act. At regional level, the regulatory authorities of the 16 German states are in charge of the regulation of the smaller networks, in particular distribution networks. The regulatory authorities monitor the compliance of network operators with applicable law and determine the general market rules for transport of electricity and gas. Their duties include the supervision of non-discriminatory network access and determination of the grid operators’ individual revenue caps, and they also ensure that grid operators comply with unbundling rules and with their system security obligations.

The Federal Cartel Office (BKartA) has jurisdiction to apply competition law to the non-network-related parts of the energy supply chain. The BKartA is also in charge of merger control.

1 Thomas Schulz is a partner, and Henry Hoda and Ruth Losch are lawyers at Linklaters LLP.
Both the regulatory authorities and the BKartA have wide-ranging powers of enforcement, such as refusal of permits, issue of prohibition orders and imposition of fines.

Since 2013, a market transparency unit at the BKartA has been overseeing and publishing fuel prices in order to increase transparency and competition in these markets. Since 2015, a parallel market transparency unit at BNetzA has supervised the wholesale trade in electricity and gas markets.

Sources of law
The key source of legislation is the Energy Industry Act (EnWG), which sets out the main regulation of the German energy market including unbundling requirements, grid operation, energy supply, grid concessions, regulators and legal protection. It was adopted in 2005 and substantially amended in 2016. A number of ordinances set out further details, such as the Incentive Regulation Ordinance and the Electricity and Gas Grid Fee and Grid Access Ordinances. The Renewable Energies Act (EEG) sets out the priority network access and remuneration for the generation of electricity from renewable sources; since 2017 it is supplemented by the Offshore Wind Energy Act. The support for co-generation power plants is regulated in the Co-Generation Act.

Another important source of law is the administrative decisions of BNetzA, addressed to individual parties or to groups of network operators. BNetzA also issues general guidelines addressed to the public and interpreting energy sector legislation. The guidelines are not legally binding. However, market participants usually respect them as they form the basis of BNetzA’s decision-making.

Regulated activities
Network operation
Operators of distribution and transmission networks must obtain a grid operation permit confirming their personal, technical and economic capability and reliability to ensure the long-term operation of the network. The permit has to be issued by the competent regulatory authorities of the federal states within six months of the authority having the complete application files at its disposal.

In addition, transmission system operators (TSOs) require certification by BNetzA confirming their compliance with unbundling regulation. Before taking a final decision, BNetzA has to submit its draft decision to the European Commission and must take utmost account of the European Commission’s statement.

When using public roads, network operators must enter into concession agreements with the municipality owning the roads. Such concession agreements have to be tendered by the municipalities every 20 years in a non-discriminatory procedure without the possibility of unduly favouring their own utilities.

Generation and supply
The construction of power generation facilities requires a permit under the Federal Immission Control Act. The construction and operation of nuclear power plants requires a special permit under the Nuclear Energy Act. However, following the nuclear accident at the Fukushima Daiichi nuclear power plant in 2011, the German government decided to phase out nuclear energy by 2022. Hence, commercial nuclear power plants will no longer be authorised.
Besides, operators of power generation facilities with a capacity of 10MW or more have to inform the responsible TSO and BNetzA of their intention to shut down a facility at least 12 months before the planned decommissioning. Facilities with a capacity of 50MW or more may not be decommissioned for a maximum period of 24 months if the facility has been designated by the responsible TSO and BNetzA as relevant for system security. In this case, the operator is entitled to reasonable compensation for the necessary maintenance expenses.

Energy supply companies delivering energy to end consumers must notify the regulatory authority of the commencement and of the discontinuance of their supply activities, including proof of sufficient resources and reliability.

Other than already mentioned, the supply or trading of energy does not require any specific licences under energy regulation provisions.

iii Ownership and market access restrictions

If a TSO or its owner is controlled by one or more persons from a country that is not a member of the European Union or of the European Economic Area, the grid operator will only be certified by BNetzA if in addition to compliance with the unbundling rules the BMWi confirms that the certification does not endanger the security of the electricity and gas supply of Germany or of the EU.

Under general foreign investment rules, the BMWi may prohibit on the grounds of public order or national security the acquisition by a non-EU or non-EEA investor of a participation of 25 per cent or more in a German company or asset. In 2017, the government has tightened the rules on foreign investment control, widening its scope and extending the time limits for review of potential acquisitions. The amended foreign investment control regime focuses on the acquisition of certain critical infrastructures, including from the energy sector, where the acquisition by a foreigner is by law considered to be a potential threat to public security. It is expected that such acquisitions will be more thoroughly examined by the BMWi in the future.

iv Transfers of control and assignments

The transfer of regulated assets (i.e., network assets) is not subject to any sector-specific restrictions. However, network operators have to inform the regulatory authority about transfers, mergers or the splitting of grid assets. In the case of a transfer of network assets, part of the revenue cap is transferred with the assets.

The acquirer of transmission assets must comply with the unbundling rules. TSOs have to inform BNetzA of any intended transactions that may require a reassessment of their certification, particularly in the case of a planned takeover or participation by an investor from outside the EU or EEA.

Any transfer of control or decisive influence must be notified for merger clearance to the BKartA or to the European Commission if certain thresholds are exceeded. A merger will be cleared if it does not significantly impede effective competition, in particular by creating or strengthening a dominant position. The BKartA decides within one month of notification or, if an in-depth investigation is initiated, within an additional four-month period. The European Commission has a maximum of 135 working days in which to carry out an in-depth investigation to review a merger (maximum of 160 working days if remedies are offered).
III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

In implementing the EU’s Third Energy Package, the EnWG provides for different unbundling regimes for TSOs and distribution system operators (DSOs).

TSOs

As of 3 September 2009, the German transmission networks were all owned by vertically integrated energy supply undertakings (VIUs); the TSOs could choose between three unbundling models: ownership unbundling, the independent system operator model and the independent transmission operator model.

Most of the TSOs have opted for the independent transmission operator model and some for ownership unbundling. The independent system operator model has not been applied so far. Following several competition law procedures initiated by the European Commission, and owing to the increased regulation of grid assets, three of the four major German VIUs (E.ON, RWE and Vattenfall) divested their electricity and gas TSOs. This resulted in foreign TSOs and financial investors, such as infrastructure funds, entering the German transmission market.

With respect to the ownership unbundling model, BNetzA holds the view that a person controlling electricity or gas production, generation or supply activities may at the same time hold a minority participation in a TSO of up to 25 per cent, provided that this participation does not confer significant minority rights. This is evaluated on a case-by-case basis.

The European Commission has in the meantime recognised that a TSO may be certified as ownership unbundled despite having a shareholder with a participation in generation, production or supply activities if it can prove that no conflict of interest exists. This will be examined on a case-by-case basis, taking into account in particular the geographic location of the transmission activities and the generation, production or supply activities concerned, the value and the nature of the participations in these activities, as well as their size and market share.

DSOs and gas storage operators

Unbundling requirements for DSOs are less strict. DSOs with at least 100,000 grid customers and gas storage system operators must be legally and operationally unbundled from the VIU. DSOs are required to ensure that their communication and branding do not create confusion with regard to the supply branch of the VIU.

At the level of the DSOs there remains a large degree of vertical integration. DSOs typically belong to municipal utilities or to one of the incumbent energy suppliers.

ii Transmission/transportation and distribution access

Connection to networks and network access is regulated. Network operators have to ensure a reasonable, non-discriminatory and transparent connection and access to their grids for all third parties, including extension of the network if required and reasonable (regulated third-party access). By way of exception, priority will be given to network connection and access of operators of renewable energy facilities.

Costs for network connection are in general borne by the network customer, except for offshore wind farms whose connection costs are socialised.
Access to electricity networks is granted on the basis of standardised network access agreements concluded between the grid operator and the grid customer or, in the case of electricity suppliers, on the basis of supplier framework access agreements. The access agreement grants nationwide access to all electricity networks. The agreements are based on a model network access agreement developed by BNetzA.

Access to gas networks is based on capacity bookings in a two-contract entry-exit system: one contract is concluded between the grid customer and the grid operator for the feed-in of the gas, and a second contract is concluded between the grid customer and the grid operator for the offtake of the gas. Gas can be transported and traded without physical restrictions across networks, including on virtual trading points, within each of two gas market areas in Germany (GASPOOL and NetConnect Germany).

Network operators do not have exclusive rights to provide services within their network areas. Transmission and distribution networks are closely interlinked, and operators are obliged to cooperate. Contracts for network access and general terms and conditions are standardised and approved by BNetzA. BNetzA has the competence to set detailed rules on network access applicable to all network operators, for example in relation to balancing energy and capacity management.

Network operators may restrict network access to maintain system security. They must use non-discriminatory and market-based measures to prevent or eliminate bottlenecks. The increase in generation of electricity from renewable energy sources and the phase-out of nuclear energy is leading to a shift of generation to northern Germany, resulting in bottlenecks on the north-south transmission lines. Costs for re-dispatch measures of TSOs to relieve bottlenecks are socialised to all grid customers. Hence construction of additional electricity transmission lines is one of the key priorities of German energy policy. In addition, the installation of new onshore wind capacity in Northern Germany has been limited to 902MW per year.

TSOs have to establish 10-year network development plans for electricity, gas and for connection of offshore wind farms every two years. The development plans set out the required grid expansion measures. BNetzA reviews the development plans and may request modifications. The necessity of all listed projects is then legally determined by the federal government. BNetzA is responsible for the actual planning approval for projects that cross the borders between German states.

iii Rates

Since 2009, grid fees have been subject to revenue cap incentive regulation. Two years prior to the beginning of each five-year regulatory period, the competent regulatory authority determines a grid operator’s allowed cost and asset base by analysing its costs of the preceding financial year (photo year). The cost and asset base in the photo year is the basis for the network operator’s allowed revenues in the next regulatory period. The regulatory authority sets the grid operator’s individual annual revenue cap for each year of the five-year regulatory period, taking into account individual and sector-specific efficiency targets and an allowed rate of return on equity set by BNetzA. During the regulatory period, the annual revenue cap will in principle only be adjusted in the case of an adjustment of the consumer retail price index or a change of the grid operator’s permanently non-controllable costs. As a result, the grid operator has an incentive to outperform its efficiency targets before the revenue cap is reset for the next regulatory period. Based on their fixed revenue caps, the grid operators charge the corresponding access fees to their grid customers.
The permitted rate of return on equity as set by BNetzA for the second regulatory period (gas: 2013–2017, electricity: 2014–2018) is 9.05 per cent before tax for new assets and 7.14 per cent before tax for old assets (commissioned before 2006). For the third regulatory period (gas: 2018–2022, electricity: 2019–2023), BNetzA has set the allowed rates of return on equity to 6.91 per cent before tax for new assets and to 5.12 per cent before tax for old assets. In March 2018, grid operators successfully challenged the new rates as too low before the Higher Regional Court of Düsseldorf. BNetzA will have to recalculate the allowed return on equity in favour of the grid operators unless it successfully appeals to the Federal Court of Justice.

In 2016, the Incentive Regulation Ordinance was amended mainly to improve investment conditions for DSOs. Capital costs for network investments made after the photo year are now recognised in DSOs’ revenue caps without delay. Very efficient DSOs may receive an efficiency bonus.

Grid customers with atypical grid use or with continuous and very high consumption (at least 7,000 hours and more than 10GWh per year) have a right to individual network fees below the regulated tariffs. Such individually agreed fees have to be notified to the competent regulatory authority.

iv Security and technology restrictions

There are no specific restrictions on technology transfer for the energy sector.

Based on a report from the TSOs, every two years BNetzA reviews whether the disruption or destruction of transmission assets in Germany could have a material impact on at least two EU Member States. BNetzA can declare such assets to be critical European infrastructure. TSOs have to develop specific security plans for such assets, including access control, security of IT systems and emergency protocols. In 2015, an IT Security Act was adopted that shall tighten IT security requirements and extend their scope to all assets required for secure network operation.

IV ENERGY MARKETS

i Development of energy markets

Gross energy consumption in 2017 increased by 0.8 per cent compared to 2016; gross electricity consumption increased also by 0.8 per cent. In 2017, gross energy consumption was composed of oil (34.5 per cent), natural gas (23.8 per cent), hard coal (10.9 per cent), lignite (11.1 per cent), nuclear energy (6.1 per cent) and renewable energy sources (13.1 per cent). Gross electricity generation in 2017 was composed of lignite (22.5 per cent), hard coal (14.1 per cent), nuclear energy (11.7 per cent), natural gas (13.2 per cent) and renewable energy sources (33.3 per cent), the latter mainly consisting of wind power (16.2 per cent), hydropower (3.1 per cent), biomass (6.9 per cent) and photovoltaic (6.1 per cent). These figures illustrate that despite an increased share of renewable energy sources, conventional energy sources are still the backbone of the German energy supply.

Germany has a joint electricity market area with Austria. However, with effect on 1 October 2018, the common German–Austrian price zone shall be split. Appeals against this decision, which results from a recommendation of the Agency for the Cooperation of Energy Regulators (ACER) are currently pending before the Court of the European Union.
Austrian stakeholders argue that the German–Austrian interconnector itself is not congested and that congestion within Germany and loop flows to neighbouring countries should be mitigated otherwise.

Germany has two separate dual-quality (high caloric and low caloric gas) gas market areas: NCG and GASPOOL. Within these gas market areas, gas can be traded without capacity restrictions at virtual trading hubs through matching buy and sell orders between two balancing groups. Owing to the decreasing production of low caloric gas in Germany and the Netherlands, until 2030 all grids and customer units will consecutively be transferred to comply with high caloric standards.

The European Energy Exchange AG (EEX) in Leipzig operates organised markets for trading in electricity, natural gas, oil, coal, carbon dioxide emission allowances and guarantees of origin. EEX offers trading of electricity futures for delivery in the market area Germany–Austria and trading of gas futures and short-term gas contracts for delivery in the two German market areas GASPOOL and NCG. The electricity spot market for Germany–Austria is operated by EPEX SPOT SE in Paris.

Prices on the spot and futures markets are based on bids by generators and customers. The order of the bids is determined by the short-run marginal costs of the power plants (merit order). Owing to the statutory priority of feed-in of renewable energies (‘produce and forget’), electricity from renewable sources is always first in line in the merit order, usually followed by nuclear energy and coal-fired power plants. The prices on the spot and forward markets are the benchmark for wholesale prices and over-the-counter trades.

The spot and futures markets are energy-only markets (i.e., there are no capacity payments). The increase in generation from renewable energies has led to a decrease of wholesale prices and has pushed conventional generation capacity out of the merit order, in particular flexible gas-fired power plants.

In order to guarantee security of supply, the Electricity Market Act of 2016 implemented several capacity mechanisms without, however, introducing a real capacity market. The ‘network reserve’ is composed of ‘system relevant’ power plants, mainly in Southern Germany, that would otherwise be decommissioned, providing additional redispatch potential if necessary. The ‘capacity reserve’ shall be provided by power plants outside the energy market being remunerated for the provision of capacity via a tendering process. Until 2023, the function of the capacity reserve will mainly be served by lignite-fired power plants that are being transferred to ‘security standby mode’ before being decommissioned four years later.

Energy market rules and regulation

The energy market operated by EEX is subject to the Exchange Act. Under the authority of the State Ministry of Economy, Labour and Transport in the German state of Saxony, an independent market surveillance body continuously supervises trading activities in order to prevent market manipulation.

Under the EU Regulation on wholesale energy market integrity and transparency (REMIT), market participants are required to publish inside information in an effective and timely manner. REMIT also prohibits market abuse in wholesale energy markets in the form of market manipulation and insider trading. Since 2015, market participants have to register with BNetzA and report details of wholesale energy transactions executed at organised market places to ACER.

Since 2014, all EU-based entities that enter into derivatives transactions are required to report details of these transactions to a trade repository under the European Marketing
Infrastructure Regulation (EMIR). There is also an obligation to report certain existing and historical derivatives transactions, although deadlines for this vary. Furthermore, EMIR established a central clearing obligation for certain over-the-counter derivatives and the application of risk mitigation techniques for non-centrally cleared over-the-counter derivatives.

### iii Contracts for sale of energy

In principle, there are no regulatory limitations as to the entering of individual contracts for the sale of energy, both at wholesale and retail level. However, household customers have a right to be supplied at standard (but not regulated) tariffs by the local supplier with the most household customers within a network area (supplier of last resort). Energy supply contracts with household customers also have to comply with certain transparency and information requirements.

While there is no *ex ante* price regulation of wholesale or retail energy prices, regulated network charges, taxes and surcharges (such as the surcharge for renewable energies) meanwhile account for more than half of the final energy prices. Competition authorities may review energy prices (except the regulated components) and prohibit dominant suppliers from charging prices that unreasonably exceed costs or that are lower than on comparable markets.

In recent years, price increases for final customers based on the passing-on of input costs (e.g., increase in fuel cost for electricity generation) have frequently been annulled by the courts, arguing that these were not justified or that provisions in energy supply contracts enabling such price increases were not sufficiently transparent. Following landmark decisions of the European Court of Justice and the German Federal Court (BGH) in 2013 and 2014, according to which a standard clause for price adjustments that was widely used in supply agreements is invalid, network operators have to provide information on the scope, reasons and preconditions for the adjustment.

### iv Market developments

The large German utilities are increasingly adapting their business to the changing market environment by divesting or consolidating their conventional power generation facilities and investing in renewable energy sources, grids and new forms of energy supply and customer solutions. In 2016, RWE transferred its renewables, grids and supply business to its subsidiary, Innogy, while E.ON spun off its conventional generation and trading business into a new listed company (Uniper). In January 2018, E.ON sold its shares in Uniper to the Finnish energy supplier Fortum and in March 2018 E.ON announced that it would acquire RWE’s majority stake in Innogy and in return E.ON would transfer to RWE most of E.ON’s renewables business. Thus, in the future, RWE would focus on conventional and renewable generation while E.ON would concentrate on energy networks and customer solutions.

### V RENEWABLE ENERGY AND CONSERVATION

#### i Development of renewable energy

***Reform of the EEG and Offshore Wind Farms Law***

In 2017, a major reform of the EEG, the law governing the development of renewable energy sources, entered into force. The main aim of the reform was to control the cost
increase for electricity generation from renewable fuel sources. It is aiming to move away from ‘produce-and-forget’ guaranteed feed-in tariffs towards market-based mechanisms for their remuneration. Therefore, the EEG 2017 introduced auctions as the basic mechanism to determine the remuneration for electricity from onshore and offshore wind power, photovoltaic power and biomass, subject to a number of exemptions; for example, for smaller facilities, for which remuneration remains fixed by law. Auctions for other renewable energy sources, for example, geothermal energy, may be introduced at a later stage. The technology-specific auction volumes are limited to:

- **a** 2,800MW/year from 2017 to 2019 and 2,900MW/year as of 2020 for onshore wind;
- **b** 600MW/year for solar;
- **c** 150MW/year from 2017 to 2019 and 200MW/year as of 2020 for biomass; and
- **d** 6.5GW until 2020 and 15GW until 2030 for offshore wind.

The first auction carried out for 1,500MW offshore wind power in March 2017 resulted in an average remuneration of only 0.44 cents/kWh with most of the capacity being awarded for no subsidies at all. This has been a shock for the industry that will change future calculation and financing of renewables projects. Recent auctions for solar and onshore wind saw prices converging around an average price level of approximately 4.3 cents/kWh (February 2018). In addition, BNetzA will carry out technology neutral auctions for onshore wind and solar power together in the amount of 400MW/year from 2018 to 2020.

In addition to the EEG 2017, a new Offshore Wind Farm Act has been adopted that sets out rules for the planning, tendering and approval of offshore wind farms (OWFs). The main aim of the law is to better harmonise the construction of OWFs and their grid connections to the onshore grid. As a main feature, the new law introduces a central planning model in which the Federal Maritime and Hydrographic Agency instead of the developers identifies suitable areas for the construction of OWFs. The law applies to OWFs in the German exclusive economic zone that will be commissioned from 1 January 2021.

**State-aid proceedings and support for energy-intensive industries**

In November 2014, the European Commission closed its in-depth investigation to examine the compatibility of the EEG 2012 support scheme with EU state aid law. The Commission considered that the EEG 2012 constitutes state aid, but found it, in principle, to be in line with its Guidelines on State Aid for Environmental Protection. However, the Commission considered the reduction of the EEG surcharge for those companies in energy-intensive industries that do not fulfil certain criteria as set out by the Commission in its decision to constitute state aid incompatible with the internal market and ordered Germany to recover such aid immediately. Meanwhile, Germany has appealed against the Commission’s decision before the Court questioning the qualification of the EEG support scheme as state aid, but the Court confirmed the Commission’s decision in May 2016. Germany’s appeal against this decision is currently pending before the European Court of Justice.

As regards the EEG 2014, the Commission in July 2014 confirmed that it is compatible with EU state-aid rules. In December 2016, the Commission also considered the EEG 2017 to be compatible with EU state-aid law.

**Energy efficiency and conservation**

Following the 2015 Paris agreement to limit global warming to well below 2 degrees above pre-industrial levels, the German government in 2016 adopted a national Climate Action...
Plan 2050 according to which Germany is to reduce its greenhouse gas emissions by at least 55 per cent compared to 1990 by 2030 and to at least 70 per cent by 2040. However, Germany is about to miss its goal to reduce emissions by 40 per cent in 2020 compared to 1990. Germany is also about to miss its goal to reduce gross energy consumption by 20 per cent in 2020 compared to 2008. In 2017, the decline was only 6 per cent compared to 2008. In reaction to that, the new German government intends to formulate a cross-sector energy efficiency strategy based on the ‘efficiency first’ principle. Based on the results of BMWi’s green paper on energy efficiency, the National Action Plan Energy Efficiency shall be further developed and implemented.

iii  Technological developments

Driven by the need to store the surplus electricity from renewable energy sources, the installation of power storage facilities, both at household and at commercial level, is developing very dynamically. Storage facilities are based on a large variety of technologies, such as battery storage, power-to-gas, power-to-heat or power-to-liquid.

Also, e-mobility picks up speed; however, from a low level. In 2017, sales of electric vehicles doubled compared to 2016 to approximately 55,000 cars. The government wants to promote this development by providing public funding beyond 2020. Various market players have announced that they will invest into the charging infrastructure and the government aims to have an additional 100,000 charging points installed by 2020.

Another trend is blockchain, a technology based on continuously growing lists of digital records (blocks) that are linked and secured using cryptography. Recently, several platforms have been launched where market players may trade peer-to-peer using blockchain technology.

In relation to smart meters, the EU has set a non-binding target of rollout to 80 per cent of all consumers by 2020. In 2016, the Act on the Operation of Measuring Points (MsbG) entered into force, which provides for the introduction of smart meters, including rules on data protection, data access, rollout and financing of the rollout. Due to the high standard on data protection, the certification of the central element, the smart meter gateway, has been delayed. The rollout is expected to start in 2018. The MsbG establishes maximum price limits for the installation and service of the smart meters depending on the individual consumption. Provided the maximum price limits and the outstanding certification requirements are met, the installation of smart meters will be mandatory for consumers with a consumption above 10,000kWh per year (as of 2020, more than 6,000kWh/year). The installation of smart meters for consumers with an annual consumption below 6,000kWh/year is optional. The goal is to complete the smart meter rollout in 2032.

VI  THE YEAR IN REVIEW

The fundamental reform of the EEG, introducing auctions as the basic mechanism to determine the remuneration level for the support of power from renewable sources, has proved successful in countering a further cost increase. The increased share of intermittent renewable generation, however, puts further pressure on the viability of conventional generation facilities. This induced the large German utilities to accelerate the restructuring and consolidation of their generation portfolios. E.ON even announced to withdraw (nearly) completely from the generation business and to focus on grids and customer solutions.
At the same time, the German energy market saw an increased entry of new market players. These are both start-ups promoting new technologies such as blockchain or e-mobility and companies from other sectors, such as IT and telecoms, driving forward the digitalisation of the energy sector.

**VII CONCLUSIONS AND OUTLOOK**

Following six months of standstill after the election of parliament in September 2017, the new German government in February 2018 announced its aim to intensify its efforts to reform the German energy market without endangering Germany’s international competitiveness and security of supply. However, in order to ensure that Germany reaches its 2030 climate goals the government will have to further specify the necessary policy measures, including in particular a plan on how to progressively reduce the generation of electricity from coal to ultimately zero as well as a coherent strategy for the integration of renewable energies into the heating and transport sector.

New policy measures will strongly depend on the route European legislation will take in the field. The European Commission’s Clean Energy Package *inter alia* promotes the interdependence of the Member States’ energy markets and foresees stronger regional planning of policy measures, also involving stronger cooperation between grid operators, both on distribution and transmission level.
I OVERVIEW

The Indian economy is undergoing large-scale transformation across various key sectors, and energy security has emerged as one of the key focus areas in unlocking the country’s potential for meaningful development. Along with key policy changes, the government is working towards improving the bankability of key energy assets by restructuring and improving the financial health as well as the operational efficiency of distribution companies, along with continuing its efforts to promote new areas of growth such as India’s offshore wind energy sector and the solar rooftop segment. The primary concerns for the country continue to be providing reliable, uninterrupted electricity to all and finding solutions to the unutilised capacity. While the majority of the contribution to India’s energy mix continues to come from conventional energy sources, the government remains keen on scaling up the Indian renewable energy market and has set a target of 175GW of renewable energy capacity to be installed by 2022. India ratified the Paris Convention on Climate Change and aims to produce at least 40 per cent of its installed electricity capacity by 2030 from non-fossil fuels. Encouraged by the success of its initiatives in the renewable energy sector, and to ensure that commitments made to the international community are fulfilled, the government has considerably increased its renewable energy production targets, especially for the onshore wind energy and solar energy production.

II REGULATION

i The regulators

The power sector is governed by the federal government through, primarily, the Ministry of Power and the Ministry of New and Renewable Energy (the Renewable Energy Ministry). Currently, the Ministry of Power and the Renewable Energy Ministry are under the charge of a single minister to ensure an identity of objectives and synchronisation in policies. The Electricity Act 2003 (the Electricity Act) is the primary statute that governs generation, transmission, distribution and trading of electricity. The Electricity Act provides for the formulation of the National Electricity Policy 2005, the National Tariff Policy 2016 (the Tariff Policy), establishment of independent electricity regulatory commissions at the central level (the Central Electricity Regulatory Commission (CERC)) and state level (the state electricity regulatory commissions (SERCs)) and the setting up of the Appellate Tribunal for Electricity. The relevant SERCs exercise jurisdiction over intrastate electricity regulatory matters.
India

(including tariffs), whereas the CERC exercises jurisdiction over all interstate electricity regulatory issues (also including tariffs). The revised Tariff Policy was announced in 2016, with some of the key highlights being an increase in the solar renewable purchase obligation (RPO) to 8 per cent by 2022, exemption on the payment of interstate transmission charges for wind and solar power projects, applicability of RPOs on co-generation power plants, compulsory procurement by distribution companies of 100 per cent power from waste to energy plants in the respective state and development of intrastate transmission projects through a competitive bidding route for projects above a particular project cost threshold, to be decided by the SERCs. The government also proposed significant amendments to the Electricity Act, particularly in terms of enabling consumers to choose their electricity supplier by segregating the entities that distribute and supply power, stricter penalties for non-compliance with the RPOs and introducing a renewable generation obligation on thermal power producers, requiring them to set up or contribute towards renewable generation capacity. While the proposed amendments have not yet been finalised, the central government is exploring other initiatives with the state governments on measures to make the power sector more competitive.

The Department of Atomic Energy and the Atomic Energy Regulatory Board regulate nuclear energy in India. The government is also in the process of setting up a statutory, independent and autonomous Nuclear Safety Regulatory Authority to replace the Atomic Energy Regulatory Board.

In the past few years, the Ministry of Coal and the state-controlled Coal India Limited (CIL) have been at the receiving end of nationwide criticism for failure to supply the requisite quantity and grade of coal, leading to strong lobbying on the part of power producers for assured coal supplies by the government. In September 2014, the Supreme Court cancelled 204 out of 218 coal blocks allocated to various entities between 1993 and 2010 by holding the procedure of allocation to be illegal and arbitrary. However, with the enactment of the Coal Mines (Special Provisions) Ordinance 2014, and subsequently, the Coal Mines (Special Provisions) Act, 2015 (Coal Mines Act), there has been a push towards ensuring continuity in mining operations and transparency in allocation of coal blocks. In accordance with the Coal Mines Act, which now governs the coal block allocation process, the government has re-started auctioning the cancelled coal blocks and out of the re-auctioned blocks, certain blocks are now operational as well. Further, with the Coal Mines Act having lifted end-use restrictions on the coal mined from some of the re-allocated blocks to enable the sale of coal in the open market, the government has recently approved the methodology for auction of coal mines for the commercial mining of coal without any restrictions on sale or utilisation of coal. This methodology envisages that the auction will be an ascending forward auction with the bid parameter being the price (in rupees per tonne) paid to the government on the actual production of coal from the mine. The government’s release in this regard also sets out that this is the most ambitious coal sector reform since 1993 and is expected to better the energy security scenario in India.

Last year, the Union Cabinet had approved a proposal for flexibility in utilisation of domestic coal with an aim to reduce the cost of power generation. The Central Electricity Authority has now devised a methodology for implementing the use of coal assigned to particular states in the power generating plants in such states, which will improve the efficiency of coal-based thermal power plants by reducing cost of coal transportation and

---

2 The Department of Atomic Energy is directly under the Prime Minister’s charge.

© 2018 Law Business Research Ltd
allow coal swapping among plants. The government has also put in place the Scheme for Harnessing and Allocating Koyala (coal) transparently in India (the SHAKTI policy), where the government coal companies will grant coal linkages on notified prices on an auction basis for coal-based power projects that have power purchase agreements in place. The bid parameter for this auction will be the levelised discount on the existing tariff that the independent power producer is willing to provide. This scheme has received a favourable response from generating companies and is expected to result in an annual generation of over 47 billion units of electricity.

The Ministry of Petroleum and Natural Gas (MoPNG) deals with issues relating to petroleum, natural gas, coal bed methane, shale gas and other petroleum products. Along with exploration and production, the MoPNG also monitors its supply, distribution, marketing and pricing. The Directorate General of Hydrocarbons (DGH), which is under the administrative control of the MoPNG, regulates the upstream segments for issues relating to exploration and production of oil and gas. The Petroleum and Natural Gas Regulatory Board (PNGRB) is the midstream and downstream regulator that regulates the refining, storage, transportation, distribution, marketing and sale of petroleum, petroleum products and natural gas.

ii Regulated activities

Electricity generation, including captive generation, is a delicensed activity. While generation activities can be freely undertaken without a licence, approvals and procedures under other laws for land acquisition, environmental, corporate safety of electrical equipment and labour compliance must be adhered to.

Electricity distribution activities (except for distribution of electricity in rural areas) require a licence from the relevant SERC. Electricity trading is a distinct recognised activity for which a separate licence is required from the CERC or an SERC (for interstate and intrastate trading respectively). Licences are awarded by the CERC for interstate transmission activity by way of a competitive bidding procedure in accordance with CERC regulations. For intrastate transmission services, licences are awarded by the relevant SERC. The proposed amendments to the Electricity Act provide for disaggregation of distribution activities by requiring the supplier of electricity and distribution network provider to be separate entities so as to enable consumers to choose their supplier. If these amendments come into force, supply of electricity will also require a licence from the relevant SERC, and the supply and distribution of electricity will be governed by separate operative codes to be issued by the relevant SERC.

Exploration of oil and gas are separately licensed activities. The DGH awarded licences through international competitive bidding for natural gas exploration blocks under the New Exploration Licensing Policy (NELP) rolled out in 1999. The production-sharing contract (PSC) under the NELP programme stipulated conditions regarding pricing and sharing of total product obtained with the government. The DGH has successfully carried out nine rounds of bidding under NELP, in which 254 oil and gas blocks have been awarded.

The MoPNG notified the New Domestic Natural Gas Pricing Guidelines 2014, which provide for the prices to be fixed on the basis of the annual average of the price of gas at specified international hubs, and require notification of the prices determined by the government on a biannual basis.

The Coal Bed Methane (CBM) Policy 1997 offered blocks for exploitation of CBM through biddable revenue-sharing based on production-linked payment. The Policy specified
modalities regarding the commercial development of CBM, identification and allotment of blocks and fiscal incentives or provisions. The government has also approved the marketing and sale of CBM by contractors on arm’s length prices in the domestic market. Recognising the constraints experienced in the present PSC format and differences in the fiscal and contractual regime for oil and gas and CBM, the government has framed the Hydrocarbon Exploration Licensing Policy (HELP), which provides for a uniform licensing system to cover all hydrocarbons, such as oil, gas and coal bed methane, under a single licensing framework, allowing the possibility of exploring overlapping resources in a single block. Under HELP, both foreign and domestic companies can have a 100 per cent participating interest without the involvement of a government company in a joint venture. Among the ostensible reasons for concluding the NELP is the fact that blocks that were bid for under numerous PSCs are mired in disputes over the inflating costs of production and deteriorating production of oil and gas. Through HELP, a revenue-sharing arrangement is proposed to be implemented, where bidders will be selected based on their upfront revenue-sharing commitment offered to the government, which will be payable from the first batch of production. The revenue-sharing model will not be subject to cost recovery and therefore aims at eliminating the often tedious process of cost scrutiny that the government was required to undertake under the previous regime. Although the move to a revenue-sharing model has largely been well received, a few industry participants are likely to get discouraged under the new model as the investment recovery periods for companies will increase. The HELP has also introduced an open acreage policy in India (OALP), which permits the licensee to exploit the full range of hydrocarbons accessible in a single block and allows companies to approach the government at any time, expressing their interest in bidding for one or more blocks, after which the government would invite competitive bids from others interested in the same blocks. However, for the OALP to be made operational, it is critical for the DGH to build a reliable national data repository of, among others, potential blocks for the exploration and production of various hydrocarbons. The government has also introduced policy guidelines for exploration and exploitation of shale gas and oil by national oil companies, pursuant to which, the oil companies have started the first phase of assessment and have initiated exploration activities in 50 areas. While the potential shale gas reserves overshadow those of conventional gas, India has a long way to go in identifying shale gas-rich basins and acquiring the necessary technology and experience to extract shale gas, specifically in the absence of private participants.

Petroleum, natural gas and city gas distribution (CGD) networks can be developed either through an expression of interest to the PNGRB or under competitive bids invited by the PNGRB. Under the expression-of-interest route, the PNGRB must publicise upon receipt such an expression of interest, to receive proposals or comments from different entities, and may invite competitive bids or allow for the proposal (with or without modification).

iii Ownership and market access restrictions

Over the past decade, the government has progressively liberalised the energy sector, although government companies continue to be active players. Up to 100 per cent foreign direct investment (FDI) is permissible in generation (except nuclear power), transmission, distribution of electricity and power trading, as well as in the oil and gas sector and up to 49 per cent in power exchanges without prior regulatory approval. Such investments are

---

3 Investments of up to 49 per cent are permitted in petroleum refining undertaken by public sector entities.
subject to sector-specific laws and policies. The Consolidated FDI Policy released by the Government of India on 28 August 2017 has maintained this status quo with the 49 per cent cap on FDI (without regulatory approval) in power exchanges being maintained.

A majority of generation, transmission and distribution capacities are with either public sector companies or with state electricity boards (SEBs); however, private sector participation is increasing, especially in generation and distribution. The interstate transmission system is mainly owned and operated by Power Grid Corporation of India Limited, a state-owned company, and the intrastate transmission system is owned and maintained by state utilities. However, the public–private partnership (PPP) structure is increasingly preferred by the government for setting up interstate and intrastate transmission networks. Electricity distribution is largely in the control of government distribution companies, with privatisation being slow largely on account of the huge legacy liabilities of the state distribution companies. However, a few examples of privatisation in certain areas (such as Delhi, Orissa, Ahmedabad and Mumbai) have met with success. Apart from private participation in the distribution sector, distribution licensees in several states (particularly Maharashtra, Rajasthan and Odisha) have engaged distribution franchisees to discharge their universal supply obligations. Given that a distribution franchisee does not require a licence to function (unlike a distribution company), there has been considerable private interest in the sector with several companies submitting bids in recent auctions. The role of a distribution franchisee typically includes supply of electricity on behalf of the distribution company with related functions such as meter reading, tariff collection and operation and maintenance of distribution assets. That said, there have been multiple bid processes for selection of franchisees that have faced delays on account of reports of considerable aggregate technical and commercial losses that have to be borne by private franchisees.

In India, the ownership of all mineral resources, including oil and gas, vests with the government, and is administered through the MoPNG. The Gas Authority of India Limited and the Oil and Natural Gas Company are the largest owners of oil and gas pipelines in the country. Private players are increasingly entering the CGD space in urban areas.

iv Transfers of control and assignments

While there are no specific restrictions on transfer of control or assignment of a generating company, power purchase agreements issued pursuant to certain renewable energy policies and bidding documents for thermal and renewable power procurement provide for shareholding restrictions for a certain period post-commercial operation. For instance, the Ministry of Power’s revised standard bidding documents for long-term (seven to 25 years) procurement of power from thermal power projects (Revised SBDs), provide for a lock-in period (though on a sliding scale) of up to 10 years following commercial operations.

Holders of licences for oil and gas exploration can transfer or assign all or part of their participating interest under the PSC, including any change in control of a party, with prior consent of the government.

Other than these sector specific restrictions, provisions of the Companies Act 2013, Competition Act 2002, and the Securities and Exchange Board of India (Substantial Acquisition of Shares and Takeovers) Regulations 2011 (applicable to listed companies) will apply with respect to change in shareholding through mergers and acquisitions.
III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling
Under the Electricity Act, SEBs were required to be unbundled into separate generation, distribution and transmission companies and most states have now completed the process. Transportation, distribution and marketing activities in the oil and gas sector are yet to be unbundled. While the PNGRB had circulated a concept paper on unbundling of activities of transportation and marketing of natural gas, no policy decision has been taken on this aspect.

ii Transmission/transportation and distribution access
In the electricity sector, transmission licensees must provide non-discriminatory open access to its transmission system for use by other persons (including electricity distributors, traders and generating companies). Open access to distribution networks is also granted to bulk power consumers (i.e., consumers of above 1MW), to procure electricity at unregulated prices from entities other than the area distribution licensee. Separately, the government has the ability to issue directions to generators on operation of their power stations in extraordinary circumstances, a tool that more often than not has been used by state governments to restrict supply of power outside the state (in the event of a shortage).

The PNGRB prescribes an access code for common or contract carrier natural gas pipelines, regulations for capacity release for natural gas pipelines and requires natural gas transporters to declare capacity available for common carriage on a monthly basis.

iii Terminalling, processing and treatment
The PNGRB regulates the storage and treatment of oil and gas, including prescribing the eligibility conditions for registration of liquefied natural gas (LNG) terminals and prescribing the technical and safety standards for pipelines and CGD networks.

For imported LNG, the price under the term contracts and spot cargoes are mutually determined and are usually very high. Consequently, the MoPNG is currently exploring options such as price pooling to average out the prices and now that new pricing guidelines have been introduced, it is to be seen whether a separate price pooling mechanism will be adopted by the government.

iv Rates
Under the Electricity Act, transmission schemes are implemented either through the tariff-based competitive bidding process or under a cost-plus mechanism where a regulated tariff is determined by the relevant electricity commission. The CERC adopts a ‘point-of-connection’ method for calculating interstate transmission charges and losses, which aims at developing a uniform transmission charge-sharing mechanism among grid constituents. However, to help meet the proposed target of 175GW of renewable energy capacity by 2022, the government has, among other measures, exempted the payment of interstate transmission charges for wind and solar power projects under the new Tariff Policy. The tariff for electricity distribution, comprising wheeling charges and cost of supply, is levelled and determined on a cost-plus basis by the relevant SERC. However, as renewable energy tariffs inch towards achieving grid parity, the government is slowly scaling back benefits allowed to renewable energy developers. For instance, the Ministry of Power has limited the exemption from payment of interstate transmission charges and losses to projects that are commissioned...
before 31 December 2019 and that are supplying power to distribution licensees. The government has also decided against extending the exemption on corporate tax on power producers (including renewable energy developers), which expired last year.

The PNGRB has enacted regulations for determination of transportation tariff for petroleum and petroleum products, natural gas pipelines and CGD network. The tariff for such pipelines is determined taking into consideration a reasonable rate of return on the normative level of capital employed plus a normative level of operating expenses in the relevant pipeline.

v Security and technology restrictions

With a sophisticated energy infrastructure and now smart grids being proposed, cybersecurity concerns are paramount. The Information Technology Act 2000 addresses hacking and security breaches of information technology infrastructure. The government issued a National Cyber Security Policy in 2013, which aims at creating a secure cyber ecosystem, encourages use of open standards to facilitate interoperability and data exchange, and provides for creating mechanisms for security-threat early warnings and vulnerability management.

Technology transfers into India are permitted in all sectors, including energy. All payments made for technology transfers into India are subject to Indian exchange control regulations. Export of technology transfers for specific sectors requires a licence under India’s Foreign Trade Policy.

IV ENERGY MARKETS

The National Electricity Policy 2005 envisions 85 per cent of power from new capacities being contracted through long-term power purchase agreements (PPAs) and the remaining 15 per cent power capacity through market mechanisms. It is also expected that more merchant capacity will be available in the next few years as the Revised SBDs provide for a quantum of installed capacity to be sold at market-determined prices. The NITI Aayog (the Indian government’s think tank and planning wing) released a draft of the National Energy Policy for public comments in July 2017. This policy sets out four objectives that the government hopes to achieve in the energy sector: access at affordable prices, improved security and independence, greater sustainability and economic growth. To achieve these objectives, this policy contains several recommendations such as better coordination between government ministries, reducing dependency on imported coal, increased use of renewable energy and enhanced investment in rural electrification.

The power market is dominated by long-term contracted power. For thermal power projects (coal and gas) and hydro projects, long-term power is procured through a negotiated route or pursuant to a competitive bidding route. The Ministry of Power has directed state governments and distribution companies to procure power under the competitive bidding route (except that mandatory competitive bidding for hydropower projects has now been postponed till the end of 2022). Bidding for long-term procurement from thermal power stations can be done on the basis of the Revised SBDs that provide for two modes of bidding and supply of electricity. Under the DBFOO4 model, a distribution licensee invites bids to procure a specified quantum of power, while also prescribing the type of fuel and technology

---
4 The DBFOO model refers to a project set up on a design-build-finance-own-operate basis.
that is to be used for the supply. Under the DBFOT\textsuperscript{5} model, a distribution licensee invites bids for setting up a project on the basis of the lowest tariff, while also specifying the fuel and location of the project (which is required to be arranged by the distribution licensees).

To specifically address stakeholder concerns on determination and impact of rising fuel import costs, the Revised SBDs provide for the cost of imported fuel to be benchmarked at actuals and linked to prevailing prices on international indices. In 2015, the government further amended the guidelines for procurement of power through the DBFOO route to revise the tenure to seven to 25 years and allowing the distribution licensees to deviate from the revised SBDs with the prior approval of the CERC or SERCs, allowing more flexibility for procurement of power.

While several states have commenced (and some have even concluded) the bidding process under the DBFOO model, the DBFOT model has met with severe criticism from market players, who have voiced concerns on the inequitable apportionment of risks. This has resulted in the Ministry of Power constituting a committee to review the DBFOT standard bidding documents, pursuant to which the further revised bidding documents for the DBFOT model are expected to be released by the ministry later this year.

While long-term procurement remains a top priority, the government is also determined to set up the short-term and medium-term markets for procurement of electricity. In January 2017, the government issued revised guidelines for procurement of electricity on medium term (one to five years) from power stations set up on a finance, own and operate basis. The revised guidelines mandate tariff determination through an open and transparent e-auction, with an overall aim of reducing power procurement costs. Similarly, guidelines for short-term (i.e., for a period of more than one day to one year) procurement of power by distribution licensees through a tariff-based bidding process have also been amended in 2016 to introduce the concept of reverse auction on an e-platform in the short-term supply of power. In April 2018, the Ministry of Power issued a pilot scheme to facilitate the purchase of power (aggregated power of 2,500MW for three years) from coal-based power plants that are commissioned but do not have a power purchase agreement in place. This scheme envisages that an aggregator will enter into power purchase agreements with the generating companies along with back-to-back arrangements between the aggregator and distribution companies.

In 2015, the Ministry of Power issued a notification introducing a targeted gas supply scheme focused on gas based thermal power plants with stranded capacity. The scheme envisaged facilitating the import of requisite quantities of gas with considerable incentives in the form of tax exemptions on the import and regasification of LNG as well as discounted gas transportation rates for financial year 2015–2016 and financial year 2016–2017. A target of 30 per cent plant load factor was set for the operational and stranded power plants, which was to be achieved towards the end of 2015–2016. Although the plant load factor remains around 30 per cent, the scheme has not been extended beyond financial year 2016–2017.

On the distribution front, the major problems plaguing the power sector in India are the abysmal credit ratings of the state distribution companies and their persistent failure to honour payments to generators under PPAs or extensive delays in doing so. Distribution companies have borrowed heavily to finance losses in their businesses, and are facing major hurdles in repaying their debt. The government launched the Ujwal Discom Assurance Yojana (the UDAY scheme) in November 2015, with the objective of improving the operational and financial efficiency of state-owned distribution companies. One of the major features of the

\textsuperscript{5} The DBFOT model refers to a project set up on a design-build-finance-own-transfer basis.
UDAY scheme involves requiring participating states to take over 75 per cent of the debt of distribution licensees by way of a grant over a period of two years and issue non-statutory liquidity ratio bonds, including state development loan bonds for subscription by pension funds, insurance companies and other institutional investors. Under the UDAY scheme, lenders and financial institutions will not levy prepayment charges on a distribution licensee’s debt, and will waive off unpaid overdue interest, including penal interest. For financing future losses and working capital of distribution companies, state governments will take over and fund future losses in a graded manner until financial year 2020-2021. The state governments have come forward in their support of the scheme and, at the time of writing, 32 states and union territories have signed up for the UDAY scheme, with almost all major distribution companies covered by UDAY. The state distribution companies participating in the scheme have reported significant interest cost savings and a sharp reduction in revenue losses. While the UDAY scheme initially reduced the woes of distribution companies in poor financial health, it has done little to bring about a significant or lasting impact on the power sector. The Parliamentary Standing Committee on Energy has estimated that investments of about 1,750 billion rupees (in private power generation) are currently at the risk of being declared ‘non-performing assets’ by the Reserve Bank of India. One predominant reason for the decline in the financial performance of these assets has been the significant delay in payments by the distribution companies. On a related note, with the inception of the Insolvency and Bankruptcy Code 2016, several captive power assets (attached to steel manufacturing units for which insolvency proceedings have been initiated) and power generation companies have been brought to the National Company Law Tribunal (NCLT) for commencement of insolvency proceedings. There have also been reports of a generation company taking a state-run distribution company to the NCLT for failure to pay dues over a period of three years. Insolvency resolution experts in India are also apprehensive about finding suitable buyers for these stressed assets given significant project completion costs and low bankability in terms of timely payments from distribution companies.

For renewable energy projects, contracts are entered into with state utilities under specific state policies at preferential tariff or through competitive bidding depending on the state or central policy. Other modes of power sale include captive consumption and sale to consumers through open access. The CERC, through its Power Market Regulations 2010, seeks to promote and regulate interstate electricity transactions in various contracts (such as ancillary services market contracts and trading in renewable energy certificates (RECs)).

In December 2016, the Ministry of Power, in consultation with the Ministry of External Affairs, issued guidelines for cross-border trade of electricity with neighbouring countries like Bhutan, Nepal and Bangladesh to facilitate the cross-border trade with greater transparency, consistency and predictability. The tariff for the cross-border transaction is proposed to be determined through government-to-government negotiations, and then adopted by the relevant electricity regulatory commission. The guidelines also aim at evolving a dynamic and robust infrastructure along with reliable grid operation for cross-border transactions of electricity.

The REC is a market-based policy instrument introduced to increase and promote renewable energy capacity. Renewable energy producers who opt for the REC route are issued tradeable generation-based certificates that represent the renewable energy component of electricity generated, in addition to the average pooled cost of electricity from non-renewable sources of electricity of the past year. Generators who opt for the REC route cannot opt for
the preferential feed-in tariff offered by the state distribution companies. These RECs can be bought by certain obligated entities (such as electricity distribution licensees and captive power consumers) to fulfil their RPOs.

In 2016, the government introduced HELP to revive the ailing gas market by providing for pricing freedom for gas discoveries in blocks that were yet to commence commercial production. HELP also removed restrictions on the companies on exploration by allowing them access to the national data repository maintained by the government that has the data and gives them the discretion to explore the areas for gas as per their choice. In addition to HELP, the New Domestic Gas Pricing Guidelines were introduced with the underlying principle that producers in India should get a price similar to the rates prevalent in the international markets, which, in turn, is expected to increase investment in the sector and reduce the dependency on imports. However, the government recently issued a notification stating that the domestic gas pricing regulations will not be applicable on coal bed methane, and granted the coal bed methane producers marketing and pricing freedom to sell CBM at arm's length price in the domestic market.

In relation to the allocation of coal blocks, the government had notified the Coal Block Auction Rules 2017 (2017 Allocation Rules) under the Mines and Minerals (Development and Regulation) Act 1957 on 13 July 2017, which set out the key aspects such as the cap on the number and quantity of coal that may be allotted to a private entity, the reverse auction-based tender process and relaxations for coal procured for ultra mega power projects (set up under the scheme of Ministry of Power in this regard). All allocations made under the erstwhile Auction by Competitive Bidding of Coal Mine Rules 2012 have now been migrated to the 2017 Allocation Rules.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

The regulatory environment increasingly seeks to incentivise renewable energy, with favourable tariff regimes established by SERCs. The Electricity Act, the National Electricity Policy and the Tariff Policy encourage private sector participation in renewable energy through measures such as providing for feed-in tariffs, fixing minimum RPOs for distribution companies and captive power users and providing incentives such as accelerated depreciation schemes, excise duty exemptions and reduced customs duty on renewable energy equipment. In addition, a renewable energy project developer is also entitled to receive RECs if it does not opt for preferential feed-in tariffs. Several states have put in place specific policies to promote renewable energy development; however, incentives and policies are not always consistent between states and developers often shop around based on the policy that best suits their financial model and operational expertise. Consequently, the development of renewable energy in India is geographically skewed.

Onshore and offshore wind power

The past year witnessed transition in the onshore wind power sector in India. The policy framework for subsidy driven wind power procurement regimes (feed-in-tariff, generation-based incentive and accelerated depreciation) have given way to a more robust market price discovery regime of competitive bidding (reverse auction). This transition from early 2017 saw greater transparency in the determination of wind tariffs; however, the uncertainties regarding the new framework have also sharply reduced capacity addition of
onshore wind power in 2017–2018. The capacity added has only been 1,739.14MW through the year against a target of 4,500MW, and far less than the 5,400MW added in 2016-2017. However, to achieve the 60GW of wind power targeted by 2022, the Renewable Energy Ministry has announced a procurement plan for 24GW of wind power (through competitive tendering processes) by March 2020. The new plan provides annual targets of 4GW of wind projects by March 2018, another 10GW over the next 12 months and another 10GW in the subsequent 12 months.

The central government issued new guidelines in 2016 for onshore wind power projects after a gap of around 20 years. The guidelines contain, *inter alia*, clear timelines for completion of project to prevent land squatting; provisions to ensure installation of international-quality wind turbines compliant with grid regulations; and provisions regarding environmental suitability of wind projects. These guidelines, issued by the central government, are in addition to the wind policies issued by the various state governments. The government also issued the National Offshore Wind Energy Policy in September 2015 with the aim of promoting the country’s offshore wind energy potential. The principal agency charged with the development of the sector is the National Institute of Wind Energy (NIWE). Under this policy, blocks are to be allocated through a competitive bidding route and developers are required to enter into seabed lease agreements with NIWE. In additional to allocation of blocks, NIWE is also required to carry out the initial wind resource assessment and assist the project developers in obtaining clearances. Taking steps towards harnessing this enormous potential, the Environment Ministry has given its approval to a wind measurement project in the Gulf of Kutch, near the Gujarat coast, for setting up an offshore data collection platform for survey, investigation, exploration, data acquisition and other related technical studies in territorial waters. Unlike the procurement of solar power, wind power procurement was not done on competitive basis until 2016. The first ever tariff-based auction for long-term wind power contracts on an inter-state procurement basis was conducted this past year, which has resulted in record low tariff of 3.46 rupees/kwh. The tariffs have further reduced to 2.44 rupees/kwh in subsequent bids (in February 2018) but have led to an uncertainty for under-construction projects from which electricity was proposed to be sold at the higher feed-in tariff determined by the SERCs.

The government has notified the Guidelines for Tariff Based Competitive Bidding Process for Procurement of Power from Grid Connected Wind Power Projects (Wind Guidelines) with a view to promoting transparent bidding in the wind sector, where traditionally electricity has been sold to distribution companies at the feed-in tariff determined by the relevant SERC. Some key incentives for wind power developers under the Wind Guidelines include that a single bidder will be allowed to bid for a minimum wind project capacity of 25MW, with at least one 5MW project at each site for intrastate projects, while for interstate projects a bidder will be allowed to bid for a minimum wind project of 50MW at one site. The procurer can also specify the maximum capacity to be allotted to a single bidder, including the bidder’s affiliates. The maximum capacity for a single bidder or company or group of companies can be fixed by the procurer taking into consideration economies of scale, land availability, expected competition timeframe, and the market need.

In the offshore wind sector, the government of the India through the NIWE has invited expressions of interest from developers for India’s first offshore wind project. The government aims to develop 5GW of offshore wind capacity by 2022. The government has currently identified the states of Gujarat and Tamil Nadu for development of offshore wind projects.
Solar energy

Solar plants can be set up under the Renewable Energy Ministry’s National Solar Mission (NSM, previously the Jawaharlal Nehru National Solar Mission), as well as under state policies. As is the case with wind energy projects, the accelerated depreciation limit has been reduced to 40 per cent on solar assets. Other incentives such as achievement-based incentives, subsidy programmes and tax benefits continue to be allowed on solar assets.

After successfully implementing both batches of Phase I, and Batch I, II and III of Phase II of the NSM, the Renewable Energy Ministry has issued final guidelines for Batch IV of Phase II of the NSM, which proposes to add capacity aggregating 5,000MW. On the date of writing, several auctions are under way under Phase IV of the NSM. In a departure from Batch II Phase II (but similar to Batch I Phase II and Batch III Phase II), recent bids under Batch IV envisaged procurement under the viability gap funding (VGF) scheme, where the tariff is predetermined and bidders are selected on the basis of the quantum of discount they are willing to accept on the VGF to be provided by the government. Giving a major push to the solar power development, especially the large scale photovoltaic (PV) projects, the government has increased the capacity of solar parks (involving projects of multiple developers) from the existing 20,000MW to 40,000MW. In an ambitious attempt to meet its renewable energy target of 175GW, the Renewable Energy Ministry has proposed development of solar power projects with capacity of 67GW, as well as an integrated solar module manufacturing capacity addition of 20GW. The new plan put in place by the Renewable Energy Ministry provides new annual targets – 17GW to be tendered out by March 2018, another 30GW in the next 12 months and a further 30GW in the subsequent 12 months.

The government has notified the Guidelines for Tariff Based Competitive Bidding Process for Procurement of Power from Grid Connected Solar PV Power Projects (Solar Guidelines) to promote standardised competitive procurement of electricity from solar PV projects and appropriate risk sharing between stakeholders. The Solar Guidelines envisage that standardised bidding documents (i.e., a request for selection, a power purchase agreement and a power sale agreement) will be prepared pursuant to the guidelines; these documents are expected to be in place over the next couple of months. The Solar Guidelines also provide several other incentives for solar power developers such as better payment security terms (a revolving letter of credit for one month of billing, payment security fund or a state government guarantee with an amount equivalent to three months’ billing), handover of land (90 per cent of land within one month from execution of the PPA) for solar parks and compensation to developers in situations where the project is available to supply power but the grid is unavailable.

On the domestic manufacturing front, the sector suffered a setback in 2016 when the World Trade Organization (WTO) ruled against the inclusion of certain domestic content requirements (DCR) in the tenders under the NSM. The guidelines under the NSM had prescribed certain DCR to promote local manufacturing capability and attract efficient and advanced technology. In response, the United States raised a dispute at the WTO following failed consultations regarding the DCR for solar cells and modules (having once challenged the requirements under Phase I as well). It has claimed that the requirements (although for a portion of the total capacity) are in violation of India’s international trade obligations, as they discriminate against foreign suppliers. The WTO in its findings, stated that India’s DCR are trade-related investment measures, thereby violating the Trade Related Investment Measures Agreement and provisions of the General Agreement on Tariffs and Trade (GATT) by providing less favourable treatment within the meaning of GATT. India appealed the
WTO’s decision before the WTO Appellate Body, which was rejected. Following the WTO ruling, the government has since restructured the Solar Guidelines to remove DCR related obligations. In another related development, the government has rejected a proposal to implement anti-dumping duties against imported solar cell technology. This decision of the Renewable Energy Ministry acknowledging that the current capacity of domestic manufacturing is inadequate to meet the targets for solar capacity addition, and focusing on growing the market first before promoting domestic manufacturing, has been hailed as highly pragmatic and investor-friendly. There are currently ongoing trade investigations for the imposition of safeguard and anti-dumping duty on import of PV cells and modules. The Ministry of Finance has proposed a provisional duty of 70 per cent for 200 days on solar cells and modules. However, this proposal has received resistance from the Indian manufacturers in the sector who propose to file a petition in relation to investigations over the past year. To further address issues regarding additional taxes being imposed on solar power projects (in terms of components or services), the Renewable Energy Ministry has explicitly clarified that a protection under change in law provisions will include a change in the rates of applicable taxes, duties and cesses. This move is expected to decrease the uncertainty around tariffs becoming commercially unviable on account of increase in taxes.

To combat global warming and climate change, the International Solar Alliance (ISA), which is a partnership of more than 120 solar resource rich countries, was officially launched in 2015 with its headquarters in India. The objective of the ISA is to create a coalition for addressing the special energy needs and capacity building among the member countries in a collaborative manner. More than 20 countries, including India, have signed the Framework Agreement to see the ISA becoming an intergovernmental body under the UN charter. India has been chosen as the host country of the ISA and a framework agreement between the Ministry of External Affairs, Government of India and the ISA has been signed in March 2017. This framework agreement gives the ISA a juridical personality and gives it power to contract, acquire and dispose of movable and immovable properties, to institute and defend legal proceedings in India.

In addition to setting up solar generation capacity through solar power plants and solar parks, various states are also looking to promote the setting up of both grid-connected and off-grid solar rooftop systems. The government launched a US$750 million subsidy scheme for rooftop solar projects to provide close to 30 per cent of the capital subsidy required. The government has already allocated around US$90 million in subsidies to various states in the country. In a bid to further encourage the use of solar rooftop systems, the government has recently exempted customs and excise duty on materials used in solar rooftop systems. Additionally, state governments are promoting the installation of such systems by introducing enabling legislation, such as net metering regulations. Solar Energy Corporation of India, which is a central government company under the administrative control of the Renewable Energy Ministry, issued a tender for 1,000MW capacity for the development of grid-connected rooftop solar capacity, utilising the rooftops of central government ministries and departments, reduced to 500MW after reassessment of the potential capacities of all the government ministries and departments.

**Biopower and waste-to-energy projects**

The Renewable Energy Ministry has proposed to launch the National Bioenergy Mission (along the lines of NSM) to boost power generation from biomass by facilitating capital investments and reducing use of fossil fuels.
In the context of municipal waste-to-energy projects specifically, there is significant scope in Indian cities for business; however, several challenges are being faced by ongoing projects. While there is opposition on account of environment and health hazards for the communities living in proximity to these projects, and low quality of waste because of lower calorific value, the government is trying to promote schemes to encourage cities and municipalities to take up waste-to-energy projects in PPP mode. Recently, India launched its largest waste-to-energy plant in Delhi, which will consume 2,000 metric tonnes of waste every day and shall generate 24MW of energy. The revised tariff policy mandates power distribution companies to buy 100 per cent of the electricity generated from the waste-to-energy plants in their respective states.

ii Energy efficiency and conservation

To institutionalise energy conservation efforts, the Energy Conservation Act 2001 was enacted and the Bureau of Energy Efficiency (BEE) was established under the Ministry of Power in 2002. Periodic energy audits have been made compulsory for power-intensive industries under the Energy Conservation Act.

The National Electricity Policy affords high priority to energy conservation and demand-side management through the BEE. To further enhance efficiency in thermal power projects, the Revised SBDs specify the station heat rate at which the power stations must be operated, failing which the developer is heavily penalised by a decrease in the fixed charge. Additionally, the CERC tariff regulations provide for operational norms such as reduction in heat rate for existing bigger units, linking of allowable heat rate to design heat rate, tightening of working capital norms, and norms on reduction in secondary fuel oil consumption.

iii Technological developments

The National Electricity Policy envisages special efforts being made for research, development demonstration and commercialisation of non-conventional energy systems. Further, it envisages the gradual introduction of efficient technologies (such as super-critical technology and integrated gasification combustion cycle) for generation of electricity. It also requires cost-effective technologies to be developed for high-voltage power flows over long distances with minimum possible transmission losses.

VI THE YEAR IN REVIEW

In the past year, the government has continued to introduce a spate of reforms across the energy spectrum, backed by swift executive action, which have enthused stakeholders in a hitherto stagnating market. The mainstay of the Indian electricity market over the past financial year has been the promotion and stabilisation of the renewable energy sector, with the introduction of competitive bidding in the wind and solar sectors that have witnessed a significant lowering of tariffs. With capacity addition of about 62GW in renewables alone, the Central Electricity Authority currently estimates that there is no coal-based capacity addition required until 2022, especially given that about 50,000MW of coal-based projects are currently under construction in the country. On the distribution front, the UDAY scheme has outlived its initial push to distribution licensees, with distribution companies focusing on operational inefficiencies (transmission and distribution losses, metering and collection
issues) to lessen the financial burden on them. With the strengthening of the law governing insolvency in India, there is a significant risk of power sector assets being brought before the NCLT for insolvency proceedings.

The Reserve Bank of India has recently withdrawn several debt restructuring schemes and is in the process of strengthening the norms and procedures for declaration of non-performing assets. This would mean greater accountability for power producers and perhaps an increase in insolvency proceedings being initiated for entities in the energy sector.

In the transmission sector, giving a boost to large-scale transmission projects – which includes setting up the ‘green energy corridor’ to provide for additional large-scale renewable energy capacity – the government has launched the National Smart Grid Mission (NSGM), with a broad aim of planning, implementing and monitoring all the smart grid projects in the country. Through the NSGM, the government plans to develop smart microgrids by using state-of-the-art technology to monitor and control power flows. However, renewable energy project developers believe that the current grid infrastructure is inadequate to complement the rapid growth witnessed by the renewable sector.

In the nuclear power sector, India’s failed attempt to gain membership of the elite Nuclear Suppliers Group despite an unprecedented diplomatic push has been a major setback to India’s aim for energy security and combating climate change. India’s commitment to reduce its dependence on fossil fuels, and to ensuring that 40 per cent of the country’s energy requirements are met from non-fossil fuels, requires a significant ramp-up in nuclear power production. There were certain concerns of suppliers and manufacturers of nuclear material and equipment who feared the possibility of exorbitant liability being passed on to them by an operator under the Civil Liability for Nuclear Damages Act 2010 in the event of a nuclear accident. The government of India has clarified that while the legislation would not be amended, it was not mandatory to include a civil liability clause in the contractual arrangements between the foreign supplier and the Indian operator. Critics are of the view that the government’s interpretation of the law is problematic in that liability will not be traced back to a supplier of nuclear equipment or material as they would rarely agree to a civil liability clause when it is not mandatory under Indian law. However, to allay the concerns of suppliers regarding their liability, the India Nuclear Insurance Pool, with a capacity of 15 billion rupees, was launched by Indian insurance companies. It provides coverage to operators and suppliers for any nuclear liability towards third parties.

At the international policy arena for energy sector, India has been successful in being at the forefront of the ISA, which is an Indian initiative and could help India in aligning its energy ambitions in the future. India has also joined the International Energy Agency this year as an associate member, which would help India to move to the centre stage of the global energy dialogue and to better represent the interests of the emerging markets. India also houses the headquarters of the ISA and is at the forefront of activities proposed by the ISA.

One of the major developments of the past year came when the government announced the new Tariff Policy in January 2016. Under the revised Tariff Policy, solar RPO was fixed to 8 per cent by 2022 and the renewable generation obligation on thermal power plants were introduced, which has been well received in the renewables market. While the introduction of the once promising system of RPOs and RECs resulted in a market where supply of RECs greatly outstripped demand on account of non-enforcement of RPOs, recent amendments by the CERC to the floor and ceiling price of solar RECs has resulted in a marked rise in the number of solar RECs traded on the market, albeit at the floor price. Further, the Supreme
Court has made it mandatory for industries with captive power plants to procure a percentage of their energy from renewable sources and empowered the SERCs to impose penalties on units that failed to fulfil its obligations, which has further shored up the REC market.

The government has been striving for increase in production of renewable power through the use of advance technology by proposing installation of ‘ultra-mega solar power projects’, and through innovative solutions to capitalise on abundant solar energy by proposing solar parks along canal banks and solar power-driven agricultural pump sets and water pumping stations. The government has also proposed feeder separation to augment power supply to rural areas, and to strengthening transmission and distribution systems.

The tariffs determined by the competitive bidding process for the procurement of solar power have fallen steeply over the past two years. India achieved its record-low tariff of US$0.044/kWh in the bid for a 750MW solar PV project at the Rewa Solar Park in Madhya Pradesh, which is one of the largest single-site solar projects in the world. Industry experts are attributing such a low tariff to the overall project design, with bidding documents that were largely seen as developer-friendly owing to provisions such as state guarantee, identified buyers and deemed generation benefits. The government has also given a massive thrust to increase the share of wind energy in the overall installed energy capacity of the country by introducing various policy initiatives in the past year in the wind energy sector that include the introduction of bidding in the wind energy sector; the Re-powering Policy; the Draft Wind-Solar Hybrid Policy; the New Guidelines for Development of Wind Power Projects, etc. Further, the promotion of solar rooftop projects by various state governments is a discernible trend, with a number of states issuing net metering regulations and upgrading local grids to match the growth of the solar rooftop sector. The introduction of competitive bidding guidelines in the wind and solar sectors has led to a fresh impetus in the provision of better risk allocation, which has led to greater investor confidence and significantly lower tariffs.

As regards interstate scheduling and forecasting obligations for wind and solar plants, the CERC amended the Indian Electricity Grid Code and Deviation and Settlement Regulations, making scheduling mandatory for wind and solar plants with a capacity of over 50MW. The deviation settlement mechanism, which has replaced the unscheduled interchange mechanism, allows scheduling with a plus-or-minus 15 per cent range, with penalties payable by the generators for exceeding the permissible range, based on the tariff under their respective power purchase agreements. To complement the interstate regulations, several states have issued their draft intrastate scheduling and forecasting regulations, with states such as Andhra Pradesh and Gujarat having notified these regulations last year. Several other states are expected to follow suit this year. On the natural gas front, welcome signs for beleaguered gas-based power plants include the significant fall in the price of gas following the bi-annual revision of gas prices under the New Domestic Gas Pricing Guidelines, and the diversion of gas from fertiliser plants to standard power stations in coastal states. In 2014, the government announced that it would lay an additional 15,000km of natural gas pipelines on a PPP basis; however, this proposal has not materialised due to lack of financial viability.

One key development revolves around the Supreme Court’s decision to deny compensatory tariffs to various power producers whose power plants are lying idle, underutilised or facing delays on account of a change in the Indonesian coal pricing regime. In 2014, the CERC and certain SERCs found that the difficulties faced by such power producers were genuine, and sought to provide relief to these power producers in the form of a ‘compensatory tariff’, to compensate the losses suffered and additional costs incurred.
by them. However, the Appellate Tribunal for Electricity (APTEL) in its judgment in 2016 held that the CERC does not have jurisdiction when it comes to varying or modifying tariffs or granting compensatory tariffs in cases where a tariff has been determined through a tariff-based competitive bidding route. The APTEL did state, however, that the CERC would have the power to grant relief in the event that a force majeure or change in law were to be established. The Supreme Court has set aside the order of APTEL and held that the change in the Indonesian coal pricing regime is neither force majeure nor change in law as per the PPA. However, the Supreme Court held that the amendment to the New Coal Distribution Policy in 2013 would be considered as change in Indian law, and that the power projects that have been impacted by the shortfall in domestic coal supply due to such amendment may be compensated as per the change in law provisions in the PPA. In this regard, the Supreme Court has asked CERC to take a fresh look at the matter to determine the relief that should be granted due to the change in Indian law, if any. However, the coal sector is unlikely to be a key focus area for the government given the current energy mix in the country, and estimates that coal based capacity need not be added till 2022 at the least.

In the oil and gas sector, the government has approved a policy for extension of production-sharing contracts for oil blocks granted prior to NELP to enable and facilitate investment to extract the remaining reserves by advanced technologies. In the past year, bidding for oil and gas blocks was conducted after a break of six years and contracts were awarded to the successful bidders under the Discovered Small Field Policy bid round – 2016. The selected bidders have been awarded the contract under the revenue sharing model, giving them pricing and marketing freedom. Further, the dispute between the government and the Reliance group (an oil and gas major) and BP Plc on the pricing of gas from the KG-D6 block that is currently under arbitration – specifically the discrepancy between the formula for determining the price of gas recommended by the Rangarajan Committee and the formula ultimately adopted by the government in the new pricing guidelines (which gives significantly lower prices) – will be crucial in determining key aspects such as pricing of gas in India, certainty of executive decisions (on key commercial aspects such as pricing) and the impact on investments in the oil and gas sector. While the government has, through HELP, introduced market and pricing freedom for gas discoveries, the benefit of this freedom will not be applicable to those blocks that are currently under arbitration – KG-D6 being one such block. BP has withdrawn arbitration proceedings against the government with a view to get an enhanced tariff of US$5.56 per unit (which is not applicable to entities that are currently in dispute with the government). Reliance is currently continuing with the arbitration with hopes of better terms with the change of the government at the federal level.

VII CONCLUSIONS AND OUTLOOK

The government has tackled policy reform in the energy sector with enthusiasm and aggression, bringing about significant key changes with the aim of increasing the bankability of power projects. The government’s policy reforms reveal a clarity of vision and a push for stability in the energy sector with a renewed commitment to non-conventional sources of energy. This is apparent from the government’s aim of restructuring financially stressed distribution companies, bringing consistency in all the standard bidding documents for procurement of power, and introducing a new pricing regime for natural gas coupled with the shift to HELP. In respect of renewable energy, the new government is making significant strides by introducing key incentives for solar and wind power producers, a push for rooftop solar plants
and ultra-mega solar power plants. The recent regulatory and policy changes made in the energy and infrastructure sector are indicative of the fact that the government is committed to greater transparency and openness in the sector, with most of the procurement moving towards a competitive bidding regime. The judicial authorities are also taking a serious look at irregularities and inconsistencies in government policies and awards, which is evidenced by landmark judgments by the Supreme Court, including in the coal block deallocation cases, compensatory tariff cases and the CCI’s decision to levy a penalty on CIL.

However, there are persisting concerns, such as inadequate transmission infrastructure to support growth of renewable energy and lack of affordable financing. While the policy reforms have led to an initial spurt in capacity addition, achieving India’s aim of energy security is quite a way from being accomplished. That said, although the government seems to gaining some ground, it will require continuous and persistent reforms over the coming year to ensure that India achieves its ambitious targets in the energy sector.
Chapter 15

IRAN

Munir Hassan and Shaghayegh Smousavi

I INTRODUCTION

The Energy Regulation and Markets Review included a chapter on Iran for the first time in 2016, when the conclusion of the Iran deal and the subsequent reopening of the country to foreign investors and companies promised a new period of potential transformations for its energy sector. More than two years after Implementation Day, Iran's energy sector, having previously lagged behind compared to other countries as a result of decades of isolation, can now boast of progress and a moderate boost. This chapter aims to be a practical and useful business tool, and therefore focuses and analyses recent changes and developments; looks ahead to expected trends, with a specific focus on the implications for foreign entities of entering the sector following the lifting of sanctions; provides an overview of the key entities in the Iranian energy sector; and looks ahead to the likely future developments in the Iranian energy sector. We provide a short summary of key aspects of the Iranian legal system to be aware of, and key considerations for operating or establishing an energy business in Iran.

II OVERVIEW

Iran's energy sector has been affected and constrained by US sanctions since the 1979 Iranian Revolution, and UN sanctions since 2006. These have hampered development and progress for a country that was otherwise a key player in the energy sector. Economic sanctions affected this sector in another manner as well. They impelled Iran to develop a strong home-grown industry capable of developing and operating assets that were for the most part independent from foreign and global players.

As with other jurisdictions that have sought to transform a state-dominated energy sector into a modern industry capable of attracting significant private capital, Iran has had to deal with issues arising from that transformation, not least of which were the cross-subsidisation and artificially depressed energy prices. However, the prize is large. Both

---

1 Munir Hassan is a partner at CMS Cameron McKenna Nabarro Olswang LLP and Shaghayegh Smousavi is a partner at CMS Pars.

2 Iran holds the world's fourth-largest proved crude oil reserves (amounting to almost 10 per cent of the world's reserves) and the world's second-largest natural gas reserves. The country ranked ninth in total primary energy production and 10th in total primary energy consumption in 2014. The US Energy Information Administration (EIA), Iran country profile, updated 19 June 2015. Retrieved from https://www.eia.gov/beta/international/analysis_includes/countries_long/Iran/iran.pdf.
the size of the Iranian energy sector and its influence in the region is expected to grow. Energy prices are significantly lower and energy consumption significantly higher than international and regional averages.

This, together with the relaxation of sanctions against Iran, has opened up opportunities in a potentially significant market for Western power and renewables companies in spite of the lingering effect of sanctions as well as those still in force, most notably those prohibiting US companies from engaging in transactions involving Iran.

III LIFTING OF SANCTIONS: KEY CONSIDERATIONS

On 14 July 2015, the Guardian Council of the Islamic Republic of Iran approved a multilateral nuclear agreement as consistent with the country’s constitution and Islamic law. Pursuant to the agreement between Iran and the permanent members of the United Nations Security Council (China, France, Russia, the United Kingdom and the United States), plus Germany and the European Union (referred to as the E3+3) the International Atomic Energy Agency confirmed to the UN Security Council on 16 January 2016, formally known as Implementation Day, that Iran had complied with the programme set out in the Joint Comprehensive Plan of Action (JCPOA). In return, the E3+3 lifted the nuclear-related sanctions on the same day.

While the EU and UN nuclear-related economic and financial sanctions have been terminated, some sanctions will remain in place and are not affected by the nuclear deal, in particular sanctions related to human rights, proliferation and support for terrorism. The major sectors that were affected by this initial phase of sanctions relief include the energy sector.

It remains important, particularly for companies with activities in the United States or the United Kingdom, to conduct due diligence and ensure compliance with the sanctions regimes before signing business contracts in or relating to Iran. A further risk for investors in the energy sector is the possibility that Iran violates its undertakings in the JCPOA. In such a case, the EU has reserved the right to reimpose sanctions on Iran – the ‘snapback’ provisions. Entities that have contracted with Iranian companies may, therefore, find themselves bound by contracts that they cannot perform.

It should also be noted that Iran, at 124th (2017–2018), ranks low on the World Bank’s Doing Business ranking of economies on their ease of doing business. Key challenges for Western companies, include being alive to the risks of bribery and corruption, as Iran scores high on the Corruption Perceptions Index. Inflation, price control and subsidies reduce proper price discovery and therefore reduce the prospect of merchant projects. A long-term

---

3 The United States has eased sanctions on Iran in respect of the oil and shipping sector. However, the easing of these sanctions principally targets non-US persons conducting business with Iran and, save for limited exceptions, the general trade embargo remains in place for US companies. The US Treasury Department’s Office of Foreign Assets Control through the issuing of General License H authorises non-US entities to engage in business with Iran, subject to certain exemptions and restrictions including strict limitations on the extent of the involvement of the parent company.


lack of investment in infrastructure means that delays can arise from limitations imposed by wider infrastructure development needs. As with other similar jurisdictions, there remains a risk of bureaucratic delays and overlapping jurisdictions in consents and similar matters.

As with other energy markets that have opened up in recent years, a common strategy for Western companies is to partner with a local (in this case Iranian) entity that can guide them through the domestic landscape (see Section IV on joint ventures with Iranian entities). However, initial experience has been that cultural and other barriers can make the process of effective partnering often difficult and, while it is important to know your counterparty well, reliable information on Iranian companies is not always straightforward to procure.

IV OVERVIEW OF THE OIL AND GAS SECTOR IN IRAN

Iran's oil and gas industry was looking to attract something close to US$200 billion over five years in investment to capitalise on the opportunities presented by the opening up of the sector following Implementation Day. The timing was perhaps unfortunate, with oil prices languishing without immediate evidence of an imminent recovery. Nevertheless, the costs of production in Iran were estimated to be significantly lower than the international average, and well below the low current oil price. In these circumstances, Iran has been pushing ahead with reforms to further open up its oil and gas sector to foreign investors.

On 1 October 2015, in response to criticisms of the previous buy-back contracts, the Iranian cabinet endorsed a new upstream oil and gas document known as the Iran Petroleum Contract (IPC).6 The purpose of the IPC is to facilitate foreign investment. The document consolidates the previous model agreements into one, and covers the exploration, appraisal and development phases.

The general terms and structure of the contractual framework of Iran's upstream oil and gas was ratified in September 2016. This ratification finally took place with many amendments after political discussion.7

In July 2017, Total and the National Iranian Oil Company (NIOC) signed the first IPC contract for the development and production of phase 11 of South Pars (SP11), the world's largest gas field. Although negotiations with other major multinational oil and gas companies have reportedly been going on, Total's investment remains the only IPC concluded to date.

The nature of the IPC was, from the beginning, a controversial issue. This is because Articles 77 and 125 of the Iranian Constitution require that international agreements have parliament's approval. However, it has been previously held that contracts in which one side is a government entity or company and the other side is a privately owned foreign company are not international agreements subject to Article 77. The criticisms also seem to rely on Article 45 of the Constitution, which requires state control of major industries and large mines (including oil and gas reservoirs).8 The IPC seeks to navigate the constitutional position by avoiding a production-sharing structure, and does not create ownership rights in reservoirs for foreigners. The contract is more akin to a risk service contract arrangement, with an exploration phase of four to six years, an appraisal phase of two years and a development phase of 20–25 years. The Oil Ministry supervises operations and the government-owned

7 ‘Iran’s Cabinet Approves IPC’, NIOC, 6 August 2016.
8 See https://www.reuters.com/article/us-iran-oil-contracts-idUSKCN12K1M1.
NIOC retains ownership of reservoirs, assets and extracted commodities. As NIOC remains responsible for oil exploration and extraction, and as all operations under the IPC are carried out on behalf of NIOC, all the assets, including equipment, wells, etc., belong to NIOC.

In contrast to the previous buy-back approach, the IPC provides for a joint-venture model, among other things, to allow collaboration and technology transfer, with decisions escalated to a committee comprising representatives of NIOC and the international oil and gas company (IOC). If oil is discovered and economical to extract then NIOC and IOC establish a joint operating company or joint venture to take implementation forward and develop, operate and produce from the field. Decisions would continue to be made through a joint committee. Further Iranian ownership participation in the company is also possible. This is a fundamental opportunity as foreign IOCs have not been able to be involved in oil production in Iran since the Revolution in 1979.

Nevertheless, the IPC seeks to attract IOCs from across the world – such as Total, Statoil, BP, Royal Dutch Shell, OMV, Wintershall, Repsol, Sinopec, as well as companies from Asia and the Middle East region – to its sector by providing attractive terms. These include a form of hedge against oil price volatility, with payments where there are significant changes in oil price, and providing some protection on risks relating to the ability to develop a field. This contrasts with the previous buy-back arrangements under which payments were linked to capital costs (typically providing a return of 15–17 per cent) and did not incentivise additional recovery in oil or account for changes in oil price. Among other things, the IPC also moves away from the previous approach under the buy-back arrangements that capped cost recovery and required the IOC to take all delay and cost-overrun risks. While costs will be recoverable under the IPC, costs and annual budgets are to be jointly agreed under a collaborative approach. The IOC would effectively take all exploration risks in the event that exploration and production targets are not met.

Also, notwithstanding ownership remaining with NIOC, the IPC could in some situations allow reserves to be booked, which is important for IOCs in terms of demonstrating their market value. The IOCs would take the risks on the costs of operation. As noted, there is also an emphasis on a collaborative approach in the IPC and a requirement on knowledge transfer into Iran.

Putting aside the single IPC-based agreement concluded with a local company,9 Iran has signed a US$4.8 billion deal with a consortium led by French oil company Total in July 2017 to develop the South Pars gas field in cooperation with China National Petroleum Company. In March 2018, Russia’s state-owned oil company Zarubezhneft signed a trilateral deal with the National Iranian Oil Company and Dana Energy Company for the development of the Aban and West Paydar oilfields near the Iran-Iraq borders. This is the second major energy deal signed in Iran since the lifting of international sanctions.

V  OVERVIEW OF THE POWER SECTOR IN IRAN

The Iran Electricity Regulatory Board (IERB) was established around the turn of the millennium. Its work is overseen by the Minister of Energy and it often works with external third-party consultants. It comprises an executive, called the Regulatory Board Secretariat.

---

9 Iran’s Oil Ministry signed a US$2.2 billion agreement with Tadbiri Energy group, affiliated with the Execution of Imam Khomeini’s order company (EIKO), which was responsible for increasing the recovery rate of three fields (Yaran, Kupal and Marun).
which runs a Logistics Unit, a Judicial Unit, a Market Process Planning and Scheduling Unit, and a Market Monitoring Analysis and Adjustment Unit. The IERB is responsible for monitoring, researching and supporting the electricity market, and suggesting regulations and electricity-related tariffs to the IERB. The IERB also has a role in maintaining an orderly functioning of the industry by managing relationships between industry participants. It is also empowered to manage claims arising between such entities. When making recommendations on regulatory changes and similar matters, the IERB may consult stakeholders and take into account comments and recommendations from industry.

Historically, Iran’s electricity market was a local, private and vertically integrated monopoly in Tehran, starting in 1905. An early Law of Iran Electricity Organisation was passed in January 1963, creating regional electricity companies, and followed by the establishment of the Ministry of Water and Electricity in 1964 (the Ministry of Energy since 1975), generally regulating the electricity sector. A year later, legislation was introduced that required all non-governmental electric companies to accept mandatory retail tariffs. As these tariffs proved to be below cost, a subsidy was required to maintain the companies as solvent and the companies in due course became Ministry subsidiaries.

The Generation and Transmission Company of Iran (Tavanir) was established in 1970, primarily to implement transmission and generation plans, and operate generation facilities and the transmission network. Today, Tavanir has been restructured to be the holding company responsible for these activities.

Pursuant to the decision of the Iranian High Administrative Council, dated 18 December 2004, ‘all legal missions and activities regarding new energies (renewable) and all affairs regarding policymaking, planning supervision and supporting the relevant activities in the non-public sector shall be concentrated in the Ministry of Energy’.

The Iran Grid Management Company (IGMC) was formed in 2004, following the establishment of a wholesale electricity market for the trading of electricity by the IERB. The IGMC acts as the market and system operator.

An impediment to private sector participation has traditionally been Article 44 of the Iranian Constitution, which required all large-scale industries and power generation (among others listed) to be fully state-owned. In 2004, this Article was amended to require the state to cede at least 20 per cent of control of power companies to private and ‘cooperative’ entities. This has led to a privatisation process in relation to this element of the generation sector (except in relation to ‘must run’ plant) and this privatisation process remains ongoing.

There is a wholesale electricity market in Iran (referred to as the IEM) comprising a day-ahead market for generators and retailers (typically the regional electricity companies) to buy and sell power. A power exchange and bilateral contracts sit alongside the market. Tavanir remains responsible for exporting power to neighbouring countries. However, as there is limited competition in the market, it functions as a fairly basic auction mechanism. Bids are submitted to offer power at specified prices. Purchasers of power specify quantities

12 For further information on the power sector, see www.igmc.ir.
13 For further information on the IEM and power exchange and trading arrangements, see further on www.igmc.ir.
required. The market operator, IGMC, then clears the market. Generators are paid for capacity even if they are not successful in the bids to provide power to incentivise the provision of capacity to the market. The maximum bidding price is capped by regulation.

Private generators can contract to sell power bilaterally to purchasers via the power exchange or through futures contracts for power delivery. These prices are privately set and not subject to regulatory intervention. Power sold in the power exchange is excluded from the day-ahead market. On a longer-term basis, generators and purchasers of power can also contract long-term power purchase agreements at a negotiated price. Trades are then notified to the system operator, IGMC.

Despite considerable hydroelectric and renewables capacity, Iran remains significantly reliant on thermal and gas generation, with thermal power plants’ 11,943MW and gas plants’ 26,200MW accounting for 20.1 per cent and 33.2 per cent of the total installed capacity respectively by the end of the previous Iranian year (21 March 2018).\(^\text{14}\) The power system and the use of energy in Iran are both notoriously inefficient, principally because of cross-subsidies, ageing infrastructure and lack of investment in advanced technologies. There is a plan to shift away from such implicit subsidies to ones that are targeted to fuel poverty. On technology and capital requirements, the focus remains on attracting foreign direct investment despite the imperfect sanctions position, volatility in the market, political uncertainties and the residual risk of a snapback occurring on sanctions.

In terms of policy, the current Sixth Five-Year Economic, Cultural, and Social Development Plan for 1396-1400 (2016–2021) has established a target of 5 per cent of the country’s total energy generated to come from renewable sources by the end of the Plan, projected to equal 5GW. Owing to the overall effects of partial lifting of sanctions and the new policies in the renewables sector, Iran has become an increasingly attractive market for foreign investment. Mindful of the need to compensate for the hold back of the sanction years, the government has been pursuing a policy shift with a view to systematically incentivise the deployment of renewable energy, to establish a revised and more stable regulatory regime under the Renewable Energy and Energy Efficiency Organisation of Iran (SATBA (formerly SUNA)),\(^\text{15}\) and to offer feed-in tariffs that are nominally high when compared internationally.

Among the incentives is a purchase scheme for any electricity produced from renewable sources (solar, wind, biomass, geothermal, small hydro power plants, and more recently fuel cells and turbo-expanders) established by the Ministry of Energy for a recently increased period of 20 years.\(^\text{16}\)

The feed-in-tariffs set in 2016, that continue to be in force until such time as new tariffs are announced, vary between 3,400 to 4,200 rials/KWh in the wind sector, and 3200–4900 rials/KWh in the solar sector, based on the capacity of the plant and taking into account the adjustment factor, namely inflation.

---


\(^\text{15}\) An act passed by the Parliament in December 2016 merged SUNA with the Iran Energy Efficiency Organisation (SABA). According to the act, all functions, obligations and authorities of SUNA, as well as its personnel will be transferred to the new organisation, called SATBA.

\(^\text{16}\) Prior to July 2015, contracts were limited to a five-year period and did not differentiate between technologies.
Under this scheme, more than €3 billion are expected to be invested in the renewable sector.\textsuperscript{17}

The success of the new tariff regime, which led to an almost seven-fold growth in development of renewable power plants in the last two Iranian years alone\textsuperscript{18} (March 2016–March 2018) encouraged a continuance along the same path, with officials promising to keep the tariffs unchanged for the current year.\textsuperscript{19}

For the time being, the Iranian contractual practice is based on the PPA model, a new and partially revised version of which is to be publically announced within the coming months. However, an additional tender-based system for large utility-scale RES projects is also under examination.

Key points in the PPA include, among other points:

\begin{itemize}
\item[a] while the PPA provides for a conditional purchase price, this price may be decreased if the project is delayed in commissioning;
\item[b] the possibility of an increase in the purchase price if locally made equipment is used;
\item[c] the seller is responsible for any work concerning the design, construction, testing and commissioning of the grid connection facilities;
\item[d] the purchaser has no responsibility for connecting the plant to the grid: any expenditure in connection with these rests with the seller;
\item[e] the seller is responsible for obtaining all applicable permits at its cost. However, the purchaser has an obligation to assist the seller in obtaining the required permits;
\item[f] the purchaser to provide a revolving letter of credit (LC) from an Iranian bank, with a validity period not less than six months and a value equivalent to the amount to be paid by the purchaser. The expenses associated with the LC shall be shared between the purchaser and the seller;
\item[g] the PPA is governed by Iranian law, with a dispute settlement mechanism requiring, first, negotiation, then referral of the dispute to an expert and, finally, to a court;
\item[h] where changes in law provisions require an adjustment to the PPA terms and the changes are a result of new decrees and directives, any additional expenditure shall be borne by the purchaser;
\item[i] force majeure provisions allowing, upon the request of the seller, the performance to be suspended for a period of six months, without any payment. If not remedied within the period of six months, the purchaser may terminate the contract; and
\item[j] termination rights in the event of certain circumstances arising, such as insolvency, assignment without consent by the seller, or loss of required permits (subject to cure periods).
\end{itemize}

A key question for the success of the new tariff regime, in particular in respect of large-scale projects and bankability issues, in general, will be the availability of project finance. Linked to the bankability of the PPA, will be the question of availability of sovereign guarantees or another structure, such as a standing fund, as a backstop for payments over the long term.

\textsuperscript{17} Statement by the president of OIETAI. Reported by IRNA: http://www.irna.ir/fa/News/82509590/.

\textsuperscript{18} Statement by the Minister of Energy: www.isna.ir/news/96020904936.

VI LOOKING AHEAD: COMPETITION IN THE IRANIAN POWER AND OIL AND GAS SECTORS

Ultimately, whether competition is introduced into Iran’s energy sector will depend on the outcome of an ongoing debate between conservatives arguing for energy independence and self-sufficiency, and moderates (led by President Hassan Rouhani and his administration since he first took office in 2013) looking at the best way to promote and advance the economy. With the energy industry having been in public hands during the era of sanctions, with significant involvement of the Islamic Revolutionary Guard Corps (IRGC), there are significant vested interests to overcome in the industry, and any opening up of the sector could be viewed with suspicion by the IRGC and Iran’s home-grown energy sector supply chain, particularly as the reforms promise to fundamentally redefine and rescupe the role of NIOC and bring in substantial foreign investment and technology.

Introducing competition and tariff reform has a number of potential benefits for the energy sector in Iran. The purpose of such reforms is to ensure that the risks associated with investments in the energy sector are allocated to the entity that can best manage them and also to force better investment decisions. Competition and liberalisation seeks to transfer greater performance risk to the private sector, harness the benefits of competition by introducing new technology and international best practice into the sector, and share financial gains with taxpayers and consumers.

Where the Iranian Ministry of Energy is also the regulator and direct investor in the power sector, the conflicts of interest can be significant. For effective regulation, a separation of key aspects of the state from the sector holds many benefits. However, Iran may wish to take a staged approach to liberalisation of the sector, to ensure that the process does not place undue upward pressure on energy prices (which can be politically difficult) or pressure on existing entities to reduce costs that create financial difficulties and unsettle the sector.

Competition will also require capacity-building in key institutions that will need to manage the capabilities and expertise in managing new market processes, as well as educating the full supply chain on the approach in Iran. Key elements that Iran may need to consider include establishing an independent transmission company and considering which entity should procure new power generation projects (as well as potentially other types of projects in the sector). A key goal is to make electricity a liquid commodity that can be traded in spot markets and wholesale markets. Where Tavanir is restructured, a regulated price control also needs to be established for the network and monopoly businesses, and the process for setting the initial tariffs involves considerations including ensuring adequate revenue, promoting efficiency and driving key policy objectives.

Iran does already have independent power projects and a number of power plants have been privatised or are scheduled to be privatised. For international investment, the sustainable PPA offered by Iran is designed to create a predictable revenue stream to facilitate the raising of finance and protect independent power projects from political risk. Also, perhaps most importantly, there has to be a clear ability for international investors to rely on the legal ‘sanctity’ of contract terms and pursue international arbitration. The existing Iranian PPA needs to be improved to provide a sustainable PPA framework and to be bankable according to international standard if international investments are to materialise. Further, while competitive procurement of new large-scale projects is usually the recommended approach, it is often the case that initial projects are not competitively procured and instead are procured on a negotiated basis.
Policy and sectoral changes in Iran will also create a question on how to deal with power purchase agreements held by existing power projects in Iran, which may not have contemplated significant market changes. As a basic principle, it will be important for Iran to honour existing contract terms and maintain confidence in the pipeline of projects. Any other approach would have an effect on market liquidity and could create above-market costs, as well as deter new entry and inhibit the gains associated with competition and market opening. They could also lead to claims and litigation. While it is worth making an effort to integrate independent power producers (IPPs), the magnitude of IPP contract terms affected can be a factor in the approach taken.

Iran is also looking to develop further its role as a major regional participant in the Middle East power market and this will be enhanced as it takes steps to implement arrangements drawing from international best practice and that are appropriate to the Iranian context.

VII ESTABLISHING AN ENERGY BUSINESS IN IRAN AND DISPUTE RESOLUTION

While it is beyond the scope of this chapter to detail the broader considerations on the appropriate form of investing or establishing a business in Iran, the recent opening up of the Iranian market means that this is a very relevant topic for entities wishing to become involved in the Iranian energy sector.

Investors, developers and supply chain entities looking to operate in the energy sector in Iran post-Implementation Day (see above) will need to decide on the form of their engagement and entry into Iran. Many entities will operate from overseas, some will consider opening up a branch office in Iran and, for more involved operations, an Iranian legal entity may need to be established or dealt with. Branch offices tend to be used typically for activities such as marketing, aftersales and certain service provision activities. However, engagement in direct commercial activities would affect the tax treatment of branch offices. Longer term and deeper operations would tend to be pursuant to the establishment of Iranian companies, such as a private joint-stock company or limited liability company. Alternatively, another route for engagement in Iranian projects is to set up a joint venture with a local entity. The joint venture could then participate in tender rounds, and this can also help on meeting local content requirements.

A foreign investment licence under the Foreign Investment Promotion and Protection Act (2002) permits the foreign investor to incorporate a company without restriction on the level of foreign ownership. It is possible, following changes to regulations that came into effect in 2008, to incorporate a fully foreign-owned entity for specified activities.

A further useful consideration is to establish a business in a free trade zone (FTZ) such as Anzali, Aras, Arvand, Chabahar, Makoo, Kish or Qeshm. Existing and planned FTZs in Iran are subject to the Law on the Administration of Free Trade and Industrial Zones 1993. Each FTZ has an authority that manages the activities in the zone and issues permits. While FTZs look to streamline and ease the process of establishing a business in Iran and may impose attractive tariffs and customs duties to act as incentives, as noted above the recent changes following the Foreign Investment Protection and Promotion Act (2002) make it viable for foreign entities to establish wholly-owned businesses generally in Iran. Iran’s 16 Special Economic Zones (SEZs) may also be a viable option for some foreign entities looking...
to establish themselves in Iran, and they provide many of the advantages associated FTZs.\textsuperscript{20} The FTZs are distinct from the SEZs, the difference is geographic: FTZs are established in border regions while SEZs can be set up anywhere on the mainland.\textsuperscript{21} In contrast to the FTZ, SEZs are considered as part of the mainland according to Iranian legal terms.

Furthermore, the law and regulations governing the FTZs are different from those applicable to SEZs. For instance, no visa is needed to be obtained beforehand to enter into the FTZs (visas are issued on arrival), but in the SEZs, entrance of foreigners is subject to mainland regulations.\textsuperscript{22} In addition, in the FTZs, applying for investment is subject to the relevant FTZ regulations, whereas the law of the mainland remains applicable in the SEZs.\textsuperscript{23}

As such, it is important for entities looking to enter the energy sector in Iran to understand the broad array of laws, regulations and industry frameworks currently in effect in Iran. The Constitution of the Islamic Republic of Iran requires all laws and regulations to be based on Islamic criteria. Iran has two coexisting systems of law, namely the law of Islamic lawyers and codified law. It is beyond the scope of this chapter to provide a detailed overview of the Iranian legal system. We set out below some aspects of particular note in conducting transactions in the energy sector.

Iran has promoted foreign participation through the Foreign Investment Promotion and Protection Act (FIPPA), 2002. According to FIPPA, sectors including industry, mining, agriculture and services in greenfield and brownfield projects are open to investment in Iran subject to satisfaction of certain criteria.\textsuperscript{24} Foreign direct investment (FDI) may be admitted in fields where private sector activity is permitted. However, purely commercial activities are not considered to be foreign investment.

Therefore, foreign investors may choose the investment method in the project as FDI or foreign investment in all sectors within the framework of ‘civil participation’, buy-back and build-operate-transfer schemes.\textsuperscript{25}

A licence for foreign investment under FIPPA is issued by the Organization for Investment Economic and Technical Assistance of Iran (OIETAI).\textsuperscript{26} The licence provides for foreign investment to be treated on a par with Iranian investments,\textsuperscript{27} allows for disputes to be resolved outside Iran and also allows for the repatriation of profits. It, generally, facilitates investment and secures against non-commercial risks including currency transfer,\textsuperscript{28} nationalisation, expropriation,\textsuperscript{29} government intervention and breach of contract by government.\textsuperscript{30} As to the major questions of expropriation and nationalisation of foreign investors’ assets, FIPPA recognises the right to receive immediately compensation based on the fair market value of the expropriated assets on the day before expropriation takes place.\textsuperscript{31} Besides, foreign investors have direct access to and possibility of withdrawal of export

\textsuperscript{20} See www.freezones.ir.
\textsuperscript{21} Ibid.
\textsuperscript{22} Ibid.
\textsuperscript{23} Ibid.
\textsuperscript{24} Article 2 FIPPA.
\textsuperscript{25} Article 3 of Implementation Regulation of FIPPA.
\textsuperscript{26} Article 15 of Implementation Regulation of FIPPA.
\textsuperscript{27} Article 8 FIPPA.
\textsuperscript{28} Article 4 of Implementation Regulation of FIPPA.
\textsuperscript{29} Article 9 FIPPA.
\textsuperscript{30} Article 17 of Implementation Regulation of FIPPA.
\textsuperscript{31} Article 9 FIPPA.
proceeds out of escrow accounts established in banks outside Iran.\textsuperscript{32} Foreign investors may export their goods and services without any commitment to reintroduce export proceeds into the country.\textsuperscript{33} Also, travel for foreign investors, directors, experts and their immediate family in relation to the investment covered by FIPPA is made easier by the grant of a three-year multi-entry visa, a residence permit, a work permit for each individual with a right of entry and a three-month residence permit on each occasion.\textsuperscript{34} Furthermore, all bilateral investment treaties concluded with other countries contain a provision whereby they are only applicable to investments for which the FIPPA licence is acquired.

According to statements from OIETAI officials, foreign investment applications are processed within 15 days, although, in practice, such a process can take up to 30 days to complete.\textsuperscript{35}

The FIPPA licence validity can be extended upon request by the foreign investor (for example, if the foreign investor fails to bring in the investment capital within the determined period and needs an extension). Otherwise, the licence will be considered null and void.\textsuperscript{36} In the renewable energy sector, applications for foreign investment licences are submitted to OIETAI, once the necessary permits have been obtained from SATBA.

In addition to the judiciary (court) system, the settlement of disputes through other methods such as arbitration has been recognised by the Iranian legislator and has developed significantly in recent years. This is aided by the considerable experience derived from the example of the Iran–United States Claims Tribunal and the work performed by different institutions providing specialised services in arbitration matters.

National arbitration in Iranian law is governed by the 2000 Civil Procedure Code (Articles 454–501). For international arbitration, a framework was established by the Iranian Law on International Commercial Arbitration of 1997. To complete the efforts in furthering the position of international arbitration under the Iranian legal system, Iran has ratified the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards of 1958.

There are two major arbitration bodies in Iran: the Tehran Regional Arbitration Centre, 2004, and the Arbitration Center of Iran Chamber, 2001. As is standard in international arbitration, there is no right of appeal against an award. A party may, however, apply to have an award set aside on certain grounds.

As far as arbitration of disputes relating to public and state property is concerned, particular attention should be given to cases where the subject matter concerns public and governmental property, or if a party is foreign, since the approval of the Consultative Assembly (the parliament) is also required in such cases.\textsuperscript{37}

\textsuperscript{32} Articles 13–18 FIPPA.
\textsuperscript{33} Articles 13–18 FIPPA.
\textsuperscript{34} Article 20 FIPPA and Article 35 Implementation Regulation of FIPPA.
\textsuperscript{35} Article 6 FIPPA.
\textsuperscript{36} Article 32 of Implementation Regulation of FIPPA.
\textsuperscript{37} Article 139 of the Iranian Constitution provides that:

The settlement, of claims relating to public and state property or the referral thereof to arbitration is in every case dependent on the approval of the Council of Ministers, and the Assembly must be informed of these matters. In cases where one party to the dispute is a foreigner, as well as in important cases that are purely domestic, the approval of the Assembly must also be obtained. Law will specify the important cases intended here.
VIII CONCLUSIONS AND OUTLOOK

The easing of sanctions marked the beginning of a new chapter in the Iranian energy sector, characterised by increased determination for progress and ambitious goals for development on the part of the Iranian government accompanied by higher, if still somewhat cautious, interest from the foreign investors’ side.

The impact on Iran’s economy has been notable and positive. With more than US$55 billion of assets unfrozen and made available, and around US$21.8 billion of foreign direct investment (FDI) approved by the OIETAI,38 the highest level in almost two decades, raising oil and gas production to pre-sanction levels of 3.85 million barrels per day (mbd) and aggressively regaining its market share with approximately 2mbd of oil exports, the country has managed to bring down inflation to single digits (9.6 per cent in February 2018) from a peak of 45 per cent in 2013.39

The re-election of President Hassan Rouhani in 2017 was a positive sign that the policy path already taken to incentivise foreign investment in the Iran energy sector will be continued over the next three years. Despite the progress made, financial challenges still persist as valid concerns. The turbulence caused by the current US administration’s policies towards Iran and the JCPOA has taken a toll on the energy sector and the wider economy. It now remains to be seen whether the efforts initiated by the current administration aimed towards attracting large-scale foreign investment while also localising know-how in the energy sector will come to fruition in the coming year.

Nevertheless, the fact that Iran, with its vast energy resources and all its potential, remains a huge player in the energy sector is undeniable.

---

I OVERVIEW

Certain key historical and constitutional matters

Prior to 2003, when the government headed by Saddam Hussein was replaced, Iraq was governed by a socialist-leaning government with a very limited private sector in place. This has continued to be the case since the overthrow of the monarchy in 1958. A series of steps were taken by the various republican governments that nationalised the principal components of the economy, culminating in the 1972 nationalisation of the oil sector. Iraq had therefore become a centralised economy, with various ministries controlling most aspects of the economy.

Between 1980 and 1988, Iraq was involved in a war with the Islamic Republic of Iran, which was followed in 1990 by the invasion of Kuwait and the subsequent Gulf War I. Immediately after Kuwait was invaded, a series of UN Security Council resolutions imposed sanctions on Iraq, which were followed by a series of nationally imposed sanctions. These sanctions were widespread and extended into most imports, including key oil and gas and technological imports.

Following Iraq’s expulsion from Kuwait, the sanctions continued (until 2003), but more importantly, the central government lost effective political and security control over a significant portion of Iraq, to be referred to as the Kurdistan Region. In 2004, the Transitional Administrative Law (the Interim Constitution) recognised the boundaries of the Kurdistan Region, with the same boundaries adopted in the Permanent Constitution of 2005 (the Constitution). The Constitution was structured in a way that provided limited powers to the central government and shared certain powers between the central government and regional governments (the Constitution provides that other regions could be formed). All remaining powers are to be vested in the regional governments.

The matter of oil was hotly debated in the constitutional process, with a compromise reached that provided that the existing fields continue to be managed by the central government, and new fields are jointly managed with the revenues going to the central government. However, in the event of a dispute between the central government and the regional government over the development of new fields, the decision of the regional government would prevail. Issues relating to gas are treated in the same way. The Constitution further provided that Iraqi oil and gas is owned by the Iraqi people, and that the management of the oil fields is to be based on a federal oil and gas law that, to date (nine years after the Constitution was approved), has not been passed.

1 Salem Chalabi is a partner at Stephenson Harwood Middle East LLP.
There have been disputes between the Kurdistan Regional Government (KRG) and the central government on a number of oil and gas issues, in particular those relating to the development of new oil fields. The KRG has entered into production-sharing agreements with a substantial number of oil companies, agreements that the Iraqi Ministry of Oil (MOO) has been critical of. As a result of these disputes, the MOO has claimed on a number of occasions that the KRG has been selling its oil directly in the oil markets (through Turkey) and keeping the income from such oil sales. In response, the KRG has claimed that the central government has withheld amounts owing to it in the budget. Despite certain interim deals, the disagreements between the central government and the KRG continue at the time of writing. These continuing disagreements have led to various court and arbitration claims in various jurisdictions. These disputes have also involved the Republic of Turkey in connection with disputes relating to the Iraq-Turkey export pipeline, from which both Iraqi and Kurdish crude is exported to Ceyhan, Turkey.

In light of the constitutional separation of powers between the central government and the KRG, the electricity sector is effectively two separate sectors: one for the areas governed by the central government, and the other governed by the KRG. Each has developed in a different manner over the past few years.

ii Developments in 2014

The year 2014 saw two key developments: the takeover of certain parts of Iraq by the Islamic State and the drop in the price of oil.

In June 2014, the Islamic State took over significant areas in Western and Northern Iraq, such as the cities of Mosul, Tikrit and parts of the governorate of Tikrit. These areas were mainly governed by the central government, and therefore the central government was unable to continue providing electricity services to those areas that fell to the Islamic State. Simultaneously, in the governorate of Kirkuk, the Islamic State took over certain oil fields and was able to sell crude oil directly. Ultimately, troops belonging to the KRG were able to take back some of these fields, which are now under their control. Constitutionally, these fields are to be managed by the MOO (through North Oil Company) but, following certain negotiations, the KRG was unwilling to hand these back to the MOO, and is now operating the fields itself. This has increased tensions between the central government and the KRG.

As for the drop in oil prices, the impact has affected the Iraqi budget significantly, and therefore the MOO is considering amending the terms of its existing service contracts with the existing international oil companies. To that effect, it is looking at different alternatives to propose to the international oil companies. Moreover, parliament has asked the MOO to address the amendments of the technical services contracts.

iii Developments in 2015

The year 2015 saw several developments that affected the energy sector, in particular the continued drop in oil prices, which affected the Iraqi economy significantly. On the positive side, there were various offensives against the Islamic State that ended up with the recovery of certain towns and cities that had fallen to the Islamic State, including Tikrit and Al-Ramadi. These victories were coupled with an almost total destruction of the capacity of the Islamic State to produce oil from fields under its control.

In order to address significantly reduced oil revenues, the Iraqi government significantly reduced its expenditures, in particular its capital expenditure on infrastructure projects. The impact of such reduced infrastructure expenditures on the growth of the Iraqi economy has
not been positive as projects stalled, causing significant arrears to Iraqi companies and, more importantly, to international oil companies. The latter, accordingly, began to reduce their expenditures in the oil fields under the technical services agreement.

iv Developments in 2016

The year 2016 was a year in which the fiscal consolidation that commenced in 2015 became more entrenched, but was also a year in which Iraq engaged with the International Monetary Fund in a Stand-By Arrangement (SBA).

As oil prices dropped further in early 2016, the government decided to commence negotiations with the International Monetary Fund (IMF) for an SBA programme that would not only lead to loans from the IMF of US$5.4 billion over a three-year period, but also would unleash facilities from the international community for a total of approximately US$18.6 billion over a three-year period. The IMF programme is premised on three pillars:

\[ \begin{align*}
   a & \quad \text{the maintenance of sustainable debt over the next five years;} \\
   b & \quad \text{the repayment of arrears as well as the non-incursion of new arrears; and} \\
   c & \quad \text{the maintenance of decent levels of central bank reserves.}
\end{align*} \]

In order to achieve these goals, a principal condition precedent was that the MOO was required to become current on its arrears to the international oil companies by the end of 2016 (which it did). The IMF programme also required a restructuring of the Iraqi economy away from a state-controlled economy and also towards increasing non-oil revenues.

Throughout 2016, the government was able to stabilise its expenditures. However, it was also required to carry out an audit of all of its arrears, which it was able to do. These proved to be larger than expected and therefore Iraq’s investment expenditures, including those in the oil and electricity sectors, were required to be reduced.

At the same time, the MOO began to consider some new large-scale investment projects, including the Basra-to-Aqaba pipeline. Moreover, there have been proposals relating to the refinancing of some large infrastructure projects, in particular, the Karbala refinery.

v Developments in 2017

The year 2017 saw a number of major developments in Iraq on a number of fronts. First, the government was able to recapture all of the territory that had been held by the Islamic State in previous years, including the city of Mosul. This allowed for large-scale returns of refugees to their homes. However, it also clarified the enormous requirements in order for Iraq to rebuild its destroyed infrastructure (with the estimated needs being US$50–90 billion). Second, and more closely linked to the energy sector, following a referendum in the Kurdistan region and disputed areas in September 2017 that was opposed by the central government, the central government recaptured the city of Kirkuk and adjoining oil fields (which had been under the control of the Kurdistan regional government from late 2014). The effect of this was twofold. First, the exports of oil from the Kirkuk fields (approximately 300,000 barrels per day) effectively stopped. Second, as a result of such stoppages, the revenues of the Kurdistan regional government from oil exports declined dramatically and the Kurdistan regional government began to face a very difficult financial situation. Since the budget deal between the central government and the Kurdistan regional government had not been implemented since 2015, the halt in oil revenues from the sale of Kirkuk oil has reduced the revenues of the Kurdistan regional government by over 60 per cent. Discussions between the two parties commenced but, by the end of 2017, no new deal had been reached.
In 2017, Iraq also completed its first real entry into the international financial markets. In January, it sold US$1 billion in bonds guaranteed by the United States Agency for International Development. This was followed in August by an offering of US$1 billion in unguaranteed bonds. The average interest rate was approximately 4.5 per cent. The banks who arranged the offerings for the Republic of Iraq were Citibank, Deutsche Bank and JP Morgan. Iraq also commenced a series of transactions with export credit agencies to complete various projects in the electricity sector, with support coming from UKEF, SACE, Euler Hermes, SERV and EKN. This is being followed by other financings for other sectors.

II THE IRAQI ELECTRICITY SECTOR

i The Ministry of Electricity – Baghdad

The Iraqi Ministry of Electricity’s (MOE’s) role in the electricity sector is, to say the least, all encompassing, with it being the principal policy maker, power producer, service provider, regulator and operator. As with most other ministries in Iraq, the MOE is beset with bureaucracy and corruption, and therefore is not conducive towards structural innovation and reform. The senior staff of the MOE are, by contrast, technically trained to a good standard and have significant knowledge of technical developments in the electricity sector.

The legislative basis for the MOE is currently vague, which has made it difficult to clarify its powers. Accordingly, the MOE’s powers are somewhat broad in the power sector. In recent years, however, it (together with the various arms of the executive branch) has prepared two drafts of an MOE law. In late 2016, the draft law was passed. The following is a brief summary:

a The MOE is designed to organise the electricity sector in Iraq, including the introduction of the private sector into the generation and distribution sectors. In connection therewith, one of the goals of the law is to transfer the electricity sector from a purely public enterprise to a mixed or private sector enterprise.

b It is also designed to make the electricity sector less centralised (with everything controlled by the office of the Minister of Electricity), by among other things encouraging the role of the provincial governments.

c It is designed to encourage renewable energy.

Administratively, the MOE is currently divided into various central departments (generation, transmission, distribution, etc.) and various regional departments (e.g., south generation). The passing of the law, which has not yet been implemented, has at the time of writing not amended too much administratively within the MOE. In an effort to carry out the above, the electricity law keeps more or less the same central departments within the ministry (generation, transmission, distribution, etc.) but then plans to convert the regional departments into public companies. In total, there will be 10 such separate public companies (mirroring the existing departments now). The idea is that assets of each of the departments

---

2 The Ministry of Electricity (MOE) was established during the time of the Coalition Provisional Authority (2003–2004). Prior to that, the various components of the MOE, which were organised as state-owned enterprises, were part of the Ministry of Industry and Minerals. Once the MOE was established, such state-owned enterprises were de facto converted into directorates of the MOE.
would be transferred to the relevant public company. Ultimately, the law proposes that these companies would be converted into publicly owned companies (listed on the Iraq Stock Exchange).

The law also contemplates opening private investment opportunities in the electricity sector. These include the introduction of private companies in the electricity distribution sector, which will charge tariffs. This could be a problem for such companies and for the MOE. In early 2015, the MOE announced the introduction of higher tariffs to be paid by the consumers. (Currently, only a small percentage of consumers pay what they actually consume in electricity, principally because of meters that are old and have been tampered with, corruption in the collection of electricity bills (which are manually collected) and rewiring of home electricity lines.) The introduction of higher tariffs caused public uproar as the public at large felt that the new tariffs would be unduly burdensome at a time of economic hardship, an uproar that was picked up on by powerful political actors who ended up opposing the new tariff. The MOE was therefore forced to withdraw this proposal. Later in the year, as part of Iraq’s entry into the IMF SBA, the Iraqi cabinet voted on a resolution that reintroduced higher tariffs. These new higher tariffs were structured to be less strenuous on the poorer elements in Iraqi society. Transferring this task to the private sector may work better, as the private sector may prove less responsive to political pressures; but at a time in which electricity shortages and cuts are the norm, the public at large may not favour such a move. In 2016, the MOE embarked on a pilot programme in a neighbourhood in Baghdad to privatise distribution and collection of electricity tariffs. This programme was followed by a wider plan, announced in the form of a ‘request for information’, for privatising the collection of electricity tariffs throughout the country. By early 2017, the tariff collection programme was introduced into several areas, although there have been demonstrations against the introduction of the programme in cities such as Basra.

The law has the right intentions, but it suffers from some of the same legislative basis that makes it difficult for the private sector to flourish in Iraq. Or rather, although the draft law itself may have the right incentives, there are a large number of legal and regulatory hindrances that make it difficult for the private sector to carry out business in Iraq. For example, there is a law in Iraq (Law No. 56 of 1977) that provides that the government or any governmental entity need not obtain judicial decisions prior to attaching private assets if they are seeking to recover their debts. Coupled with the fact that Iraq is not party to the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards, such laws make it very hard for international financial institutions and investors to feel comfortable doing business in Iraq generally.3

ii The private sector in the Iraqi electricity sector

There were significant developments in the private sector entering the electricity business in 2014. First, however, by way of background, there are a few matters to keep in mind:

a The Iraqi transmission and distribution network is owned completely at this stage by the MOE. There is no direct private ownership interest in the transmission and distribution sector. The MOE, in conjunction with the World Bank, has indicated that it intends to privatise these two sectors, although no concrete steps have been taken

3 Recently, in an effort to ensure a more advantageous dispute resolution venue for international investors, Iraq joined the International Centre for the Settlement of Investment Disputes, which is a part of the World Bank.
in connection with it. Accordingly, other than as mentioned above with respect to the attempted privatisation of the collection of electricity tariffs, the only private sector involvement in transmission and distribution has been in the fulfilment, construction and implementation of MOE procurements orders.

In 2010–2011, the MOE conducted a tender for four independent power producer (IPP) projects in the generation sector, using GE Frame 9E turbines that had been recently acquired by the MOE (and which it was to sell to the winning bidders). The total of these projects combined was 2,750MW. However, owing to certain structural difficulties, in particular to do with the supply of fuels (the MOE did not want to assume the risks of supply and requested that the developers enter into separate supply agreements with the MOO), there was little or no international interest in these tenders. Accordingly, only local companies bid (with some international participation in the consortiums) and, with one exception, these bidders had no experience of the IPP sector. Shortly after the bids were analysed by the MOE’s IPP team, a new minister was appointed who was not in favour of these projects. He therefore cancelled the tendering process, and ran tenders to award these as engineering, procurement and construction contracts.

In late 2013, the Iraqi cabinet instructed the MOE to commence negotiations with three independent Iraqi companies to develop independent power plants in Iraq. In February 2014, the Iraqi cabinet passed resolution 90 of 2014, authorising the MOE to enter into power purchase agreements with these three companies, pursuant to which these companies were to develop up to 9,000MW. Some of the locations were allocated in the cabinet resolution. In particular, one of the developers was to develop a 3,000MW power plant in the Al-Rumailah area of the Basra Governorate, while another developer was to develop a 1,500MW power plant in the Besmaya area south of Baghdad (adjacent to a new real estate development project), subsequently extended to 3,000MW. In April 2014, two of the developers entered into heads of terms with the MOE and the National Investment Commission to develop combined cycle plants, which were followed in June 2014 with the execution by the MOE of power purchase contracts with these two developers.

In late 2015, two further projects were entered into with one developer. These projects, one of which is in Al-Rumailah and the other in Shatt Al-Basra, are somewhat uniquely structured. They involve the expansion of open cycle power plants to combined cycle power plants, with ownership of the open cycle power plants remaining in the hands of the MOE and ownership of the steam turbine portion of the plant remaining in the hands of the developer, with the developer operating the whole plant. This structure has many of the characteristics of a build-operate-transfer structure. Although negotiations have been completed with respect to these two projects, at the time of writing, there are various practical and technical matters that are still being discussed.

In late 2016, a fourth developer, Raban Al-Safina, entered into a power purchase contract to develop a 750MW combined cycle plant in the Maysan Governorate in Southern Iraq. At the time of writing, the developer has not yet identified the equipment to be used in this plant or the principal construction contractor.

From a regulatory perspective, key issues facing these projects include the following:

- There have been difficulties in transferring the land to the projects. Again, by way of background, the vast majority of land in Iraq is owned by the Iraqi Ministry of Finance (MOF), which has been somewhat reluctant to transfer land (even by way of lease) to
developers of various projects, including electricity projects. Other government entities have followed the lead of the MOF. This matter has proved to be a hindrance to private investment in Iraq in general.

Although a grid code has been developed by the MOE, which the companies have been willing to comply with, in practice this has not been tested by the private sector and it seems certain integrating difficulties are being experienced at the early stages of these projects.

The companies have covenanted to comply with the environmental laws and regulations in Iraq, which have generally been developed by the Ministry of the Environment. The process will entail the projects having to obtain environmental licences from the Ministry of the Environment, which grants these after conducting an examination similar to a Phase I environmental impact study. However, the Ministry of Environment is not very experienced in the electricity sector and has not developed specific regulations for this sector. In practice, therefore, at this stage, environmental compliance is still untested and, since the financing of these projects are not contingent on international project finance, one is not sure whether these projects would comply with the World Bank Group Environmental, Health and Safety Guidelines.

Learning from the experience of 2011, the MOE has assumed the obligation of providing fuels to these companies. The MOE is looking at ways of securing these fuels, including the natural gas that Iraq lacks. Although both the MOO and the MOE are experienced with respect to the laying out of pipelines (and have processes for usage of the land on which the pipelines may be located), difficulties could arise in particular due to the security situation in certain parts of Iraq. Certain difficulties have also arisen with respect to the supply of water, in particular with respect to the needs of steam turbines (in the combined cycle power plants).

The cabinet further approved the issuance by the Ministry of Finance of payment guarantees to the developers, which are the international norms for such power purchase contracts. These payment guarantees have been issued and, to date, they have been accepted by the lenders to these projects.

The tariffs were agreed between the cabinet and the developers, and therefore were not left for market forces. These tariffs were not divided into capacity charges and output related charges, but one tariff was agreed for the production of each of the simple cycle and the steam turbines productions. These tariffs have since become the benchmark, although there are new tenders in various stages of development that could impact these benchmarks.

As the first two projects are groundbreaking projects, the licensing processes have not been tested out and are not fully clear. The National Investment Commission established a one-stop shop mechanism to assist in moving matters forward, but this has not been successful. As a result, there have been substantial delays in every single step. Indeed, Iraqi bureaucracy is stultifying. For example, in discussing with international oil companies the difficulties that they face, near the top of the list is always the matter of obtaining visas. Whereas in most developed countries, the process for obtaining visas is a relatively simple process, the Iraqi Ministry of Interior intentionally makes things difficult, ostensibly for security reasons.

The first IPP in the electricity sector, in the town of Besmaya, near Baghdad, commenced production in the second quarter of 2017, and by the end of the year it was producing
approximately 1,500MW. The plant will produce another 1,000MW by mid-2018. Another power plant, in Al-Rumaila, Basra Governorate, will be producing another 1,000MW by the end of 2018.

As these new projects move forward and get implemented, Iraq would be faced with a significant portion of its power generation sector in private hands, and with the MOE paying significant sums for electricity under the various power purchase contracts. However, the transmission and distribution side of the grid requires significant upgrade to be able to receive the additional generated power. Accordingly, at this stage, the focus is on moving forward with the transmission and distribution side of the electricity sector.

There is significant potential for investment in the transmission and distribution side of the electricity sector; yet, at this stage, there is no regulatory framework for this. Accordingly, the MOE continues taking steps to improve its transmission grid, which it owns. The plans to privatise this sector have not been adopted, despite proposals introduced by international experts. As for the distribution sector, Iraq is still reliant on old technology, with little introduction of more modern technologies such as smart meters. Having stated this, in 2013, the MOE launched a pilot project for smart meters; but this was a pilot project that was not very clearly part of a structured plan.

At a time when Iraq is facing serious budgetary difficulties, the MOE tried unsuccessfully to launch tariff increases but had to withdraw them in some areas owing to political pressures. This leaves Iraq collecting very low levels of income from its electricity generation (with significant subsidies going to loss-making state-owned enterprises belonging to the Ministry of Industry and Minerals). In connection with the stand-by arrangements with the IMF, the issue of electricity tariffs and their collection is being addressed, as non-oil revenue is required to increase.

Coupled with this, the lack of natural gas and, due to the mature state of the refineries, limited availability of refined products, Iraq imports refined products and increasingly uses other less efficient products (such as heavy fuel oil) to fuel its generators. The imports of products such as diesel (which fuels a large number of small production generators) ends up exacting even more pressure on the state budget. Electricity, therefore, continues to be a major drain on the state budget.

### III The Ministry of Electricity – Kurdistan

The evolution of the electricity sector in the Kurdistan Region has been somewhat different. As it became apparent that the central government’s generation capacity was not going to meet sufficient demand in the areas under central government control, the KRG decided to develop its own generating capacity and, realising it had limited funding to do so, requested that the private sector do so. In addition, the KRG took over the existing grid and began to develop it. In doing so, it relied on the existing central government grid code and practices.

In 2007, the KRG entered into its first power purchase agreement with Mass Global, a private sector company owned by a reputable Kurdish businessman for the development of a 500MW plant in Erbil, which is the capital of the Kurdistan Region. Although this power purchase agreement was designed on a similar basis to international standards, its terms were more favourable to the developer. As the power plant was implemented quickly, the KRG entered into two other power purchase agreements, each for 500MW, with the same company to develop generation plants in the other two major Kurdish cities – Suleymaniyah and Dohuk. As these plants were also set up quickly, it became apparent that demand had increased and therefore the capacities of each of these plants was significantly increased. At
the time of writing, the International Finance Corporation acquired from Mass Global a portion of the project company operating the Suleymaniyah power plant. In addition, the KRG entered into power purchase contracts with other developers more recently.

The critical issue for the development of these plants was that the KRG assumed responsibility for bringing natural gas to these plants, and it did so from one of the undeveloped natural gas fields in the Kurdistan Region, the Khor Mor field. Lacking money, it entered into development arrangements with a Sharjah-based company, Dana Gas, in order to develop the fields. Dana Gas carried out the development and was able to supply, through self-funded pipelines, the natural gas to the various power plants. This was one of the success stories of the KRG, in that not only were untapped gas deposits utilised but they were done so to bring power to the Kurdistan Region, which currently has 24 hours of electricity a day. However, a dispute arose between Dana Gas and the KRG, which went to arbitration, and in November 2015, Dana Gas was victorious in the arbitration and was awarded approximately US$2 billion in damages. In addition, due to the budgetary difficulties faced by the KRG, owing to its dispute with the central government (over the division of oil revenues) and lower oil revenues in general, the KRG has begun to default on certain financial obligations. It is unclear how that will impact on its obligations under the power purchase contracts, as well as its ongoing relationship with the gas suppliers.

III THE IRAQI OIL SECTOR

i The Ministry of Oil

In federal Iraq, Iraq’s Ministry of Oil administers the oil sector. Under the Constitution, Iraq’s oil belongs to the people of Iraq. With respect to the upstream sector, the constitution provides that existing fields will be managed by the federal government, whereas new fields will be jointly operated by the federal government and the regional governments – and in the event of dispute, it is the regional government that has the decision-making powers. Accordingly, with respect to new fields in the Kurdistan region, the KRG’s interpretation is that it has the power to manage fields. The constitution goes further and provides that exports are to be coordinated by the central government’s apparatus (i.e., the State Organisation for Marketing Oil (SOMO)). Relying on this interpretation, the KRG passed an oil law in the Kurdistan region, providing that the KRG can enter into production-sharing agreements with international oil companies developing and operating new fields in Kurdistan. The agreement between the central government and the KRG at the time was that the oil being produced in the KRG would continue to be marketed and sold by SOMO, and that the central government would pay an agreed share of the expenditures in the budget to the KRG. Over the past few years, there continued to be disputes between the KRG and the central government over the appropriate payments to the KRG in the budget, and therefore, with the exception of a short period in late 2014–2015, this budget agreement has not been implemented. The KRG has therefore continued to export oil through the pipeline in Turkey. After the Islamic State took over large areas of Iraq in 2014, the Iraqi government pipeline to Turkey was damaged and stopped exporting oil. It had been used to export oil from the Kirkuk fields. The Islamic State was expelled from certain areas around the fields of Kirkuk, which fields were taken over by the KRG. As a result, an agreement between the central government and the KRG was reached allowing the KRG to export oil from Kirkuk and keep the majority of its revenues, together with the revenues from the oil produced in fields in the Kurdistan region. This agreement was changed in 2017 (see Section I.v, above).
The Ministry of Oil, which administers the oil sector, is divided into a number of directorates and companies. The Ministry is run by a Minister, who has four deputies (production, refinery, gas and distribution). The upstream oil fields are each administered by an oil company that is owned by the Ministry. Therefore, for example, the oil fields in Basra are administered by the Basra Oil Company. With respect to the other sectors, for example, the refineries sector, again the refineries are owned by government-owned companies, with ultimate control residing with the deputy minister of oil for refining, reporting to the Minister of Oil.

In 2009, the Ministry of Oil commenced a series of bidding rounds for technical services agreements to develop the oil fields under its control. A number of IOCs won these bidding rounds and entered into technical services contracts with the relevant government-owned oil company administering the relevant fields. The bidding rounds and the administration of the technical services contracts are carried out by the Petroleum Contracts and Licensing Department.

As for gas, the Ministry of Oil carried out a two-pronged approach. Three gas fields were awarded to bidders under the bidding rounds, although two of the fields were in territories that fell under the control of the Islamic State, leading to their abandonment. These areas have since been captured by the government and the government is considering new approaches to the development of these fields. As for the oil fields, the Ministry of Oil, through the South Gas Company, entered into a joint venture with Shell and Mitsubishi (called the Basra Gas Company) to capture and treat associated gas from three fields – Rumailah, West Qurna I and Zubair. The gas produced by the Basra Gas Company is currently being sold to the Ministry of Electricity. The Ministry of Oil is currently considering other approaches for the capturing of associated gas in other fields.

With respect to refineries, the Ministry of Oil carried out and continues to carry out a series of policies. Unfortunately, one of its main refineries (Beiji) fell to the Islamic State and was recaptured in late 2015 (having been badly damaged). Steps are being taken to rehabilitate it although this may take significant time and costs. The Ministry, in reliance on Law No. 64 of 2007 (as amended), which addresses investment in oil refineries, entered into two agreements with private companies (in Maissan governorate and Kirkuk governorate). To date, actual work has not commenced on these projects. The Ministry also embarked on a new 150,000 barrels per day refinery near Karbala, owned by the Ministry, which is currently in the construction phase and is expected to be completed in 2021. Once completed, this refinery would significantly reduce Iraq’s imports of refined products.

At the time of writing, the Iraqi parliament passed a law establishing the Iraqi National Oil Company (INOC). The company is expected to become operational in late 2018. INOC is mainly focused on the upstream oil sector and will become the owner of the various government-owned upstream oil companies, as well as SOMO. It is intended that INOC will become independent of the Ministry of Oil, although the legislation provides for significant controls by the council of ministers.

**ii Energy markets**

*Development of power markets and contracts for sale of power*

At the time of writing, with limited exceptions discussed below, electricity in Iraq is provided by three types of providers – the MOE, one independent power producer and private unregulated owners of generators scattered across the country. The MOE’s supply was discussed above and, owing to the fact that it cannot supply electricity 24 hours a day across
the country, there are thousands of private owners of generators who have developed their own neighbourhood grids. These private owners of generators are unregulated and therefore they do not comply with any of the government-imposed regulations. Owing to the general security breakdown in the country, and coupled with the fact that the central government has not been in a position to provide electricity 24 hours a day (especially in the hot summer months), the government has allowed these private generator owners to carry out their unregulated neighbourhood activities. Generally, there is no uniform pricing mechanism for these private owners, but through conversations with these private participants, it seems that after covering their costs (maintenance and diesel costs), they are making profit margins of 30–40 per cent. The suppliers of diesel are also making similar profit margins, as the risks of supply are significant.

In addition to the above, there is effectively a third limited producer of electricity in federal Iraq: the international oil companies who are producing electricity for their own use. Since these fields have not developed completely, electricity production has not reached its capacity. Under the technical services agreements between the international oil companies with the companies belonging to the MOO, the plants are owned by these government-owned companies (such as the South Oil Company), with the power produced only being used in the relevant oil fields. Although this is not necessarily ideal or efficient, the grid between oil fields is not well developed or integrated, and therefore electricity production is limited to the individual field where such generation plants are located. Again under the relevant technical services agreements, the government counterparty is required to provide electricity or to reimburse the international oil companies for the costs of electricity production. The costs have been relatively high because the international oil companies have been using smaller diesel generators. The regulatory framework for this electricity generation has been very limited, and the MOE is not involved in these activities as its grid is not used. The only regulations applicable are environmental, but these are not applied uniformly.

As for the main power suppliers who have entered into power purchase contracts with the MOE, as indicated above, these companies are not allowed to sell their production other than to the MOE (as buyer under the power purchase contracts). As generation capacity increases over the next few years, it is anticipated that this may change. In the Kurdistan Region, the matter is slightly different. As other private plants have emerged, the KRG is only committing to purchasing a minimum percentage of generated electricity, and the developers are allowed to supply power to third parties, including the international oil companies developing the fields in the Kurdistan Region. The problems with this are mainly related to the grid, as it is still relatively undeveloped and there are technical difficulties in the private sector development. Independent electricity producers in the Kurdistan region commenced supplying power to liberated areas, like the city of Mosul.

**Budgetary impacts**

The reduction in the price of crude oil in 2014–2015 caused major budgetary problems in Iraq, and therefore certain existing obligations of the state were delayed or amended. For example, there has been speculation that the structure and terms of the technical services agreements between the international oil companies and the MOO may be amended. Moreover, the delays in the development of the oil fields may cause the collection and treatment of the associated gas from the oil fields to be delayed. At the time of writing, however, and based on discussions with personnel from the MOO, the South Gas project with Shell Oil (to gather and treat the associated gas from several giant oil fields) is still on track.
Security situation

The deterioration in the security situation, especially in the western desert areas of Iraq, has caused delays in the development of some of the gas fields in the areas, such as Akkaz. Moreover, the strategic pipeline project to Jordan has also been delayed owing to the fact that there are large tracts of land not under government control.

Additional borrowing

In light of the budgetary constraints in 2015 and 2016, Iraq may begin entering into loans and other types of borrowing in the international financial markets. In addition, various ministries including the MOE may enter into vendor financing agreements for the supply of equipment, in particular for the transmission grid. At the same time, owing to the difficult environment in Iraq (legal, regulatory and security), traditional project finance may not be available and accordingly non-traditional forms of financing would be required to be made available (or more aggressive lenders, such as Chinese financial institutions).

IV  RENEWABLE ENERGY

The Iraqi renewable energy sector is still in its infancy, without any significant renewable energy projects in place. At the time of writing, the MOE intends to enter into agreements with two sets of developers for a total of 100MW. The basis of these new contracts are still being negotiated.

V  CONCLUSIONS AND OUTLOOK

The Iraqi electricity and oil sectors have significant opportunities. However, there are current obstacles – legal, regulatory and financial (as well as the lack of natural gas and refined products) – that can delay the development of the electricity and oil sectors in Iraq. Coupled with the above is the significant corruption that exists, which makes it reasonable to conclude that development would move at a measured pace.
Chapter 17

ITALY

Andreina Degli Esposti

I OVERVIEW

This Overview is drafted on the grounds of the analysis of the Italian Regulatory Authority for Energy, Networks and Environment (ARERA) Annual Report for 2016. The ARERA Annual Report for 2017, which provides relevant information concerning the energy market, has not yet been published. As reported by the Authority, the forthcoming Annual Report is expected for June 2018. For this reason, the present work will not deal with operations (e.g., mergers and acquisitions) that took place in the market in the past year.

In 2016, Italy’s gross domestic product increased by about 0.9 per cent (in 2015 it had grown by 0.8 per cent), and the demand for electricity and gas followed the same trend.

With regards to the electricity market, we have witnessed a decrease in both demand (by almost 2.1 with respect to the demand registered in 2015) and net imports (50.8TWh in 2015 and 43.2TWh in 2016). On the contrary, there was an increase in exports (by almost 37 per cent).

With reference to the analysis of individual sources, in 2016 there was a sharp decline (i.e., 10 per cent) in the use of coal, owing to the obligation to close coal-fired power stations.

In relation to renewable energy sources the Energy Services Manager (GSE) received €15.9 billion for the incentivisation of green energy. Furthermore, Italy reached the target set by the European Union on the percentage of final electricity consumption generated from renewable sources (17.1 per cent), surpassing this goal in 2015 (17.5 per cent) and again in 2016 (17.6 per cent).

The number of sellers in the end-user market has been expanding since 2008. As in the previous years, in 2016, the safeguarded service declined in terms of both the power supply and the number of customers served, to the advantage of the free market. The switching activity was also lively.

The gross domestic consumption of natural gas rose by around 5 per cent, as well as the net imports, with respect to the same consumption that was registered in 2015.

The drop in the use of coal led to a 5 per cent increase in the profitability of natural gas during 2016.

However, the downward trend of the production of natural gas still continued. Therefore, since the increase in imports was higher than the consumption, the level of dependence on imports from abroad grew.

1 Andreina Degli Esposti is a founding partner of Studio Legale Villata, Degli Esposti e Associati.
Differing from the previous years, in 2016 the number of companies that operated in the wholesale market did not grow despite the fact that the gas volume sold by them in said market increased.

In the markets managed by the Energy Market Manager (GME), we have observed transactions of the amount of around 47.5 TWh, in line with transactions that were executed in 2015.

As well as sales (whose growth increased in comparison with 2015), the number of active vendors on the final market of the industry recorded a significant rise.

Looking exclusively at the sales on the free market, the sectoral volumes showed a marked rise in domestic electricity consumption. On the other hand, as well as in 2015, very marked losses in terms of both customers and volumes were recorded on the safeguarded market.

II  REGULATION

i  The regulators

The energy market is regulated by the entities given below.

Ministry of Economic Development

Organised in four different departments, the Ministry of Economic Development (MISE) is responsible for all the authorisation procedures of state competence and for the enforcement of all statutes and regulations concerning the energy sector. Within the Energy Department of the above-mentioned Ministry, a very important role in the energy sector is performed by the Commission on Hydrocarbon and Mineral Resources, which carries out an advisory function for all activities connected with the research, production and exploitation of hydrocarbons.

Regulatory Authority for Energy, Networks and Environment

The Italian Authority for Energy, Gas and Water (AEEGSI), introduced by Law No. 481 of 14 November 1995, was transformed into the ARERA by Law No. 205 of 27 December 2017, which has also given the Authority regulatory tasks in the waste sector.

Aside from its main regulatory functions of protecting the interests of consumers, promoting completion and ensuring efficient and profitable services (it defines the tariff-system for the use of infrastructure, ensures free access to the gas and electricity grid and promotes investments through incentives), the ARERA also plays a supervisory role (it is granted the power to impose administrative sanctions in cases of non-compliance with its provisions, aimed at ensuring the transparency of service conditions and promoting the rational use of energy).

To fulfil these activities, the ARERA is supported by the Antitrust Authority to ensure the implementation of the rules on free competition in the energy market.2

---

Furthermore, the ARERA plays an advisory role to the parliament and may issue proposals and reports (see the report published annually about the state and the activity of the energy supply sector).³

**Compensation Fund for Energy and Environmental Services**

The Compensation Fund for Energy and Environmental Services is an economic public body established through Article 1, Paragraph 670, Law No. 208/2015. It collects certain tariff components payed by the industry operators, which are then stored in management accounts in favour of the businesses.⁴

**Energy Services Manager**

The GSE is a public limited company, established by Legislative Decree No. 79 of 16 March 1999, with the function of promoting renewable energy sources in Italy, mainly through the distribution of economic incentives and information campaigns aimed at spreading the culture of environmental protection in the energy field.⁵

**Energy Market Manager**

The company GME, wholly owned by the GSE, was established by Legislative Decree No. 79 of 16 March 1999. It is responsible for organising and managing the electricity, natural gas and environment markets, respecting neutrality, transparency, objectivity and competition criteria.⁶

### ii Regulated activities

With regards to the electricity market, its deregulation arose after the approval of Legislative Decree No. 79 of 16 March 1999, which established that the production, importation, exportation, purchase and sale of electricity are completely free.

The transmission and dispatching of electricity, however, continue to be under the monopoly of the state. More specifically, while a single operator (Terna SpA) runs long-distance energy transmission, the distribution of electricity to consumers was deregulated and carried out by several operators. Regardless, the distribution was given under concession to a single operator (a natural monopoly).⁷

As for the gas market, deregulation was achieved as a result of Legislative Decree No. 164 of 23 May 2000 (Letta Decree), which recognised that no licence is generally required for the production, import and sale of natural gas. Storage, transport and distribution activities are operated under a concession regime.

---


⁴ E Picozza, S Sambri, op. cit., p. 155.

⁵ E Picozza, S Sambri, op. cit., p. 165.

⁶ E Picozza, S Sambri, op. cit., p. 176.

⁷ Legislative Decree No. 79 of 16 March 1999.
The development and construction of new facilities (e.g., transmission lines, power plants and gas storage facilities) require prior authorisation under state and regional legislation, in order to ensure compliance with, *inter alia*, health and safety standards, environmental protection and existing infrastructure.\(^8\)

### iii Ownership and market access restrictions

There are no restrictions on ownership of new and existing assets, service providers or licence holders. The only ones are those – in relation to mergers and acquisitions – that antitrust authorities may impose on operators in order to comply with competition rules.

### iv Transfers of control and assignments

By Decree-Law No. 21 of 15 March 2012, Italy issued an innovative framework describing the intervention powers reserved to the state in the case of corporate transactions involving businesses operating in the energy sector.

Specifically, the Decree establishes that any decision, act or measure taken by a company owning one or more national interest energy networks (i.e., any changes in the ownership, control, use or availability of energy assets, the merger or demerger of the company, the transfer abroad of its registered office, the change in the company objects, the dissolution of the company and the transfer of whole or parts of the company) must be notified within 10 days to the Presidency of the Council of Ministers.

Within 15 days of the notification, the government may veto the aforementioned decisions, acts and measures, if they constitute an exceptional threat of serious prejudice to national interests. Once this period has passed, the operation can be carried out.

Finally, in the event of purchases of shares of the aforementioned companies by a non-EU person or body, the condition of reciprocity is to be respected.

### III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

#### i Vertical integration and unbundling

The unbundling obligations on vertically integrated energy operators represent one of the main regulatory instruments adopted by Italy in order to impose impartiality and neutrality in the management and development of the energy infrastructure network, which is a natural monopoly market system (the ‘essential facility’).\(^9\)

With regard to the electricity transmission grid, Legislative Decree No. 93/2011 has imposed the independence of the transmission system operator in terms of its organisation and decision-making powers from other activities (generation, distribution and sales).\(^9\)

With reference to the gas transportation pipeline, in 2013, the ownership unbundling model (OU system), managed by the operator Snam SpA, was introduced\(^10\) as certified by the ARERA via Resolution No. 515/2013.

---

\(^8\) Legislative Decree No. 164 of 23 May 2000.

\(^9\) The transmission system operator Terna SpA was declared compliant with the OU model on 5 April 2013 (see ARERA Resolution No. 142/2013/R/eel).

\(^10\) Eni SpA currently owns 8 per cent of the capital.
The electricity and gas distribution is regulated as a territorial monopoly, meaning that a public tender for the concession of the distribution service to a single operator in each minimum geographical area must be held.

However, in the electricity sector, such tenders shall start no earlier than 2030, because of the legislation aimed at restricting the service to the current operators (Enel Distribuzione and other companies), on the basis of the concessions issued by 31 March 2001 by the MISE, which are valid until 31 December 2030.

In the gas sector, the Letta Decree (Legislative Decree No. 164/2000) gave local authorities the power to award the service through public tenders for a maximum of 12 years after the ending of the transitional period, during which the current concessions shall remain in force.\(^{11}\)

By Resolution No. 296/2015/R/com, the ARERA has eventually imposed upon electricity and gas distribution network providers both the functional separation (unbundling) and the separation between brand and communication policy (debranding), as well as the integrated information system for the provision of commercially sensitive information.

## ii Transmission/transportation and distribution access

All network operators must ensure that any interested service provider has access to the transmission and distribution networks of gas and electricity. At the same time, the third-party access (TPA) must not affect the continuity and safety of the transmission and distribution service.

With reference to the electricity sector, the ARERA issued the ‘integrated text of active connections – technical and economic conditions for the connection to electricity grids with the obligation to connect third parties’,\(^{12}\) which is valid for both the transmission and distribution networks.

Moreover, pursuant to the Decree of the President of the Council of Ministers dated 11 May 2004, on 1 November 2005 the Terna Grid Code came into force, with prior approval by both the ARERA and the MISE.\(^{13}\)

Furthermore, the ARERA has established an alternative disputes resolution (ADR) procedure by Resolution ARG/elt 123/08, which provides that the ARERA shall decide on disputes over rights of access to the network. This ADR system is currently regulated by Resolution 188/2012/e/com.

With reference to the gas sector, the ARERA has approved the Snam Network Code\(^{14}\) and the Network Type Code\(^{15}\) as a reference model applicable to all operators of distribution networks.

Finally, it is also noteworthy that Law No. 239/2004 has exempted from TPA all private operators that promote investments on the network, in order to enable them to carry out trading activities through the infrastructure use (the ‘merchant lines’).

---

\(^{11}\) At present, only the municipality of Milan has concluded the public tender and the service has been awarded to A2A. In the other municipalities, public tenders are still ongoing. For this reason, in respect of Law No. 96/2016, MISE could take over the responsibility in order to conclude the said public tenders, carrying out the reform that started with the Letta Decree.

\(^{12}\) See ARERA Resolution No. 99/2008.

\(^{13}\) See ARERAI Resolution No. 79/2005.

\(^{14}\) See ARERA Resolution No. 75/2003.

The Ministerial Decree dated 21 October 2005 sets forth the competitive criteria for the granting of the exemption, which are evaluated by the MISE. However, the European Commission carries out the final assessment.

iii Rates
In accordance with a pro-competition regulatory strategy, the ARERA predetermines the rates for transmission/transportation and distribution of electricity and gas through a pricing mechanism based on a balance between the several interests at stake (network maintenance, promotion of investments, safety and efficiency of the network, environmental protection and accessible costs for the customers).

With respect to the electricity market, on 23 December 2015 the ARERA adopted the ‘Pricing Regulation on transmission, distribution and metering of the electric power, for the period 2016–2023’ (Deliberation No. 654/2015/R/eel).

As regards the gas market, through Deliberation No. 575/2017/R/gas on 3 August 2017, the ARERA issued the ‘Pricing criteria for the rates of transportation and dispatching of natural gas for the transition period 2018–2019’.

Moreover the ARERA approved the tariff regulation for the gas distribution service, whose validity was extended until the end of 2019. The distribution and metering tariff is aimed at guaranteeing the coverage of distribution service costs (VRD). In particular, the VRD covers:
\[\begin{align*}
a & \text{ the centralised investments in fixed assets;} \\
b & \text{ the amounts invested in each distribution area; and} \\
c & \text{ the operating costs related to distribution.}
\end{align*}\]

Furthermore, Law No. 290/2003 introduced a price cap incentive. This mechanism has imposed a profit restriction based on the harmonised rate of growth of consumer prices for a certain number of years. Within the boundaries of this restriction, each operator is free to determine the rate.

iv Security and technology restrictions
Legislative Decree No. 61/2011 sets forth the criteria for the identification of European critical infrastructure. In the energy sector, such infrastructure are then concretely identified by the MISE.

A fundamental element for the security of electrical infrastructure is to ensure the continuity of the service, measured by the 'energy not supplied' indicator.

The regulation of the quality of the natural gas transportation service in terms of security, continuity and commercial quality in the period 2018–2019 is governed by Resolution No. 43/2018/R/gas of 1 February 2018. Furthermore, Part I of the Consolidated Law on ‘Regulation of the quality and the tariffs of distribution and gas metering services over the period of 2014–2019’ regulates certain activities relevant to the safety of the gas

---

16 See ARERA Resolution ARG/gas 159/08.
17 See ARERA Deliberation No. 573/2013/R/gas, updated by Deliberation No. 774/2016/R/gas.
18 See ARERA Resolution No. 574/2013/R/gas.
distribution service. Such regulation is intended to minimise the risk of explosions and fires caused by the gas distributed, and therefore its ultimate goal is to protect people and property from damages due to accidents caused by gas.

In addition, by Resolution No. 255/2015/R/eel of 29 May 2015, the ARERA has taken the first steps for the regulation of the cyber security of the 'smart grid' (intelligent distribution network). The ARERA is participating in a workgroup organised by the Council of European Energy Regulators, specifically set up in order to better identify the boundaries of this topic and the role played by the regulators. Other institutions are responsible for the cybersecurity of the country. In particular, following the approval of a cyber security national programme by the Committee for the Security of the Italian Republic, in February 2017 the President of the Council of Ministers has granted a Decree containing the strategic measures for cybersecurity and national data protection.

In February 2018, the Italian government published a draft decree with the aim of transposing the European Directive No. 1148/2016 (Network and Information Security – NIS) that is still under approval by the Parliamentary Commission. The main purpose is to adopt a national strategy of cybersecurity managed by the President of the Council of Ministers.

IV ENERGY MARKETS

i Development of energy markets

As previously mentioned, the GME manages the Italian energy market (the Italian Power Exchange, or IPEX) on which electricity is sold and bought wholesale.

More specifically, the GME organises and manages:

- the Forward Electricity Market;
- the Daily Products Market in which continuous negotiations take place;
- the Day-Ahead Market, organised in the form of auctions; and
- the Intraday Market, with auctions, divided into five sessions.

On behalf of the Italian grid operator (Terna SpA), the GSE also manages both the Ancillary Services Market through which it collects offers and communicates the results, as well as a platform registering the transactions carried out over the counter. On this platform, the parties that have concluded contracts outside the IPEX register their trade obligations and set forth the relevant electricity input and output plans, committing to perform these contracts.\(^19\)

With the entry into force of Law No. 99 of 23 July 2009 (laying down provisions for the development and internationalisation of companies, as well as relating to energy), the GME was entrusted with the organisation and economic management of the natural gas market on an exclusive basis. The GME gas markets include:

- the natural-gas trading platform (P-GAS);
- the natural-gas market (MGAS); and
- the natural-gas balancing platform (PB-GAS)\(^20\).

---

\(^{19}\) See Article 5 of Legislative Decree No. 79 of 16 March 1999.

\(^{20}\) The PB-GAS market has been suspended since October 2016 by ARERA Resolution No. 312/2016.
ii Energy market rules and regulation

The Italian Power Exchange is regulated by the Decree of the Ministry of Economic Development approved on 19 December 2003 (as subsequently amended by several Ministerial Decrees – the last one approved on 21 September 2016 – as well as by the ARERA Opinion No. 8 of 26 May 2009).

The gas markets are regulated by the Decree of the Ministry of Economic Development approved on 6 March 2013 (as subsequently amended by the Ministerial Decrees approved on 13 March 2017 and 18 December 2017).

The electricity markets, M-GAS, P-GAS and PB-GAS each have their own market and technical rules. The market rules include the criteria and procedures for the admission of new participants, the trading and settlement rules, as well as the sanctions and sanctioning procedures in the event of a breach of market rules. The GME is generally responsible for the oversight of market operations, as well as for the enforcement of market rules.21

iii Contracts for sale of energy

Regarding the market at wholesale level, bilateral contracts for the sale of electricity and gas – which must be in compliance with the technical requirements provided by the GME – are not subject to restrictions.

At the retail level, since 2007 (for electricity) and 2003 (for gas), all customers can freely enter into contracts for the purchase of gas or power from sellers that meet certain minimum requirements.

Given that the power and gas sellers must comply with certain specific rules on transparency and fairness of information to customers, under the supervision of the ARERA, each user is essentially free to choose the energy seller that applies the best contractual and tariff conditions in relation to its individual case (the ‘free market’).

However, Law No. 124/2017 provides the possibility for consumers to avail themselves of the safeguarded market for the supply of electricity and gas until 1 July 2019 (entering the ‘free market’ into force; see below). This market guarantees the application of the prices laid down by the AEEGSI, which updates the reference values used to calculate the rates applied to residential and non-residential consumers each trimester.

iv Market developments

The Annual Competition Law No. 124 of 4 August 2017 introduced a retail reform in the electricity and gas sectors with the aim of ensuring competition and the plurality of Suppliers and Consumers in the free market.

Indeed, starting from 1 July 2019, user protection will no longer be based on administrative price control exercised by the relevant Authorities.

The main purpose of the abovementioned regulation can therefore be identified in the progressive elimination of the price protection regime in order to promote competitive dynamics. During the transition period, users can operate in the safeguarded market.

---

21 See the Decrees of the Ministry of the Economic Development approved on 19 December 2003 and 6 March 2013 as last amended by, respectively, the Ministerial Decrees dated 21 September 2016 and 18 December 2017.
The success of the reform of the free market will depend on the adoption of appropriate measures provided by Competition Law, including:

a. the creation of a web portal for the collection and publication of suppliers offers;
b. the obligation for sellers to formulate a variable-price and a fixed-price offer;
c. the adoption of guidelines by the Authority aimed at facilitating the aggregation of small consumers and the creation of purchasing groups; and
d. the obligation for suppliers to provide adequate information to consumers and a high level of disclosure.

The regulation on the matter at hand is still in progress as the Ministry of the Economic Development and the ARERA will have to issue multiple directives and resolutions to coordinate the transition to the free market.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

In 2017, legislation modified the legal framework on renewable energy.

Firstly, Law Nos. 96/2017 and 124/2017 amended Decree No. 28/2011 regarding the promotion of renewable energy. In particular, the abovementioned regulations replaced the suspension of the incentive tariff with a reduction of 20 per cent and 30 per cent, respectively, to photovoltaic plants with a power higher than 3kW and to those between 1kW and 3kW that are not in possession of certificates necessary to utilise the said tariff.

The same Law No. 96/2017 allowed for wind plants, previously not permitted to utilise incentives owing to the incorrect registration of the plants, to obtain the incentives provided by the MISE Decree dated 6 July 2012.

By Law No. 205/2017, the legislation consented to use, until the end of 2021, incentives provided by paragraphs 150 and 151 of Law No. 208/2015 for biomass, biogas and bioliquid plants that will cease to benefit from incentives by 31 December 2018.

Law No. 205/2017 also modified GSE’s sanctioning powers provided for by Article 42 of Law No. 28/2011. In particular, if relevant violations occurred during an inspection, instead of the incentives’ forfeiture, GSE will reduce them within the range of 20 per cent and 80 per cent in accordance with the level of the violation. By a decree expected to be issued in seven months, MISE will identify said relevant violations in order to apply the abovementioned rule.22

Lastly, MISE in accordance with the Ministry of Environment, has recently approved a draft of the new decree regarding incentives for electricity produced by renewable sources for the period 2018–2020. Said incentives would no longer be provided for by direct access but through registration and auction mechanisms.

ii Energy efficiency and conservation

The Italian efficiency incentive system comprises a variety of mechanisms.

In particular:

22 By Order Nos. 216, 217, 218, 219, 220, 221 and 222, dated 19 January 2018, the Council of State has temporarily suspended GSE’s forfeitures provided before the entry into force of Law No. 205/2017.
In the energy saving sector, ‘White Certificates’ certify the achievement of energy savings through energy efficiency initiatives and projects. Law No. 205/2017 has modified Article 14 of Legislative Decree No. 102/2014 to extend until 31 December 2018 incentives granted to large projects of energy efficiency (no more than 35,000 tonnes of petrol per year) whose White Certificates had expired prior to 2014, if they will initiate activity by 31 December 2018.23

The Ministerial Decree of 16 February 2016 has improved the energy efficiency and the thermal energy production from renewable sources by a mechanism of incentives managed by GSE. The beneficiaries of incentives are the public administration, private companies and individuals that could access the €900 million government fund yearly.

Law No. 205/2017 has extended the duration of tax deductions for energy redevelopment projects up to 31 December 2018. Through this incentive mechanism, building owners can deduct 65 per cent of the expenses, whereas apartment owners can deduct 70 per cent.

By Article 15 of Legislative Decree 102/2014, the legislation established under the MISE the National Fund for Energy Efficiency in order to promote the actions needed to reach targets for national energy efficiency through a mechanism of co-working between European and Italian financial institutions and private investors. Said Fund is governed by an Interministerial Decree dated 22 December 2017.

iii Technological developments

Following the smart-grid pilot projects carried out by several operators in Italy since 2011, the MISE recently established a state-aid programme aimed at supporting investments for the construction of intelligent electricity distribution networks.

The aforementioned ministerial decree provides the legal framework for all national or regional administrations that intend to make public investment tenders, in order to promote the upgrading and optimisation of the electrical network in the assisted areas of the country. Indeed, through the recent award of the public tender provided by the Ministerial Decree of 20 March 2017, E-Distribuzione SpA could benefit from €80 million in order to finance 21 smart-grid projects in the south of Italy (in Basilicata, Calabria, Campania, Puglia and Sicily).

As for second generation smart metering (2G) (i.e., the systems that enable the remote reading and control of electricity, gas and water meters), in the electricity sector the ARERA has recently approved the recognition of costs for low voltage electricity metering, in addition to commissioning provisions25 and functional specifications.

In the gas sector, the ARERA has finally updated the commissioning requirements of smart gas meters up to 2018.26

23 By sentence Nos. 1316 and 1317 in 2018, the Regional Administrative Court of Lazio has upheld many Energy Service Companies’ appeals against acts of the GSE that denied the issuance of White Certificates for projects of energy efficiency realised by biomass plants. GSE should return the White Certificates to said companies for a value of around €270 million.
26 See ARERAResolution No. 554/2015/R/gas.
VI THE YEAR IN REVIEW

The key developments in energy legislation in 2017 include:

a Law No. 96 of 21 June 2017, which allows incentives for photovoltaic and wind plants (see Section V.i, above);

b Law No. 124 of 4 August 2017 (the Annual Competition Law), which allows incentives for photovoltaic plants (Section V.i, above) and introduces the legal framework of the free market (see Section V.i, above);

c Law No. 205 of 27 December 2017 (the 2018 Budget Law), which introduces modifications to the powers of the Authority (see Section II.i, Regulatory Authority for Energy, Networks and Environment), GSE’s sanctioning powers (Section V.i, above), incentives for renewable energy plants and energy efficiency projects (see Section V.ii, above);

d Interministerial Decree 22 December 2017, which governs the National Fund for Energy Efficiency;

e MISE Decree dated 21 September 2016, amending the rules on the energy market; and

f MISE Decree dated 18 December 2017, amending the rules on the gas market.

VII CONCLUSIONS AND OUTLOOK

In conclusion, to look at the development prospects of the energy market, it is necessary to refer to the MISE Decree dated 10 November 2017 on the National Energy Strategy (SEN). It concerns the 10-year development plan of the Italian government and has the purpose of anticipating and managing future changes to our energy system.

The SEN intends to make our national energy system much more:

a competitive, in particular through the reduction of the gap between the price and costs of the energy in comparison with the European price and costs;

b sustainable, by the decarbonisation process defined by the EU; and

c safe, with regard to supply and flexibility of the systems and infrastructures.

The targets provided by the SEN are:

a energy efficiency, with a final consumption saving of approximately 10Mtep in 2030;

b renewable sources, with 28 per cent of the total energy consumption in 2030 through renewable energy;

c reduction of the gap between the national energy price and the European price both in the electricity and gas sectors;

d termination of electrical energy production from carbon;

e decarbonisation in order to reduce the emissions level to 39 per cent in 2030 and to 63 per cent in 2050;

f increasing the investments in clean energy research and technological development by €444 million by 2021; and

g reducing the energy dependency on foreign countries from 76 per cent in 2015 to 60 per cent in 2030.

The achievement of such objectives presumes the fulfilment during the transition period of some necessary conditions; for example:

a the improvement of infrastructure and simplification of regulatory models;

b the reduction of transition costs through technology and efficiency;
c the compatibility with the protection of the landscape and environment; and

d the generation of positive employment effects by the implementation of plants powered by renewable sources.

In conclusion, the SEN has set out very ambitious and complex goals that may only be achieved through an efficient governmental policy, in addition to an increased public awareness on energy sources.
Chapter 18

JAPAN

Reiji Takahashi, Norifumi Takeuchi, Wataru Higuchi, Kunihiro Yokoi, Kunitaro Yabuki and Kei Takada

I OVERVIEW

Japan is a country with limited natural energy resources and as such, energy legislation in Japan can essentially be divided into legislation concerning electricity and that concerning gas.

Given the high level of public interest attached to the provision of electric utilities, certain market entry regulations have long been in place. However, because of the Great East Japan earthquake and the subsequent accident at the Fukushima Daiichi nuclear power plant, government energy policy is currently in the midst of vast and rapid structural change. As of 31 March 2018, all nuclear power plants, except for five, are currently under suspension in Japan and over recent years other measures to secure alternative resources (including increasing the supply of renewable energy sources and traditional thermal power), conserve existing energy supplies and increase local energy production have been discussed concurrently with a review of the current industry regulations. As a result, the current legislation is in a transitional phase. There are three headline changes affecting the regulation of electricity markets. Firstly, under the Electricity System Reform programme, entry into the electricity retail business was fully liberalised as of 1 April 2016. In preparation for this, a new regulatory authority for monitoring the new liberalised market was established in 2015. Secondly, the legal unbundling of the electric power transmission function and sector from the existing dominant power suppliers will be implemented in 2020. In addition to these two changes, feed-in tariffs (FITs) were introduced in 2012 and the renewable energy market has been rapidly expanded since then. In response to rapid expansion of the renewables market, the FIT system has been continuously revised to address several problems.

The gas industry in Japan can be divided into the following two major enterprises: the town gas industry, which is the primary source of natural gas to consumer residences through piping; and the liquefied petroleum gas (LPG) industry, which provides LPG via cylinders to consumers in areas where piped gas is not yet available. Significant reform liberalising the town gas retail business was implemented on 1 April 2017. As a result, subcategories of the town gas-related business was reorganised and entry into the retail gas business has been relaxed (i.e., only registration is required). Entry into the LPG industry requires registration with the relevant authority, and the prices for the provision of LPG may be freely set by the provider.

---

1 Reiji Takahashi, Norifumi Takeuchi and Wataru Higuchi are partners, Kunihiro Yokoi is a special counsel, and Kunitaro Yabuki and Kei Takada are associates at Anderson Mōri & Tomotsune.

© 2018 Law Business Research Ltd
The energy industry in Japan, which encompasses electric power, gas and other energy resources, is regulated by the Ministry of Economy, Trade and Industry (METI) or, more specifically, the Ministry’s Agency for Natural Resources and Energy and the Electricity and Gas Market Surveillance Commission. The Ministry of Economy, Trade and Industries Establishment Act grants the Ministry jurisdiction over various matters including comprehensive policies in relation to energy and mineral resources and the securing of the stable and efficient provision of gas, electric power and heating to Japan. In addition to these matters, comprehensive policies in relation to energy and mineral resources and the securing of the stable supply of energy are handled by the Ministry's Agency for Natural Resources and Energy, and the monitoring of the liberalised electricity markets, as well as compliance with a code of conduct for network sectors, is handled by the recently established Electricity and Gas Market Surveillance Commission.

The Organization for Cross-regional Coordination of Transmission Operators (OCCTO) is not a governmental organisation but is an independent organisation constituted by all of the electricity business entities pursuant to the Electricity Business Act (EBA). The OCCTO’s remit is to monitor the electricity supply–demand balance and frequency, and order electricity business entities to supply electricity to other electricity business entities. The OCCTO has the power to instruct or recommend electricity business entities to ensure stable electricity supply subject to Article 28-40, Item 6 of the EBA.

Other governmental agencies regulate certain aspects of the energy industry in Japan, including the Ministry of Environment, the Nuclear Regulation Authority and relevant local governments.

Main sources of law and regulation

The EBA is the main source of legislation regulating businesses involved in the generation, transmission and distribution, and sale of electric power. In addition to this, the Electricity Business Act Enforcement Orders and the Ordinance for Enforcement of the Electricity Business Act further provide detailed regulations for the enforcement and governance of the system provided under the EBA. A number of relevant orders and ordinances ruling the generation, transmission and sale of electricity have also been enacted.

As for nuclear power, regulation is provided in the Atomic Energy Fundamental Act, the Act on Compensation for Nuclear Damage and other specialised legislation.

The Gas Business Act (GBA) is the primary source of legislation regulating businesses involving town gas. In addition to this, the Gas Business Act Enforcement Orders and the Ordinance for Enforcement of the Gas Business Act further provide detailed regulations for the enforcement and government of the system provided under the GBA.

The primary source of legislation regulating businesses involving LPG is the Act Concerning the Securing of Safety and the Optimisation of Transaction of Liquefied Petroleum Gas (the LP Gas Act). In addition to this, the LP Gas Act Enforcement Orders and the Ordinance for Enforcement of the LP Gas Act further provide detailed regulations for the enforcement and government of the system provided under the LP Gas Act.
Regulated activities

Electricity

After the Fukushima incident, the Japanese government decided to undertake significant reform of the energy regulation system. The regulations for electricity businesses are also undergoing substantial changes at the moment. Prior to the new EBA (which came into effect on 1 April 2016), licences for electricity businesses were required when the intended activities fell within one of five categories, and only 10 prominent regional companies (which used to be categorised as general electricity utilities) were allowed to supply electricity to general consumers and businesses (low-voltage electricity) in their respective markets. However, the amendment to the EBA to liberalise the entire retail electricity market has streamlined regulated electricity business into three simple categories (i.e., electricity retail businesses, generation businesses and transmission and distribution businesses) to adjust to the liberalised retail market and promote a level playing field for competition between the general electricity utilities and other electricity business entities.

Electricity retail business

A company running an electricity retail business (the sale of electricity to general and large-scale consumers and businesses) is required to be registered by the METI. For a company to be registered as a retail company, it is first required to become a member of the OCCTO. Then an application document must be filed to the METI. The METI and the Electricity and Gas Market Surveillance Commission will then examine the application. An application for the register will be accepted unless the business entity’s activities are found to fall under certain negative requirements, including a lack of ability to procure electricity to respond to the maximum demand of its customers and being unable to properly operate an electricity retail business. In anticipation of the market liberalisation, many retail entities have entered this new market with various types of electricity price plans. As of 5 April 2018, 466 entities are registered as retail companies.

Electricity generation business

Companies that generate and supply electricity in excess of 10,000kW to retail companies are required to file with the METI to commence their generation business. They are also required to apply for membership of the OCCTO before filing. Under the old regulation structure of the EBA, independent power producers did not need approval or to file for the commencement of their generation business (provided they filed the price and met the other required terms of the supply of electricity), but under the new EBA, generation business entities are required to file their generation business and are also subject to certain obligations. For example, generation companies are required to submit a plan stating the amount of electricity generation that can be produced by a unit of the facilities they possess. Additionally, by a standard contract with general transmission companies, generation business entities are required to report their estimation of supply for the next 30 minutes.

Electricity transmission and distribution business

The electricity wheeling service industry is classified into three subcategories: general transmission, transmission and specific transmission by the amended EBA; and each is
covered by a different regulatory scheme. Entry to this area has not been liberalised even following the amendment of the EBA because these businesses are responsible for ensuring that all consumers have sufficient access to electricity.

Of the different companies in the three categories, the most prominent are general transmission companies. General transmission companies are business entities providing electricity wheeling services through their own transmission lines throughout their service area. Those intending to engage in the general transmission business are required to obtain approval from the METI in advance. The company must submit a business plan to the METI, which must be satisfied that the plan is feasible. Its facilities also need to be capable of covering the electricity demand. To gain approval, the company must submit a 10-year plan, as do companies in the other two categories above.

A transmission company supplies the electricity to general transmission companies throughout its own grid. Those intending to engage in the wheeling industry are also required to obtain approval from the METI.

In contrast to these two, specific transmission companies, which transmit electricity to a specific point, are only required to notify the METI.

**OCCTO**

These three types of electricity business entities are all under an obligation to be a member of the OCCTO to allow the OCCTO to monitor and coordinate the whole electricity market. Members of the OCCTO have to provide information about the amount of electricity produced by their facilities, etc. on a continuous basis. The OCCTO can instruct its members to maintain a balance of electricity supply and demand in the market to ensure the stable supply of electricity to consumers.

**Gas**

*Town gas businesses*

In line with the Electricity System Reform, the amendment to the GBA, which came into effect on 1 April 2017, significantly changed the town gas regulation, which is called the Gas System Reform. This amendment implements full liberalisation of entry into the gas retail business, which accounted for 36 per cent of the total town gas supply as of October 2016. The amendment includes reform of the business licence categories that streamline the regulated gas business into three simple categories: gas retail business, generation business and transportation (pipeline) business.

*Town gas retail business*

A company operating a town gas retail business is required to be registered with the METI from 1 April 2017. Before 1 April 2017, approval from the METI was required to do business and removing this requirement is one of the main purposes of the Gas System Reform. Applications for the relevant registration involve the necessary submission of application forms in which statutorily required data, such as gas generating facility and other necessary information, are described. As in the case of an electricity retail business, an application for registration will be accepted unless the applicant’s activities are found to fall under certain negative requirements, including the lack of ability to procure gas to respond to the demand of its customers and being unable to properly operate a gas retail business. In principle, the entire application and registration process will require around one month to complete.
As of 30 March 2018, the number of town gas retail business operators was 59. It should be noted that regional monopolies have been recognised in relation to town gas retail business operators and, accordingly, the percentage of operators for the service areas in large metropolitan areas is understandably high. The share of the largest operator, Tokyo Gas (service area: Kanto region with Tokyo as its main focus), currently accounts for about 38 per cent of the market whereas the combined share of the three major corporations (Tokyo Gas, Osaka Gas and Tohou Gas) providing service areas in large metropolitan areas accounts for about 73 per cent (based on sales volume as of March 2016). The Gas System Reform aims to change the situation by furthering competition in the town gas retail business under the relaxed requirements for entry into the gas retail business.

Town gas generation business

Before 1 April 2017, a town gas generation business was not required to obtain a registration or licence, or file other documents with the METI. However, after 1 April 2017, companies that generate town gas are required to file with the METI.

Town gas transportation business

Under the new regulation, a town gas transportation business is categorised into two subcategories under the new GBA: general gas transportation business and specific gas transportation business. A general gas transportation business is a business that transports gas through its gas pipeline throughout its service areas. In order to operate a general gas transportation business, approval from the METI is required and the business is subject to certain regulations and controls by the METI as explained below. On the other hand, a specific gas transportation business is a business that transports gas through its gas pipeline to a specific point. Only notification to the METI is required in order to operate a specific gas transportation business.

The purpose of this two-tier regulation is to expand the gas pipeline network, which is established on an area basis (especially in urban areas) by separating the gas between the various networks. General gas transportation business operators now have to make their gas pipelines readily available due to strict regulations imposed by the METI, while specific gas transportation business operators may operate their businesses without strict control by the METI.

Sellers of LPG

The LP Gas Act stipulates that necessary registration for the sale of LPG must be obtained from the METI when intending to establish sales offices catering to two or more prefectures and from the prefectural governor when catering to only one prefecture.

Registration involves the necessary submission of application forms in which statutorily required data, such as details of the sales office, gas storage facilities and other necessary information, are described. Applicants will be registered with the corresponding authority (either the METI or the prefectural governor) as long as there are no applicable statutory grounds for denial of the application.

Registrations will require 30 days to process or 15 days if the registration is applied for via the relevant authority’s electronic information processing system.

As of 31 March 2017, the number of business operators that had obtained the necessary registrations and were currently engaged in the sale of LPG was 19,024. Entry barriers to this section of the industry are low and a large number of small and medium-sized businesses
have been entering into the LPG industry in which even retail rates are not regulated. While all-electric technology products were widely spread by the electric power companies to replace the use of gas, this figure is still less than half of when LPG sales were at their peak (54,000 operators in 1967).

iii Ownership and market access restrictions

The only existing restrictions on foreign investment in the electric power industry or the gas industry are those imposed by the general laws regulating the entry of foreign investment in Japan stipulated in the Foreign Exchange and Foreign Trade Act. For example, if a foreign investor were to obtain 10 per cent or more of the shares of an electric power or gas utility (including both town gas and LP gas), intend to set up a branch for the conduct of electric power or gas business or otherwise engage in any such activities, the Foreign Exchange and Foreign Trade Act requires that the relevant authorities be notified in advance of such activities. Furthermore, in the event of the performance of any such activities requiring advance notification of the relevant authorities, a follow-up report after the performance must also be submitted accordingly. Both prior notification and follow-up reports must be submitted to the Bank of Japan, which in turn will facilitate the submission of the notifications and reports to the Minister of Finance or other relevant minister in charge. The relevant authorities have the power to provide a recommendation or an order to suspend such foreign investment, if it hinders national security, public order or public safety.

iv Transfers of control and assignments

Electricity

The prior approval of the METI is necessary in the event of a transfer of the whole business of a general transmission company or in the event of a merger or demerger whereby the surviving entity completely absorbs any such business. The criteria for granting such an approval are the same as those for the original grant of approval to operate such businesses. A merger or demerger of other types of electricity business entities obliges them to notify the METI. Notification to the METI is also required upon the handover of any equipment or facilities to retail companies, power suppliers and any types of transmission companies.

Gas

The transfer or acquisition of all or part of a general gas transportation business requires authorisation from the METI before it can be effective, as does the merger or demerger of any entity that is a general gas transportation business operator whereby all or part of the business is succeeded by the surviving company. The criteria for the grant of the required authorisation are the same as those for the original grant of approval to operate such businesses. Only post facto notification is required for transfer of the business or merger or demerger of the town gas-related business (i.e., town gas retail business, town gas generation business and specific gas transportation business).

In the case of LPG businesses, however, in the event of any transfer of the business in its entirety or of any merger or demerger whereby the surviving entity completely absorbs the business, the succeeding entity is only required to notify whichever is relevant of the METI or the prefectural governor.
III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Electric power

Integrated system for the production and transmission of electric power

In Japan, following the end of World War II and up until 1995, the production and transmission of electric power, as well as its assorted related retail operations, were run as a single integrated utility by 10 electric power companies, each with a regional monopoly over the 10 main regions of Japan.

However, amid the institutional reform post-1995, Japan realised the liberalisation of its electric power generation and retail sectors. That being said, the electric power transmission sector is still very much dominated by the aforementioned 10 power companies (former general electricity utilities).

Because the electric power distribution grid is public infrastructure, measures have been implemented to prevent general electricity utilities from abusing their dominant market positions and to ensure the transparency of the electric power industry. Specifically, anti-trust measures that have been implemented include, the compulsory notification of electric power transmission details; the requirement of equal treatment of consumers; and the compulsory separation of the electric power transmission division accounts of general electric power business operators from their other divisions.

Government policy on separation and unbundling of electric power transmission sectors

As part of the Electricity System Reform, the amendment to the EBA passed in 2015, which aims for the legal unbundling of the transmission sector to ensure the neutrality of all entities engaged in electricity-related business. No electricity company can run an electricity retail business or generation business with a transmission business in the same entity after April 2020, unless otherwise permitted by the METI. That means that the 10 former general electricity utilities, except for Okinawa Electric Power Company, must split those departments to an affiliate or others by that date.

Obligations undertaken by general transmission companies

Because transmission facilities and the business conducted with them are mostly owned by the former 10 general electricity companies, to secure the effective liberalisation of other sectors, these companies are required to provide neutral treatment to retail companies. General transmission companies are not allowed to refuse to execute a grid connection contract without reasonable grounds. The EBA provides that the electricity supply-demand balance and frequency must always be maintained within a certain threshold. General transmission companies must also provide final assurances to each consumer to deliver electricity where consumers do not have a contract with any of the retail companies. General transmission companies are also responsible for the delivery of electricity to consumers on Japan’s remote islands.

Cybersecurity

As most activities involved in the electricity business are controlled by information technology, it is urgent for businesses in the sector to establish a reliable cybersecurity system. The Basic Act on Cybersecurity stipulates that Critical Infrastructure Information (CII) operators shall make an effort to assure cybersecurity voluntarily and proactively. Because there is no regulation that clearly stipulates the concrete actions a CII should take with regard to IT...
protection, a strategy for cybersecurity committee established by the Cabinet has announced that the security criterion for CII operators will be clarified. It is clear that electricity business entities, especially general transmission companies, fall within the definition of CII operators, and will almost certainly be required to adapt their processes in line with any changes to the security requirements.

ii  Gas

*Terminalling, processing and treatment*

After importation, LNG meant for the town gas industry is converted into gas and sent through pipelines or transported by tanker lorries, and stored in gas storage facilities for supply to consumers. The facilities for processing, transportation and storage are mainly owned by the gas utility business operators, who supply the gas to consumers.

Pipelines that are used for gas transportation and gas holders that are used for storage of gas are regulated by the GBA and the technical standards for gas facilities prescribed by ministerial order. Likewise, tanker lorries are regulated by the High-Pressure Gas Safety Act and the Safety Regulations for General High-Pressure Gas.

The transportation and storage of LPG are regulated by the LP Gas Act and the High-Pressure Gas Safety Act. More particularly, whereas storage and transportation at distribution and wholesale levels are regulated by the High-Pressure Gas Safety Act, the storage and transportation supply level to general end-users are regulated by the LP Gas Act.

*Government policy on separation and unbundling of town gas transportation sectors*

As part of the Gas System Reform, as in the case of the Electric System Reform, for a town gas-related business, the legal unbundling of the transportation sector is scheduled for April 2022 to ensure the neutrality of all entities engaged in a gas-related business. This reform is expected to apply to three major players: Tokyo Gas, Osaka Gas and Tohou Gas. By April 2022, these companies will have to separate those sectors and transfer them to an affiliate or other entity.

*Obligations undertaken by general transmission companies*

Since gas pipelines are dominantly owned and operated by a few operators, such as the three major players, in order to secure the effective liberalisation of other sectors, general gas transportation business operators are prohibited from refusing to execute a transportation contract without reasonable grounds. Also, the terms and conditions of such contracts and amendments are required to be approved by the METI in advance.

### IV ENERGY MARKETS

i  Japan Electric Power Exchange

The Japan Electric Power Exchange (JEPX) exists for the benefit of all electric power-related transactions. It was founded on 28 November 2003 as a market for the commodity trading of electric power and serves as an intermediary for electric power spot trading, forward transactions and other similar transactions. (It is possible to undertake both buy and sell orders through the JEPX.) To participate in electric power commodity trading on the JEPX, membership as a trade affiliate is necessary. As of 2 April 2018, 135 companies were trade affiliates of the JEPX. As of 1 April 2018, JEPX has the spot market opening 365 days and
established a market in which members can trade electricity until one hour prior to its actual use. This market enables electricity business entities to adjust the amount of electricity they provide until the last minute.

The JEPX is managed by a general incorporated association comprising electric power companies and other such entities. It is a private exchange that operates and is regulated by its own market rules.

### ii Terms and conditions of supply

**Electricity**

As explained above, the amendment to the EBA that came into effect on 1 April 2016 liberalised entry into the electricity retail business, but provides a provisional measure that requires former general electric utilities (utilities allowed to retail electricity at low voltage market before the liberalisation) to continue to provide the existing terms and conditions until 2020 at earliest in order not to let the electricity price raise unreasonably. Additionally, all retail companies are subject to regulations in certain codes of conduct such as to deliver explanations and documents in relation to certain matters, for their supply to customers.

**Gas**

**Obligation to supply**

Similarly to the electricity sector, on 1 April 2017, entry into the town gas retail business was fully liberalised. However, certain town gas retail business operators specified by the METI shall continue to supply gas under the terms and conditions approved by the METI. Further, gas retail companies are also subject to regulations on certain codes of conduct such as to deliver explanations and documents regarding the terms of certain matters for their supply to customers.

No such obligations are imposed on LPG business operators.

### iii Market developments

**Electricity**

The Amendment to the Commodity Futures Act that took effect in 2016 provides that electricity becomes subject to commodity futures trading, which enables market participants to avoid the risk of volatility. The Tokyo Commodity Exchange, Inc. aims to launch an electricity future market by September 2018 according to its midterm management plan announced in November 2017.

An infrastructure fund market that enables the listing of funds that invest in certain infrastructure such as electric generation facilities, established by the Tokyo Stock Exchange, Inc. in April 2015, has developed over the past three years. Following the first listing of an infrastructure fund in June 2016, three additional infrastructure funds were listed on the market. The four infrastructure funds invest in solar power facilities. The market provides opportunities for a broad range of investors, including retail investors, to invest in infrastructure-related investments and adds an option for developers who, in particular, develop large-size power facilities.

**Gas**

With respect to gas, no particularly noteworthy market developments are currently anticipated or under consideration.
V RENEWABLE ENERGY AND CONSERVATION

i Electricity

The Renewable Electric Energy Act

Japan has recently been subject to huge developments in the area of renewable energy. The Act on Special Measures concerning the Procurement of Renewable Electric Energy by Operators of Electric Utilities (the Renewable Electric Energy Act) was enacted with the objective of introducing FITs (a system whereby the total volume of electricity should be purchased at a fixed price and a fixed term). The Renewable Energy Act became effective on 1 July 2012, and the FIT scheme was amended on 1 April 2017. The major requirements for a generator to sell electricity at the fixed price under the FIT scheme can be summarised as follows:

a Execute an interconnection agreement with one of the general transmission companies or one of the specific transmission companies for its renewable energy generation facility.

b Obtain certification by the METI for its plan on the generation business relating to the renewable energy generation facility in accordance with the requirements under the Renewable Energy Act. Renewable electric energy, which is subject to the FIT scheme, is currently limited to certain renewable energy sources: solar, wind, water (currently statutorily limited only to small and medium hydroelectric generators with an output of less than 30,000kW), geothermal and biomass.

c Execute a power purchase agreement with one of the general transmission companies and the specific transmission companies for a renewable energy generation facility with the above certification. Such transmission companies are obliged to accept an offer by a generator to execute such a power purchase agreement, unless it falls into certain exceptions.

Sales prices and contract terms

Set out below are the changes in sales prices and contract terms granted by the FIT scheme in recent years. In relation to solar power, as a reflection of the sudden drop in price of solar panels, the sales price is falling (as per our further notes below). In comparison, measures have been taken to establish favourable pricing and to support investment in respect of offshore wind power and existing headrace tunnel-type medium and small-scale hydroelectric power generators. A bid system, which was newly adopted by the recent amendment, is applicable to facilities with (1) solar power of 2MW or more; and (2) biomass power (generated by certain wood or agricultural products with a capacity of 10MW or more or by biomass liquid fuel) as of 2018.
<table>
<thead>
<tr>
<th>Electricity generated</th>
<th>Sales price (excluding tax)</th>
<th>Contract term</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
<td>2014</td>
</tr>
<tr>
<td>Solar power &lt;10kWh</td>
<td>¥38</td>
<td>¥37</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>≥10kWh &lt; 2,000kWh</td>
<td>¥36</td>
<td>¥32</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>≥2,000kWh</td>
<td>¥36</td>
<td>¥32</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wind power &lt;20kWh</td>
<td>¥55</td>
<td>¥55</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>≥20kWh</td>
<td>¥22</td>
<td>¥22</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Offshore wind power*</td>
<td>¥36</td>
<td>¥36</td>
</tr>
<tr>
<td>Geothermal power &lt;15,000kWh</td>
<td>¥40</td>
<td>¥40</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>≥15,000kWh</td>
<td>¥26</td>
<td>¥26</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydroelectric power  &lt;200kWh</td>
<td>¥34</td>
<td>¥34</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>≥200kWh &lt; 1,000kWh</td>
<td>¥29</td>
<td>¥29</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>≥1,000kWh &lt; 5,000kWh</td>
<td>¥24</td>
<td>¥24</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>≥5,000kWh &lt; 30,000kWh</td>
<td>¥24</td>
<td>¥24</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Existing headrace tunnel-type medium and small-scale hydroelectric power†</td>
<td>¥25</td>
<td>¥25</td>
</tr>
<tr>
<td>&lt;200kWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>≥200kWh &lt; 1000kWh</td>
<td>¥21</td>
<td>¥21</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>≥1,000kWh &lt; 5,000kWh</td>
<td>¥14</td>
<td>¥14</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>≥5,000kWh &lt; 30,000kWh</td>
<td>¥14</td>
<td>¥14</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Biomass power</td>
<td>¥13 to ¥39 depending on material used</td>
<td>¥13 to ¥39 depending on material used</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

* Offshore wind power: generators that require a vessel for access for construction and operational maintenance.
† Existing headrace tunnel-type medium and small-scale hydroelectric power: generators that utilise existing headrace tunnels with renewable electric power equipment and hydraulic steel pipes.
Increase in renewable electric energy generation and associated problems

Following the introduction of FITs, renewable source energy generation – solar power generation in particular – is increasing rapidly. Set out below are recent data on electricity generated by renewable source energy generation facilities and purchased by business operators (million kWh).

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar power (&lt;10kWh)</td>
<td>485,686.0</td>
<td>578,017.8</td>
<td>514,854.4</td>
<td>647,426.3</td>
<td>198,036.4</td>
</tr>
<tr>
<td>Solar power (≥10kWh)</td>
<td>425,466.9</td>
<td>1,317,731.0</td>
<td>1,860,298.5</td>
<td>3,048,280.8</td>
<td>1,005,480.9</td>
</tr>
<tr>
<td>Wind power</td>
<td>489,638.3</td>
<td>492,082.3</td>
<td>349,975.4</td>
<td>493,690.3</td>
<td>265,774.1</td>
</tr>
<tr>
<td>Hydroelectric power</td>
<td>93,552.6</td>
<td>107,277.2</td>
<td>112,223.6</td>
<td>174,341.6</td>
<td>61,855.0</td>
</tr>
<tr>
<td>Geothermal power</td>
<td>570.9</td>
<td>608.1</td>
<td>3,931.7</td>
<td>6,870.5</td>
<td>2,699.1</td>
</tr>
<tr>
<td>Biomass power</td>
<td>316,940.0</td>
<td>364,438.0</td>
<td>383,095.3</td>
<td>611,217.6</td>
<td>281,208.0</td>
</tr>
<tr>
<td>Total</td>
<td>1,811,854.7</td>
<td>2,860,154.4</td>
<td>3,224,378.9</td>
<td>4,981,827.4</td>
<td>1,617,017.10</td>
</tr>
</tbody>
</table>

On the other hand, problematic businesses, such as those that utilised favourable pricing to obtain facility certification from the METI but delayed commencement of work and attempted to obtain fraudulent profits, had been frequently reported. In response, the METI has placed conditions on certified solar power facilities since 2014, requiring them to secure the land title and procure the solar modules. In addition, the Renewable Energy Act was amended on 1 April 2017 and as a result the certification for a plan for a generation business relating to a renewable energy generation facility will only be granted by the METI where the renewable energy generation facility reaches the stage of certain development, including the execution of an interconnection agreement with certain transmission companies and when there is the prospect of obtaining the necessary land titles.

Further, a rapid increase in renewable energy generation has caused a lack of capacity in transmission lines in some areas. Currently, new solar and wind-power projects held in certain areas are subject to unlimited restrictions on the output from renewable energy generation facilities that satisfy certain requirements, including that they expect an oversupply of electricity. Although transmission companies have recently embraced policies to expand the capacity of transmission lines, this issue is still yet to be fully resolved.

ii Gas

In terms of gas-related renewable energy, biogas has been generating a lot of attention in recent years. Biogas is a flammable gas produced by the fermentation of organic waste such as raw sewage, food waste and livestock excretions, a feature that allows it to be harvested at sewage treatment plants, food factories and other such locations. Major town gas utilities such as Tokyo Gas and Osaka Gas have in recent years established guidelines for and promoted the purchase of biogas. Additionally, several local governments began to produce biogas in a sewage facility or refuse disposal facility.
VI THE YEAR IN REVIEW

The electric power industry regulations have, following the events at Fukushima in 2011, already witnessed great reforms. First, the electric system reform started, including full liberalisation of entry into the electricity retail business, and the following phase of the reform, including legal unbundling of the electric power transmission function and sector from the existing dominant power suppliers, will be implemented in 2020. Second, the introduction of FITs has encouraged the emergence of new entrants to the renewable energy industry and the renewable energy market has been expanded, but the FIT system is being revised to address several problems, including a newly adopted bid pricing system for solar power generation of a certain size, the first of which is expected to occur this year.

As explained above, the gas system was reformed along the same lines as the electric system reform, and from April 2017 the full liberalisation of entry into the gas retail business was implemented and new regulations for gas transportation businesses (especially general gas transportation businesses) have been imposed to make gas pipelines available to gas retail business operators. Furthermore, from 1 April 2022, the gas transportation (pipeline) business sector of three major companies (Tokyo Gas, Osaka Gas, and Tohoku Gas) will be unbundled.

Two remarkable trends in renewable energy have been seen. As for offshore wind power, the cabinet has submitted a bill to allow the long-term use (up to 30 years) of seawater in the general ocean area for offshore wind power projects. In addition, a bid that was implemented on solar power of 2MW in 2017 resulted in ¥17.20 at its lowest bid price.

VII CONCLUSIONS AND OUTLOOK

The events at Fukushima in 2011 served as the main catalyst for the reforms that the electric power industry has recently been facing. The full extent of these reforms and their effects, however, remain to be seen. As of April 2018, all 48 nuclear power stations in Japan except five are stopping operations. In the meantime, the Nuclear Regulation Authority issued new nuclear power station safety standards in July 2013 and, as of September 2017, 14 nuclear power stations are in the process of review for restart under the new safety standards (12 stations have already passed). However, it is still unclear when and how many nuclear power stations will restart operations.

Under these circumstances, Japan will become increasing reliant on its remaining sources of energy, that is, oil and LNG. These traditional sources of fuel are regarded as more stable and reliable; however, because they are ultimately non-renewable resources, this in and of itself introduces an entirely different set of issues. At the end of the day, Japan’s energy requirements may push it in the direction of renewable energy such as those discussed above. The output of such energy sources is, however, substantially smaller compared with nuclear energy, not to mention inherently unstable and less reliable. Accordingly, Japan’s demand for alternative and reliable sources of energy may even result in renewed interest in the gas industry, which in turn will surely lead to further developments in this field.

With all facets of the energy industry shifting so rapidly at the moment, the only thing that can be said with any certainty is that change is imminent. Exactly how and what form this change will take remains to be seen, and it is certainly worth keeping a close eye on Japan in the years to come.
I OVERVIEW

Korea relies on over 97 per cent of its primary energy sources from overseas acquisition, and fossil fuels, such as petroleum, gas and coal account for 85 per cent of these sources. Therefore, there are policy needs in the short term to take measures against fluctuations in the supply and demand for energy based on global factors, and in the long term to take measures against the depletion of fossil fuels. The 2011 Fukushima nuclear power plant accident in Japan has served as a warning to carefully consider the use of nuclear energy policy and the new energy environment, and the effects of climate change, has increased the use and interest in new and renewable energy.

Under the current environment and policy needs, Korea has designated the Energy Act and Framework Act on Low Carbon and Green Growth (the Framework Act) as its basic laws. These energy laws were prepared with the intention of achieving certain policy goals such as having a steady supply of energy, eco-friendliness, market principles and energy security, and these goals are being implemented in line with the changes to the energy market and environment through the enactment and amendment of individual laws.

The energy policy framework is not likely to change fundamentally under the new Moon Jae-In government, which has been in place since 10 May 2017. One thing that is notable about the move of the new government is its introduction of a policy to phase out nuclear power. The new government has announced that it will not build new nuclear power plants except for those already under construction. Under the new government, it is also expected that the safety of energy facilities, in particular nuclear power plants, will be strengthened by preparing for natural disasters and enhancing cybersecurity. The new government will promote the new and renewable energy development.

II REGULATION

i The regulators

Regulators

The Ministry of Trade, Industry and Energy (MOTIE) is in charge of all regulations regarding individual energy resources (e.g., electricity, petroleum and gas). In particular, the MOTIE carries out duties regarding entry regulations for individual energy resources with respect to licences, reporting and registration. Among the individual energy resources, with respect

---

1 Soong-Ki Yi and Kwang-Wook Lee are partners and Changwoo Lee is a senior associate at Yoon & Yang LLC.
to electricity, the Electricity Regulatory Commission is an affiliated organisation within the MOTIE that was formed to, *inter alia*, decide on granting approval and licences for electric utility businesses, electric business acquisitions and other matters.

The Korea Power Exchange (KPX) is in charge of duties regarding establishing or managing the electricity market, and duties regarding transactions involving electricity, etc.

Further, the Prime Minister’s Office is in charge of matters related to the Framework Act, which is a basic law regarding the macroscopic energy policy, and the Energy Commission, which is an affiliated organisation within the MOTIE, was formed to, *inter alia*, deliberate over matters regarding important energy policies and plans. The Ministry of Environment and the Ministry of Foreign Affairs are also involved in energy-related policies such as establishing emissions-trading systems, clean energy and climate change, as well as joining international treaties.

**Main sources of law and regulation**

The Framework Act, which was enacted in January 2010, is a general law regarding energy policies. In the past the Energy Act was the general law regarding energy policies, but after the enactment of the Framework Act, several of its provisions were transferred to the Framework Act. The Framework Act establishes or promotes comprehensive government energy policies and national strategies, including solutions to climate change and energy issues, expansion of growth and development, strengthening the competitiveness of companies, efficient use of land and creation of a pleasant environment (Article 3(1)).

The Energy Act still regulates matters such as the establishment of regional energy plans and emergency energy plans and the establishment and operation of the Energy Commission.

Individual energy resources and the related businesses are regulated pursuant to the following laws:

*a* Electricity: the Electric Utility Act (EUA) regulates matters such as the production, distribution and sale of electricity and the Electrical Construction Business Act was enacted to ensure the safety of businesses that engage in electricity-related construction.

*b* Petroleum and gas: the Petroleum and Petroleum Substitute Fuel Business Act (PBA) and the Urban Gas Business Act (UGBA) regulate the adequate distribution of petroleum and gas to consumers, and the High-Pressure Gas Safety Control Act was enacted to introduce safer measures to prevent the possibility of gas exploding.

*c* Nuclear energy: the Nuclear Energy Promotion Act regulates the research, development, production and use of nuclear energy; the Nuclear Safety Act regulates the safety of nuclear energy; and the Nuclear Damage Compensation Act regulates matters regarding damage compensation arising in relation to nuclear energy.

*d* New and renewable energy: the Act on the Promotion of the Development, Use and Diffusion of New and Renewable Energy (the New and Renewable Energy Act) acts as the basic law regarding the development of technology for new and renewable energy as well as the use and dissemination of new and renewable energy.
ii Regulated activities

Electricity

Under the EUA, electric utility businesses are categorised into five types of business, the definitions of which are as follows:

a. Electricity generation business: a business, the main purpose of which is to generate and supply electricity to operators of the electricity sales business via the electric utility market.2

b. Electric transmission business: a business, the main purpose of which is to set up and operate electric installations necessary to transmit electricity produced at power stations to operators of the electricity distribution business.3

c. Electric distribution business: a business, the main purpose of which is to establish and operate electricity installations necessary to distribute electricity transmitted from power stations to consumers of electricity.4

d. Electric sales business: a business, the main purpose of which is to deliver electricity to consumers.5

e. District electric business: a business, the main purpose of which is to generate electricity with electric generating units of up to 35,000kW to meet the demand of a specific supply district, and to supply the produced electricity to consumers of electricity in that specific supply district, not via any electric utility market.6

The Korea Electric Power Corporation (KEPCO) had a monopoly on the production and supply of electricity in Korea until the late 1990s, and was entirely responsible for generation, transmission, distribution and sales. Currently, KEPCO is still responsible for transmission, distribution and sales of electricity, KEPCO’s subsidiaries and various private companies are competing in the electricity generation business.

According to Article 7 of the EUA, any person who intends to operate an electric utility business must obtain a licence, based on the business type, from the Minister of the MOTIE (the Minister); the Minister's approval is required when the person intends to modify important matters relating to the licence, such as the business district or specific supply district, supply voltage and, in the case of electricity generation businesses and district electric businesses, the place of electric installations, equipment capacity and the type of motive power.7 To obtain a licence, the following documents must be submitted to the Minister: 8

b. a business plan;

c. the articles of incorporation, a profit and loss statement and balance sheet (the articles of incorporation are only required in the case of an entity that is being established); and

d. the shareholder's registry (unless the applicant's power capacity is 3,000kW or less; if the applicant is a new entity whose financial capability cannot be assessed, the largest shareholder of the entity will be constructively deemed as the applicant).

---

2 Article 2(iii) of the EUA.
3 Article 2(v) of the EUA.
4 Article 2(vii) of the EUA.
5 Article 2(ix) of the EUA.
6 Article 2(xi) of the EUA; Article 1-2 of the Enforcement Decree of the EUA.
7 Article 7(1) of the EUA; Article 5(1) of the Enforcement Rule of the EUA.
8 Article 7(1) of the EUA; Article 4(1) of the Enforcement Rule of the EUA.
The Minister will grant electricity utility licence after an application has undergone deliberation by the Electricity Regulatory Commission. The criteria for issuing the licence as provided by Article 7(5) of the EUA are:

a to have the financial and technological capability necessary to operate the electric utility business in the optimal manner;

b to be able to carry out the electric utility business as planned;

c all or a part of two or more business zones for operators of the electric distribution business or specific supply districts for operators of the district electric business must not overlap;

d in the case of district electric businesses, to meet at least 50 per cent of the electricity demand of a specific supply district and not to constitute any obstacle to the supply of electricity by another operator to consumers residing in the neighbouring area because of that business;

e power plants and power generation fuel must not be concentrated in certain areas to disrupt the power system; and

f to conform with the standards set by the Enforcement Decree of the EUA on the basis of public necessity.

An operator of the electric utility business must set up the electric installations necessary to operate the electric utility and start up the business within the preparation period determined by the Minister.9

The EUA requires the Minister to take into consideration the economic efficiency of the electric installations and their impact on the environment and public safety when establishing a basic plan for electric supply.10

**Petroleum**

Article 2 of the PBA defines the term ‘petroleum’ as ‘crude oil, natural gas (including liquefied natural gas)’ and ‘petroleum products’ as ‘gasoline, kerosene, diesel, fuel oil, lubricating oil, hydrocarbon oil and petroleum gas (including liquefied petroleum gas)’11 and categorises petroleum businesses into three types of business: petroleum refinery businesses,12 petroleum export and import businesses13 and petroleum sales businesses.14

Anyone who intends to operate a petroleum refinery business must register his or her business with the Minister by submitting an application for registration and a business plan to the Korea Petroleum Quality and Distribution Authority, which was established pursuant to Article 25-2 of the PBA.15 In connection with petroleum refinery businesses, anyone who intends to operate a business for manufacturing asphalt, base oil and lubricant must report the business to the Minister.16

---

9 Article 9(1) of the EUA.
10 Article 3(2) of the EUA.
11 Article 2(i) and (ii) of the PBA.
12 Article 2(iv) of the PBA.
13 Article 2(v) of the PBA.
14 Article 2(vi) of the PBA.
15 Article 5(1) of the PBA; Article 4(1) of the Enforcement Rule of the PBA.
16 Article 5(2) of the PBA; Article 8(1) of the Enforcement Decree of the PBA.
Also, anyone who intends to operate a petroleum export and import business must register his or her business with the Minister 30 days prior to the expected date of the initial customs clearance, by submitting an application for registration, a business plan and import agent agreement to the Korea Petroleum Quality and Distribution Authority.\(^{17}\) Such a registration, however, is not required for a person who is already registered as an operator of a petroleum refinery business, and for the import and export of certain petroleum products such as asphalt, lubricant and base oil.\(^{18}\) To qualify for the registration of a petroleum export and import business, an applicant must be equipped with a storage facility capable of storing the greater of the quantity of 15 days’ worth of planned domestic petroleum sales or 2,500kL.\(^{19}\) The previous storage capacity requirement of the greater of the quantity of 30 days’ worth of planned domestic petroleum sales or 5,000kL has been relaxed to the current requirement since December 2016 to induce price cuts by lowering entry barriers to the petroleum export and import business and thus promoting price competition among petroleum products both domestic and foreign.

Petroleum sales businesses are classified into (1) general agents and solvent agents; (2) gas stations; (3) solvent vendors; (4) manufacture and sales businesses of petroleum by-products; (5) secondary fuel oil vendors; and (6) general vendors, aviation fuel sales business and special vendors. While (1) to (5) need to be registered with the head of the local government,\(^{20}\) petroleum sales businesses that fall under (6) need to be reported to the head of the local government.\(^{21}\)

To facilitate integrated controls and regulations of liquefied petroleum gas businesses, the PBA excludes liquefied petroleum export and import business from petroleum export and import business.\(^{22}\) To further protect consumers of petroleum products, the PBA prohibits the sale of petroleum and petroleum alternative fuels whose volumes have been improperly increased by artificial heating, and punishes violations.\(^{23}\) In addition, the PBA adds the Customs Office as an agency from which the Minister of the MOTIE may request tax information for efficient supervision and monitoring of conducts that may disrupt sound distribution of petroleum products in the market or violate prohibition against manufacturing of fake petroleum products.\(^{24}\)

Urban gas

The UGBA defines the term ‘urban gas’ as natural gas (including liquefied gas), petroleum gas, by-products from naphtha cracking and biogas,\(^ {25}\) and synthetic natural gas (SNG).\(^ {26}\) Under the UGBA, urban gas businesses are categorised into five types of businesses: gas wholesale business, general urban gas business, urban gas recharging business, by-products from naphtha cracking and biogas manufacturing business, and SNG manufacturing business.\(^ {27}\)

\(^{17}\) Article 9(1) of the PBA; Article 8(1) of the Enforcement Rule of the PBA.
\(^{18}\) Article 9(1) of the PBA; Article 10(2) of the Enforcement Decree of the PBA.
\(^{19}\) Article 12(1) of the Enforcement Decree of the PBA.
\(^{20}\) Article 10(1) of the PBA; Article 12(1) to (6) of the Enforcement Rule of the PBA.
\(^{21}\) Article 10(2) of the PBA; Article 12(7) of the Enforcement Rule of the PBA.
\(^{22}\) Article 9(1) of the PBA.
\(^{23}\) Article 39(1)(iii) of the PBA.
\(^{24}\) Article 41-3 of the PBA.
\(^{25}\) Article 2(i) of the UGBA; Articles 1–2 of the Enforcement Decree of the UGBA.
\(^{26}\) Article 2(i) of the UGBA.
\(^{27}\) Article 2(i-2) of the UGBA.
Besides the above, recently, there has been very active development of shale gas. To allow private businesses to flexibly take appropriate measures and seek new business opportunities in response to the changes in the international energy market, such as the expansion of the Northeast Asia LNG purchase market, a reporting system was implemented for businesses that carry natural gas in and out, and the sale of natural gas abroad for self-consumption by a direct importer (which imported the natural gas) is permitted.

According to the UGBA, the definition of each urban-gas business is as follows:

a. Gas wholesale business: a business by which urban gas is supplied by a person, other than an operator of general urban gas businesses or by-products from naphtha cracking and biogas manufacturing businesses, to general urban gas business operators, urban gas recharging business operators or large users.

b. General urban gas business: a business that supplies urban gas supplied by gas wholesale business operators, or petroleum gas, by-products from naphtha cracking or biogas produced by the general urban gas business operator itself, to users through pipelines according to the general demand.

c. Urban gas recharging business: a business that supplies urban gas supplied by gas wholesale business operators, or by-products from naphtha cracking or biogas produced by the urban gas recharging business operator itself, by recharging the gas in a container, storage tank or tank fixed to a vehicle.

d. By-products from naphtha cracking and biogas manufacturing business: a business that manufactures by-products from naphtha cracking and biogas itself for self-consumption or supplies to gas wholesale dealers or general urban gas businesses (except for a business that manufactures naphtha by-products with manufacturing permit as required under Article 4 of the High Pressure Gas Safety Control Act and supplies by-product gas through dedicated piping directly to such facilities designated under the MOTIE Ordinance).

e. SNG manufacturing business: a business that manufactures SNG itself for self-consumption, supplies to gas wholesale dealers or supplies to a party that holds the majority of the shares of the applicable SNG manufacturing business for the parties’ self-consumption.

f. Natural gas export and import business: a business exporting or importing natural gas.

g. Business that carries natural gas in and out: a business pursuant to Article 154 of the Customs Act that carries natural gas in or out from the storage facility in the bonded area.

28 Article 2(ix-2) and (ix-3); Article 10-2(3) of the UGBA.
29 Article 10-6 of the UGBA.
30 Article 2(iii) of the UGBA.
31 Article 2(iv) of the UGBA.
32 Article 2(iv-2) of the UGBA.
33 Article 2(iv-3) and Article 8-3 of the UGBA.
34 Article 2(iv-4) of the UGBA.
35 Article 2(vii) of the UGBA.
36 Article 2(ix-2) of the UGBA.
Under the UGBA, a person who intends to operate a gas wholesale business must obtain a licence from the Minister of the MOTIE 37 and a person who intends to operate general urban gas business must obtain a licence from the head of the local government. 38 A licence for the gas wholesale business and general urban gas business will only be granted if applications meet the following requirements: 39 (1) the relevant urban gas business is of an economic scale appropriate for the public interest and general demand; (2) the relevant applicant has financial resources and technical capability necessary to properly conduct such an urban gas business; and (3) the relevant applicant has the capability of establishing and maintaining appropriate supply facilities for the stable supply of urban gas. A person who intends to operate an urban gas recharging business and by-products from naphtha cracking and biogas manufacturing business must obtain a licence from the head of the local government for each place of business. 40 A person who intends to operate an SNG manufacturing business must obtain a licence from the Minister for each place of business. 41

Anyone who intends to operate a natural gas export and import business must register his or her business with the Minister 30 days prior to the expected date of the initial customs clearance, by submitting an application for registration and a business plan (including current status or construction plan of the storage facility of natural gas and a supply plan for the five years following the year of the import of natural gas). 42 If a natural gas export and import business operator who is an urban gas business operator intends to conclude a natural gas import, export or transportation agreement, he or she must obtain approval from the Minister after meeting the urban gas requirements in relation to demand and supply, and appropriateness of price. 43 Anyone who intends to operate a business that carries natural gas in and out must report the business to the Minister. 44

On the other hand, the UGBA includes provisions to improve regulations on natural gas export and import business operators, and to strengthen safety requirements. In addition, to flexibly respond to natural gas supply and demand situations at home and abroad, the UGBA exempts natural gas import agreements that meet certain criteria from the requirement to obtain pre-approval from the Minister. With respect to these natural gas import agreements, the importers are required to report to the Minister only after concluding the agreements. 45 The UGBA strengthens safety requirements by stipulating that, in cases where liquefied petroleum gas facilities are changed into urban gas facilities, urban gas operators and gas users must implement certain safety measures such as demolition of liquefied petroleum gas containers and ancillary equipment. The UGBA imposes penalties for violations of the safety requirements, and even gas users who fail to comply with the safety requirements will be subject to penalties. 46 The UGBA also requires that safety measures for gas plumbing and gas use facilities be implemented in the case of an extension or alteration to a building.

37 Article 3(1) of the UGBA.
38 Article 3(2) of the UGBA.
39 Article 3(7) of the UGBA.
40 Article 3(3) of the UGBA and Article 3(4) of the UGBA.
41 Article 3(5) of the UGBA.
42 Article 10-2(1) of the UGBA; Article 10-6 of the Enforcement Rule of the UGBA.
43 Article 10-5(1) of the UGBA.
44 Article 10-2(3) of the UGBA.
45 Article 10-5(2) of the UGBA.
46 Article 28-2 and 54(6) of the UGBA.
where urban gas pipelines are installed. The UGBA also newly introduces penalty provisions against those parties that cause damage, or inflict harm to the functionality of, urban gas pipelines.

**New and renewable energy**

The New and Renewable Energy Act authorises the Minister of the MOTIE to establish a basic plan to promote use, dissemination and technological development of new and renewable energy every five years after consultation with the head of the relevant central administrative agency and deliberation by the New and Renewable Energy Policy Council. Also, to achieve the goals set out in the basic plan, plans for implementation must be established and carried out for each type of new and renewable energy every year.

The New and Renewable Energy Act provides that tradable renewable energy certificates (REC) will be issued to new and renewable energy suppliers. On the other hand, in cases where new and renewable energy suppliers receive support from the MOTIE in an amount equal to the balance between the trading price of the electric power supplied by new and renewable energy sources and the standard price announced by the MOTIE, RECs will be issued to the state. The MOTIE may trade the certificates issued to the state in the market to keep the balance of demand and supply and to stabilise prices. In addition, the New and Renewable Energy Act abolishes the renewable energy installation specialist system and the renewable energy building certification system, which have been found to be ineffective, and integrates the renewable energy facility certification system into the Korean Industrial Standards certification system under the Industrial Standardisation Act.

To ensure the adequate quality of new and renewable energy fuels, the New and Renewable Energy Act authorises the Minister of the MOTIE to announce quality standards for new and renewable energy fuels, and requires that new and renewable energy suppliers must pass a quality inspection for new and renewable energy fuels by a designated quality inspection agency. The New and Renewable Energy Act also introduces renewable fuel standards that require petroleum refinery operators and petroleum exporters to mix more than a certain percentage of new and renewable energy fuel in fuel for transport. Violations of these requirements may be punished by civil fines. Moreover, the New and Renewable Energy Act requires a new and renewable energy facility certification holder to take out an insurance policy against damage to be suffered by a third party. Under the New and Renewable Energy Act, new and renewable energy suppliers may join a mutual aid association for the purpose of developing new and renewable energy technology and facilitating new and renewable energy business operations.

---

47 Article 28-3 of the UGBA.
48 Article 48(4) and (8) of the UGBA.
49 Article 5(1) and (2) of the New and Renewable Energy Act.
50 Article 6(1) of the New and Renewable Energy Act.
51 Article 12-7 of the New and Renewable Energy Act.
52 Article 13 of the New and Renewable Energy Act.
56 Article 30-2 of the New and Renewable Energy Act.
iii Ownership and market access restrictions

Article 96 of the EUA provides that a foreign-capital invested company under the Foreign Investment Promotion Act may not obtain a licence for an electricity generation business under Article 7(1) of the EUA (this restriction is limited to the operation of atomic power stations) or approval for a plan for the manufacture and supply of fuel for atomic power generation under Article 28 of the EUA. There is no other restriction on foreign-capital invested companies with respect to the operation of electric utility businesses. The PBA and UGBA do not contain any provisions limiting foreign-capital invested companies’ operation of the relevant businesses.

iv Transfers of control and assignments

With respect to an electric utility business, if a person intends to acquire all or part of an electric utility business from its operator or to divide or merge an electric utility company or to acquire more than a certain percentage of shares in an electric utility company (except for those with power capacity less than 20,000kW) to ensure management control, it must obtain approval from the Minister.57 There are no particular restrictions on the acquisition, division or merger of petroleum businesses and urban gas businesses.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Electric power

In Korea, KEPCO, which was established pursuant to the Act on the Korea Electric Power Corporation, initially had a monopoly on the production and supply of electricity as the Korean government decided that, to protect the public interest, it would be appropriate for a public corporation to conduct the business of generating and distributing electricity. The supply of electric power, however, became unstable from the late 1980s because of a rapid increase in the demand for electricity, so the Korean government enacted the Act on the Promotion of the Reorganisation of Electric Power Industry in 2000 and privatised the electricity generation business by dividing KEPCO’s electricity generation business into six subsidiaries. As of January 2017, the number of private companies participating in the electricity market increased to 1,421. Other electric utility businesses (i.e., electricity transmission business, electricity distribution business and electricity sales business) are still wholly operated by KEPCO.

Urban gas

The UGBA has various provisions that regulate the proper management of the supply and consumption of urban gas, which is public property. A general urban gas business operator and gas wholesale business operator must prepare and submit to the head of the local government a gas supply plan for five years.

57 Article 10(1) of the EUA.
ii Transmission/transportation and distribution access

Electric power

According to the EUA, only members of the KPX are entitled to carry out electric utility transactions at the electric utility market and, other than a consumer who uses 30,000kVA or more, no consumer may purchase electricity directly from the electric utility market. Accordingly, electricity produced by electricity generation business operators must be supplied to electricity consumers by operators of electric transmission, distribution and sales businesses. The EUA further provides that no operator of the electricity generation business and electric sales business may refuse to supply electricity without just cause as prescribed by the Enforcement Decree of the EUA and the operator of an electric utility business must maintain the quality of service that it provides. Moreover, operators of electric transmission businesses, electric distribution businesses and district electric businesses must be equipped with and maintain and manage installations meeting the standards determined and publicly notified by the Minister so as to smoothly transmit or distribute electricity regardless of changes in the supply and demand of electricity.

Petroleum

The PBA has various provisions that regulate the management of the quality of petroleum products and prevent the distribution of pseudo-petroleum products. In the event that a petroleum refinery business operator, petroleum export and import business operator or a registered petroleum sales business operator intends to sell or deliver certain petroleum products (e.g., petrol for vehicles, kerosene, light oil, petroleum by-products), the operator must have the petroleum products inspected by a quality inspection institution appointed by the Minister. Any operator will be prohibited from selling or delivering petroleum products that have failed the quality inspection. According to Article 29(1) of the PBA, no one may engage in manufacturing, importing, storing, transporting or keeping pseudo-petroleum products.

Meanwhile, to promote the expansion of the exporting of petroleum products, Article 29(2)(v-2) of the PBA stipulates that the blending of petroleum products at the general bonded area for the purpose of export only, as well as storing and transporting such mixtures, will not be viewed as the manufacturing of fake petroleum products.
Urban gas

No gas wholesale business operators shall refuse to supply natural gas, or have the supply thereof interrupted, to general urban gas business operators, urban gas charging business operators or bulk buyers without justifiable cause.67

Each urban gas business operator must have the urban gas that it supplies inspected by an urban gas quality inspection institution to confirm that the gas fulfils the required quality standards.68

iii Rates

Electric power

An operator of an electric sales business must prepare terms and conditions concerning electric utility charges and other conditions of supply (i.e., supply districts, type of supply and supply voltage and frequency), and obtain approval from the Minister.69 Further, an operator of the electric sales business must specify the details of the utility charges based on items in electric utility bills charged to consumers of electricity.70 An operator of the electric transmission business or electric distribution business must set charges for the use of electric installations and other matters concerning the conditions of their use.71

Petroleum

A petroleum refinery business operator, petroleum export and import business operator and petroleum sales business operator must report their sale prices of petroleum products to the Minister.72

Urban gas

A general urban gas business can have a party that is requesting a change in the contract regarding the supply of urban gas or supply of gas pay for all or a portion of the installation costs of the gas supply equipment or facilities (Article 19-2). Also, where it is difficult to supply urban gas for any of the reasons stipulated under Article 19, the national and local government can pay for all or a portion of the installation costs (Article 19-3). Gas wholesale business operators must obtain the approval of the Minister of the MOTIE in determining the rate. When a determined rate is changed, the same approval is required (Article 20(1)).

67 Article 19 of the UGBA.
68 Article 25-2(1) of the UGBA.
69 Article 16(1) of the EUA; Article 16(1) of the Enforcement Rule the EUA.
70 Article 17 of the EUA.
71 Article 15(1) of the EUA.
72 Article 38-2(1) of the PBA.
iv  Security and technology restrictions

Electric power
Where an operator of an electric utility business intends to perform the works for setting up or altering electric installations for the electric utility, he or she must obtain approval for the plan for the works from the Minister,73 and undergo periodic inspections conducted by the Minister.74

New and renewable energy
If the Minister of the MOTIE deems it necessary for the promotion of the use and supply of new and renewable energy or to increase the vitality of the new and renewable energy business, it may make it mandatory for a party that holds over 500,000 kilowatts of generating units (excluding equipment for new and renewable energy), the Korea Water Resources Corporation and the Korea District Heating Corporation to use new and renewable energy with respect to a determined generation quantity per year within the scope of 10 per cent of the total power production amount for supply energy.75 Where the Minister of the MOTIE deems that the above party with the obligation to supply did not fulfil its obligation by not using sufficient new and renewable energy in supplying its energy, the Minister may impose an administrative fine.76

IV  ENERGY MARKETS

i  Development of energy markets

Electricity
As previously described, transactions regarding electricity take place at the KPX pursuant to the EUA, which was established as an independent legal entity on 2 April 2001. Specifically, transactions occur between the over 1400 electricity generation business operators and a sales business operator 24 hours a day and 365 days a year, based on prices that change every hour.

Gas
Gas is divided into the wholesale sector and retail sector. The Korea Gas Corporation is in charge of business in the wholesale sector, and regional urban gas companies are in charge of business in the retail sector. Specifically, through the main line operated by the wholesaler operator (i.e., the Korea Gas Corporation), gas is supplied to the general urban gas companies, and urban gas companies supply consumers through the pipes that are operated regionally. Because of the public nature of the gas business, the central government oversees and supervises each of the duties of the wholesaler operator and local governments oversee and supervise each of the duties of retail operators.

73 Article 61(1) of the EUA.
74 Article 65 of the EUA.
75 Article 12-5(1) and (2) of the New and Renewable Energy Act; Article 18-3 of the Enforcement Decree thereof.
76 Article 12-6(1) of the New and Renewable Energy Act.
ii  Energy market rules and regulation

Electricity

Electricity is regulated through the EUA. Electricity transactions must occur through the KPX and users of electricity cannot directly purchase electricity from the power market (EUA, Article 31). Electricity transactions are regulated by the power market operating regulations as determined by the KPX pursuant to Article 43 of the EUA and, pursuant to Article 53 of the EUA, the Electricity Commission, which is a part of the Ministry of Trade, Industry and Energy (MOTIE), regulates the above.

Gas

Gas is regulated pursuant to the UGBA. With respect to the importing (wholesale) of gas, aside from the direct importing system for self-consumption, it is exclusively imported by the Korea Gas Corporation (KOGAS). Urban gas businesses purchase urban gas from KOGAS and sell it to consumers. Recently, however, signs of changes in the effective monopoly of KOGAS over the gas market (including LNG and LPG) are visible. The government is attempting to amend the Enforcement Decree of the UGBA, which will enable direct importers of LNG to sell it to each other (up to 10 per cent of the direct import volume) without going through KOGAS. The completion of additional LNG storage facilities of private companies will also open up competition for the domestic LNG market.

iii  Contracts for sale of energy

Electricity

The price on the electricity market is determined based on the electricity demand price predicted by the KPX a day in advance and the supply bid price of the electricity generation business operators. The electricity charge (the sales price of businesses that sell electricity), however, is approved by the government pursuant to laws such as the EUA, as opposed to supply and demand, because of its public nature. After a large-scale power outage in Korea on 15 September 2011, electricity costs were increased a total of four times until November 2013. The main reason for the increase was the need to align costs with actual usage. In particular, in November 2013 electricity costs increased by an average of 5.4 per cent and, included in this, the industrial electricity cost increased by 6.4 per cent. Since that time, there has been no further increase or decrease in electricity rates. According to the Second Basic Energy Plan confirmed in January 2014, besides classifying electricity rates based on use (e.g., industrial, general and housing), as was done in the past, seasonal or time differential pricing has also been introduced.

In 2017, KEPCO has resolved to amend its Implementation Rules of General Terms and Conditions of Supply to expand new and renewable energy and energy storage systems (ESS) by modifying renewable energy discount standards, introducing new incentive to install new and renewable energy and ESS together, and extending new and renewable energy and ESS discount periods.

Gas

The transacting price in the wholesale sector is determined based on the contracts executed between the Korea Gas Corporation and urban gas companies. Since the Korea Gas Corporation imports all of its gas, it is directly or indirectly regulated by the government regarding the import volume and conditions. With respect to the issue of whether to strengthen or relax
regulations on importing gas, there are differences in views between the government (which favours relaxation) and the National Assembly (which favours strengthening). In the retail sector, approval of the charge is required from local governments.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

The Act on Promotion of Alternative Energy was enacted in the 1980s, and the government later established its comprehensive support policy, the Basic Plan for Technical Development for Alternative Energy (1988–2001). Also, to achieve its efficient promotion, the government established the Alternative Energy Business Department within the Korea Energy Management Corporation as the organisation in charge of the development of new and renewable energy.

In the 1990s, to prepare for the Climate Change Convention, the comprehensive technology development plan for energy and the environment, the Energy Technology Development 10-Year Plan (1997–2006), was established to establish a system to promote technological development of not only new and renewable energy, but also to help saving energy, and develop clean energy and resource technology.

As 2000 approached, there was a new understanding of the importance of new and renewable energy and, to strengthen policies regarding technical development and its increased use, the Act on Promotion of Alternative Energy was amended to become the Act on Promotion of Development, Use and Diffusion of Alternative Energy. This Act served to form the basis for business promotion regarding feed-in tariffs (FITs) for new and renewable energy general output, an obligation for public institutions to use new and renewable energy and new and renewable energy equipment certification procedures, etc., which made it possible to create an early market for new and renewable energy.

The Basic Plan for Development and Use of New and Renewable Energy (2003–2012) was established and implemented for the further promotion of new and renewable energy development and dissemination, and the relevant law was again amended in 2004. Korea applied FITs from 2002, but in 2012 they were replaced by the Renewable Portfolio Standard (RPS), which obligates certain operators of energy businesses to supply certain amount of new and renewable energy.

As of 2016, renewable energy accounted for 7 per cent of Korea’s electricity generation, which is lower than other major countries. In December 2017, the government set the goal of increasing the proportion of renewable energy to 20 per cent by growing the capacity of renewable energy facilities to 63.8GW by 2030. In order to achieve this goal, the government plans to promote:

a city-type private solar power for one household per 15 households by 2030;
b small-scale projects under 100kW through introducing the Korean FiT, which combines the advantages of existing RPS and FiT;
c projects in rural areas utilising subprime farmland; and
d large-scale project development with policy support.

The sources of renewable energy in Korea, as of 2016, are waste (58 per cent), bio (16 per cent), and solar (13 per cent). In order to reduce the proportion of non-renewable wastes, the government will improve the licencing system for energy businesses by mandating
environmental impact assessments. The government will also exclude non-renewable wastes from the scope of renewable energy and ensure that more than 95 per cent of new power plants will supply clean energy such as solar power and wind power.

The government plans to leverage renewable energy as an opportunity to foster new energy businesses. For that purpose, the government will:

a. set up an R&D roadmap to reduce the price of solar and wind power, to catch up with new technology and to acquire a competitive edge in next-generation technology;
b. pursue strategic pilot projects to demonstrate new technologies, to verify business models and to promote pre-emptive deregulation;
c. create renewable energy innovation growth clusters; and
d. establish a comprehensive support system for promoting overseas market entry.

Furthermore, in order to foster new energy industries based on small-scale distributed power such as solar power and wind power, the government also plans to establish an intelligent power grid and IoE infrastructure and strengthen certification standards. In doing so, the government is expected to induce the creation of new service industries based on the advanced power infrastructure and IoE technology, and to foster the new services industries through smart city business models.

ii Energy efficiency and conservation

In 1995, the government established the use of demand management investment plans for energy suppliers pursuant to Article 12 of the Energy Use Rationalisation Act (Article 9 in the current version of the Act) and these plans have been in use since 1996 by companies such as KEPCO, the Korea Gas Corporation and the Korea District Heating Corporation. Meanwhile, because of the restructuring and privatisation of the electricity industry, and based on the amendments to the EUA, the government established the groundwork formation plan for the electricity industry in December 2000, which, with the government funds for this groundwork, separately promotes demand-side management businesses.

Under the electricity demand management policy, which was established to achieve a stable supply and demand of electricity and efficient electricity use, the representative businesses are divided into load management businesses, which reduces the maximum electricity demand, and energy-efficiency businesses, which reduces electricity consumption through high-efficiency devices. In terms of gas and heating, for the management of a stable supply and demand, emphasis is put on the dissemination of gas cooling and cogeneration facilities and efforts are being made to obtain greater energy efficiency compared with individual heating systems through regional heating and cooling businesses.

According to the Sixth Electricity Supply and Demand Basic Plan, which was announced by the MOTIE in February 2013, the government has strengthened measures to manage demand by companies, such as the demand adjustment programme of advance notice (where financial incentives are offered to customers who reduce their demands at peak times by observing contract terms and conditions during the KEPCO-announced summer and winter peak periods) and load reduction by adjusting vacation or maintenance schedules, as well as using smart meters to manage the electricity-saving system and intelligent demand. Subsequently, in July 2015, the MOTIE released the Seventh Electricity Supply and Demand Basic Plan and announced that it would actively consider the temperature fluctuation and demand trends in developed countries for precise power-demand forecasting. For efficient supply and demand management, the MOTIE is adopting innovative technological solutions,
including the negawatt market, ESS and energy management systems (EMS). Through these policy improvements, the MOTIE will be able to provide electricity without resorting to mandatory power-saving for industries or limiting air-conditioning temperatures, except in exceptional cases. The MOTIE announced at the plenary session of the National Assembly in July 2016 that it would release the Eighth Electricity Supply and Demand Basic Plan in July 2017. In the Eighth Electricity Supply and Demand Basic Plan released in December 2017, the government will gradually reduce its nuclear power plants and coal power generation facilities; expand eco-friendly energy focusing on new and renewable energy; operate facilities that reduce coal power generation and increase LNG power generation, taking into consideration environmental costs; and increase the LNG facility capacity and generation capacity to achieve stable power supply and environmental improvement.

### Technological developments

The fourth industrial revolution is revolutionising the energy sector among others, and the energy 4.0 era is emerging that fuses energy and related fields and promotes the digitisation of energy. Faced with this new development, the government will establish and implement plans to build an ICT-based energy infrastructure that effectively links distributed energy supply, flexible and intelligent consumer demand responses, and distributed grid. According to Article 5 of the Smart Grid Construction and Utilization Promotion Act, the MOTIE is expected to release the Second Smart Grid Basic Plan for the next five years by July 2017. The Second Smart Grid Basic Plan aims at transitioning to a private-led industrial mature stage. More specifically, it focuses on creating new business through convergence of industries such as IT and telecommunications and fostering industries linking power networks and new energy business such as AMI and ESS. In particular, the MOTIE announced that it would set up a government-wide institutional support for private investment.

In the market, industries relating to smart factories or power plants, smart home appliances, eco-friendly energy towns, and zero energy buildings are expected to grow. In particular, investment is expected to increase in connection with the construction of smart grid and IoT-dedicated infrastructure.

In addition, the new government’s policy initiative to promote green cars will expand the supply of green cars by building electric vehicle charging infrastructure, reducing the green car toll by 50 per cent and completing highway charging facilities. The policy initiative is expected to increase investment in green cars.

### VI THE YEAR IN REVIEW

Key concepts in 2017 are the fourth industrial revolution, climate change and environment.

The government has revised the existing electricity supply-and-demand basic plan, which was established mainly for supply-and-demand stability and economic efficiency, by substantially enhancing environmental stability and safety. In order to cope with fine dust pollution due to thermal power generation, the government has set up a coal power generation reduction plan to abolish 10 old coal power plants by 2022 and to convert coal fuels to LNG. The government will also adjust tax rates in order to reduce the cost gap between coal and LNG power generation. In addition, the government will introduce a system to restrict the coal power generation in spring when there is a fine dust alarm, and to shut down coal power generators older than 30 years.
Furthermore, in order to gradually phase out nuclear power, the government has decided to abandon the construction project of six new nuclear power plants and to cancel the life extension of 10 old nuclear power plants. On the other hand, in order to avoid problems in energy supply and demand due to the phase-out of nuclear power, the government is supplementing measures to improve energy efficiency and manage demand.

With respect to climate change issues, Korea signed a universal climate deal, the Paris Agreement, adopted at the Paris climate conference (COP21) in December 2015 to replace the 1997 Kyoto Protocol on climate change. The National Assembly ratified the Paris Agreement in November 2016. Pursuant to the Paris Agreement, the government is obligated to cut greenhouse gas emissions by 37 per cent compared to its emissions forecast by 2030. In addition, in order to meet another goal of the Paris Agreement to limit the global average temperature to 1.5°C, the government should establish a carbon emission reduction target and a long-term low carbon development strategy by 2020. In that regard, the government held a cabinet meeting on 6 December 2017 and confirmed the First Basic Plan for Response to Climate Change, and the Basic Roadmap for 2030 National Greenhouse Gas Reduction, a detailed plan to achieve the 2030 greenhouse gas reduction target (37 per cent reduction in 2030 emission estimates) proposed by Korea in the Paris Agreement. In the process of implementing the Paris Agreement, there may be conflicts between existing market participants and government regulators. In order to mitigate such conflicts and to create new markets by establishing new energy regulations, the new Moon Jae-in government aims to reduce greenhouse gas emissions by creating a wood industry complex through the expansion of forest investment, and invigorating forest carbon management and trading.

The new energy industry, which is strongly driven by the government, is expected to become the catalyst for the fourth industrial revolution. In particular, the emergence of ESS, renewable energy, and ICT convergence technologies are triggering a fundamental paradigm shift in traditional energy systems. On the other hand, there is a criticism that the government may restrict the creative initiatives of the market participants by limiting or micromanaging the roles of public and private enterprises in the new energy industry.

VII  CONCLUSIONS AND OUTLOOK

The Fukushima nuclear power plant accident in Japan on 11 March 2011 and the large-scale power outage on 15 September 2011 in Korea have had a significant effect on Korea’s energy policies and laws. Because of the Fukushima nuclear accident, the likelihood is high that nuclear energy, which accounted for about 12 per cent of the country’s energy mix, will be reduced in the future and the reduced amount would be replaced with new and renewable energy. The power outage was the combined result of factors such as the failure to predict electricity demand, the price of electricity, which fell short of the production cost, and structural deficiencies in the industry, and this is likely to cause policy-oriented changes to the electricity industry, such as an increase in electricity rates.

As Korea signed the Paris Agreement, it is bound by obligations to reduce greenhouse gas emissions. These obligations are expected to produce further promotion of the sectors that develop and implement new, clean and renewable energy sources.

2018 will be an important year to determine the future of national energy policy as there are a number of challenges to the national energy policy that was addressed in 2017, such as the 3rd Energy Basic Plan, the 8th Electricity Supply Plan, the Basic Plan for Emissions Trading Scheme, and the Basic Plan for Climate Change.
In particular, the new Moon Jae-In government which has been in place since 10 May 2017 aims at suspending all new nuclear power plants, immediately shutting down nuclear power plants that have reached their design life, strengthening emission standards and emission charges for factory facilities as countermeasures against fine dust, and strictly controlling fine dust concentrate discharge areas such as industrial complexes, thermal power plants, airports and harbours. It is also expected that the new government will promote green cars, invigorate the new and renewable energy industry, and build additional new and renewable energy generation facilities.
I OVERVIEW

Lebanon has been plagued by a chronic electricity crisis since the end of the 1975–1990 Civil War, with successive governments failing to make large investments to regain a sustainable position in the ailing sector and its outdated infrastructure. Most Lebanese regions experience 10 to 12 hours of electricity rationing a day, and these power cuts increase dramatically in the event of malfunctions in any of the aging plants. It is common for residents to pay additional costs for external generators to compensate for frequent power cuts. The electricity sector in Lebanon has long suffered from the lack of a global strategy aimed at revitalising it by addressing the needs with respect to infrastructure, generation capacity, operation and maintenance. The large influx of Syrian refugees over recent years has exacerbated the electricity crisis.

The energy sector in Lebanon is mostly controlled by the government and other public sector institutions, namely the state-owned Electricité Du Liban (EDL) founded in 1964. EDL is an autonomous public institution operating under the tutelage of the Ministry of Energy and Water (MOEW), and is vested with certain prerogative rights with respect to the transmission and distribution of electricity throughout Lebanon. Generation of electricity in Lebanon is mainly produced through thermal power plants constituting 80 per cent of the total generation capacity, while hydroelectric power plants provide around 10 per cent of such capacity. Also, and until 2010, additional electricity was purchased from neighbouring countries.

The year 2010 was a turning point for the electricity sector as it witnessed the approval by the Lebanese government of a Policy Paper for the Electricity Sector initiated by the MOEW (the Policy Paper). The Policy Paper comprised a comprehensive plan and a realistic implementation programme for the radical rehabilitation and development of the electricity sector to respond to the economic and social needs and aspirations of Lebanon. It covers three strategic areas: infrastructure, supply and demand, and legal framework. The electricity sector requires drastic reform of the wider energy sector. The Policy Paper addresses renewable energy and energy efficiency, Lebanon being one of the wealthiest countries in terms of renewable energy resources, notably, solar and wind. Accordingly, and with the support of the Lebanese Centre for Energy conservation (LCEC), the MOEW launched a number of tenders for solar and wind energy projects.
While the MOEW initiatives and action plans provide for a series of solutions as part of a national energy strategy, the Lebanese electricity sector still requires long-term reform.

The first attempt to organise hydrocarbon resources in Lebanon in line with international standards occurred in August 2010, with the enactment of the Offshore Petroleum Resources Law (OPRL); this law established the Lebanese Petroleum Administration (LPA), which, together with the Lebanese Council of Ministers and the MOEW, participates in the regulation of the oil and gas sector.

In 2012, the Council of Ministers approved the launching of the first offshore licensing round for hydrocarbon exploration. In 2017, two long-awaited decrees were finally published in the Official Gazette, governing respectively:

- the delineation of the Lebanese maritime waters into 10 distinct blocs; and
- the tender protocol for the award of exploration and production agreements.

The first exploration and production agreements were signed on 9 February 2018 between the Lebanese government and a consortium of France’s Total, Italy’s Eni and Russia’s Novatek for bloc No 4 and bloc No. 9.

Regarding onshore hydrocarbon resources, a draft law is still being discussed at the level of parliamentary commissions.

A draft hydrocarbon policy is currently being developed by the LPA, and will ultimately be subject to the approval of the Council of Ministers.

II REGULATION

i The regulators

The MOEW was established by virtue of Law No. 20 of 1966, and later reorganised by virtue of Law No. 247 of 2000, and is vested with the following powers, among others:

- Setting the general policy for the sector, as well as the general master plan, and the discussion of directive studies and putting them in their final version and submitting them to the Council of Ministers for ratification.2

- Proposing the comprehensive rules for the organisation of the services related to the electrical energy production, transmission, distribution and the supervision of execution.3

- Proposing draft laws and decrees related to the electricity sector.4

- Proposing general safety conditions, environmental conditions and technical specifications applicable to the electrical installations and equipment, provided that the same are issued by virtue of a decree taken by the Council of Ministers upon the competent minister’s proposal after consulting the competent authorities.5

- Entering into the necessary contacts with other countries aimed at establishing electrical interconnections and exchanging electrical energy, and the ratification of the necessary contracts after the parliament’s approval.6

---

2 Article 6 of Law No. 462 of 2002.
3 Article 6 of Law No. 462 of 2002.
4 Article 6 of Law No. 462 of 2002.
5 Article 6 of Law No. 462 of 2002.
6 Article 6 of Law No. 462 of 2002.
Taking all available measures, including the provision of distribution networks according to the laws and contracts ratified by the government to remedy any defects in any of the electricity sector's activities that may have a negative effect on this sector's interests or on the consumers' rights and interests.7

The OPRL vested various prerogatives related to hydrocarbon resources in the Council of Ministers, the MOEW and the LPA. Most of the decisions taken by the MOEW are subject to the approval of the Council of Ministers and such decisions are backed by the LPA's technical advice and recommendations.

The Council of Ministers approves the state's petroleum policy and all decrees related to petroleum activities. The Council of Ministers also approves all exploration and production agreements, appoints the LPA's board, approves petroleum licences and decides on extending the duration of the exploration or production periods after consulting with the LPA.

The MOEW is responsible, inter alia, for signing exploration and production agreements (following authorisation of the Council of Ministers), implementing the OPRL, supervising petroleum activities and protecting the environment from hydrocarbon-related pollution.

The LPA is an independent, technical, regulatory and advisory public entity in charge of regulating, managing and monitoring the petroleum sector, under the supervisory authority of the MOEW. The LPA's prerogatives encompass the preparation of strategic, economic, financial, technical, geological and environmental plans so as to ensure a prudent and efficient management of Lebanon's upcoming hydrocarbon wealth. The LPA's goal is to ensure a successful, transparent and sustainable development process for all petroleum activities, in concert with various governmental bodies, international organisations and civil society.

The main laws and regulations governing hydrocarbons in Lebanon are:

a the OPRL dated 24 August 2010;
b Decree No. 9438 dated 4 December 2012, appointing the LPA;
c Law No. 163 dated 18 August 2011, identifying and delineating the marine zones of Lebanon;
d Decree No. 6433 dated 1 October 2011, governing and delineating the Lebanese Exclusive Economic Zone;
e Council of Minister Decision No. 41 dated 27 December 2012, opening the first offshore licensing round for hydrocarbon exploitation;
f Decree No. 9882 dated 16 February 2013, on the pre-qualification of companies;
g Decree No. 10289 dated 30 April 2013, providing for rules and regulations governing petroleum activities, as amended by Decree No. 1177 dated 31 July 2017;
h Decree No. 42 dated 19 January 2017, on the delineation of maritime blocs;
i Decree No. 43 dated 19 January 2017, approving the tender protocol for the award of exploration and production agreements and the model exploration and production agreement;
j Petroleum Tax Law No. 57 of 12 October 2017; and

7 Article 6 of Law No. 462 of 2002.
Council of Ministers’ Resolution No. 32 dated 14 December 2017, granting two petroleum licences over blocks 4 and 9 and mandating the MoEW to sign the corresponding exploration and production agreements, in accordance with the OPRL provisions.

Regulated activities

EDL is a public establishment with an industrial and commercial vocation. It was founded by Decree No. 16878 dated 10 July 1964, and is responsible for the generation, transmission, and distribution of electrical energy in Lebanon.8

Currently, EDL controls over 90 per cent of the Lebanese electricity sector (including the Kadisha concession in North Lebanon, which is owned by EDL), with a standing monopoly despite the enactment of Law No. 462 in September 2002 (Law 462) providing, inter alia, for the privatisation of electricity production and distribution activities. Some private companies hold a concession to generate or distribute electrical power. EDL’s capacity to generate electricity stands at approximately 1,800MW, leaving a gap with the actual market demand that is currently filled by unregulated private generators, mainly in residential and commercial sectors.

Other participants in the sector include hydroelectric power plants owned by the Litani River Authority, concessions for hydroelectric power plants such as Nahr Ibrahim and Al Bared, and distribution concessions in Zahle, Jbeil, Aley and Bhamdoun.

In order to ensure equality and competition, Law No. 462 provides that licences and permits are granted to those who satisfy the prerequisite conditions specified by the National Regulator for the Electricity Sector Organisation (NRESO), an establishment affiliated to the MOEW. Preferential treatment and imposing uncodified restrictions on the provision of services is explicitly prohibited by Law No. 462.

Although Law No. 462 entered into force in 2002, the privatisation process and the formation of the NRESO are not yet implemented for various reasons, mostly political.9 The long-awaited Law No. 48 regulating public-private partnerships (the PPP Law) was enacted on 7 September 2017. Such Law applies to government and municipality projects such as infrastructure projects, and also to electricity production and distribution projects.

The licence is an official document issued by the NRESO to joint-stock companies that are granted a concession for a maximum duration of 50 years to (1) establish, equip, develop, appropriate, operate, manage or market equipment within the scope of public services in the fields of production, transportation and distribution of power exceeding 10MW, or (2) use the aforementioned equipment by virtue of a financing leasing contract.10 Since the NRESO has not been established yet, the Lebanese Parliament enacted several laws granting the authority to the Council of Ministers to issue the licences and permits for a specific period of time until the establishment of the NRESO.

The OPRL subjects the performance of ‘petroleum activities’ to a licence; the term ‘petroleum activities’ encompasses planning, preparation, installation and implementation of

---

8 Article 1 of Decree No. 16878 of 1964.
9 Article 19 of Law No. 462 of 2002.
10 Article 1 of Law No. 462 of 2002.
activities associated with a subsea reservoir, such as reconnaissance, exploration, production and exploitation, laying of pipelines, development of facilities, production and transportation. The OPRL singles out the following licences:

a Reconnaissance licence: The general conditions and scope of this licence and the corresponding fees are determined by the Council of Ministers by decree upon the proposal of the MOEW based on the opinion of the LPA. This non-exclusive licence is granted by virtue of a MOEW resolution, based on the opinion of the LPA, for a period not exceeding three years.

b Construction, placement and operation of transportation or storage facilities: the Council of Ministers may grant such a licence if the corresponding works are required as part of the approved plan for development and production.

c Production licence: The general conditions and scope of this licence and the corresponding fees are determined by the Council of Ministers by decree upon the proposal of the MOEW based on the opinion of the LPA. This licence is granted by virtue of a MOEW resolution based on the opinion of the LPA.

d The OPRL also provides that the Council of Ministers awards exclusive authorisations to carry out petroleum activities in a specific bloc by virtue of an exploration and production agreement, setting out the right-holders’ authority to explore, develop and produce oil and gas offshore.\textsuperscript{11}

iii Ownership and market access restrictions

There are no major ownership and market access restrictions in the energy sector. However, it should be noted that there is a market monopoly by EDL, which controls approximately 90 per cent of the electricity generating capacity in Lebanon, save for the few above-mentioned concessions.

Lebanon recently witnessed instances where private sector companies were granted the right to generate electricity. Most notably, two power ships owned by a Turkish private company have been leased by the Lebanese government since 2013 in order to compensate for the shortage in the electric supply resulting from the lack of proper maintenance of existing plants. The two power barges are anchored at a specially constructed dock off the coast of Beirut, and have a total output of 370MW, with an output to the national grid of an extra two hours’ electricity a day.

The transmission of electrical energy remains exclusive to EDL, but it is possible, through a decree taken by the Council of Ministers upon the proposal of the Minister of Energy and Water, to ratify contracts with the private sector for the management, operation, development or equipment of the transmission’s activities.

The OPRL and Decree No. 43 of 19 January 2017 regulate the terms of exploration and production agreements to be entered into between the Lebanese state and a consortium of at least three right holders. The various right holders form an unincorporated joint venture in which each of them has an indivisible interest. However, the OPRL and Decree No. 43 unequivocally provide that the Republic of Lebanon has title to all petroleum resources in the seabed of Lebanese waters and the exclusive right to their management.

There are no specific restrictions on the award of licences pursuant to the OPRL, except for qualification requirements with which any prospected licensee is required to comply.

\textsuperscript{11} As per the specific provisions of the draft EPA enacted by virtue of Decree No. 43 dated 19 January 2017.
iv Transfers of control and assignments

Licensees and permit holders are not allowed to waive or assign their participating interest or permits to any other party, unless they have obtained the prior approval of the NRESO’s (currently the Council of Ministers) and provided that the transfer or assignment conforms with Law No. 462 and the regulations issued for its implementation.12

The OPRL provides that the interest of a right holder in an exploration and production agreement is a ‘non-transferable participation interest’. The OPRL further provides that:13

\( a \) the rights and obligations pertaining to a petroleum right may not be transferred or assigned in whole or in part except to a company qualified according to the provisions of the OPRL, and only after obtaining the approval of the Council of Ministers;

\( b \) the same shall apply to the direct assignment of any right in a company that enjoys a petroleum right, including, \textit{inter alia}, the transfer of shares or other rights that may grant the holder thereof decisive control over said company; and

\( c \) no ownership or usage right in any facility upon which a petroleum activity depends shall be transferred, except after approval by the Council of Ministers.

Finally, the OPRL\(^{14}\) provides that the conditions for the sale or transfer of any interest in petroleum shall be set out in a Decree taken by the Council of Ministers.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

As stated above, the Lebanese electricity sector is monopolised by EDL, who currently controls over 90 per cent of the sector (including the Kadisha concession in North Lebanon). Moreover, the sector includes hydroelectric power plants owned by the Litani River Authority; concessions for hydroelectric power plants such as Nahr Ibrahim and Al Bared; and distribution concessions in Zahle, Jbeil, Aley, and Bhamdoun, each of which serves a particular geographical area.

According to the 2010 Policy Paper for the Electricity Sector, this structure should be subject to several changes that are aimed at a partial liberalisation of the electricity sector in Lebanon. After the Paper was announced, investors became interested in the electricity sector, and in engaging in the production and distribution of electricity according to the regulations in force. An important focal point is the collaboration between the public and private sectors since 2012, which consists in outsourcing to private sector companies some of EDL’s activities related to the design, implementation, operation and maintenance of a distribution network with the customers and metering services. This is encouraging for the private investors to invest increasingly in the Lebanese electricity sector.

In relation to natural gas, there is no market regulation yet; the only relevant instrument issued so far is Law No. 549 dated 20 November 2003 governing the design, financing,
development and reconstruction of two refineries; building a terminal for the import and export of LNG; building facilities for the storage of LNG; and establishing networks for its sale and distribution.

Currently, no LNG terminals or facilities have been erected. Accordingly, there is no effective market for LNG sale or distribution.

ii  Transmission/transportation and distribution access
As stated above, the transmission of electrical energy remains under EDL’s monopoly and it is possible, by a decree of the Council of Ministers upon the Minister of Energy and Water’s proposal, to ratify contracts with the private sector for the management, operation, development or equipment of the transmission’s activities. The ‘private sector’ includes any privatised company or any company owned by the private sector.\(^\text{15}\)

In relation to natural gas, these issues have not been addressed yet.

iii  Rates
The rates of the distribution and sale of electricity for all voltage levels are set by EDL according to its investment and financing needs in order to develop its activity.\(^\text{16}\)

In relation to natural gas, these issues have not been addressed yet.

iv  Security and technology restrictions
The MOEW is entitled to take any measures, including those aimed at ensuring that the distributions are executed according to the laws and contracts ratified by the government, in order to remedy any defects in the electricity sector’s activities that may negatively impact this sector’s interests or on the consumers’ rights and interests. The MOEW may also propose general safety conditions, environmental conditions and technical specifications with respect to electrical installations and equipment, provided that they are issued by virtue of a decree taken by the Council of Ministers upon the competent minister's proposal after consulting the competent authorities.\(^\text{17}\)

Similar considerations to those outlined above govern petroleum activities. Chapter 9 of the OPRL, entitled ‘Health, Safety and the Environment’, outlines the safety and security obligations imposed in conjunction with petroleum activities. These include ensuring the highest levels of safety, having in place a ‘health, safety and emergency response plan’ and efficient emergency preparedness. The competent authorities also have the right to request that the right holder place a determined facility at their disposal and facilitate any specific measures for the purpose of protecting health, safety, security or the environment.

In addition, it should be noted that the Israel Boycott Act enacted by the Lebanese parliament on 23 June 1955 prohibits, under penalty of criminal sanctions, any natural or moral person from conducting, directly or through an intermediary, any agreement with or in the interest of bodies or persons residing in Israel.

\(^{15}\) Article 5 of Law No. 462 of 2002.  
\(^{16}\) Article 8 of Decree No. 16878 of 1964.  
\(^{17}\) Article 6 of Law No. 462 of 2002.
The Council of Ministers may, pursuant to a recommendation of the Boycott Bureau (a stand-alone body operating at the Lebanese Ministry of Economy and Trade), enlist any company breaching the provisions of the Israel Boycott Act on a blacklist and prohibit any dealings with such company.

IV ENERGY MARKETS

i Development of energy markets

Law No. 462 was expected to liberalise the sale and distribution of electricity in Lebanon and create a competitive free market for electricity. The NRESO, that was supposed to play a leading role in regulating the electricity sector, has not been established yet. The Policy Paper for the Electricity Sector provides for (1) the implementation of a programme to cover the traditional power supply infrastructure whereby international private companies have carried out the rehabilitation of existing power plants and construction of new plants, and (2) a promising renewable energy programme under which qualified developers will build and operate solar or wind power stations and sell the power generated to EDL, which retains the exclusive right of transporting the electricity to end users. However, until Law No. 462 is fully implemented, the supply and sale of energy remains primarily controlled by EDL. Some flexibility has been witnessed on that front since the management of EDL’s distribution business was handed over to three distribution service providers under service contracts. Further, the sale prices of sources of energy are fixed by the state, and investors can engage in the production of electricity subject to applicable regulations using the tariffs and fees mandated by EDL.

In relation to natural gas, no markets have been developed or regulated yet.

ii Energy market rules and regulation

With regard to electricity, EDL is solely entitled to transmit and distribute electricity to end users in Lebanon. However, and as stated above, other parties play a partial role in the sector, such as the concessions for hydroelectric power plants of Nahr Ibrahim and Al Bared and the distribution concessions in Zahle, Jbeil, Aley and Bhamdoun.

It is important to mention that, up until the full liberalisation of the electricity sector in Lebanon, the tariffs and rates are set by EDL even for the above-mentioned concessions. As for any electricity production activities carried out by the private sector, the transmission of such produced electricity remains the sole right of EDL.

In relation to natural gas, no markets have been developed or regulated.

iii Contracts for sale of energy

Electricity producers and distributors are permitted to have individual contracts for the sale of electric power to EDL, since the latter possesses the sole right to transmit the electricity. Hence, electricity producers are required to connect their production to EDL’s grid in order for it to reach the end users, while the rates and other charges are mandated by the government.

In relation to natural gas, the corresponding guidelines are yet to be developed.
iv Market developments

The full implementation of Law No. 462 would be considered a huge step forward in the liberalisation and encouragement of private investments in the energy sector. However, this law presents some flaws pertaining to the tendering process for the operation and management by independent power producers (IPPs) of existing power plants, as a prelude to the IPPs entering into power purchase agreements with the Lebanese government.

The PPP Law will undoubtedly create new prospects for the implementation of power projects in Lebanon. The PPP Law introduces a new legal regime, replacing the traditional procurement processes, which suffered from weak transparency, competitiveness and accountability standards. The PPP Law renames and grants the High Council for Privatization and PPP the authority to evaluate potential PPP projects. The PPP Law stipulates the main mandatory provisions that must be included in the PPP agreement.

The Sustainable Oil and Gas Development in Lebanon project is being developed as part of the United Nations Development Programme (UNDP). One of the programme’s components is titled ‘Enabling Environment for the Use of Alternative Fuels in the Energy and Transport Sectors’, and provides for the conducting of cost-benefit analyses for the introduction of natural gas and other low carbon fuels in the energy and transport sectors. These should act as a precursor for the development of the corresponding legislation, including without limitation in relation to market development.

In December 2017, the Council of Ministers awarded exclusive licences to a consortium of three companies (Total, Eni and Novatek) for the exploration and production of petroleum offshore, in the Lebanese Exclusive Economic Zone.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

There is an obvious trend to increase the inclusion of the production of renewable energy as part of the implementation of the national electricity strategy. The MOEW encourages public, private and individual initiatives to adopt the utilisation of renewable energies to reach the 12 per cent target in the generation of electricity by 2020. In an initiative launched in partnership with the MOEW, the UNDP established the Country Energy Efficiency and Renewable Energy Demonstration Project for the Recovery of Lebanon (CEDRO) in 2007, with an initial budget funded by the government of Spain to enhance the national energy strategy by contributing in achieving renewable energy projects.

Also, the LCEC18 works closely with the MOEW by setting action plans and national strategies in terms of energy efficiency and renewable energy. In an effort to reach the 12 per cent objective, the LCEC has set two consecutive four-year action plans, known overall as the National Energy Efficiency Action Plan (NEEAP).19 The 2011–2015 NEEAP comprises 14 initiatives of which seven were dedicated to renewable energy. The 2016–2020 NEEAP includes 26 initiatives, setting targets and strategies for the achievement of the

---

18 The Lebanese Center for Energy Conservation (LCEC) is an independent governmental organisation operating under the supervision of the Lebanese Ministry of Energy and Water.

19 The National Energy Efficiency Action Plan is a national action plan developed based on the requirements of the League of the Arab States and according to the format used by the European Union.
energy-saving targets. The LCEC, with support from the MOEW, has further put in place the National Renewable Energy Plan (NREAP) 2016–2020, a follow-up report to the 2011–2015 NEEAP specifically dedicated to renewable energy strategies and their implementation. Lebanon has already witnessed the implementation of projects using renewable sources that are connected to the grid via EDL:

Wind energy: Lebanon constitutes a viable country for energy wind production. In 2013, as part of the implementation of the national strategy for renewable energy development leading to achieving the 500MW wind generation target by 2020, the MOEW launched a tender to private corporations to build the first wind power farm in Lebanon with a capacity of 50–100MW. Under its first power purchase agreement, signed on 1 February 2018, the Lebanese government agreed to purchase 200MW in total from three Lebanese companies. In March 2018, the MOEW launched a second bid round to build additional wind farms for a total capacity of 200–400MW. The electricity generated by the wind farm will be sold to EDL via offtake agreements.

Solar energy: a first of its kind on a national level, the Beirut River Solar Snake, consisting of a photovoltaic (PV) farm, with a total planned output of 10MW, comes as part of the NEEAP to install 200MW of solar farms by 2020. The first phase of the project has been achieved, connecting an extra 1MW of electricity to the grid. Also, the MOEW plans to install around 30MW of solar farms for the public sector between 2016 and 2020. In 2017 and 2018, the Moew launched two consecutive bids for 12 and 24 PV farms respectively (of 10–15MW each). Recently, a new bid has been launched for three PV farms (of 70–100MW each) to include for the first time electricity storage of 70 mw/70mwh. The development of PV farms is becoming more appealing, especially with the decrease in related solar installations’ prices, the decentralisation of PV farms and the growing involvement of the private sector.

Water energy: while 75 per cent of Lebanon’s market demand was covered by electricity generated from hydroelectric sources in the 1970s, the production of hydroelectric power was seriously affected during the civil war and afterwards. Opportunities in the hydropower sector are numerous, as the General Directorate of Hydraulic and Electric Resources at the MOEW envisages a promising strategy encompassing rehabilitation of the existing hydropower plants, the development of dams and the construction of new hydroelectric plants and micro hydropower systems. The current hydropower installed capacity is approximately 221MW, the main plant being the Litani station located in the Bekaa Valley. Also, as part of the NREAP 2016–2020 action plan, the MOEW launched the implementation of the Janna dam,20 which will include the hydroelectric power plant supplying the grid with approximately 100MW of hydroelectricity. In 2018, the MOEW launched a bid for hydroelectric power plants based on studies carried out by leading European engineering firms, aimed at identifying potential sites for such projects. It is expected that hydroelectric sources will generate approximately 300MW by 2020.

Bioenergy (including waste to energy): 23 bioenergy streams have been identified as potential resources for energy production. All action plans stated in the National Bioenergy Strategy for Lebanon set in 2012 by the MOEW along with the UNDP as part of the CEDRO project have been reinstated in the NREAP 2016–2020, as the

20 The construction of the 300-foot high Janna Dam was suspended in May 2016, only to resume later despite local ecological and environmental warnings and concerns.
Ministry recognises that the future of bioenergy is promising. On-ground surveys and assessments have been carried out to identify the most efficient and promising biomass streams. As for waste to energy, the process for producing electricity was launched in 2015 through the establishment of a 7MW plant in the Naameh landfill to produce electricity.

ii Technological developments
The LCEC has drafted an energy conservation law, the Renewable Energy and Energy Conservation Law, which sets the legal framework for the implementation of the NREAP and addresses the production by the private sector of electricity from renewable energies, the management of energy supply and demand and the computation of renewable energy tariffs. The proposed law also covers topics related to energy efficiency in connection with the electricity grid. It provides for mandatory audits and certifications while catering for incentives to promote green solutions.

Notwithstanding the above, a series of initiatives are being carried out with respect to the development of smart technologies that would have an estimated impact on energy demand management. The launching by EDL of the advanced metering infrastructure, comprising the installation by three private distribution service providers of smart meters over the Lebanese territory, is expected to provide energy efficiency in terms of monitoring and synchronisation of wide area networks. A pilot project is currently being carried out to test the responsiveness of the Lebanese network.

VI THE YEAR IN REVIEW
There is a growing national momentum to develop action plans and strategies for the electricity sector, and to encourage all related initiatives. The political commitment in a country like Lebanon plays a crucial role in achieving the goals of the 2016–2020 NREAP. The involvement of the private sector in the various tenders relating to energy and electricity projects is increasing, especially in light of the incentives proposed by the Central Bank of Lebanon and private financial institutions to finance such projects.

A 10-year reform plan proposed by the incumbent Minister of Energy and Water based on the 2010 Policy Paper was approved by the Council of Ministers on 28 March 2017. The first phase of the plan involves the lease of two additional power barges from the Turkish company that already operates two smaller ships in Lebanon, and the activation of the two recently overhauled power plants of Zouk Mikael and Jiyyeh, with the aim of increasing electricity supply to 21 hours a day this year. The main idea behind the leasing of the barges is to give the MOEW more time to build new power plants that can provide all of Lebanon with 24 hours of electricity in the future. The two additional floating power plants will reportedly generate up to 890MW at a cost of US$340 million a year. The plan also envisions the construction of solar power plants and hydroelectric power plants in several areas of the country.

The plan has been met with scepticism and controversy, with challengers alleging its high-cost factor, lack of transparency and the expectancy that it will result in a significant increase in electricity tariffs.

The issuance in early 2017 of the decree on the delineation of maritime blocs and the decree on the tender protocol and the model exploration and production agreement has paved the way for the closing of the prequalification process; the grouping of the qualified
companies in consortia; and, finally, following approval by the Council of Ministers, the execution of the corresponding exploration and production agreement between the winning consortia and the Lebanese state for one or more of the maritime blocs.

On 26 January 2017, the MOEW announced that five out of the 10 maritime blocks were open for bids. Prequalified companies should submit their bids by 15 September 2017. The aim of the Lebanese government is to have one or more exploration and production agreement signed by the end of 2017.

VII CONCLUSIONS AND OUTLOOK

While the Lebanese energy and electricity sector is currently witnessing drastic progress, it is essential to ensure a full correlation between the development of the legal framework and the privatisation process set out by the PPP Law and Law 462. The restrictions imposed by Law 462 should be lifted so as to offer a more flexible legal framework, allowing the private sector to invest in energy production and distribution at fair yet competitive rates to third parties. Additionally, the introduction of legal reforms for alternative technologies and renewable energy activities should be envisaged to fill a considerable gap towards a sustainable national energy strategy.

After a long stalemate (between 2013 and 2017), Lebanon is steadily heading towards becoming a hydrocarbon state, provided extractable discoveries are made in the near future. A successful first licensing round will be a decisive step.

Lebanon’s key challenge is to ensure that the process is managed with a sound governance system and utmost transparency. The Lebanese government’s recent request to join the Extractive Industries Transparency Initiative is a key indicator in this direction, and a message of confidence to both the applicant companies and the Lebanese civil society.
OVERVIEW

Power generation in Malaysia has historically been reliant on fossil fuel such as cheap regulated natural gas and coal. Up until 2010, the country’s reliance on natural gas as an energy source has been steadily increasing, and at the end of 2010 natural gas accounted for 71,543 ktoe of the 106,794 ktoe total energy produced nationwide. Since then, the increasing local demand for energy supply and rapidly diminishing hydrocarbon resources has instigated a gradual but sure shift in energy sector policies as the country strives to reduce its dependency on fossil fuels and develop its renewable energy market infrastructure. In 2014, the Malaysian government awarded the first utility-scale solar project, with an aggregate capacity of 50 MW and a 25-year power purchase agreement. Since then, the Energy Commission of Malaysia (the Commission) has held two further tenders for large scale solar projects, which were awarded in 2016 and 2017, placing Malaysia on track to develop 1,000 MW of utility scale solar in 2020. As of 2016, the country’s energy grid generation mix of 154.1 TWh comprised 36.5 per cent natural gas, 44 per cent coal, 2 per cent fuel oil and diesel and 17.5 per cent renewable resources of which 16.6 per cent comprised hydropower and the remaining was sourced from biodiesel, geothermal, solar energy, biomass and biogas.

The national electric utility company, Tenaga Nasional Berhad (TNB) remains the largest power generation company in Malaysia but several other independent power producers operate in Malaysia such as YTL Power, Genting Sanyen, Malakoff and Edra Global. At the time of writing, we understand that the general policy of the government is that foreign equity participation in power generation projects is capped at 49 per cent and that exceptions to this policy will be considered on a case-by-case basis.

REGULATION

The energy sector in Malaysia was formerly a state monopoly, where TNB held the exclusive rights to generate, transmit and distribute electricity in Peninsular Malaysia and Sabah. However, a nationwide blackout that resulted in losses of an estimated 218 million ringgit in

---

1 Fariz Abdul Aziz is an energy partner and Karyn Khor is a legal associate at Skrine.
2 PricewaterhouseCoopers, ‘The Malaysian Oil & Gas Industry: Challenging times, but fundamentals intact’ (May 2016).
the manufacturing sector alone\(^5\) set off a chain of events that culminated in the privatisation of the energy distribution sector and the entry of independent power producers (IPPs) into the energy market, as well as the emergence of the first power purchase agreements (PPAs). The PPA dictates the terms upon which the IPPs would sell the electricity that they generate to TNB, who is the exclusive owner and operator of Malaysia’s electricity distribution network.

i **The regulators**

The energy market in Malaysia and its participants are subject to a host of legislation governing the supply of electricity generally and the mining of energy resources. More recently, new legislation has been introduced to account for the growing renewable energy sector. The laws that are relevant to the energy sector in Peninsular Malaysia and Sabah\(^6\) are as follows:

\(^a\) Electricity Supply Act (ESA) 1990;
\(^b\) Gas Supply Act 1993;
\(^c\) Renewable Energy Act 2011;
\(^d\) Environmental Quality Act 1974;
\(^e\) Occupational Safety and Health Act 1994;
\(^f\) Factories and Machinery Act 1967;
\(^g\) Petroleum Development Act 1974;
\(^h\) Petroleum (Safety Measures) Act 1984; and
\(^i\) Petroleum and Electricity Control of Supplies Act 1974.

The legislation listed above also require compliance with the regulations, orders, rules and other sub-legislation made thereunder. Some of the more relevant ones are listed below:

\(^a\) Efficient Management of Electrical Energy Regulations 2008;
\(^b\) Electricity Regulations 1994;
\(^c\) Licensee Supply Regulations 1990;
\(^d\) Gas Supply Regulations 1997;
\(^e\) Renewable Energy (Feed-In Approval and Feed-in Tariff) Rules 2011;
\(^g\) Renewable Energy (Technical and Operational Requirements) Rules 2011; and
\(^h\) Petroleum Regulations 1974.

The sub-legislation deals in much greater detail with the practicalities of complying with the laws, and include regulations on, *inter alia*, safety, licensing, management of supply, transport and transmission, technical and operational requirements and exemptions. The laws may also empower the relevant ministers or regulatory authorities to make further guidelines or directives in respect of their regulatory sphere.

---


\(^6\) On 1 September 1990, legislative powers in respect of energy laws in the state of Sarawak were delegated to the local state authority.
There are multiple regulatory authorities in Malaysia overseeing the various segments of the energy sector. Today, the Commission is the primary regulator of the energy and gas supply in Peninsular Malaysia and Sabah. The Commission is empowered with, *inter alia*, the following functions:

1. to advise the Minister of Energy, Green Technology and Water (Minister) on all matters concerning national policy objectives for energy supply activities;
2. to advise the Minister on all matters relating to the generation, production, transmission, distribution, supply and use of electricity as provided under the electricity supply laws and the supply of gas through pipelines and the use of gas as provided under the gas supply laws;
3. to promote and safeguard competition and fair and efficient market conduct or, in the absence of a competitive market, to prevent the misuse of monopoly or market power in respect of the generation, production, transmission, distribution and supply of electricity and the supply of gas through pipelines;
4. to promote the use of renewable energy and the conservation of non-renewable energy; and
5. to promote research into, and the development and the use of, new techniques relating to:
   - the generation, production, transmission, distribution, supply and use of electricity; and
   - the supply of gas through pipelines and the use of gas supplied through pipelines.

The Commission reports to the Malaysian Ministry of Energy, Green Technology and Water (KeTTHA) and is responsible for the oversight of all elements of the industry from tariffs and licensing to consumer safety. The Commission works in close cooperation with the Sustainable Energy Development Authority of Malaysia (SEDA), which is a statutory body formed under the Sustainable Energy Development Authority Act 2011 to administer and manage the implementation of the feed-in tariff mechanism under the Renewable Energy Act 2011 (see below). A company seeking to participate in the extraction of oil and gas in Malaysia will generally do so by entering into production-sharing contracts, joint operating agreements or farm-out agreements with Petronas Nasional Berhad (PETRONAS), and a PETRONAS licence is required in order to operate a business of processing or refining of petroleum and marketing or distributing petroleum or petrochemical products.

---

7 The regulation of energy and electricity in the state of Sarawak is under the purview of Sarawak Energy Berhad (SEB), known as the Sarawak Electricity Supply Corporation (SESCO) prior to privatisation. Additionally, Sarawak has its own state laws for environmental protection and occupational health and safety.
9 Section 2, Petroleum Development Act 1974.
10 Section 6, Petroleum Development Act 1974.
ii Regulated activities

Generation and supply of electricity

The construction, operation, management and use of electrical installations, plants and equipment designed for the supply or use of electricity requires a licence from the Commission. There are two main types of licence issued under the ESA:

a licences for ‘private installations’, meaning any installation operated by a licensee or owner solely for the supply of energy to and use on the licensee’s or owner’s own property or premises, or, in the case of a consumer, taking electricity from a public installation or supply authority, for use only on the licensee’s or owner’s property or premises; and

b licences for ‘public installations’, meaning an installation operated by a licensee for the sale and supply of electricity to any person other than the licensee.

The ESA provides that, except where expressly approved by the Minister, the maximum period for which such a licence may be granted is 21 years, and the licensee shall be required to pay an annual fee for the licence. The licences are non-transferrable and the licensee must at all times comply with the terms of its licence, which will state, inter alia, the area of supply, the declared and permitted voltage and the maximum charges that consumers may pay for the electricity. The licensee must also comply with the provisions of the Commission’s guidelines and directives (e.g., the Single Buyers Rule Guidelines) as well as those of the Grid Code Operator. The Commission may attach other terms and conditions to the licence as they see fit.

A person seeking a licence under the ESA must apply via the Commission’s online application system. Although neither the ESA nor the rules and regulations issued thereunder expressly imposes any ownership or equity limitations on the applicant, such limitations are usually set out in the terms and conditions of the licences and other regulatory approvals or, alternatively, they may be contained in the provisions of the PPAs signed between the IPPs and TNB.

The Commission may issue a provisional licence in restricted circumstances. A company that has obtained a Feed-in Tariff Approval from SEDA (see below) for any of the following types of public renewable energy installations may apply to the Commission for a provisional licence:

a biogas installations;

b biomass installations;

c solar photovoltaic installations; and

d small hydropower installations.

This is typically done to facilitate the development of the renewable energy project and to enable them to apply for financial incentives and programmes prior to the construction and operation of the facilities, and is intended to ease the entry of new participants to the renewable energy market. The Commission has stated that any company that requires a bank

11 Section 9, Electricity Supply Act 1990.
12 Section 9(4), Electricity Supply Act 1990.
loan for the project and wishes to obtain a provisional licence is required to have a paid-up capital of at least 2 per cent of the total cost of the project, or 200,000 ringgit, whichever is the greater.\textsuperscript{13}

\textbf{Generation and supply of gas via pipelines (for private gas utilities and supply of gas to consumers)}

The Gas Supply Act 1993 (GSA) applies to the delivery of gas to consumers via pipelines, downstream from the connection flange of the loading arm at the regasification terminal, or the last flange of the gas processing plant or onshore gas terminal.\textsuperscript{14} Prior to 2016, there were only two types of licences for the supply of piped gas in Peninsular Malaysia:

\begin{itemize}
  \item[a] private gas licence – allowing its holder to supply and use piped gas on their own premises, for example restaurants; and
  \item[b] gas utility licence – allowing licence holders to supply gas via pipeline to third parties for use.
\end{itemize}

However, as part of the Tenth Malaysia Plan and the country’s New Energy Policy, the Malaysian government has recently opened up the gas supply market in order to manage the growing demand for energy and gas in Malaysia and encourage economic growth. In 2016, the GSA was amended to provide more opportunities for third parties to have access to and manage gas distribution networks that they do not operate. Interested parties may now apply to the Commission for any of the following licences:

\begin{itemize}
  \item[a] import into regasification terminal licence;
  \item[b] shipping licence;
  \item[c] regasification licence;
  \item[d] transportation licence;
  \item[e] distribution licence;
  \item[f] retail licence; and
  \item[g] private gas licence.
\end{itemize}

In order to obtain a licence under the GSA, the applicant:\textsuperscript{15}

\begin{itemize}
  \item[a] must be a Malaysian-incorporated company or, if incorporated outside Malaysia, must be approved by the Commission;
  \item[b] must meet the minimum paid-up capital stipulated by the Commission (this ranges from 1 million ringgit to 5 million ringgit and depends on the type of licence being applied for);
  \item[c] must not already hold any other GSA licences, and the applicant’s directors must not hold any directorships in other GSA licence holders;
  \item[d] must have sufficient financial capability;
  \item[e] must have sufficient relevant technical capability; and
  \item[f] must comply with such other additional requirements as may be set by the Commission from time to time.
\end{itemize}

\begin{footnotes}
\item[13] Commission Guidelines on Application for a Provisional Licence.
\item[14] Section 1(3), Gas Supply Act 1993.
\end{footnotes}
Presently, licences shall not be granted to any person who is not incorporated in Malaysia, or who does not have a place of business in Malaysia (except for a licence for import of gas into a regasification terminal). Licences granted under the GSA are not transferrable or assignable without the written consent of the Commission or the Minister. The Commission has stated that the third-party access system will be implemented on 16 January 2017, and there will be a 12-month grace period for existing players to obtain the necessary licences in order to comply with the GSA.

An application to the Commission for a licence for the distribution, retail or use of gas must include details regarding the area of supply; the site location plan and piping layout; the technical specifications of the piping system; and any other information that the Commission may request in order to enable it to organise and supervise the gas distribution network in the country.

Other licences, certifications and approvals
The above licences relate to the construction of power plants and power installations, supply, sale, distribution and transmission of energy. Any person interested in entering the energy market in Malaysia should also be mindful that other ancillary licences and certifications may be required in the process of obtaining the above-mentioned licences and approvals from the Commission. Approvals from the Department of Environment of Malaysia or the Malaysian Department of Occupational Health and Safety would also be relevant to an IPP. As a condition of the ESA licences or PPAs, a licence holder would generally also be required to employ certain technically skilled and qualified persons, and potential applicants should bear in mind that although the Malaysian government has been gradually liberalising professional services in Malaysia – including engineering and construction services – the relevant laws continue to prescribe minimum qualification requirements that are favourable to Malaysians or require local participation (e.g., a minimum period of residency in Malaysia, or a minimum percentage of Malaysian or Bumiputera equity in an applicant company). A variety of other laws, such as the Factories and Machinery Act 1967 and the Petroleum (Safety Measures) Act 1984, also contain provisions addressing licences, approvals, certifications and registrations relating to safety, transportation and other ancillary matters that are ancillary, but nonetheless essential, to any party interested in entering the Malaysian energy market.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling
The electricity transmission network in Peninsular Malaysia, known as the National Grid, is owned and operated by the national energy company, TNB. IPPs sell the electricity generated to the Single Buyer Unit of TNB at a pre-determined tariff. Likewise, the electrical grid that supplies power in Sabah is operated by Sabah Electricity Sdn Bhd, a company owned partly by TNB and partly by the Sabah State government; whereas the grid in Sarawak is owned by Sarawak Energy Berhad, which is fully owned by the Sarawak state government.

20 The term ‘Bumiputera’ or ‘Bumiputra’ is used to describe Malays and the indigenous peoples of Malaysia.
These companies collectively have a monopoly on the ownership and operation of Malaysia’s power grids, and are responsible for their construction, operation and maintenance. Since the privatisation of power production in the early 1990s, the upstream market for the generation of electricity remains highly competitive with a mix of local and foreign power producers and a competitive bidding system for power plant projects.

Regarding gas, as at the beginning of 2017, only two companies have been granted a gas utility licence by the Commission: Gas Malaysia Sdn Bhd, a PETRONAS-associated company that operates and maintains the Peninsular Gas Utilisation pipeline system in Peninsular Malaysia; and Sabah Energy Corporation Sdn Bhd, which operates and maintains the gas distribution pipelines in Sabah. However, as stated above, recent amendments to the GSA are expected to facilitate the entry of new market players into an industry that is presently dominated both on the upstream and downstream level by state-controlled enterprises comprising a duopoly market in Peninsular Malaysia and a monopoly in Sabah.

## ii Transmission/transportation and distribution access

The ESA provides that, save in very limited circumstances, an ESA licence holder has a duty to supply electricity to the premises to which his or her licence relates upon receiving a notice of request from the owner or occupier of those premises. The amended GSA imposes a similar duty on the holder of a gas retail licence to supply gas to (1) a consumer’s premises; and (2) any regasification, transportation or distribution licensee, upon receiving notice of a request from them.

## iii Rates

The Commission is empowered to determine the tariffs for both electricity and gas under the ESA and GSA, and to issue guidelines of tariffs and charges including the methodology, principles or categories of tariffs and charges, and the duration for the imposition and review of said tariffs and charges.

Electricity prices are set by TNB under the regulation of the Malaysian government, via the Commission. Similarly, the tariffs for gas supply are set by Gas Malaysia Sdn Bhd, after approval of the rates by the Commission.

## iv Security and technology restrictions

In the case of a lock-out, strike, or other emergency, or if he decides that public interest so requires, the reigning monarch of Malaysia, the Yang di-Pertuan Agong, may authorise the Commission to suspend the ESA licence or take temporary possession of any power installation or gas pipeline, and operate it in a manner that the Commission sees fit, or he may order that the licence and use of the installation or pipeline be withdrawn either partially or completely.

As to information security, both the ESA and GSA have similar information security provisions, requiring an ESA licence holder and GSA licence holder respectively to be

---

23 Section 24 and Section 25, Electricity Supply Act 1990.
responsible for the preservation of confidentiality, integrity and availability of its information, information systems and supporting network infrastructure pertaining to its duties and other matters as provided under the relevant Act. He or she would also be required to take all necessary measures to protect the relevant information from unauthorised access, intrusion or removal or any risk thereof, and in the event he or she becomes aware of any incident that may interfere or affect the performance of his or her activities under the licence, he or she is obliged under the ESA to inform the Commission immediately.25

IV ENERGY MARKETS

i Development of energy markets

The current Malaysian energy sector framework is based on a single-buyer model whereby IPPs and the power generation arm of TNB are responsible for generating electricity that is sold to the single-buyer unit of TNB (in Peninsular Malaysia), Sarawak Energy (in Sarawak) and Sabah Electricity (in Sabah). The single-buyer unit of TNB (in Peninsular Malaysia), Sarawak Energy (in Sarawak) and Sabah Electricity (in Sabah) are thereafter responsible for distribution and retailing electricity in their respective jurisdictions. Malaysia also has a number of captive power plants of which the centralised utilities facilities of PETRONAS Gas in Kerteh is the largest by capacity. Captive power is nonetheless a marginal contributor to Malaysia's total energy generation capacity. The Commission also recently introduced the New Enhanced Dispatch Arrangement (NEDA) system, which allows IPPs to supply power to the National Grid without necessarily entering into a PPA. (Although existing IPPs may also participate, they must at all times comply with the terms of their respective PPAs as well and in the event of conflict, the PPA terms will prevail). NEDA introduces a system by which energy generators bid against each other on variable operating rates on a daily basis, according to the rules set by the Commission, and it is hoped that the increased competition will drive down energy prices. The NEDA system is about halfway into its third year and is still undergoing changes and development, with the latest version of the NEDA Rules being published in April 2017. It is too early to determine if the implementation of NEDA has helped keep energy prices down, although on a related note, the government announced in December 2017 that energy tariffs in Peninsular Malaysia would be maintained until December 2020.26

Since the early 1990s, the Commission has awarded power plant projects to companies based on a competitive bidding system, although the absolute discretion regarding who to grant these projects to lies with the Malaysian government; to date, there have been three recorded instances where a power plant project has been awarded by direct negotiation with the company involved, as opposed to a bidding process. The Commission has stressed that direct awards of power plant projects are the exception and not the rule.27

Prior to 2015, no PPAs had ever been granted to a foreign company (i.e., a company owned and controlled by non-Malaysians). Government policies required an IPP operator to

have no more than 49 per cent of its equity in the hands of non-Malaysian entities. At the end of 2015, the government made an exception for the acquisition of 1Malaysia Development Bhd’s power assets by China General Nuclear for 9.83 billion ringgit, making it the largest acquisition by value in the history of Malaysia’s energy industry and the first – and so far, the only – instance where the Malaysian government has made an exception to the foreign equity rule and allowed a non-Malaysian entity to acquire 100 per cent of the equity in an IPP.28

ii Energy market rules and regulation

The same laws, regulations and guidelines regulating the generation of energy also govern the supply and sale of that energy. The electricity generation licences granted under the energy laws of Malaysia (as detailed above) also authorise the generator to sell energy. Energy is sold to consumers at fixed tariff rates, which are approved by the Malaysian government. Notwithstanding Malaysia’s policy of privatisation, which was announced by the then Prime Minister of Malaysia, Mahathir Mohamad in 1988, competition in the energy market lies mainly at the level of bidding for power projects and power generation, and has little direct effect on the price paid by end-consumers for their electricity (although the generation capacity in the country at a particular point in time may affect the government’s decisions on approved tariff rates).

iii Contracts for sale of energy

In Peninsular Malaysia, electricity generated by the IPPs is sold to the Single Buyer Unit of TNB (as offtaker) pursuant to the terms of their respective PPAs. TNB then sells on the electricity to the final consumers. IPPs do not enter into contracts with individual consumers, save in highly exceptional circumstances (for instance, where the power is generated by a captive plant, to provide power to users that do not have access to the national power grid).

As for gas, all gas that is used in the generation of electricity is sold by PETRONAS to IPPs pursuant to the terms of the gas sales agreements between PETRONAS and the IPPs, and in accordance with the Commission’s Guidelines for Implementation of Gas Framework Agreement. The single buyer determines the quantity of gas that the IPPs require in order to generate their allocated capacity, and arranges for the delivery and offtake of the same as between PETRONAS and the IPPs. The commercial terms of the individual gas sales agreements are negotiated between PETRONAS and the IPPs, but these agreements are fairly standard and generally there is little room to negotiate on non-commercial points. The liberalisation of the market for the supply of gas (see Section II.ii, above) has recently opened up the possibility for third parties to sell on the gas to consumers through the former’s own piping system. However, the capacity for negotiation of the terms of supply is restricted by the fact that consumers do not have a choice of supplier; they obtain their gas supply from whichever retail licensee owns the piping system providing the gas to the consumer’s premises. The Malaysian government also maintains the power to determine gas prices and will do so when it deems it necessary to protect the consumer’s interest.

iv Market developments

Net Energy Metering

The Net Energy Metering (NEM) scheme is one of the more comprehensive developments to the renewable energy market in Malaysia. Under NEM, energy produced from the solar photovoltaic (PV) system installed will be consumed first, and any excess to be exported and sold to the distribution licensee (such as TNB for Peninsular Malaysia or Sabah Energy Corporation Sdn Bhd (SESB) for Sabah and Labuan) at the prevailing displaced cost (prescribed by the Energy Commission). The NEM programme was introduced with the intention of replacing the Feed-in Tariff (FiT) mechanism for solar photovoltaic installations, which closed at the end of 2017 (see below).

The scheme is executed by KeTTHA and regulated by the Commission, with SEDA as the implementing agency. To participate in NEM, applicants must register as consumers of distribution licensees in Peninsular Malaysia, Sabah and Labuan. Foreign entities are also eligible to apply as long as they are customers of the distribution licensees. The resources for producing electricity shall be from Solar Photovoltaic only; however, other renewable energy resources such as biogas, biomass, or micro hydro may be allowed on a case-by-case basis at the sole discretion of the Commission.29

The scheme is applicable to all domestic, residential, commercial (inclusive of government buildings) and industrial sectors, subject to the capacity limits set out in the Commission’s Guidelines for Solar Photovoltaic Installation on Net Energy Metering Scheme.

Applications for NEM shall be on a first come first served basis up to the allocated quota, which is provided by SEDA on its website.30 The application may be made by the applicant’s appointed registered PV service provider (RPVSP) or Registered Electrical Contractor (REC), and it should be submitted either manually to SEDA or online via SEDA’s online application portal.

If NEM approval is granted, the NEM consumer will need to apply for a public generation licence with the Commission. Once successful, a NEM contract can be signed between the NEM consumer and the distribution licensee.

NEM consumers may apply to convert to the FiT scheme provided that the consumer is successful in achieving the FiT quota; in such cases, all requirements under the FiT scheme shall apply.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

Since the implementation of the Tenth Malaysia Plan, the government – via the Commission, KeTTHA, and SEDA – have implemented a range of programmes and projects to educate the Malaysian public and encourage electricity efficiency and energy conservation. Energy laws and regulations are reflective of this; for example, the Efficient Management of Electrical Energy Regulations 2008 authorises the Commission to require operators and owners of


30 See SEDA’s website at https://services.seda.gov.my/nem/auth/login.
Malaysia
installations that consume 3 million kWh or more over a six-month period to engage a
registered energy manager to analyse the total consumption of electrical energy, advise on the
development and implementation of measures to ensure efficient management of energy and
monitor the effectiveness of the implemented measures.31 The introduction of the feed-in
tariff mechanism under the Renewable Energy Act 2011(REA)and the implementation of
the Solid Waste and Public Cleansing Management Act (2007) were similarly enacted in
aim of growing and developing the country’s green energy industry while creating jobs and
improving the quality of life of Malaysians generally.
There are currently a number of fiscal incentives in place that are specifically targeted
at potential entrants to the renewable energy market in Malaysia. For example, KeTTHA
has approved a budget of 5 billion ringgit to help fund new energy efficiency projects in
Malaysia for the period 2018–2022.32 As of 1 September 2016, there have been a total of
509 applications processed, of which 243 projects were approved.33 Following the spirit of
the Eleventh Malaysia Plan, SEDA – with the blessing of the Economic Planning Unit – has
introduced the Energy Efficiency Projects Malaysia, which is a conditional energy audit grant
for commercial buildings consuming more than 3 million kWh for six consecutive months.34
The Malaysian Investment Development Authority (MIDA) offers tax incentives
for green technology projects and services. Subject to any other conditions imposed by
MIDA, a Malaysian company that undertakes a green technology project may be eligible for
Investment Tax Allowance of 100 per cent of the qualifying capital expenditure incurred in
a green technology project from the year of assessment 2013 until year of assessment 2020.
Similarly, a Malaysian company that provides green technology services or a company that
purchases green technology assets as listed In MIDA’s MyHijau Directory is eligible for an
income tax exemption of 100 per cent of their statutory income from the year of assessment
2013 until year of assessment 2020.35
Feed-in tariff approvals and renewable energy power purchase agreements
A small producer of renewable energy may apply to SEDA for its approval to participate in
the feed-in tariff system established under REA, which will allow locally produced electricity
to be sold to power utilities at a fixed premium for a specific period. In particular, the REA
states that the feed-in tariffs will provide for:
a
the connection to supply-line connection points for the distribution of renewable energy
generated by renewable energy installations that are owned by feed-in approval holders;
b
the priority of purchase and distribution by the distribution licensee (meaning the
holder of an ESA licence) for renewable energy generated and sold by feed-in approval
holders; and
c
the feed-in tariff to be paid by distribution licensees to feed-in approval holders for such
renewable energy.

31
32
33
34
35

Mohd Khalemi, ‘Green Tech Financing Scheme to Continue With RM5bil Funding | Green Technology
Financing Scheme (GTFS)’, KeTTHA, 2 March 2017.
More information is available on SEDA’s website at www.seda.gov.my/?omaneg=00010100000001010101
000100001000000000000000000000&s=5400.
Malaysia Investment Development Authority, ‘Application for Incentive and/or Expatriate Posts for Green
Technology’.

271
© 2018 Law Business Research Ltd


In order to be eligible to participate in the feed-in tariff system, the applicant must propose to generate renewable energy from a renewable energy installation with an installed capacity of not more than 30MW, or such higher installed capacity as may be approved by the Minister. In addition, Rule 3 of the Renewable Energy (Feed-In Approval and Feed-In Tariff Rate) Rules 2011 provides that where the producer is a corporate body, it is subject to the following requirements and provisos:

- the company must be incorporated in Malaysia;
- the foreign equity participation in the company must not exceed 49 per cent during the application and for the entire period of approval; \(^\text{36}\) and
- if the company is already a holder of a ESA licence, or if it is an associate of an existing ESA licence holder, then that company is prohibited from making any application for a feed-in approval relating to a renewable energy installation proposed to be connected to the electricity distribution network of the ESA licence holder. \(^\text{37}\)

The application may be made by the company or its authorised representative, and it should be submitted either manually to SEDA, or online via SEDA’s online application portal. The application should include supporting information regarding the renewable energy installation, including:

- a description of the installation including the type of renewable energy resource to be used;
- the proposed location of the installation;
- the proposed installed capacity of the installation;
- the proposed feed-in tariff commencement date; and
- the name of the ESA licence holder whose electricity distribution network is proposed to be connected to the renewable energy installation, including the location, details and specifications of the proposed connection.

The other pre-requisites for SEDA approval may vary according to the source of the renewable energy (solar, biomass, hydroelectricity, etc.) and the output of the renewable energy installation. SEDA has a number of guidelines and documents on its website detailing the application processes, tests and checks to be carried out and technical requirements for each particular type of renewable energy installation. For instance, corporate applicants must have a minimum paid-up capital of 20,000 ringgit or equivalent if they intend to develop renewable energy installations with a rated kWp or net export capacity of up to 72kWp or kW. If the installation’s net export capacity exceeds 72kWp, then this minimum paid-up capital is increased to 50,000 ringgit or its equivalent. \(^\text{38}\) Additionally, SEDA may require the applicant to conduct tests and checks, including a Connection Confirmation Check or Power System Study conducted in accordance with the Renewable Energy (Technical and Operational Requirements) Rules 2011.

---

\(^{36}\) Rule 10 of the Renewable Energy (Feed-in Approval and Feed-in Tariff Rate) Rules 2011 requires the applicant company to submit ‘its corporate information, including the ultimate beneficial shareholders of the company’.


\(^{38}\) Guidelines and Determinations of the Sustainable Energy Development Authority of Malaysia dated 5 February 2016.
A feed-in approval granted under the REA may be assigned or transferred, but only with the consent of SEDA, which has absolute discretion as to whether to approve or refuse to allow the assignment or transfer of the feed-in tariff approval. SEDA will not approve such assignment or transfer unless it is satisfied that the proposed assignment or transfer:

a was not reasonably foreseeable at the time of application for the initial feed-in tariff approval;

b is just and reasonable; and

c is not inconsistent with the objectives of the REA and the current energy policies of the Malaysian government, taking into account the need for sustainability and diversity in renewable resources and the need for fair competition and transparency in the implementation of the feed-in tariff system.

If the feed-in tariff approval is granted, then the ESA licence holder whose distribution network is to be connected to the renewable energy power plant or installation to which the approval relates is required to enter into a renewable energy power purchase agreement (REPPA) with the feed-in approval holder in the form prescribed under the Renewable Energy (Renewable Energy Power Purchase Agreement) Rules 2011. The minimum terms of the REPPA vary according to the type of renewable resource used, and the capacity of the renewable energy installation. Similar to PPAs, REPPAs may contain restrictions on foreign participation, foreign control or transfer/assignment that are more stringent than those prescribed under the renewable energy laws, although these will generally be reflective of the existing government policies on foreign investment in the Malaysian energy sector.

It should be noted that Feed-in Tariff approvals are subject to a quota. Successful applications will be placed in a queue and subject to a ballot process until the quota is exhausted. With the introduction of the Net Energy Metering and Large Scale Solar Photovoltaic Plant Schemes (as described above), the Feed-In Tariff is being phased out with quotas only available for small hydropower installations at the time of writing.

**Large-scale solar photovoltaic plants**

As part of its plans to phase out the Feed-in Tariff Scheme, the Commission conducted a competitive bidding process to select developers or developer consortiums for the development of large scale photovoltaic plants to be located in West Malaysia and Sabah. The plant will be connected to the distribution or transmission grid depending on its proposed capacity, and sell its energy to the Single Buyer Unit of TNB or to SESB (as the case may be) under a power purchase agreement, and the large-scale solar capacity to be tendered will be from 1MWac to 50MWac.

Only Malaysian companies that pass the prescribed minimum Malaysian equity interest thresholds may participate in the large-scale solar (LSS) programme. These thresholders are:

a the equity of the participant company is held by at least 51 per cent Malaysians; or

b the equity of the participant company consists of a consortium of legal entities that includes a minimum of one Malaysian company, and where the Malaysian equity interest in the consortium is at least 51 per cent.

---

40 Ibid. at footnote 36.
Successful bidders will enter into a PPA negotiation process with the distribution licensee or the single buyer based on the PPA that has been approved by the Commission. Upon successful negotiation, the bidders must fulfil all conditions precedents under the PPA. All LSS plants shall be licensed under Section 9 of the Electricity Supply Act 1990.

In December 2016, TNB, Malakoff Corporation Berhad, Mudajaya Group Bhd and Integrated Logistics Berhad were awarded projects to develop LSS plants. The PPAs signed were for a period of 21 years and are expected to become operational in 2018, save that the Commission subsequently revoked the approval of Malakoff Corporation Berhad.

ii Technological developments

A vital part of the Malaysian government’s drive towards energy efficiency involves monitoring and educating consumers so as to improve management on the demand-side. In 2011, the Sustainability Achieved via Energy Efficiency programme was launched, whereby a total of 44.3 million ringgit was allocated as rebates for the purchase of new energy efficient refrigerators and air conditioners for domestic use, as well as chillers for industries. The total energy saved as a result of this initiative was 306.9GWh.41

In 2014, TNB, along with the government, launched a 1,000-unit smart meter, two-year pilot smart grid project in Melaka and Putrajaya.42 The project was funded by the government and is targeted at reducing energy consumption by encouraging Malaysians to be more engaged with their management of energy usage. The pilot has since extended to regions in the state of Selangor, according to a joint press statement by KeTTHA and TNB in late 2017. TNB has also announced plans to install advanced metering infrastructure in 8.3 million households across the country by 2021.43

The Malaysian government has also taken a ‘lead-by-example’ approach when it comes to renewable energy. Starting in 2013, the Ministry of Finance issued Government Green Procurement Guidelines, through which the government will actively acquire products and services that are environmentally friendly, and leverage its purchasing power to encourage industries and private enterprises to do likewise.44 Since its pilot in July 2013, five selected ministries have procured green products and services worth 352 million ringgit as of April 2015.45

VI THE YEAR IN REVIEW

a In September 2017, Malaysia signed a cross-border power trading agreement with Laos and Thailand. It is the first multilateral power exchange project in ASEAN and will allow Malaysia to purchase power from Laos, transmitting it through the transmission network of Thailand, before reaching Peninsular Malaysia.

---

43 ‘TNB: Smart meters nationwide by 2021’ (18 April 2017), as reported by The Malaysian Reserve.
44 At the time of writing, the GGP (Version 2014) is available at www.scpmalaysia.gov.my/images/GGP%20GUIDELINES%20FINAL%20-%20NATIONAL%20-%20080814.pdf.
In September 2017, construction began on a 50MW LSS project in Kuala Langat, Selangor, which is reported as already being 50 per cent completed at the time of writing.\textsuperscript{46}

TNB is expanding its renewable energy portfolio on an international scale, including the acquisition of assets in solar, wind and hydro in the United Kingdom, Turkey and India. It most recently acquired an 80 per cent stake in two United Kingdom-based renewable energy companies for 418.13 million ringgit, bringing its total international renewable energy portfolio to about 280MW.\textsuperscript{47}

It was recently announced by the Sarawak Chief Minister that, as of July 2018, Sarawak will assume full regulatory authority over the upstream and downstream operations and activities of the oil and gas industry. He further announced that all persons and companies in the oil and gas industry in Sarawak would be required to obtain the requisite licences, permissions and approvals under the Sarawak Oil Mining Ordinance 1958 and the Gas Distribution Ordinance. Such announcement appears to indicate a prequel to changes in how exploration and production of oil and gas will be regulated in Sarawak in the future, which may also necessitate wholesale changes in the federal legislative framework. The Chief Minister’s statements appear to have been made on assurances granted by the current Prime Minister of Malaysia, and it will be interesting to observe this development in Malaysian oil and gas law.\textsuperscript{48}

In an interview given by KeTTHA Minister Datuk Seri Dr Maximus Johnity Ongkili, Malaysia is currently on track to reach its 50 per cent renewable energy target by 2050, with power being mainly generated through solar energy, hydro, biomass and biogas. It was reported that, while geographically limited, there is still great potential to be gleaned from Malaysia’s geothermal, wind, and wave power.\textsuperscript{49}

The Commission has recently published its Guidelines on Implementation of Gas Framework Agreements in the Power Sector, which sets out the gas power framework in Malaysia and defines the roles of the single buyer, gas supply operators, TNB, PETRONAS and IPPs, with respect to the nomination and allocation of gas to the Malaysian power sector.

\section*{VII CONCLUSIONS AND OUTLOOK}

Over the past year, Malaysia has made visible strides in its efforts to steer the country away from an overdependence on coal and gas, and encourage the production and use of renewable energy on a private and corporate level. The continuing decline in the cost of solar power generation looks to be the main driver of the continued growth of the renewable energy generation in Malaysia.

\textsuperscript{46} TNB Press Statement, ‘TNB Seeks Opportunities to Dive Malaysia’s RE Aspiration’, 14 September 2017. See also: TNB’s Large Scale Solar project already 50pct completed as reported by the News Straits Times.

\textsuperscript{47} Sangeetha Amarthalingam, ‘Tenaga buys 80% of two UK renewable energy firms for £77.37m’, The Edge Markets, 1 March 2018.


\textsuperscript{49} Kristy Inus, ‘Malaysia will meet 2050 target of 50%’, News Straits Times, 25 January 2018.
Gas price reforms in Malaysia and third-party access for gas distribution also points to the eventual removal of subsidies in the power sector, and may reduce the attractiveness of gas-fired plants, although gas will remain one of the major sources of power generation in the country in order to support the drive towards compliance with Malaysia’s commitments under the Intended Nationally Determined Contribution to reduce its greenhouse gas emissions intensity (per unit of GDP) by 45 per cent by 2030, relative to the emissions intensity in 2005.

However, the most intriguing development in the Malaysian energy industry in the past year has been the recent announcement by the Chief Minister of Sarawak that the state of Sarawak fully intends to enforce its constitutional right to complete regulatory authority over the upstream and downstream oil and gas Industry in Sarawak. At the time of writing, the regulation of the oil and gas industry in Sarawak remains, as it has since the 1960s, within the jurisdiction of the Malaysian federal government. Being the largest state (by land mass) in Malaysia and one of the richest in natural resources, the shift of regulatory authority back to Sarawak after over 50 years would mean that current operators in Sarawak will have to apply for a new licence, permit or registration with the Sarawakian government in order to continue operating there. In addition, the announcement also raises questions on the status of the practical implementation process of the above, which remains unclear. It will be interesting to see how the state and federal government of Malaysia decide to move forward and how it will impact existing and incoming foreign investors.

50 See the official statement released by the office of the Chief Minister of Sarawak, available at the following link: www.cm.sarawak.gov.my/modules/web/pages.php?mod=news&sub=news_view&nid=1968.
MOZAMBIQUE

I OVERVIEW

Mozambique is a rapidly developing country with great potential for the production and export of hydrocarbons and the generation of electrical power.

However, legislation in energy matters is only now trying to keep up with the pace of the growing complexity of the energy investments being made in the country, and the aspiration of establishing specific incentives for the generation of renewable electricity and for off-grid power initiatives in non-urban and ‘peri-urban’ communities. The framework of the electricity sector, the Electricity Act, for instance, is over 15 years old. A regulatory overhaul in the electricity sector is said to be in the pipeline and the new legislative framework for oil, approved by Law No. 21/2014 of 18 August, has, after several years in the pipeline, finally been enacted.

Other legislation recently enacted in the oil and gas sector, includes, notably, Decree No. 45/2012 of 28 December, relating to the production, import, loading, storage, handling, distribution, sale, transport, export and re-export of petroleum products (the Petroleum Products Regulation), and Decree-Law No. 2/2014, relating to the specific legal and contractual regime applicable to projects in the Rovuma Basin.

The electricity sector is a concession-based system with limited competition, in which one company, state-owned Electricidade de Moçambique, EP (EdM) is the national transmission grid operator, and also holds concessions for generation, transmission, distribution and supply of electricity. Other notable concessionaires include Hidroeléctrica de Cahora Bassa SA, which produces most of the energy consumed in Mozambique, and MoTaCo SA, a joint venture between the Mozambican, South African and Malawian governments, which transmits power from South Africa to the Moza aluminium smelter.

The oil and gas sector also has a concession system, where operating risks from the exploration of hydrocarbons are mostly borne by private investors. Empresa Nacional de Hidrocarbonetos EP (ENH) operates mainly in the upstream sector and holds participations in all oil and gas fields concessions in Mozambique. Recent years have witnessed very significant discoveries of natural gas, which have attracted several oil and gas market participants to the country and transformed the upstream industry.

1 Fabrícia de Almeida Henriques and Paula Duarte Rocha are partners at Henriques, Rocha & Associados, member of MLGTS Legal Circle as Mozambique Legal Circle.
2 Law No. 21/97 of 1 October.
In the petroleum products sector, there have been recent legislative attempts at creating an unbundled and competitive market. State-owned company Petróleos de Moçambique SA (Petromoc) is active in the midstream and downstream sector, storing and selling petroleum derivatives such as fuels, oils and lubricants.

The latest and most detailed instrument of government policy for the energy sector is contained in Resolution No. 10/2009, of 4 June (the Energy Strategy), in which one can find the main policy goals defined by the Mozambican government in this matter, notably:

- to provide greater access to electricity and fuels to rural and peri-urban areas;
- to discourage the non-sustainable use of lumber as a source of energy;
- to stimulate the sustainable production of biofuels;
- to diversify energy sources;
- to implement a cost-based tariff system, one that includes environmental externalities; and
- to engage in international cooperation, especially with the Southern African Development Community (SADC).

Other important policy resolutions for the government can be found in:

- Resolution No. 27/2009 of 8 June, which adopted the Strategy for the Concession of Areas for Petroleum Operations;
- Resolution No. 62/2009 of 14 October, which adopted the Policy for the Development of New and Renewable Energies; and
- Resolution No. 64/2009 of 2 November, relating to the Strategy for the Natural Gas Market in Mozambique.

II REGULATION

i The regulators

The most relevant administrative entities regulating the Mozambican energy industry are:

- the Council of Ministers, for all sectors of the energy industry;
- the Ministry of Natural Resources and Energy, for all sectors of the energy industry;
- the Energy Regulation Authority (ARENE); and
- the National Petroleum Institute (INP), for the oil and gas sector.

The Council of Ministers represents the executive branch of government in Mozambique and, as such, the Constitution and main legislative diplomas in this sector grant it substantial powers in this field. Pursuant to the terms of the Constitution, the Council of Ministers may propose or enact legislation and promote and regulate economic activity. Making use of these powers, the Council of Ministers has adopted the vast majority of energy legislation in Mozambique.

In addition to the powers of legislation and regulation, the Council of Ministers has regulatory powers set out in the law, such as the granting of concessions (after the applicable tender offer) for electricity projects with nominal installed capacity of over 100MVA, according to the terms of Decree No. 8/2000 of 20 April (the Energy Concessions Regulation).

The Ministry of Natural Resources and Energy, as part of the central government, also has important powers in what the energy sector in Mozambique is concerned, defined in Presidential Decree No. 21/2005 of 31 March, such as in adopting regulations in the energy sector and licensing the activities of storage, distribution, supply and sale of natural
gas and petroleum products, as well as the granting of concessions of electricity projects with nominal installed capacity between 1MVA and 100MVA. More importantly, the Ministry of Natural Resources and Energy is the entity that instructs and (in tandem with the Council of Ministers) decides on concession requests for electricity and oil and gas projects, and monitors the activities of the concessionaires.

ARENE is the energy regulation authority that was established by Law No. 11/2007, the same statute that abolished the former CNELEC. ARENE is an independent public company charged with supervising and regulating the energy sector. Among ARENE’s powers are:

- a. implementation of energy development policies and strategies;
- b. participation and supervision of public tenders for electricity concessions;
- c. ensuring compliance with the terms and conditions of concession contracts and licences;
- d. issuance of opinions on proposals and recommendations on energy policy; and
- e. performing studies on different aspects of the electricity sectors.

ARENE also has mediation and arbitration functions for disputes arising between:
1. concessionaires and other licensed entities; and
2. concessionaires and their respective consumers.

Finally, the INP has its powers set out in Decree No. 25/2004 of 20 August, categorised as:

- a. management of National Petroleum Database;
- b. research activities;
- c. powers relating to petroleum development, production and transport activities;
- d. powers relating to the safekeeping of operators interests; and
- e. general powers of administration, monitoring and regulation.

By virtue of Law No. 11/2017, all the rights and obligations of CNELEC were transferred to ARENE. As such, ARENE now has the competences that previously belonged to its predecessor and has also been given more extensive powers in this regard.

The INP also has powers to license as well as inspect any facilities relating to petroleum operations.

As for the applicable sources of law, the main framework legislation both in the electricity and in the oil and gas sectors is enacted in the form of law of the Mozambican parliament (the Electricity Act and Law No. 21/2014 of 18 August, the Petroleum Act). This legislation is implemented largely in the form of Decrees adopted by the Council of Ministers. Finally, the Ministry of Natural Resources and Energy may also issue orders.

ii Regulated activities

All activities in the electricity value chain (generation, transmission, distribution and supply) and most activities in the oil and gas value chain (prospection, research and production and transport of oil and natural gas, as well as the distribution and supply of natural gas) are subject to a regulatory approval by the Ministry of Natural Resources and Energy, the Council of Ministers or local authorities, depending on what is established in the applicable law, in the form of a concession agreement. Activities in the petroleum products value chain (production, storage, transport, distribution and sale, as well as the operation of unloading terminals and oil pipelines) are subject to licensing by the Ministry of Natural Resources and Energy in accordance with the terms of the Petroleum Products Regulation.
Energy facilities across all sectors are also subject to licensing, pursuant to the terms of the relevant legislation.

Concessions in the electricity sector are subject to tender offers, in accordance with the Energy Concessions Regulation. Tenders must follow the guidelines set out in the terms of reference and are directed to the relevant competent authority (i.e., the Council of Ministers, the Ministry of Natural Resources and Energy or local authorities). Tenders must also specify the technical and financial details of the project and provide sufficient evidence of the appropriate qualifications of the applicant. Hydroelectric projects require additional information on the characteristics of the hydroelectric use of the water resources; energy generation and transport concessions are also subject to additional requirements.

After the tender has been requested, ARENE issues an opinion on the subject; projects that imply the acquisition of land-use rights must also be preceded by a public consultation. After these steps have been undertaken, a decision by the relevant regulatory authority must be issued within 15 days. The effectiveness of this decision may be subject to conditions, such as expropriation or the granting of land-use rights.

A favourable decision by the authority will determine the entering of a concession agreement, where terms such as duration, applicable taxes and tariffs, conflict resolution mechanisms, guarantees, reversion and applicable law must be included. The concession agreement must also include a draft of the agreement to be signed by the National Transmission Network operator.

Electricity facilities are also subject to the granting of establishment and operation licences by the Ministry of Natural Resources and Energy prior to the start of operations. For the establishment licence, technical features of the facilities must be presented with the application, which must be decided within 15 days, except if additional documents or information are requested by the Ministry of Natural Resources and Energy. If granted, the publication of an edict in the Official Gazette will ensue and the project for the construction of the facility may begin. At the end of construction, a site visit accompanied by a favourable opinion from the competent inspector is required for an operation licence to be issued.3

Concessions pertaining to hydrocarbons prospection, research and extraction or construction and operation of pipelines are also subject to tender offers, according to the terms of Decree No. 34/2015 of 31 December (the Petroleum Operations Regulation). Exceptions are made for tender offers in which no bidder has been chosen, termination of concession, or unitisation purposes, among others. In such cases, the Decree stipulates that a concession agreement may be attributed via a direct or simultaneous negotiation with applicants.4

In the sale and distribution of natural gas, the competent authority to grant a concession depends on the area for distribution or sale awarded pursuant to the terms of Decree No. 44/2005 of 29 November through a tender offer. As in oil and gas upstream concessions, the procedure for the awarding of a concession is also not regulated in the diploma.

Licensing of oil or gas facilities must include an establishment licence, requested from the INP, which has 10 days to make its decision upon receipt of the necessary information and documents, as well as the opinion of various regulatory entities such as for health,

---

3 Such procedure simplified by the provisions of Decree No. 10/2016 of 25 April.
4 A ‘model’ or ‘draft’ concession agreement for research and exploration of oil was implemented by Resolution of the Council of Ministers No. 25/2016 of 3 October.
environment, labour and civil protection. The operation licence is then granted after construction, and a site visit made by a committee, which will confirm whether the facility conforms to the project, any regulatory conditions and applicable technical norms.

Finally, licensing of activities relating to petroleum products and the corresponding facilities is subject to the approval of the Ministry of Natural Resources and Energy, except for licensing of fuel stations for resale and sale to end users, which is carried out by the local authorities and by the provincial directorates of the Ministry of Natural Resources and Energy, respectively. Licence requests must be accompanied by several elements of identification, as well as the main technical characteristics of the facilities at which the activities will be undertaken; different activities entail specific documentation or information, which must be presented with the request. The licensing entity must decide within 30 days of receipt of the request, and is bound by certain criteria to overrule it, such as the occurrence of anticompetitive effects stemming from the granting of the licence. Licences may be subject to conditions to be defined by the relevant licensing entity.

Before the start of operations of any of the aforementioned activities in the petroleum products fuel chain, licences must be registered after a mandatory site visit, to be carried out by a commission that includes representatives of various regulatory authorities, including the licensing entity.

iii Ownership and market access restrictions

In the electricity sector, there are no obvious limitations on the ownership of both new and existing assets and companies in this business sector, nor direct restrictions on asset ownership save for the general merger and takeover control provisions introduced in Law No. 10/2013, enacted on 20 March 2013 (the Competition Act), the scope of which is the protection of competition in the undertaking of economic activities. Preference, however, is given to applicants for oil or natural gas concessions that are Mozambican nationals or are associated with Mozambican nationals if two or more applicants are on equal footing.

In the petroleum products sector, however, several restrictions of this nature exist, set out in the Petroleum Products Regulation, the most relevant being:

- the prohibition of the mingling of distribution and retail activities, except when it relates to liquid petroleum gas (LPG) or compressed natural gas and for training purposes (undertaken in fuel stations);
- licensed entities may be entitled to hold more than one licence in the value chain, as long as no anticompetitive effects stem from this situation; and
- only Mozambican nationals and Mozambican companies may hold licences for petroleum products (there appears to be no restrictions for Mozambican companies held by foreign equity holders, however).

There are no restrictions on the provision of regulated services (i.e., supply of electricity and natural gas) and no restrictions on the ownership of assets or licensed activities other than those set out in the previous paragraph.

iv Transfers of control and assignments

Transfer of interests in electricity concessions, of assets encompassed by an electricity concession and of establishment licences of electricity facilities are subject to regulatory approval by the regulatory authority that granted the concession or the licence, according to the terms of
the applicable Mozambican law. Transfer of operation licences of electrical facilities is not possible under Mozambican law and, as such, should the licensee change, a new licence will have to be issued pursuant to the terms of Decree No. 48/2007 of 22 October.

The procedure for the transfer of concession rights or assets encompassed by the concession itself is not clear in either the Electricity Act or the Electricity Concessions Regulation, but will likely depend on a request submitted to the relevant regulatory authority and, if land-use rights are transferred, a public consultation, the same as with the granting of a new concession. In respect of establishment licences, the transfer will be subject to a request to the Ministry of Natural Resources and Energy. No express standards for reviews or decision-making guidelines are established in these procedures for the regulatory authorities, but such authorities in Mozambique are, according to the Constitution, bound by principles of equality, impartiality, ethics and justice.

With regards to the transfer of interests in oil or natural gas concessions, the new legislation makes direct and indirect transfers of the concession subject to prior governmental approval, along with other forms of assignment of participation interests, directly or indirectly, in concession agreements, including the transfer of shares or other forms of participation of the holder of concession rights.

As for the petroleum products sector, transfer of facilities in the corresponding value chain is subject to prior authorisation from the Minister of Natural Resources and Energy, who is bound to grant it if the licensee does not obtain, after the transaction, more than a 30 per cent market share of the relevant petroleum products market.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Shortly after the independence of the Republic of Mozambique from Portugal in 1975, EdM was granted, by Decree Law No. 38/77, a quasi-monopoly in the generation, transmission and distribution of energy, with the exception of off-grid generation and other existing concessionaires (notably the Cahora Bassa dam, albeit not in operation at the time). The result was a fully integrated vertical system in the electricity sector until the adoption of the Electricity Act. Nowadays, the sector is still bundled to some degree, as EdM still holds a single concession for distribution and sale of electricity. It is the main transmission concessionaire, as well as the national transmission grid operator, through the provision set out in Decree No. 43/2005 of 29 November, as unbundling requirements in this sector do not exist under Mozambican law.

With regards to oil and natural gas, there is also no formal bundling or concentration of the upstream industry, notwithstanding the fact that ENH is a party to all concessions in the upstream sector.

Recent efforts towards the implementation of networks for distribution and sale of natural gas have been made, and the law determines that concessions must be unbundled. Concessions for suppliers of natural gas are further subject to an exclusivity period, after which third parties may sell natural gas to end consumers.

ii Transmission/transportation and distribution access

Operators of storage, transport, transmission and distribution networks are obliged to provide access to these networks and to practise non-discriminatory treatment of third parties.
In the electricity sector, the Electricity Act provides for the mandatory granting of access to third parties to electrical networks. Decree No. 42/2005 of 29 November (the National Transmission System Regulation) establishes that transmission concessionaires must enter into agreements for the transmission of electricity to any generation and distribution concessionaire, and to any final consumer that requires connection to the grid. Likewise, distribution concessionaires must guarantee the supply of electrical energy to all consumers who have the capacity to ensure payment for their respective connections. Connection may be refused only in certain cases; for example, where the supply is in medium or low voltage and the requested capacity may cause damage to the distribution grid, or if the applicant is declared insolvent or bankrupt. Distributors also have the obligation to install new lines whenever so required (as long as a minimum consumption per 100 metres of new distribution lines is assured). Access to transmission and distribution grids must be made in a non-discriminatory fashion regarding quality of service and agreed-upon tariffs.

Pipelines and petroleum product facilities must also transport, store, unload or handle hydrocarbons or fuels from third parties without discrimination, as long as there is available capacity and no insurmountable technical issues exist. Furthermore, capacity must be increased if such an operation does not affect the integrity of the facilities and as long as those third parties provide the necessary funding. Access to natural gas distribution networks, on the other hand, is subject to rules for negotiated access to be enacted by the Minister of Natural Resources and Energy. In any case, all activities must be conducted with transparency and without discrimination against third parties.

Network providers in distribution and transmission of energy, as well as distributors of natural gas, are granted rights over a predetermined area. The law is not clear, however, on whether the rights are exclusive.

Finally, competition concerns have definitely played a role in the rules concerning third-party access to energy networks. Council of Ministers’ resolutions regarding energy policy mention tackling competition issues, which necessarily implies dissipating the negative effects of ‘bottlenecks’ for consumers by giving suppliers ease of access to electricity and natural gas networks. A general provision on the matter has been implemented by the Competition Act regarding the abuse of a dominant position.5

### iii Terminalling, processing and treatment

Storage, processing and treatment of oil and natural gas, as well as the storage of petroleum products, are subject to licensing of the activity and registration of the respective facilities (see Section II.ii, above). There does not appear to be any specific regulation on liquefied natural gas facilities.

---

5 Article 19(3)(b) of the Competition Act establishes that the following is considered an abuse of a dominant position: the refusal by a company to grant to any other company, for adequate compensation, access to a network or other essential infrastructure that the first company controls as long as the other company cannot, for legal or practical reasons, operate as a competitor of the company that controls the assets at issue. This provision is not applicable if the company that controls the assets at issue demonstrates that such access is impossible under reasonable conditions.
iv Rates

As a general rule, rates for transport and distribution of energy are mostly determined by bilateral contracts rather than regulated tariffs (which are only set for the sale of electricity, natural gas and fuels to the end-consumer). There are, however, standards that some concessionaires must consider when setting the fees for the rendering of their services.

Nonetheless, the Electricity Act in the electrical sector establishes a ‘transit tariff’ for third-party use of transmission and distribution facilities, which is not regulated. The National Transmission System Regulation determines that contracts entered into with transmission concessionaires must set rates that:

a. assure non-discriminatory treatment of consumers;

b. assure the coverage of costs consistent with ‘standard costs’;

c. stimulate new investment in the expansion of electrical systems;

d. induce the use of electrical systems; and

e. minimise the costs for expansion or use of electrical systems.

As for distribution, rates are fixed with generation and energy supply concessionaires. For the latter, a tariff for use of the distribution system must be set.

Oil and gas pipelines are subject to tariffs set in the relevant concession agreement and are based on the following principles:

a. the tariff is to contemplate total reserved capacity for the infrastructure;

b. the tariff shall include the cost of capital and operational costs; and

c. the tariff shall take profitability into account, which must not exceed the designated rate of return.

Petroleum product storage facilities are subject to ‘non-discriminatory’ and ‘commercially acceptable’ terms in the setting of use rates. In oil re-exporting services (in bunkers), rates must be fair, competitive and non-discriminatory, taking into account the prices charged in other terminals in Southern Africa.

Natural gas distribution network rates are set by concessionaires, subject to the rules of negotiated access set by the Minister of Energy.

v Security and technology restrictions

Energy legislation in Mozambique takes into account several security policy concerns, such as:

a. fuel supply security and safety;

b. theft of energy and theft and vandalism of power lines; and

c. energy supply and network security.

As regards supply security and safety of hydrocarbon fuels supply (e.g., petrol), the Petroleum Products Regulation addresses safety concerns regarding petroleum product facilities by imposing several obligations on their respective owners, such as:

a. the obligation of distributors to keep a permanent deposit of 6 per cent (or 3 per cent, in the case of LPG) of the fuels acquired for sale in the previous 12 months, as well as ‘operational reserves’ of the aforementioned fuels;

b. the mandatory decommissioning of redundant petroleum product facilities;

c. specialised works on petroleum products’ facilities being conducted or supervised by licensed oil technicians;

© 2018 Law Business Research Ltd
The Energy Strategy expressly issues recommendations for tackling the problem of theft and vandalism in the electricity networks, notably by advocating greater involvement of local communities in distribution and transmission power lines projects. Notwithstanding the foregoing, the Electricity Act establishes the theft of electricity or power lines as a crime.

Security of electricity supply is also a relevant concern in energy policy and the National Transmission System Regulation provides relevant rules on this subject. First, capacity of transmission and distribution networks must be adequate in relation to expected consumer demand. Solely regarding the distribution grid, the National Transmission System Regulation obliges distribution concessionaires to ensure service quality and supply of energy through the grid may only be interrupted under certain conditions. Finally the operator of the National Transmission System, as the coordinator of the electricity grids in Mozambique, has the obligation regarding the overall management of the system’s quality, security and continuity of supply.

IV ENERGY MARKETS

i Energy market rules and regulation

There are no organised markets for the sale of energy commodities in Mozambique. The import and export of electricity is subject to a concession, to be granted according to the terms of concessions for the generation, distribution or transmission of electricity (see Section II.ii, above).

With regards to petroleum products, imports of LPG, gasoline, jet fuel and diesel are aggregated through IMOPETRO, a company under both state and private ownership, and customers of this entity must be holders of generation or distribution licences. In exceptional cases (e.g., to ‘defend the country’s economic interests’) imports may be made through a duly licensed distributor and only if and when local production does not meet demand.

ii Contracts for sale of energy

The sale of electricity and natural gas in Mozambique takes place exclusively through bilateral agreements between generators and suppliers.

iii Market developments

As mentioned above, the electricity market is expected to undergo a regulatory overhaul, and statutes for petroleum operations and the fiscal treatment thereof were approved by parliament in August 2014. These statutes define new rules regarding state participation in oil and gas projects, introduce local content obligations and introduce changes to royalties and taxes payable for the production of oil and gas. One change worth noticing in particular is the government’s obligation to ‘allocate’ to the Mozambican market a quota of at least 25 per cent of the oil or gas, or both, produced and sold in Mozambique.
V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

Mozambique has seen timid, yet steady, development in renewable energies, notably solar energy. In this regard, it is worth noting that a few solar power plant projects are under development and construction and that, also, a solar panel factory sponsored by the Mozambican Electricity Fund is currently operating in the city of Matola, next to Maputo.

The Council of Ministers enacted the Policy for the Development of New and Renewable Energies. Its main objective is to promote greater access to clean energy through the equitable, efficient, sustainable and culturally sensitive use of new and renewable energy.

Additionally, the Regulation that Establishes the Tariff Regime for New and Renewable Energies was approved by Decree No. 58/2014 of 17 October. This statute sets out feed-in tariffs remunerating the electricity generated by: (1) biomass power plants; (2) wind farms; (3) mini-hydro power plants; and (4) photovoltaic power plants with an installed capacity of up to 10MW and that comply with eligibility requirements defined in the diploma.

ii Energy efficiency and conservation

The aforementioned Renewable Energy Development Policy also approaches energy-efficiency issues but, as in the area of renewable energy, no rules or policies have yet been enacted to promote it.

iii Technological developments

Encouragement of greater technological developments in the field of renewable energies has recently taken place through the creation of a laboratory for photovoltaic energy, the first in the field of renewable energies in Mozambique.

VI THE YEAR IN REVIEW

Key events in the energy sector in 2016 for Mozambique included:

a the enactment of the legal framework regarding atomic energy (providing for the possibility of using ionising radiation for non-military use);

b the creation of ARENE, as the new energy regulatory authority (see Section II.i, above);

c the announcement of the development and construction of the second largest solar power plant in Sub-Saharan Africa (in the province of Zambézia);

d the approval of the concessions of the floating LNG marine terminal (to service the exploration of natural gas in Area 4 of the Rovuma Basin); and

e the acquisition by Exxon Mobil of a 25 per cent indirect participation in Area 4 of the Rovuma Basin from ENI.

VII CONCLUSIONS AND OUTLOOK

The Mozambican energy sector faces a multitude of challenges, outlined throughout this chapter:

a the country’s infrastructure is not sufficient to meet demand, which is reflected in the fact that large areas of the country are without electricity or natural gas, and electrical power distribution networks are outdated;
because of the inefficient power purchase arrangement with South African utility company Eskom, Mozambique still has to ‘import’ electrical energy from its own hydroelectric power plant in Cahora Bassa; and

Mozambique’s oil and gas findings require a stable governance structure, and experienced participants in the oil and gas industry, for commercial development of the findings to begin. The enactment of the new Petroleum Act and the approval of corresponding regulations (including regulations specific to projects located in the Rovuma Basin) may aid the achievement of this goal.

These problems are being tackled, but most are very capital-intensive. Electrification of rural areas, promoted by the Mozambican Electricity Fund by way of small distribution networks, off-grid projects and small renewable energy generation, and the various electricity generation projects that are being planned for this decade, are both examples of how the country is dealing with some of these issues.

Once these obstacles are finally overcome, Mozambique, with its abundant natural resources and strategic geographical position in the region, will doubtless stand poised to become one of the key players in the sub-Saharan Africa energy market.
I OVERVIEW

The Myanmar energy market started legal reform in 2011, when the country first opened up to foreign investment after decades of isolation. The recent optimism in Myanmar’s economy is largely attributed to its abundant untapped resources, particularly oil, hydropower and natural gas. Presently, Myanmar’s energy sector accounts for more than half of its export earnings and foreign direct investment.

On 15 January 2018, in Myanmar’s parliament, the Deputy Minister for the Ministry of Electricity and Energy (MOEE), Dr Tun Naing, announced that the MOEE has committed to provide an additional 3,600MW in Myanmar within the next four years. The MOEE announcement is attributed to an expert ministerial report indicating that the consumption of electricity in Myanmar is expected to increase to 5,774MW by 2022 from the present rate of 3,189MW. Demand for electricity in Myanmar has progressively increased since 2012.

The MOEE has developed an aggressive plan to reach this goal. The plan includes:

a upgrading existing power plants;
b developing 10 new gas and hydropower plants located in Kengtawng, Upper Yeywa, Kyaunkphyu, Kanbauk, Ywama, Patolon, Myanaung, Thilawa and Mee Luang Chiang by 2022;
c developing an additional 500 new transmission lines and substations from power generated by the following power plants, to be completed by 2019: the 4MW Yarzagyo hydropower plant, the 40MW Minbu solar power plant, the 118.9MW Thaton gas power plant, the 106MW Thaketa gas power plant and the 225MW Myingyan gas power plant; and
d purchasing additional power from neighbouring countries in China, Laos and India.

The MOEE 2018 announcement is a great win for Myanmar citizens and both local and foreign sponsors, as presently poor infrastructure impedes the economic development of Myanmar. Currently, 84 per cent of households in rural Myanmar have no electricity; only 30 per cent of the entire Myanmar population is connected to the electricity grid; and the average annual per capita electricity consumption is 160kWh (5 per cent of the world average). Strengthening Myanmar’s energy sector is crucial to reducing poverty and enhancing...
development prospects for the country. Social and economic progress in Myanmar depends on electrification, without which health, education and other key services will continue to suffer.

Recently, foreign investment has been liberalised by the Myanmar government for the importation, storage and distribution of petroleum products into Myanmar, with the promulgation of the Petroleum and Petroleum Products Law 2017.

A new government of the Republic of the Union of Myanmar (the Union Government) started on 1 April 2016, ending over 50 years of control by the military, most recently under the Union Solidarity and Development Party (USDP) led by President U Thein Sein.

The new government of Myanmar is led by the National League for Democracy (NLD). The NLD is led by Daw Aung San Suu Kyi; however, she is constitutionally barred from holding the office of President because her children are British citizens. She is currently holding the newly created position of State Counsellor. The Presidency is currently held by U Win Myint.

Prior to the end of the USDP reign over Myanmar (in the period from December 2015 to January 2016), over 35 new laws were passed by the USDP. These new laws passed by the USDP included the new Arbitration Law (Union Law No. 5/2016; the 2016 Arbitration Act) enacted on 5 January 2016, which provides a domestic legal framework to fully implement and comply with the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards of 1958 (the New York Convention), which Myanmar signed and ratified in 2013.

In stark contrast, the NLD government has passed very little new legislation since taking office in April 2016, although the President's Office has made positive steps to combat bribery and corruption in Myanmar through issuance of new guidelines for the acceptance of gifts by public servants.

That said, there have been other sweeping changes inside the Union Government since the NLD assumed control from the USDP, including a complete reorganisation of the prior 36 Union Government ministries, reducing the overall number to 21, either by consolidation or elimination. The Ministry of Energy (MOE) and Ministry of Electric Power (MOEP) have recently been consolidated into the new MOEE. Although it is difficult to predict how the NLD will manage the MOEE portfolio, we remain optimistic.

i Lifting of sanctions and key considerations

There are presently no sanctions in force against Myanmar (save for arms embargoes) from the European Union, United Kingdom or Australia. On 7 October 2016, US President Obama issued an Executive Order (EO) on the Termination of Emergency with Respect to the Actions and Policies of the Government of Burma (the October EO), thereby terminating the national emergency declared in EO13047 of 20 May 1997 with respect to Myanmar and revoking the EOs previously issued to sanction Myanmar.

Notably, the October EO does the following:

a it lifts the import ban on rubies and jadeites of Myanmar origin into the United States;

b it lifts immigration restrictions on specified Myanmar nationals and removes all individuals from the Specially Designated Nationals List. However, this will not affect Myanmar nationals who are subject to separate sanction regimes (e.g., counter-narcotics sanctions);

c it terminates all Office of Foreign Assets Control restrictions on banking with Myanmar. This includes a suspension of a prohibition by the Financial Crimes Enforcement
Network (FinCEN) against US financial institutions maintaining correspondent accounts for Myanmar banks. However, it should be noted that the suspension is contingent on Myanmar’s progress in addressing money laundering, corruption and narcotics-related activities. FinCEN will remove the prohibition entirely when Myanmar has made sufficient progress on this front; and it removes the requirement to comply with the State Department Responsible Investing Reporting Requirements. This is now voluntary.

Based on relevant Myanmar experience, that the process is more transparent and efficient than in some regional ASEAN countries; however, significant regulatory reform is still required to bring Myanmar’s power sector to the standard of more developed jurisdictions such as Japan and Australia.

II GOVERNMENT FRAMEWORK AND REGULATIONS

i Governmental divisions

Under the state-owned Economic Enterprises Law of 1989 (the SOE Law), the Union Government has the sole right to carry out power generating services and is also empowered to grant exemptions. With the consolidation of the new MOEE, Myanmar’s power sector remains regulated by a state-owned buyer model, with two key offtaking government entities, detailed below.

a the Electric Power Generation Enterprise (EPGE) (formerly the Myanmar Electric Power Enterprise (MEPE) alongside the Department of Electric Power (DEP)). EPGE operates and plans the Myanmar National Grid System, buys electricity from both public and private producers and then onsell the electricity to distributors. The Yangon Electricity Supply Board and other regional and state electricity supply boards assist the EPGE in the purchase and distribution of power.

b The Hydropower Generation Enterprise (HPGE) alongside the Department of Hydropower Planning and the Department of Hydropower Implementation. The HPGE operates and maintains large-scale hydroelectric facilities for the public sector.

ii Legal history of the MOEE

The legal history of the MOEE from 1951 to 2018 is as follows:

a in 1951, the Electricity Supply Board (ESB) was formed under the then Electricity Act of 1948. The ESB was under the then Ministry of Industry and Handicraft;

b in 1972, the ESB was changed into the Electric Power Corporation (EPC);

c in 1975, the then Ministry of Industry and Handicraft was reorganised into the Ministry of Industry No. 1 and Ministry of Industry No. 2. The EPC was under the control of the then Ministry of Industry No. 2;

d in 1985, the then Ministry of Industry No. 2 was extended and reorganised into the Ministry of Industry No. 2 and the Ministry of Energy. The EPC was under the umbrella of the Ministry of Energy;

e on 1 April 1989, the EPC was renamed the MEPE;

f in 1997, the Ministry of Energy was extended and reorganised into the Ministry of Energy and the Ministry of Electric Power. The MEPE was under the control of the Ministry of Electric Power;
in 2006, the Ministry of Electric Power was reorganised into the Ministry of Electric Power No. 1 and the Ministry of Electric Power No. 2. The MEPE was under the direct control of the Ministry of Electric Power No. 2; in 2012, the Ministry of Electric Power No. 1 and the Ministry of Electric Power No. 2 were merged to form the MOEE pursuant to Notification No. 63/2012; in March 2016, the MOE and MOEP were consolidated into the new MOEE; and in March 2016, following the reorganisation of the Union Government’s ministries and departments, the MEPE was reformed as the EPGE.

III LEGAL SYSTEM

The legal system in Myanmar is based on English Common Law. Myanmar legislation includes 13 volumes of codified laws enacted from 1841 to 1954 and published in the Burma Code, as well as various other laws, notifications, rules and regulations passed from time to time. However, the current legal framework poses significant challenges for foreign investors as many laws are presently outdated and remain untested in the courts, providing little case law and guidance to both investors and lawyers on the ground.

The relevant laws governing Myanmar’s power sector include:

a. the Arbitration Law 2016;
b. the Contract Act 1872;
c. the Environmental Conservation Law 2012;
d. the Foreign Investment Law 2016;
e. the Farmland Law 2012;
f. the Income Tax Law (ITL), as amended up to November 2011;
g. the Myanmar Companies Act 1914; 2
h. the Myanmar Constitution 2008;
i. the Myanmar National Committee on Large Dams Law 2015;
j. the Petroleum and Petroleum Products Law 2017 (PPPL);
k. Presidential Notification 1/2013;
l. Presidential Notification 1/2017;
m. the Public Debt Management Law 2016;
n. the Registration Act 1908;
o. the Stamp Act 1891 (and the Amendment of the Stamp Duty Act 2014);
p. the State Owned Economic Enterprises Law of 1989 (the SOE Law);
q. the Environmental Conservation Law of 2012;
r. the Environmental Conservation Rules, published in June 2014;
s. the Electricity Law of 2014;
t. the Myanmar Investment Law of 2016 (MIL);
u. the Transfer of Immovable Property Restriction Law 1987;
v. the Transfer of Property Act of 1882; and
w. the Vacant, Fallow and Virgin Lands Management Law 2012.

---

2 On 6 December 2017, Myanmar’s former President U. Htin Kyaw approved the new Myanmar Companies Law 2017 (MCL), replacing the country’s century-old Companies Act 1914. However, the implementation of the MCL is only expected to become effective on 1 August 2018.
The above laws are not an exhaustive list of all relevant legislation. Additional local legislation, regulations and customary practice may be relevant depending on the source fuel, project location and project complexity.

IV PROCUREMENT

The government understands the need for facilitating transparent procurement processes in order to instil confidence both domestically and internationally to the business community and, of equal importance, to attract local and foreign investment in support of the government’s rapid energy reform initiatives for Myanmar.

Since 2013, via Presidential Directive No. 1/2013 titled ‘Regulations to be abided by when issuing tenders for investment and economic activities’ (the Tender Directive), government departments and ministries are required to hold public tenders for goods, major works, and services that they may require. The Tender Directive is the only guiding authority in Myanmar on procurement, and is often criticised because it is not actual law but only a Directive. Generally speaking, at present the Tender Directive in Myanmar is local and does not follow international standards.

The Tender Directive, while lacking substance, does set out the premise to be followed by the government departments, ministries, and state-owned enterprises, including the establishment of procurement or tendering committees, open invitation to tender, and public announcement of tenders. On 10 April 2017, the Union Government issued new Notification No. 1/2017 introducing a new tender procedure (the Tender Procedure) in order to ‘eliminate waste of the State’s fund, corruption and monopolizing tender’ and to ‘ensure just and fair competition, transparency, accountability and responsibility.’ The Tender Procedure provides the threshold for launching a tender for construction or procurement of goods and services valued at 10 million Burmese kyat. Importantly, irrespective of the fact that the participation eligibility for foreigners is not clear, foreign companies without any presence in Myanmar may participate in the tender subject to the absolute discretion of the relevant department. In the event of a bid award to a foreign company, a subsidiary is required for the purpose of execution of contract with the relevant government department.

Currently, Myanmar has no specific PPP laws or regulatory framework dealing with the procurement of large-scale power projects or PPP projects. Pursuant to the Tender Procedure, specific tender procedures for PPP projects may vary depending on the nature of the bid. The MIL provides a basic framework for private foreign investors to obtain an investment permit and project approval. However, the MIL does not deal with tendering- and procurement-related issues in any detail.

Any investor seeking to develop a self-proposed project will face difficulty, as this is uncommon in Myanmar.
V FOREIGN INVESTMENT IN MYANMAR’S ENERGY SECTOR

i Myanmar Investment Commission Permit

A foreign sponsor must obtain a Myanmar Investment Commission Permit (an MIC Permit, or investment licence) to develop a power plant in Myanmar and obtain project consent. Apart from providing for project consent, an MIC Permit allows a foreign investor to benefit from certain investment incentives available under the MIL. Key incentives include:

a investment protection. The MIL guarantees that a company operating with an MIC Permit under the MIL will not be nationalised during the permitted investment period. There is also a further guarantee that investments with an MIC Permit will not be terminated before the expiry of the term of the MIC Permit without sufficient cause; and

b tax incentives. Income tax holidays are potentially available for foreign sponsors for periods of three, five or seven years, subject to MIC discretion and what zone the project is located in. Zone 1 includes the least developed areas of Myanmar excluding Yangon and Nay Pyi Taw; Zone 2 (moderate) includes more developed zones, but still excludes Yangon and includes Nay Pyi Taw; and Zone 3 (developed zones) includes Yangon and Mandalay. The income tax holidays are inclusive of the year the project company begins operations.

The MIC Permit may also grant one or more of the following exemptions and reliefs to any project company:

a exemption of internal taxes on imported raw materials within the first three to seven years of commercial production;

b exemption or relief from income tax on profits of the business kept in reserve funds and reinvested in the business within one year after the reserve is made;

c right to deduct accelerated depreciation from the profit after calculation of accelerated depreciation concerning machinery, equipment, building or other capital assets used in the business at rates set by Myanmar;

d relief from tax on up to 50 per cent of the profits accrued from the export of goods produced in Myanmar;

e right to pay foreign employees’ income tax at the rates applicable to citizens residing within the country;

f rights to deduct from assessable income the expenses incurred with respect to necessary research and development carried out within Myanmar;

g exemption or relief from customs duty or other domestic taxes on imported machines and other equipment used during the period of construction of the business; and

h exemption or relief from commercial tax on any goods produced for export.

Right to transfer foreign currencies

A foreign sponsor has the right to transfer abroad the types of foreign currencies set out below:

a the amount of foreign currency brought into Myanmar as foreign capital; and

b the net profit after deducting all taxes and reserve funds by the party who brought in the foreign capital.
Foreign currency permitted for withdrawal includes the value of assets on the winding-up of a business, subject to MIC approval.

A foreign employee can transfer his or her salary and lawful income after deducting taxes and other living expenses incurred domestically.

Right to enter into a long-term lease

A foreign-owned company (i.e., sponsor) without an MIC Permit or Endorsement (as specified below) is only allowed to enter into a lease agreement not exceeding one year.

With an MIC Permit or Endorsement (as specified below), a foreign sponsor may be permitted to lease or use land for an initial period of up to 50 years, which may be extended for two further periods of 10 years each.

ii MIC Endorsement

A foreign sponsor intending to make a small-scale power investment (having investment capital of less than US$5 million) who desires a long-term lease right for a period exceeding one year may apply for an Endorsement from the MIC. If the investor's investment capital exceeds US$5 million it must instead apply for an MIC Permit, as it will unlikely be eligible for an Endorsement.

It is not industry practice in Myanmar, nor is it recommended for a foreign sponsor, to only obtain an Endorsement to develop a power plant. Rather, the tried and tested approach is that a foreign investor will obtain an MIC Permit. We would recommend any sponsor intending on developing a power plant in Myanmar to obtain an MIC Permit.

iii Processing time

The MIC Permit is granted on a case-by-case basis depending on the size of the power project. At a minimum, a sponsor should expect to wait at least six months to obtain an MIC Permit. Coincidently, the period to obtain an Endorsement is also the same, although, this was not the intent of the legislature.

Tenders are issued through the MOEE, and investors and sponsors can visit the MOEE website for up to date information on independent power producer (IPP) tenders.

VI BANKABLE PROJECT DOCUMENTS

Arguably, the project documents (e.g., memorandum of agreement, power purchase agreement, build-operate-transfer agreement, EPC contracts, land lease agreement (LLA), security documents, fuel supply agreement) used for the Myingyan IPP Deal should be adopted as good practice for other IPP projects in Myanmar going forward. This is critical for foreign sponsors because, before the Myingyan IPP Deal, the scale of a power deal of this magnitude had never been done before.

If the energy deal is funded by way of project finance, the main challenge for foreign sponsors will be ensuring the documentation structure remains within the framework for limited recourse project financing. Sponsors need to consider in advance that foreign lenders will push hard to enhance the recourse to the sponsors and shareholders of any project company. Another hurdle will be if the financing involves syndicated contributions from

---

3 www.moep.gov.mm.
multilateral development financial institutions (multilaterals). Sponsors need to be aware up front that multilaterals may show little inclination to negotiate any deviation from their standard project documentation.

VII INVESTOR PROJECT APPROVAL

The investor project approval process involves many stages, and the process can be time-consuming. There rarely are any shortcuts or fast-track procedures afforded to any tendered project. It is a process that must run its course (a check-the-box type of process):

a. Stage 1: preparation of application dossier;
b. Stage 2: application processing by MIC;
c. Stage 3: first technical meeting;
d. Stage 4: MIC review of application;
e. Stage 5: approval meeting;
f. Stage 6: draft permit;
g. Stage 7: condition sheet; and
h. Stage 8: Permit to Trade (business licence) and certificate of incorporation issued.

VIII GUARANTEES

The government has been reluctant to provide sovereign guarantees in power projects to date. Perhaps as a signal of change, or given external pressures from the international business community, the government is providing contractual sovereign guarantees for the Myingyan IPP Deal (however the creditworthiness of the EPGE will remain an issue when dealing with project financing, as the sovereign guarantees on payment are merely contractual in nature without additional security in the form of bank guarantees provided by the government). For investors, the sovereign guarantee regards payment obligations only.

Myanmar became a member of the Multilateral Investment Guarantee Agency (MIGA) in 2013. MIGA provides political risk insurance (guarantees) for projects in a broad range of sectors in developing member countries, covering all regions of the world. In principle, this means political risk guarantees can be provided for investments in Myanmar, which can include MIGA coverage for breach of contract by the EPGE. As a guide, MIGA may insure up to US$220 million per project, and if necessary more can often be arranged through a syndication of different insurers. Whenever a project exceeds MIGA's own capacity, MIGA reinsures itself, through a syndication process, with private and public sector insurance and reinsurance companies in order to meet the insuree's needs.

Under the standard MIGA contract of guarantee for shareholder loan, the guarantee holder shall, prior to or simultaneously with payment of compensation for a loss, assign and transfer to MIGA the right to a percentage of cover of the guarantee holder's pro rata share of the Project Enterprise's rights, as applicable, in the project agreement.

As a side note, there is also no specific protection in Myanmar against material adverse government action. However, under the MIL the government guarantees that a business that acquires an MIC Permit shall not be nationalised within the term of the contract or during the extended term of the contract. Basically, the government guarantees not to suspend any investment business carried out under the MIC Permit before the expiry of the permitted
term without ‘sufficient cause’. What constitutes ‘sufficient cause’ is not defined. However, the guarantee provided under the MIL is yet to be properly tested in any Myanmar courts or arbitral tribunal, and as such there is no guiding jurisprudence or commentary.

The Public Debt Management Law 2016 (PDML) was passed on 5 January 2016, essentially to regulate matters relating to the ‘financial liabilities’ of the Myanmar government. Of possible relevance to the energy projects would be the provisions of the PDML relating to guarantees issued by the state, although the precise realm of the PDML in that respect remains somewhat unclear.

The PDML provides that the Minister of Finance may issue guarantees for any person, entity or project on such terms and conditions as may be approved by the Myanmar government and the legislature. Prior to the issuance of a state guarantee and throughout the guarantee period, the Ministry of Finance shall assess the risk relating to such guarantee. If the guarantee is required to be issued in foreign currency, the Ministry shall consult with the Central Bank on the matter. However, thus far, we are yet to witness guarantees issued by the state referring to the provisions of the PDML.

IX PROJECT FINANCING

The difficulties involved in financing power projects to date mainly revolves around Central Bank of Myanmar (CBM) and MIC approval (for companies with an MIC Permit) of the loan facilities, and challenges in perfecting security interests, including the following:

a charge over shares (normally referred to as a pledge of shares, but since share certificates are not commonly used in Myanmar, there is nothing for the onshore security agent (OSA) to take physical possession of);

b fixed and floating charges (this usually includes the land mortgage, project accounts onshore in Myanmar (which is typically an operational account and basic petty cash account, because generally all revenue is eventually paid offshore), movable plant and equipment, buildings and fixtures). As part of the fixed and floating charge, commonly a separate land mortgage will be executed and annexed to the fixed and floating charge documentation and this will be required to be registered at the relevant Myanmar Office of Registration of Deeds; and

c assignment of contracts (generally this will include the assignment of the lessor’s rights under the LLA, over the location of where the power plant is situated. To comply with Myanmar property laws, foreign lenders often engage a local bank to act as an OSA to enable registration of the security interest).

All of the above securities are permitted under law; however, the registration of these security interests still remains enormously challenging owing largely to complicated Myanmar property laws and foreign ownership restrictions over land as well as a void of a modern legal mechanism allowing the government to facilitate registration of security. There is no official land titles register or electronic database, making it difficult for investors to accurately determine the ownership of privately-held land plots. When locals sell land, they often do not change the name of the title deed holder. Therefore, locals rely primarily on legal contracts, which state the transfer of land ownership after a sale. This could be confusing for investors. Hence, investors need to take care in conducting a careful due diligence process on landowners.
Use of an OSA is highly recommended to streamline the perfection of security process, as there are few restrictions in place regarding a Myanmar person (individual or corporate entity) taking the security interests listed herein. In terms of OSA responsibilities, it would be highly advantageous to request an annual declaration that the security interests remain perfected and the OSA is not aware of anything that would affect the security remaining perfected.

Section 109(1) of the Myanmar Companies Act 1914 provides for the granting by a Myanmar company of a fixed and floating charge (FFC) over its assets in favour of a lender, including book debts, cash flows, receivables, intangible assets, contractual rights and bank accounts. This is a flexible form of security that applies in the common law jurisdictions and can cover the following assets:

\[\begin{align*}
a & \quad \text{a mortgage or charge for the purpose of securing any issue of debentures;} \\
b & \quad \text{a mortgage or charge on uncalled share capital of the company;} \\
c & \quad \text{a mortgage or charge on any immovable property wherever situated, or any interest therein;} \\
d & \quad \text{a mortgage or charge on any book debts of the company;} \\
e & \quad \text{a mortgage or charge, not being a pledge on any movable property of the company except stock-in-trade; or} \\
f & \quad \text{a floating charge on the undertaking or property of the company.}
\end{align*}\]

The FFC and any individual mortgage or charge over a company's assets must be registered with the company registration office within 21 days of its creation, otherwise it is void against a liquidator and other creditors of the company in a winding-up. It may be pertinent to mention that the mortgage of immovable property can only be in relation to the long-term lease of the land on which the facility is built (i.e., the right to lease the land, not the land itself).

The approval of the MIC is required for companies with an MIC Permit. Usually the MIC will obtain a CBM 'no objection' as part of the scrutiny process. If the project company holds an MIC Permit, the loan can be approved under an initial MIC Permit application or at a later date. This usually applies when the terms of the loan are not agreed at the time of the MIC application. Once MIC or CBM approval is obtained with the loan payment and the repayment schedule is attached, no further approvals are required for each payment made under the loan either from the MIC or from the CBM.

CBM approval is required for all foreign exchange remittances. All foreign exchange remittances made by the project company must be made through a local bank with an 'authorised dealers licence'. CBM Directives of 2012 and 2014 set out the documentary requirements that authorised local banks need to see before making any foreign exchange remittances out of the country. If in doubt, refer the matter to the CBM for approval.

Myanmar law does not provide much guidance in relation to refinancing during the life of the loan facility documents. Most foreign investors channel funds to their Myanmar companies via shareholder loans. Offshore loans into Myanmar are becoming more frequent. The first large bank loans deals are being done now, but usually on a full recourse basis.

Given the uncertainties regarding 'onshore security', lenders will also require overseas-based sponsors to provide 'offshore' security over their interests in the Myanmar-based project company in the usual manner, including offshore pledges of shares in the project company and an offshore (and secured) accounts structure.
X  TAX CONSIDERATIONS

Investors need to account for local tax duties when costing out an IPP project in Myanmar. Stamp duty must be levied on all project documents and any security documents if third-party project financing is involved. Pursuant to the latest bill amending the Myanmar Stamp Act 1899 dated 1 August 2017, stamp duties can be excessive from 0.5 per cent to 2 per cent on the total loan facility depending on the type of agreement. Exemptions may be applied for and are permitted under law; however, there is no certainty that such exemptions will be granted.

Furthermore, certain tax reliefs may potentially be available under applicable tax treaties. Myanmar has tax double taxation avoidance treaties (DTAs) in force with eight countries. These countries include India, Korea, Malaysia, Singapore, Thailand, the United Kingdom and Vietnam, with a number of other DTAs in the draft phase.

The Income Tax Law (ITL) provides that a DTA must be ‘notified’ before it is to override provisions of the ITL. The details concerning if a DTA has been ‘notified’ are contained in the Myanmar Government Gazette. Accordingly, the terms of any DTA will be followed despite anything to the contrary contained in any other provisions of the ITA.4 The sponsor must follow an administrative procedure for claiming a tax exemption based on the DTA with Myanmar’s Internal Revenue Department (IRD). Under Myanmar law, the application of the DTA is not automatic and is at the discretion of the governor of the IRD.

XI  ENVIRONMENTAL CONSIDERATIONS

Under Section 42(b) of the Environmental Conservation Law 2012, the Ministry of Environmental Conservation and Forestry has issued an Environmental Impact Assessment Procedure (EIA Procedure). The EIA Procedure states that:

[All Projects undertaken by any . . . enterprise…which may cause impact on environmental quality . . . are required to undertake EIA to develop a project document to avoid, protect, mitigate and monitor adverse impacts caused by . . . operation . . . of a project.]

In the power sector, issues concerning air quality and greenhouse gas (GHG) emissions are prevalent. An emphasis on reducing GHG emissions is vested in local regulations addressing control measures. International guidelines providing commentary on reducing GHG emissions highly recommend the use of less carbon intensive fuels, combined heat, power plants, higher conversion efficient technology as well as high monitoring levels.

Myanmar’s EIA Procedure is gradually developing in the face of increasing public expectations. Health and climate change-related issues, impacts on biodiversity and sensitive habitats are among other matters of growing significance.

4 The Income Tax Law provides if the Government of the Republic of the Union of Myanmar enters into an agreement with any foreign state or international organisation relating to income tax, and if the agreement is notified, the terms of the said agreement will be followed despite anything to the contrary contained in any other provisions of the Income Tax Law.
XII MEETINGS WITH THE REGULATORS

Meetings with any Ministry, department, division, or sub-department of the government will generally take place in Nay Pyi Taw. Aside from the MIC and Directorate of Investment and Company Administration (DICA), which have offices in Yangon, the government’s principal ministerial offices are located in Nay Pyi Taw.

Meeting requests typically are requested in letter-form. Hard-copy originals must be sent to the relevant authority to arrange the meeting. Email communication remains uncommon in practice.

From our experience, meetings should be arranged at least seven business days in advance and the meeting request letters should state a preferred day and time and be accompanied by an agenda to allow the relevant authority to coordinate representatives from the MOEE, DEP, etc.

A short meeting agenda is preferable, as very frequently meetings are cut short, postponed or delayed. It is suggested, depending on the importance of the meeting, to stay overnight to afford the relevant authority more flexibility should unexpected changes occur on the initial day of the meeting.

Given these limitations, it is strongly suggested to have more frequent meetings in short duration as opposed to attempting a one-day marathon session with the Union Government, as rarely is that possible, and if so it tends to be unproductive.

Bringing a translator is recommended. Despite most meetings being in English, having a translator available can ensure the meeting is more efficient.

XIII INVESTOR TIPS

i Myanmar and expatriate counsel

We recommend that the investor engages experienced and skilled on-the-ground legal counsel (comprising a combination of Myanmar and expatriate counsel) to drive the entire project with the MOEE. One lead counsel acting for the sponsor is a must, considering the complications of power deals here in Myanmar. The process is long and requires the expertise of both skilled Myanmar and expatriate counsel to persist with the constant follow-up meetings and drafting of endless bilingual letters to the MOEE. This is an enormous task for even the most experienced emerging market lawyers.

ii Patience

Myanmar’s recent political and economic reforms have been rapid and significant, paving the way for foreign investments into the country; however, this does not mean that developing a large-scale power project and doing business in Myanmar is not without its challenges. Foreign investors should also be aware of the following:

- the average productivity of a worker in Myanmar today is US$1,500 – about 70 per cent below that of benchmark Asian countries;
- there are four years of average schooling in Myanmar;
- there will be 10 million additional people to absorb in Myanmar’s large cities by 2030; and
- a total investment of US$650 billion is needed by 2030 to support growth potential (US$320 billion in infrastructure alone).
Investors must be prepared to deal with the current challenges of poor infrastructure, in terms of transport, telecommunications and utilities supply. Improvements to the country’s infrastructure will take time.

It is not uncommon when visiting the offices of the government in Nay Pyi Taw for meetings to be cancelled, delayed, or postponed entirely. In addition, investors may experience long wait times from the original scheduled meeting time.

As Myanmar gains speed in its reform process, many draft laws are pending consideration by Myanmar’s parliament. Investors are still eagerly awaiting the actual implementation of Myanmar Companies Law 2017. Myanmar is in the process of developing its legal system and one would need to prepare for changes as legislation is being adapted.

XIV POTENTIAL DOWNSTREAM AND POWER PROJECTS

The downstream sector, *inter alia*, involves refining of petroleum crude oil and the treating and purifying of natural gas, marketing and distribution of petroleum products.

Recently, foreign investment has been liberalised by the Myanmar government for the importation, storage and distribution of petroleum products in Myanmar. It has been a welcome move for the potential downstream investors, and will create the opening of the downstream petroleum market for foreign investors in Myanmar.

The PPPL substitutes the Petroleum Act 1934, and provides clarity on aspects on import and export, transportation, storage, refinery, distribution, inspection and testing of petroleum and petroleum products. The PPPL also earmarks the authority concerned towards issuance of relevant licences. However, the implementation of the provisions of PPPL are yet to be observed.

The MOEE has been in discussion with entities on construction of new refineries and revamping of the existing refineries in Myanmar. Currently Myanmar has three major refineries: Thanlyin, Chauk and Mann Thanpayarkan. With the promulgation of the recent regulations in the sector, foreign investment is possible in connection to loading, offloading and operating and maintaining of jetty facilities as well.

XV INDIAN INVESTMENT IN MYANMAR’S ENERGY SECTOR

Aside from the Indian downstream entities (mostly publicly-owned) that are dominant players in India’s downstream petroleum sector, the recent legislative developments in Myanmar have opened up potential opportunities in Myanmar.

Myanmar’s urgent need for power after years of political isolation has been well documented. Its potential for renewable energy resources is significant. Myanmar’s government has been formulating programmes towards utilisation of renewable energy resources such as wind, solar, hydro, geothermal and bioenergy for sustainable energy development in Myanmar. With various fuel sources alternatives available in Myanmar, the Indian private entities that have sophisticated technical skill-sets in the energy and power sector, can look forward to Myanmar as a potentially rewarding market. India also benefits from its own geographical location – an advantage, as it can easily cater to Myanmar’s energy requirements in the energy and power sectors.
XVI CHINESE INVESTMENT IN MYANMAR’S ENERGY SECTOR

Driven by the One Belt, One Road initiative, first introduced to the international community in September 2013, Myanmar has witnessed a massive inflow of Chinese investment into the country. China, like India, shares the advantage of bordering Myanmar, making it strategically well placed to support and benefit from Myanmar’s fast-growing energy sector. There is a combination of Chinese state-owned enterprises (SOEs) and private Chinese investors developing Myanmar’s energy sector. The majority of inbound Chinese investment into Myanmar’s energy sector is largely led by Chinese SOEs.

According to Myanmar official statistics released by the DICA, China is ranked as the number 1 foreign investor in Myanmar, boasting investment volume of (26 per cent) of Myanmar’s foreign investment value. The latest DICA statistics reveal that up to February 2018, the overall foreign direct investments in Myanmar’s oil and gas sector from China hit US$22 billion, followed by the power sector in second place with Chinese investments totalling over US$21 billion.

One of the key landmark projects in Myanmar is the China-Myanmar oil and gas pipeline, linking Myanmar’s deep-water port of Kyaukphyu (Sittwe) in the Bay of Bengal with Kunming in Yunnan province of China. This project was completed in 2014.

Three Chinese SOEs (China Electric Power Equipment and Technology Company Ltd, China Southern Power Grid Company Ltd (CSG), CSG’s subsidiary Yunnan International Company Ltd) have proposed separate plans to plug Myanmar’s national power grid into Yunnan’s electricity network. Daw Aung San Suu Kyi met with Chinese President Xi Jinping in May 2017 to discuss, among other things, Myanmar’s energy sector and developing closer ties. Our understanding, based on information released by the MOEE, is that initial talks have taken place but there has not been any further developments on point. The Chinese and Myanmar diplomatic meetings are the most encouraging cooperation to date since the suspension of the Chinese-backed Myitsone dam back in 2011.

We envisage China to be the leaders in the development of Myanmar’s energy sector.

XVII CONCLUSIONS AND OUTLOOK

Myanmar has abundant energy resources – hydropower and natural gas in particular. Owing to underdeveloped legislation and lack of financial and technical capacity, the energy sector of the country is still underdeveloped. However, with the government’s commitment to reform, foreign investment will have more access to this sector with simplified formalities. The recent regulatory and policies changes in foreign investment are indicative of the fact that the government is making greater effort to create a more transparent atmosphere to attract foreign capital and technology. We look forward to a remarkable uptick in the energy sector in the near future.
I OVERVIEW

The energy markets in the Netherlands have been fully liberalised for almost 15 years now. Numerous companies are active in the production/generation, trade and supply market – activities that are strictly separated from the operation of electricity and gas networks. The government opted for full ownership unbundling of vertically integrated energy companies, the strictest model available under the European Union energy directives. Ownership unbundling was not only required for transmission system operators (TSOs), but also for distribution system operators (DSOs), the last remaining two of which were unbundled in 2017.

As regards energy consumption, natural gas has traditionally been one of the most important resources in the Netherlands. After having initially discovered several small pockets, in 1959 the Dutch Crude Oil Company (NAM, a 50-50 joint venture of Shell and ExxonMobil) discovered a large natural gas field in the Groningen province, under the town of Slochteren. Since 1963 the NAM has been producing natural gas from this field, and in the same year Gasunie was founded as a trade and transportation company fully owned by the Dutch state. The public-private cooperation framework pertaining to the production and trade of gas is known as the ‘Gasgebouw’ (Gasbuilding).

The Netherlands has been dependent on its natural gas for more than half a century, but owing to the increasing occurrence of earthquakes in the Groningen province as a consequence of the production of natural gas, public opinion has gradually turned negative. In a recent letter to parliament, the Minister of Economic Affairs and Climate (the Minister) proposed to reduce production from the Groningen field from 21.6 billion m3 in 2017 to 12 billion m3 per year, by October 2022 at the latest. The termination of gas production in Groningen requires a series of drastic measures on both the supply and demand side. As the majority of Dutch consumers still uses low calorific Groningen gas, most gas-fired equipment (for, inter alia, central heating and cooking) is not compatible with high calorific gas and will have to be replaced in due course. In the meantime, Gasunie Transport Services (GTS, a subsidiary of Gasunie that is designated as the national gas network operator) intends to expand its nitrogen facilities, where (imported) high calorific gas is converted into low calorific gas by adding nitrogen.

The political desire to decrease dependency from natural gas is also reflected in the coalition agreement of the new national government that was formed in October 2017. The government coalition agreement envisages an ambitious energy policy, to be implemented

---

1 Dick Weiffenbach is a partner, Sander Simonetti is executive director and Nicolas Jans and Pieter Leopold are associates at HVG Law LLP.
2 Letter from the Minister to the speaker of the Dutch lower house of parliament, dated 29 March 2018.
in energy-related legislation, as well as a proposed new climate act. Pursuant to the coalition agreement, greenhouse gas emissions must be reduced by 49 per cent by 2030. This is predominantly to be achieved by the capture and storage of carbon emissions resulting from heavy industry and the closing of all coal-fired power stations by 2030. Concrete agreements will be made in the context of an anticipated national climate agreement between (decentral) governments, industry and other relevant parties. The current national energy agreement dates back to 2013 and is therefore in need of renewal, also in light of the recent developments regarding Groningen gas. Together with the gradual, but swift phasing-out of the production of natural gas from Groningen, the Dutch energy transition is facing huge challenges.

II REGULATION

i The regulators

The Authority for Consumers and Markets (ACM)\(^3\) is the designated national regulatory authority in the field of energy market regulation. The specialised Energy Department of the ACM monitors and enforces compliance with the Electricity Act 1998, the Gas Act (together: the Acts) and the Heat Act, and the rules laid down in several EU regulations and delegated legislation. To that end, the ACM has a wide range of powers in order to enforce compliance with energy regulations. It has the competence to, depending on the nature of the infringement, impose an order subject to a penalty or a fine of up to €900,000 per violation or in some cases up to 10 per cent of a company’s annual turnover. Besides ex officio investigative and enforcement powers, the ACM also has the power to resolve and settle disputes between customers and network operators and the discretion to act upon a request for enforcement action. Apart from enforcing compliance with the Acts, the ACM adopts regulation regarding tariffs and tariff-setting methodology, technical codes and rules concerning information exchange between operators.

In February 2018, the ACM disclosed its policy priorities for 2018 and 2019. Transition of the energy supply market is one of the key priorities as the ACM wishes to ensure that the transition to sustainable energy sources takes place efficiently, while preventing the energy transition from becoming more expensive than necessary.\(^4\) The ACM emphasises the importance of reliable and well-functioning energy markets during the transitional period.

As regards mining, the State Supervision of Mines (SSM) is the independent supervisory authority to monitor compliance with the Dutch Mining Act. It supervises the exploration, production, transport and storage of minerals such as oil, gas and salt, as well as geothermal heat (an increasingly important source of renewable energy). Its supervision focuses on safety, health, environment and (technically) efficient extraction. SSM also regularly advises the Minister and other competent authorities on mining related topics.

ii Regulated activities

The operation of electricity and gas transmission and distribution networks is strictly regulated, in accordance with the EU rules on energy market liberalisation. The Minister has appointed

---

3 ACM was established in 2013 as a merger between the Netherlands Consumer Authority, the Netherlands Independent Post and Telecommunications Authority and the Netherlands Competitions Authority, the latter of which monitored compliance with energy regulation until 1 April 2013.

TenneT as the TSO for the national high-voltage electricity network and GTS as the TSO for the national gas transport network. These TSOs have been certified by the ACM to confirm their compliance with the unbundling requirements from Directive 2009/73/EC (Gas) and Directive 2009/72/EC (Electricity). The regional electricity and gas network operators, DSOs, are required by law to have economic ownership over their operated networks. Both TSOs and DSOs have specified tasks pursuant to the Acts and are prohibited from providing goods or services in competition with third parties (apart from certain exceptions). This competition prohibition does not apply to group companies of network operators, but these group companies may only engage in certain infrastructure-related activities, as further explained below.

In addition to transportation activities, network operators perform certain other statutory tasks as well, such as providing connections to customers and performing metering services to small (household) consumers. The provision of metering services to other than small consumers is in principle an unregulated market activity. Parties that carry out metering responsibility must be accredited by TenneT.

The supply of electricity and gas to small consumers requires a supply licence from the ACM (through delegation by the Minister). Pursuant to the Acts, small consumers are users with a grid connection with a maximum capacity of 3x80A for electricity and 40m³(n)/h for gas. Suppliers can either choose to apply for a licence or cooperate with a licensed supplier and act as reseller. Applicants must demonstrate that they have the required organisational, financial and technical capabilities and comply with the applicable regulations for the supply of electricity, gas or both to small consumers. The ACM has the competence to attach conditions and restrictions to a licence, and has the right to revoke a licence.

The supply of heat to small consumers (e.g., via district heating networks) requires a licence from the ACM (through delegation by the Minister) in accordance with the Heat Act, unless the heat is supplied to only up to 10 users at the same time or to one or more buildings the supplier itself owns or leases, or amounts to less than 10,000GJ of heat per year. The ACM sets the maximum tariffs for the supply of heat. The Heat Act is currently under review and several amendments have been proposed, including proposed changes to the tariff structure.

For the generation of electricity no licence is required under the Electricity Act. However, a licence from the Minister is required for building and operating an offshore wind park, pursuant to the Offshore Wind Energy Act. The applicant must perform a feasibility study in order to apply for a licence and the Minister can attach conditions to such licence.

For balancing purposes, programme responsibility applies to the feed-in and extraction of electricity and gas from the relevant networks, which must be exercised by a programme responsible party accredited by TenneT or GTS, respectively.

Exploration and production activities regarding minerals, including oil and gas, and the exploration and production of geothermal heat, require a licence from the Minister pursuant to the Mining Act. Furthermore, the Minister can grant a licence on the basis of the Mining Act for the underground storage of substances such as gas and CO2. Licences can be subject to conditions.

LNG installations are also subject to several provisions in the Gas Act, including the obligation to designate an operator and submit the applicable tariff structure to the ACM for approval.
iii Ownership and market access restrictions

The Acts stipulate that transmission and distribution networks, as well as the shares in TSOs and DSOs, must be owned directly or indirectly by the Dutch state, provinces, municipalities or other public bodies. The Acts also contain the group prohibition, which provides that a company that produces/generates, trades or supplies electricity or gas cannot be part of the same group of companies as a network operator (the network group). The Acts also prohibit network operators to deliver goods and provide services by means of which they enter into competition.

In April 2018, the Energy Transition Progress Act was adopted, which amends the Acts. The new act comprises a set of policies that previously appeared in the STROOM Bill, which was rejected by the upper house of parliament in 2016, and mainly aims to further define the role of the network operator and the other companies in the network company group. The legislator deems it important to protect the network infrastructure against unnecessary (commercial) risks on the one hand, and to prevent network group companies from operating too broadly, thereby hampering innovation from private market parties, on the other hand. The new Act demarcates the tasks of the network operator and its group companies. The network operator is only allowed to perform certain tasks specifically assigned to it. For group companies of the network operator, an exhaustive list of allowed activities is included in the Acts. These permitted side-activities relate to infrastructure and network operation and include the construction and operation of cables, pipelines, electric vehicle charging infrastructure, installations for hydrogen, biogas and heat, as well as the provision of metering services. While introducing stricter definitions of allowed activities, the new Act also creates the possibility for the Minister to assign temporary tasks to network operators and grant exemptions to deviate from certain provisions (restrictions) in the Acts by way of experiment. Other matters that are regulated by the new act include the possibility for the national TSOs (TenneT and GTS) to enter into cross-participations with foreign TSOs, and potential relocation or underground reconstruction of parts of the high-voltage network that are close to housing. The new Act will enter into force on 1 January 2019.

iv Transfer of control and assignments

The Electricity Act 1998 provides that any change of control (within the meaning of the Dutch Competition Act) with respect to a power generation plant with a nominal capacity of more than 250MW must be notified to the Minister. In cases of a change of control in an LNG installation or LNG company, a similar notification requirement applies under the Gas Act. Following such notification, the Minister assesses the risks with respect to public safety and security of supply and may attach conditions to the change of control. An (appealable) decision will normally be taken by the Minister within four months; however, there is no compulsory waiting period. Transactions that are not (timely) notified are subject to possible annulment.

---

5 Parliamentary Papers Second Chamber 2010-2011, 32 814, No. 3, p. 10.
III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

The Dutch government opted for unbundling of TSOs as early as in 2001, two years before European unbundling regulations were adopted in the second energy package. Under the current Acts, TSOs are subject to full ownership unbundling and certification by the ACM, which must verify that the TSO is organised and structured in accordance with the conditions of ownership unbundling. Although not required by the EU rules on energy market liberalisation, ownership unbundling is also required by law for DSOs in the Netherlands. This is reflected in the Acts by the aforementioned group prohibition that was introduced by the Independent Network Operators Act (WON). When the WON entered into force in 2008, the group prohibition was challenged before the Dutch courts by three (at the time) vertically integrated energy companies. After lengthy proceedings and a preliminary ruling from the Court of Justice of the European Union, the Dutch Supreme Court finally ruled in 2015 that the group prohibition is compatible with EU law. Subsequently, the last two remaining vertically integrated energy companies, Delta and Eneco (two of the claimants in the legal proceedings), were unbundled in 2017.

ii Transmission/transportation and distribution access

For both electricity and gas, a distinction is made in the Acts between the national transmission networks (operated by TenneT and GTS) and the regional distribution networks (operated by several DSOs). Each DSO operates the public network in its own designated region and is responsible for its construction, maintenance and operation as well as possible expansion. Access to the networks must be granted on a non-discriminatory basis and can only be denied if capacity is reasonably not available. Tariffs for use of the network are regulated pursuant to the Acts, and the entire process regarding access is supervised by the ACM.

In respect of certain private energy networks, the Acts provide for an exemption from the obligation to designate a network operator, which can be granted by the ACM to owners of closed distribution systems.

iii Tariffs

The tariffs for services rendered by network operators (transport tariffs) are regulated by the ACM, which determines these tariffs \textit{ex ante} in three steps. First, the ACM adopts a method decision for a regulatory period of three to five years. Five different types of network operators are discerned and for each of these groups a different method decision is published.\textsuperscript{6} The method decisions explain how the ACM will calculate the allowed revenue of the operators in question, based on efficient costs. Second, the ACM publishes X-factor decisions for each individual network operator, in which the ACM calculates the base level of revenue for the network operator and the annual tariff cut (this is the X-factor, being an efficiency factor). X-factor decisions are adopted for the same regulatory period as the method decisions they are based on. Lastly, the ACM publishes annual tariff decisions for each regulatory period, in which the ACM sets the maximum tariffs for each individual operator by making use of the calculations in the X-factor decisions and in accordance with the tariff codes.

\textsuperscript{6} The two TSOs, several gas network DSOs, several electricity network DSOs and the operator of the offshore electricity network.
With respect to heat, the Heat Act provides that the ACM determines maximum tariffs for the supply of heat.

iv Security and technology restrictions
Under a new act regarding rules on data processing and cybersecurity notification requirements, which was adopted in July 2017, companies operating in vital sectors are obliged to notify cyberattacks to the National Cyber Security Centre. The notification obligation applies irrespective of the public or private nature of a company. Vital sectors include the gas, electricity, telecommunications and drinking water sectors. Gas and electricity network operators, as well as the NAM, are mentioned explicitly in a delegated act as vital companies to which the notification obligation applies.7

IV ENERGY MARKETS

i Development of energy markets
On the Dutch wholesale markets for gas and electricity, various types of energy spot and forward contracts can be entered into. These energy contracts can be concluded for different periods and times. The energy markets are characterised and subdivided based on the type of contract that is offered.

In the Netherlands, GTS offers the title transfer facility (TTF) as a virtual market place that enables parties to transfer gas in the transport network (entry-paid gas) to another party. Gas can be traded on the TTF via ICE ENDEX (European Energy Derivatives Exchange) under spot and future contracts.

Electricity is traded on different markets: via exchange markets ICE ENDEX and the Amsterdam Power Exchange (APX), which is now part of the pan-European energy trading market EPEX SPOT, via the over-the-counter market and via the imbalance markets for gas and electricity that are operated by GTS and TenneT respectively. ICE ENDEX enables trading in future contracts for electricity. The APX offers day-ahead and intraday trading in electricity.

ii Energy market rules and regulation
Exchanges for derivatives (such as futures) must be licensed by the Ministry of Finance under the Financial Services Act, and are supervised by the Netherlands Authority for the Financial Markets and the Dutch Central Bank. Parties that wish to trade on an exchange need to be members and must meet the administrative requirements that are imposed by the relevant platform.

iii Contracts for sale of energy
Suppliers of gas and electricity enter into individual supply contracts with end users. Gas and electricity prices for medium and large consumers are not regulated. Suppliers to small consumers must have a supply licence and are obliged to provide a reliable supply of energy at reasonable tariffs and conditions. These suppliers must inform the ACM annually regarding the tariffs and conditions they will apply for the supply of electricity and gas in the following year. If a supplier is planning on changing the tariffs for the coming year, the supplier has to

7 Decision (order in council) of 4 December 2017, Stb. 2017, 467.
submit the new tariffs to the ACM four weeks in advance, before adjusting the rates. When the ACM deems the new rates to be excessive, it may impose a maximum rate in order to protect the consumers.

Suppliers must also inform the ACM about organisational, financial and technical changes within their companies. In addition, licensed suppliers must have a customer complaints procedure in place and inform customers about the origin and environmental quality of the electricity supplied. Licensed suppliers are obliged to offer small consumers a model supply agreement (in accordance with the uniform model established by the ACM), but may in addition also offer other contract forms.

iv Market developments
The Dutch government intends to close all coal-fired plants in the Netherlands by 2030 at the latest. According to the Minister, this is an important measure to achieve the required CO2 reduction. The Council of State has advised the Minister that the phasing out of coal-fired plants can best be realised by introducing a specific production prohibition.

As regards heat, on 6 March 2017 an amendment to the Heat Act was adopted in the lower house of parliament. The revised Heat Act will remove a number of bottlenecks for block heating. Also, associations of owners and landlords are no longer considered as suppliers under the proposed act. The revision will introduce new regulations as well. It is proposed that the ACM not only determines the maximum heat prices, but also the rates for, inter alia, the connection fee and the delivery device. In addition, the Act creates room to apply for exemptions to deviate from certain provisions by way of experiment, for instance to gain experience with new market models. Finally, the compensation scheme for malfunctions has also been adjusted to make it more in line with that for electricity and gas.

V RENEWABLE ENERGY AND CONSERVATION
i Development of renewable energy
In order to encourage the development of renewable energy and meet its ambitious climate goals, the Netherlands has reserved €12 billion to provide subsidies in 2018 for the production of renewable energy under the Renewable Energy Grant Scheme (SDE+). The SDE+ budget will be divided into two tranches, whereby each tranche will allocate a budget of 6 billion euros. The SDE+ is a grant that provides producers with a financial compensation for the renewable energy they generate. It is available for the production of renewable electricity, renewable gas and renewable heat or a combination of renewable heat and electricity. For energy produced from biomass, a system of controls is in place to ensure that the production meets the criteria for sustainability. Eligible applicants for an SDE+ subsidy are companies, institutions and non-profit organisations. The renewable energy project must be realised in the Netherlands.

The SDE+ scheme is a form of a feed-in-subsidy where the compensation is equal to the difference between the base rate and the correction amount. The base rate is equal to the production costs of the relevant renewable energy (electricity, gas or heat) and the correction amount is the energy market price. For each technology, a base energy price is determined that sets the lower limit for the correction amount and thus maximises the compensation received per unit of renewable energy.

Another development is that the Ministry intends to amend the Energy Invoice, Consumption and Indicative Cost Overview Decree, introducing new obligations for
regional network operators and for suppliers of gas, electricity, heating and cooling in order
to accelerate further CO2 reduction, thereby creating a better environment. The Ministry
aims to realise this reduction by ensuring that energy suppliers provide consumers (that have
a smart energy meter) with a monthly consumption and indicative costs overview.

This amendment has been introduced following a covenant that was signed on
23 May 2017 by private associations Energie-Nederland, Netbeheer Nederland (association
of network operators), UNETO-VNI, the Dutch Association for Sustainable Energy and
the Ministries of Interior Affairs and Economic Affairs. One of the goals of the covenant is
to realise by 2020 an extra saving of 10 petajoule (PJ) in energy consumption by residents
(owners or tenants) of a living space, associations of owners, tenants and small-business users.
Part of the covenant is to improve the consumption and indicative cost overview, so that this
stimulates more energy saving. Other improvements in the covenant include adjusting the
presentation of the consumption and indicative cost overview to customer wishes (e.g., by
mail, e-mail or website, depending on preference and effectiveness), giving information about
behavioural alternatives and presenting the information in an attractive and stimulating
manner for the customer.

ii Energy efficiency and conservation

In September 2013, the public-private Energy Agreement for Sustainable Growth (the
Energy Agreement) was concluded between the Dutch government and employers, trade
unions, environmental organisations and others. The Energy Agreement contains provisions
on energy conservation, boosting energy generation from renewable sources and job creation,
in line with the Dutch government’s aim of achieving a wholly sustainable energy system by
2050. The main goals set for achieving this sustainable energy supply system are:

a reducing final energy consumption by an average 1.5 per cent annually, which
   corresponds to a saving of 100PJ in the country’s final energy consumption by 2020;
   and

b an increase in the proportion of energy generated from renewable sources to 14 per cent
   in 2020, and an even further increase to 16 per cent in 2023.

In October 2017, the Energy Research Centre of the Netherlands published the National
Energy Exploration (NEV). ECN signals a strong growth in renewable energy in the
Netherlands, which will result in a total growth in the proportion of energy generated from
renewable sources of 17.3 per cent in 2023, surpassing the above-mentioned target of 16 per
cent. Furthermore, the pace of the annual energy consumption saving has been accelerated
to 1.7 per cent per year, well above the annual 1.5 per cent agreed upon in the Energy
Agreement. The NEV on the other hand does note that, with the current efforts, the goal of
14 per cent renewable energy and 100PJ extra energy saving in 2020 are not yet within reach.
In this respect, the NEV formulates additional measures to bring these goals within reach.

The anticipated measures include an accelerated approach for onshore wind energy. The
central government, provinces and municipalities need to use a more coordinated approach
to remove bottlenecks that threaten to slow down the realisation of the agreed 6,000MW
of onshore wind capacity by 2020. Furthermore, the Dutch government’s own substantial
areas of land may also be used for the generation of renewable energy. To ensure an optimal
use, six or seven solar energy pilot projects are being prepared with an average capacity of
80–100MW per project. These projects will be realised before 2020. Based on the experiences
with these pilot projects the Dutch government will decide in more detail in which way the property of the state can or will be used for climate and energy transition and reaching the agreed targets.

In addition, on 19 June 2017, the Dutch government together with Energiebeheer Nederland, TNO and seven consortia signed a Green Deal for Ultra-Deep Geothermal Projects. The consortia are developing potential pilot projects, divided over different regions, for the extraction of geothermal heat from a depth of more than 4km, with a temperature far above 100 degrees Celsius, mainly for heat supply in the process industry. The aim of the Green Deal is to realise the three most promising ultra-deep geothermal energy projects. The projects of the consortia each have a size of approximately 1PJ.

The improvements to the SDE+ and the budget of €12 billion for 2018 should be sufficient to meet the targets for 2020 and 2023. In the SDE+ for 2018, a number of improvements were made for the cost-efficient promotion of renewable energy production, including on the terrain of renewable heat projects and biogas.

In 2018, the Investment Subsidy for the Promotion of Renewable Energy (ISDE scheme), for the purchase of solar boilers, heat pumps, biomass boilers and pellet stoves by private and business users, will be continued with a budget of €100 million. Also, the government and the business sector will try to draw more attention to the advantages of small-scale heat options within the built environment.

### iii Technological developments

The Netherlands wants to reduce the negative effects and the use of fossil energy sources such as coal, petroleum and natural gas, in order to reduce CO2 emissions and create a more sustainable energy production. Carbon Capture and Storage (CCS) is one of the tools to achieve this. As mentioned before, the new government aims at a CO2 reduction target of 49 per cent in 2030 compared to 1990. Under the new coalition agreement, CCS is set to play a major role in reducing industrial emissions. Of the total CO2 reduction in 2030 (56Mton CO2), no less than one-third (18Mton) is envisaged to be captured by industry and stored in empty gas fields (but a lower number than 18Mton is currently being discussed). The coalition agreement states that ‘CCS can be a major contribution to the reduction of emissions in industry, the electricity sector and waste incineration plants’. To stimulate technologies for the reduction of CO2 emissions, the coalition agreement announces that SDE+ subsidy scheme will also support investments in CCS and other low carbon technologies.

### VI THE YEAR IN REVIEW

In 2017, the issue of decreasing Groningen natural gas production (as a result of earthquakes) played an important role in the public and political debate. This faster-than-anticipated decrease in gas production can be regarded as an important driver for the energy transition and was also one of the core topics in the parliamentary elections of March 2017. Following these elections, a new government was formed in October 2017. The newly formed government envisages a (new) public–private climate and energy agreement and set an ambitious emission reduction objective of 49 per cent by 2030. Other developments in 2017 included the ownership unbundling of the last two vertically integrated energy companies (Delta and Eneco).

Significantly more sustainable energy was produced in the Netherlands in 2017 compared to 2016. Solar PV energy generation rose by around 40 per cent, owing to a
sharp increase in installed capacity (number of solar panels) in the Netherlands. Wind energy production rose by around 30 per cent in 2017 compared to 2016, mainly as a consequence of the commissioning of the Gemini offshore wind park.

VII CONCLUSIONS AND OUTLOOK

Even though the Energy Transition Progress Act has just recently been adopted by parliament, a proposed new Energy Act is already anticipated for early 2019 (the ‘Energy Act 1.0’, to be followed up in due course by an ‘Energy Act 2.0’). This new Energy Act should eventually unify and replace the existing Acts and further streamline energy market regulation. A review of the Mining Act is envisaged as well, in order to better facilitate the production and use of geothermal energy as a relatively new source of energy. In addition, the Netherlands will have to implement the new European Clean Energy Package, which is currently being prepared and will most likely be ready for implementation by 2021.
Chapter 25

NIGERIA

Gbolahan Elias and Okechukwu J Okoro

I OVERVIEW

i Petroleum

The Nigerian petroleum industry is regulated by the Department of Petroleum Resources (DPR), an arm of the Federal Ministry of Petroleum (the Ministry). The Ministry is headed by the Minister of Petroleum Resources (the Minister). The petroleum industry is also dominated by major joint venture arrangements, production sharing contracts and service contracts between the Nigerian National Petroleum Corporation (NNPC), wholly-owned by the federal government of Nigeria (FGN), and international oil companies with global operations (IOCs). A number of statutes and policies encourage indigenous companies to actively participate in the industry.

Activities in the petroleum industry are regulated by several laws. These laws regulate the ownership, control and enjoyment of rights, construction and maintenance of installations, and environmental protection in the industry. The principal law regulating the exploration, production and distribution of petroleum in Nigeria is the Petroleum Act 1969 (PA).

ii Electricity

The Nigerian Electricity Regulatory Commission (NERC), established under the Electric Power Sector Reform Act 2005 (EPSRA), regulates the Nigerian electricity industry. EPSRA is the legal framework for the electricity industry. Through EPSRA, the FGN unbundled and privatised the then state-owned monopoly, the National Electric Power Authority (NEPA) into the Power Holding Company of Nigeria, generation companies (Gencos), distribution companies (Discos) and the Transmission Company of Nigeria (TCN). Today, the Gencos and Discos are controlled by private sector investors. The FGN retains sole ownership of the TCN.

II REGULATION

i The regulators

Petroleum

The Constitution of the Federal Republic of Nigeria 1999 (as amended) (the Constitution) and the PA vest the ownership and control of petroleum under or upon any land in Nigeria, its territorial waters and exclusive economic zone in the FGN. The FGN exercises its control

1 Gbolahan Elias is presiding partner and Okechukwu J Okoro is a senior associate at G Elias & Co.
Nigeria

over and regulates the petroleum industry through the Ministry. The Ministry has general oversight responsibilities, and determines and formulates policies governing the petroleum industry. The Minister has broad discretionary powers to grant licences and leases; regulate construction, maintenance and operation of installations and refineries; and supervise all operations carried out under the licences and leases granted.

The DPR ensures that operators in the industry comply with the applicable laws, supervises all petroleum operations and processes applications for licences, leases and permits required to operate in the industry. The DPR also regulates the abandonment and decommissioning of installations.

The DPR and Federal Ministry of Environment (FMoE) regulate the environmental aspects of the production, transmission, distribution and supply of petroleum and petroleum products in Nigeria. Also on environmental protection, the National Environmental Standards and Regulations Enforcement Agency (Establishment) 2007 Act, the Environmental Impact Assessment Act 1992 (the EIA Act) and the Environmental Guidelines and Standards for the Petroleum Industry in Nigeria 2002 prescribe the environmental and emission standards applicable to petroleum activities in Nigeria.

There is also a ‘local content’ regulator, the Nigerian Content Development and Monitoring Board (the Board), established under the Nigerian Oil and Gas Industry Content Development Act, 2010 (NCA). The Board is required to ensure the growth of ‘Nigerian content’ in the petroleum industry.

Other regulatory agencies whose functions have an impact on the industry include:

a. the Joint Development Authority, which promotes and supervises petroleum activities in the Nigeria-Sao Tome and Principe joint development zone;

b. the Nigerian Investment Promotion Commission, which registers foreign investments in Nigeria;

c. the Central Bank of Nigeria (CBN), which under the Foreign Exchange (Monitoring and Miscellaneous Provisions) Act 1995 supervises foreign exchange dealings in Nigeria (including the importation of foreign capital and repatriation of export proceeds from oil and non-oil exports);

d. the Niger Delta Development Commission, which formulates policies and guidelines for the development of the Niger Delta area and liaises with operating companies to ensure pollution prevention and control;

e. the National Oil Spill Detection and Response Agency, which deals with waste emanating from petroleum production and exploration; and

f. the Nigerian Ports Authority and Nigeria Customs Service acting under the Nigerian Ports Authority Act 1999, the Pre-shipment Inspection of Exports Act 1996 and the Customs and Excise Management Act 1959, all of which regulate the export of petroleum.

The NNPC is not a regulator. It is a vertically-integrated state-owned statutory corporation. The NNPC has various subsidiaries, one of which is the Nigerian Gas Company (NGC). The NGC owns and operates the main gas transmission systems in Nigeria. The Nigerian Petroleum Development Company Limited has the responsibility for petroleum exploration and production activities. The National Petroleum Investment Management Services, a division of the NNPC, oversees the NNPC’s interests in joint venture arrangements,
production sharing contracts and service contracts with IOCs. The Pipelines and Products Marketing Company Limited and NNPC Retail Ltd import and market refined petroleum products respectively.

There are a number of regulations made pursuant to the PA that regulate specific aspects of the industry. The Mineral Oils (Safety) Regulations 1962 prescribe standard safety measures for lessees and licensees. The Petroleum Regulations 1967 regulate importation, shipping, unshipping and landing of petroleum; storage of petroleum; transport of petroleum; fuelling of aircraft and so forth. The Petroleum (Drilling and Production) Regulations 1969 regulate applications for leases and licences, exploration and drilling, field development, and payment of fees, rents and royalties. The Petroleum Refining Regulations 1974 regulate construction, operation and maintenance of refineries.

The construction, operation and maintenance of oil pipelines are regulated by the Oil Pipelines Act 1956 and the Oil and Gas Pipeline Regulations 1995. The transportation of crude oil in Nigerian waters and payment of terminal dues on any ship evacuating oil from terminals in Nigeria are regulated by the Oil in Navigable Waters Act 1968 and Oil Terminal Dues Act 1969 respectively. The Associated Gas Re-injection Act 1979 regulates the re-injection of associated gas into oil wells. The Petroleum Profit Tax Act 1958 taxes profits from upstream mining operations in Nigeria.

**Electricity**

EPSRA is the principal statute for the electricity industry in Nigeria. Under EPSRA, NERC, as the regulator of the Nigerian electricity industry, issues regulations and orders giving effect to EPSRA. NERC is also vested with the power to grant licences for the generation, transmission, system operation, distribution, and trading of electricity. NERC is also required to promote competition and private sector participation, and ensure quality standards in the electricity industry. EPSRA further established the Rural Electrification Agency to promote, support and provide access to electric power by rural and semi-urban areas of Nigeria.

The Federal Ministry of Power (FMoP), guided by EPSRA and the FGN’s National Electric Power Policy 2001, formulates electricity policy in Nigeria. The FMoP is empowered under EPSRA to issue general policy directions to NERC on the electricity industry, and NERC is bound to comply except where such policy is in conflict with EPSRA or the Constitution. The Energy Commission of Nigeria (ECN) also plays a strategic role in the electricity industry. The ECN was established by the Energy Commission of Nigeria Act 1979 (as amended) with the mandate to plan and coordinate national policies in the field of energy, and has been promoting the use of renewable energy sources in generating electricity.

The TCN has two key operating officers: the systems operator and the market operator. The market operator administers the wholesale electricity market, promotes efficiency and competition. The systems operator is responsible for planning, administration and grid discipline. In addition, the National Inland Waterways Authority established under the National Inland Waterways Authority Act 1996, regulates inland waterways navigation and issues permits for generation projects requiring water usage.
ii Regulated activities

Petroleum

The petroleum industry consists of the upstream, midstream and downstream sectors. The rights to explore, prospect, produce, process and distribute petroleum and petroleum products are granted through the issuance of leases, licences and permits by the Minister and the DPR (in some cases) to operators in these sectors.

For the upstream sector, the relevant leases and licences are the Oil Exploration Licence (OEL), Oil Prospecting Licence (OPL) and Oil Mining Lease (OML). An OEL confers a non-exclusive right to explore for petroleum for a term of one year. An OEL can be further renewed for one year.

An OPL has a duration of not more than five years including renewals, and confers a right to prospect for petroleum. However, the duration of an OPL granted in respect of the deep offshore and inland basin is a minimum of five years and an aggregate period of 10 years. An OML has a duration of 20 years and is subject to renewal. The OML confers an exclusive right to explore, carry away and dispose of petroleum. A drilling rig licence is also required to operate a drilling rig while a permit is required to conduct seismic data survey.

For the midstream and downstream sectors, a licence is required to construct or operate a refinery or processing plant, export, import, store, sell or distribute petroleum and petroleum products. The approval of the DPR is required to construct and operate a petroleum products filling station, and a blending plant, and to retail lubricants. A permit is required to survey the route for a pipeline. A licence is required to construct and operate a pipeline, any pumping station, storage tanks, loading terminals or other ancillary installations. Further, to construct pipelines, a right of way must be obtained from the state government on which the land is located. This may be conveyed through a certificate of occupancy or permit from the relevant state government or by special agreement with the owner of the land (subject to payment of compensation).

DPR permits are also required to render services in the petroleum industry. The permits are in three categories: general, major; and specialised. The general category covers minor supply, works and maintenance services. The major category covers rehabilitation, upgrade and fabrication works, onshore pipeline and storage facility maintenance, equipment supply, consultancy, survey and calibration. The specialised category covers pipeline laying, drilling, exploration, technical consultancy, dredging and environmental restoration services.

The procedures for obtaining these leases, licences and permits vary but are all overseen by the DPR. In addition, the EIA Act requires the issuance of a certificate stating that an environmental assessment of a petroleum project has been conducted before one can embark on such a project, and that the outcome has been officially approved. The environmental laws of some states make it mandatory to obtain a permit from the state environmental agency to construct or operate any project or activity that affects the environment.

Electricity

As with the petroleum industry, activities in the Nigerian electricity industry are also strictly regulated. Through EPSRA, a NERC licence is required to construct, own or operate an electricity generation, transmission, distribution, system operation or trading undertaking. Applications for licences are made in writing to the chairman of NERC, accompanied by the prescribed fees and in the manner prescribed by NERC.
Licences issued by NERC include generation licences, which authorise the licensees to construct, own, operate and maintain generation stations. A licence is not required, however, to construct or operate a generating plant not exceeding 1MW in capacity.

A transmission licence allows the licensee to carry out grid construction, operation and the maintenance of transmission system in Nigeria, or connect Nigeria with a neighbouring country. The holder of a transmission licence may also be required to carry out system operation and the procurement of ancillary services. A system operation licence authorises the licensee to carry out system operation such as generation and transmission scheduling, transmission management and coordination, procurement and scheduling of ancillary services and administration of wholesale electricity market.

A distribution licence holder has the right to construct, operate and maintain a distribution system and facilities such as supply of electricity, installation, maintenance and reading of meters, billing and collection. A licence is not required for a distribution station not exceeding 100kW in aggregate. A trading licence authorises the licensee to purchase, sell and trade in electricity. NERC may also issue a temporary bulk purchase and resale licence authorising the purchase of electrical power and ancillary services from independent power producers and Gencos for resale.

In addition to the licences required under EPSRA, the Factories Act 1987 requires factory owners (which includes electricity generating and distribution companies) to apply to the Director of Factories for registration within a month of commencement of business. A licence from the Minister of Water Resources is also required to undertake any hydroelectricity project as the Ministry of Water Resources regulates the diversion, storage, pumping or use on a commercial scale of any water.

iii Ownership and market access restrictions

Petroleum

Except for the general requirement to incorporate a Nigerian company before carrying on business in Nigeria, there are no restrictions on a foreign company acquiring an interest in the petroleum industry in Nigeria. The NCA, however, provides for certain privileges for companies in the industry with over 51 per cent Nigerian equity participation. Under the NCA, such companies will be given first consideration in the award of oil leases and licences. Also, in awarding contracts for the provision of services, Nigerian indigenous companies will be exclusively considered. The DPR also has a practice of not granting majority stakes in OPLs or OMLs to foreigners.

The Minister has the right to require refinery licence holders to deliver petroleum products to the FGN, or OPL or OML holders to deliver crude oil to a person with a refinery licence. Also, where there is a state of emergency or war, the Minister has the right of pre-emption of all petroleum obtained under a lease or licence subject to payment of an agreed price; or, if there is no such agreement, a fair price for the time being at the point of delivery as may be agreed; or in default of such an agreement, by arbitration. By the National Domestic Gas Supply and Pricing Policy (the Domestic Gas Policy) and National Gas Supply and Pricing Regulations 2008 (the Gas Pricing Regulations), OPL and OML holders are required to supply up to a specific volume of gas for domestic consumption. An OML holder is further required to relinquish one-half of the leased area 10 years after the grant of the OML.

The Minister may revoke an OPL or OML if the holder is not conducting operations in accordance with the basic approved work programme and good oilfield practice, or fails to pay
rent, royalties, furnish reports on its operations or comply with the PA, regulations and the terms of the licence or lease. The Minister may also revoke these rights if the holder becomes controlled directly or indirectly by a citizen of or a company incorporated in a country the laws of which do not permit citizens of Nigeria or companies incorporated in Nigeria or controlled by Nigerians to acquire, hold and operate petroleum concessions on conditions that, in the opinion of the Minister, are reasonably comparable with the conditions upon which such rights are granted to subjects of that country.

**Electricity**

EPSRA prohibits anyone holding a NERC licence from assigning or ceding his or her licence or transferring his or her undertaking without the prior consent of NERC. Similarly, no person holding a licence from NERC may, without NERC’s consent, acquire or affiliate with, the licence or undertaking of any other licensee or person who is in the business of generating, transmitting, distributing or trading electricity.

In addition, every licensee is required by NERC Regulations on National Content Development for the Nigerian Electricity Supply Industry 2013 to develop a framework for the development and promotion of ‘Nigerian content’ in the electricity industry. The licensees are also mandated to maintain a technology transfer plan (detailing various technologies deployed by the operator and the modalities for transfer to Nigerians where applicable).

iv **Transfers of control and assignments**

**Petroleum**

The prior consent of the Minister is required before any transfer of an interest, power or right in a licence or lease whether by way of acquisition, merger, takeover, exchange or transfer of shares, listing, testamentary devises, judgment or arbitral award. For the farm-out of marginal fields, the consent of the President is required. The DPR is, however, to be notified prior to the commencement of any such transaction. The responsibility for obtaining consent is that of the assignor. Also, a production-sharing contract or joint venture agreement, depending on the contractual arrangement of the parties, may require that the non-assigning parties waive or assert their pre-emption rights.

Consent will only be granted where the Minister is satisfied that the proposed assignee is of good reputation, has sufficient technical knowledge, experience and financial resources to effectively carry out the operations under the licence or lease and is in all other respects acceptable to the FGN. For the farm-out of marginal fields, the President will only give his consent if he is satisfied that it is in the public interest to do so. In the case of a non-producing marginal field, the marginal field must have been left unattended for an unreasonable time, not less than 10 years, and the parties to the farm-out must be acceptable to the FGN.

**Electricity**

NERC has the statutory responsibility to consider whether or not to approve a merger, acquisition or affiliation. To do so, NERC may require information from licensees, undertake inquiries and establish or contract with an independent entity to provide monitoring services. The prior consent of NERC is required for a licensee to assign or cede his licence or transfer his undertaking, or any part of it, by way of sale, mortgage, lease, exchange or otherwise to another. The prior written consent of NERC is required for a licensee to acquire, by purchase
or otherwise, or affiliate with, the licence or undertaking of any other licensee under the EPSRA. However, a distribution licensee may also be issued with a trading licence to provide electricity to customers.

The approval of the Securities and Exchange Commission is required for mergers, acquisitions, takeovers and business combinations. Mergers and schemes of arrangement are also required to be sanctioned by the Federal High Court. In addition, mergers, acquisitions and other forms of business arrangements concluded through schemes of arrangement are to be registered with the Corporate Affairs Commission (Nigeria's companies' registry) to become effective.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Petroleum

The NNPC is vertically integrated. Through its subsidiaries, the NNPC engages in exploration, production, processing, importation, transportation, distribution and retail of petroleum and petroleum products. IOCs also have control over exploration, production and transportation facilities in the petroleum industry. Some IOCs have downstream operations in Nigeria, but those operations are not integrated with the upstream operations of the group. In exercise of statutory powers, the Minister may grant third parties access to pipelines to aid transportation of petroleum from the field or well to processing plants or terminals for export.

Electricity

The Nigerian electricity industry was originally controlled by the NEPA (the old, state-owned monopoly). The NEPA controlled generation, distribution, transmission and trading of electricity. Through EPSRA, the NEPA was unbundled into the Power Holding Company of Nigeria, 18 successor companies consisting of six Gencos, 11 Discos and the TCN. With the unbundling and subsequent privatisation of the NEPA, EPSRA reduced vertical integration in the electricity sector with the aim of developing a competitive electricity market in Nigeria.

ii Transmission/transportation and distribution access

Petroleum

In Nigeria, petroleum is usually transported from the field and well through pipelines owned and operated by a holder of an oil pipeline licence. The licence holder has exclusive rights to use the land covered by the licence for the construction of a pipeline and ancillary installations required (e.g., pumping stations, storage tanks and loading terminals) for the conveyance of petroleum, and any substance (including steam and water) used or intended to be used in the production or refining or conveying of petroleum.

However, a third party may apply to the Minister for a right to use the pipeline constructed and operated by the licence holder. Before approving such use, the Minister must consult the applicant and the licence holder. The terms for the use of the pipeline are to be negotiated between the licence holder and the applicant. Where the licence holder and the applicant fail to reach an agreement, the Minister may determine such terms. The Minister,
if satisfied with the application for use of a pipeline, may serve a notice on the licence holder to secure the applicant’s right to use the pipeline, regulate the charge payable and ensure that the applicant’s right is not prevented or impeded.

The NGC owns, operates and maintains most gas pipeline facilities in Nigeria. There are other private participants who own gas pipeline facilities in Nigeria. Transportation and storage of gas are usually governed by gas transportation agreements. The NGC imposes terms and tariffs for gas transportation agreements. To boost the gas sector, a Gas Master Plan Infrastructure Blueprint, which provides for the development of central gas processing facilities and gas transmission systems, has been developed.

**Electricity**

In the electricity sector, Discos have monopolies over their distribution areas. However, a captive power generator (generating electricity exceeding 1MW for, and that is consumed by, the generator itself, and not sold to a third party) requires the prior written consent of NERC before it can supply surplus power not exceeding 1MW to an offtaker. Such a captive generator holder must apply for a generating licence before it can supply power exceeding 1MW to an offtaker. Also, embedded power generators (generation of off-grid power to be evacuated through a distribution network to end users) with a capacity above 20MW are required to evacuate the power produced through the grid.

In respect of third-party access to transmission, transportation and distribution facilities in the electricity sector, owners and operators of these facilities are not obligated to provide third-party access. There are also no restrictions on the provision of such third-party access. Therefore, third-party use of transmission, transportation and distribution facilities in the electricity sector is based on agreements between third parties and the owners or operators.

### Rates

**Petroleum**

Under the PA, the Minister is to fix prices at which petroleum products may be sold in Nigeria. However, the Petroleum Products Pricing Regulatory Agency (PPPRA) Act 2003 created the PPPRA to determine the pricing policy of petroleum products, regulate the supply and distribution of petroleum products and moderate volatility in petroleum product prices. Retail petroleum product prices were previously fully subsidised by the FGN. In May 2016, the FGN announced the removal of subsidy on petroleum products. However, to date, the NNPC, as the major importer of petroleum products in Nigeria, still bears the loss for the high landing cost of petroleum products.

The price of gas in the domestic market is regulated by the Domestic Gas Policy and the Gas Pricing Regulations. The Domestic Gas Policy defines the policy of the FGN in respect of the pricing of gas to be supplied to customers in the downstream gas sector. The Department of Gas, established under the Gas Pricing Regulations, is to establish the aggregate price that shall be used as a basis for gas supply to the domestic market.

**Electricity**

NERC is responsible for creating tariff methodology in the electricity industry. In fixing the methodology, NERC is required to consider full cost-recovery plus reasonable return on investment, promotion of technology and market efficiency through incentives, fairness and openness to consumers, and reduction or elimination of cross-subsidies. NERC established
the Multi-Year Tariff Order (MYTO) for the electricity industry. The MYTO provides a 15-year tariff path for the electricity industry, with limited reviews each year to cover changes in a limited number of parameters (such as inflation and gas prices) and major reviews every five years. Recently, NERC issued MYTO 2.1 for the period 1 January 2015 to 31 December 2018. On 1 April 2015, NERC approved an amendment to MYTO 2.1. The MYTO does not apply to embedded power. Embedded power is priced on a discrete basis to cover cost of production and distribution with a margin added. Purchases of embedded power are also subject to open tender.

iv Security and technology restrictions
The acquisition, promotion and development of technology in Nigeria are regulated by the National Office for Technology Acquisition and Promotion (NOTAP). NOTAP has regulatory oversight over all contracts for the transfer of foreign technology to Nigerian parties. The registrable contracts include use of trademarks and patented inventions; supply of technical expertise, detailed or basic engineering, machinery and plant; the provision of operating staff or managerial assistance; and training of personnel. Failure to register with NOTAP does not make a contract between a Nigerian and a foreign company for transfer of technology void or unenforceable, but NOTAP prohibits purchases of foreign currency from the CBN-regulated foreign exchange market to make payments under the unregistered contract.

IV ENERGY MARKETS
i Development of energy markets
The first utility company, the Nigerian Electricity Supply Company, was established in 1929, about 33 years after the first power generating station in Nigeria. From mainly hydroelectric and coal sourced energy, Nigeria has developed to a multi-source generation market (though gas is now the dominant source of power generation). The industry initially had distinct generation and transmission operations; energy was produced by the Nigeria Dams Authority and sold to the Electricity Corporation of Nigeria for distribution to end-users. These companies were integrated in 1972 to form NEPA, which was responsible for the generation, transmission, distribution of electricity and the overall management and administration of the energy market.

With the reforms introduced by the National Electric Power Policy 2001 and EPSRA, the Nigerian Bulk Electricity Trading Plc (the Bulk Trader) was incorporated. The Bulk Trader is licensed to purchase grid electricity in bulk from the Gencos and other independent power generation companies for resale to the Discos until such a time as the market would be fully competitive and the Discos achieve self-sufficiency. This arrangement is backed by both Nigerian and international governmental financial assistance in diverse forms. Another significant milestone in the energy market occurred when the National Integrated Power Project power plants built by the FGN were sold to private investors to encourage competition in the market.

ii Energy market rules and regulation
The energy market is regulated by NERC. NERC is responsible for rule-making and the licensing of market operators. The market rules in force govern the different stages the industry is anticipated to undergo; the ‘pre-transition’, ‘transitional’ and ‘medium’ stages.
The pre-transitional stage involves the unbundling of NEPA, the old, state-owned monopoly. Trading arrangements in the transitional and medium stages are and will be through contractual arrangements, and the market is expected to be centrally-administered and fully competitive.

### iii Contracts for sale of energy

The applicable documentation for sale of energy will generally depend on the stage of the market in force. The Bulk Trader, as the major purchaser of on-grid power, has its standardised bulk power purchase agreements for electricity off-take from the Gencos. Vesting contracts are used for the resale of electricity by the Bulk Trader to the Discos.

For natural gas sales, gas aggregation agreements are typically used for domestic supply obligation gas (gas that producers of petroleum in Nigeria must sell locally and not export), while gas sale agreements are used for non-domestic supply obligation gas. Increasingly, private producers are developing their own standard form gas sale agreements. Template alternative energy supply agreements are also available for renewable energy projects. For the transmission and delivery of evacuated electricity, the TCN enters into grid connection agreements and transmission use of system agreement.

### iv Market developments

NERC has continued to grow and reform the electric sector. It grants generation licences to investors with both on-grid and off-grid intentions. Embedded generations are now popular and have been embraced by independent generators and the Discos. Some of the ready-made National Integrated Power Project plants that were privatised, with construction shortcomings yet to be fully fixed in many cases, have been commissioned and in some cases, installed with additional capacity and are now producing electricity. NERC has also expressed its intention to regulate the generation and distribution of electricity in unserved mini-grid areas.

The transitional stage of the electricity market, whereby wholesale buying and selling of electricity is based on contractual arrangements subject to regulatory rules, took off in the second month of 2015. When this stage of the market is fully in force and effect, it is expected that there will be greater investment certainty triggering investors’ interest and growth of the market. NERC’s MYTO 2.1 is also in place to govern electricity pricing for both individual and industrial users.

### V RENEWABLE ENERGY AND CONSERVATION

#### i Development of renewable energy

The clamour for renewable energy arose in Nigeria as a result of increased awareness of the environmental impacts of fossil-based generation. It was not until 2006 that the actual need for sustainable energy can be said to have been recognised by the FGN with the formulation of a renewable energy plan as part of its national energy policy to depart from a monolithic fossil-fuel economy to one driven by an increasing share of renewable energy in the national energy mix.

The FGN, NNPC and NERC have encouraged the exploration and development of renewable energy in Nigeria because of the wide range of renewable natural resources (such as hydro-power, solar, wind, geothermal, biofuel). A Renewable Energy Division was created at the NNPC to develop renewable energy initiatives. The NERC through its Renewable
Energy, Research and Development Division developed the feed-in-tariff regulations for renewable energy-sourced electricity to further support the aim of generating 2,000MW of renewables-sourced electricity by 2020 and to encourage favourable pricing for such electricity. NERC also grants licences for renewable power generation like solar and coal. The Nigerian Biofuel Policy and Incentives 2007 (which specifies a plan to produce biofuel primarily for thermal and power generation) includes several tax exemptions from withholding tax, capital gains tax, value added tax and custom duties. There is a wide range of renewable energy projects at various stages of implementation. In fact, roads in numerous urban areas are lit or powered by solar sourced energy.

ii Energy efficiency and conservation
Efficiency and conservation are still poorly advanced despite the inclusion of basic policies and strategies, for the efficiency and conservation of energy in the national energy policy and the energy master plan. However, there are no definitive codes and regulations for energy efficiency and conservation. The FMoE’s renewable energy programme unit has introduced initiatives to address the need to source and deploy sustainable energy sources.

The ECN established the National Centre for Energy Efficiency and Conservation. This Centre is responsible for organising and conducting research and development in energy efficiency and conservation, and has conducted studies into promoting energy efficient appliances and light bulbs. Also the ECN in partnership with the Cuban government and with support from the Economic Community of West African States has advanced the usage of compact fluorescent lamps. Likewise, under the supervision of the FGN’s National Clean Cooking Scheme, there has been production and distribution of a purpose-designed biofuel stove.

In addition, NERC has expressed its intention to develop energy-efficiency labelling standards for domestic appliances and energy efficiency standards for luminaires, air conditioners and other household appliances. Market operators have advocated the use of energy-saving equipment that is now more readily obtainable in the Nigerian market such as high-efficiency voltage controllers.

iii Technological developments
Technological development in Nigeria is significantly slower than it should be. There are, however, indications that some Discos have signed memoranda of understanding to formalise agreements with the United States Trade and Development Agency to promote smart-grid solutions for Nigeria’s transmission and distribution challenges. We anticipate that these solutions will be in place in the near future.

VI THE YEAR IN REVIEW
i Petroleum
Recently, there has been an increase in the international price of crude oil. However, most operators of oil acreage in Nigeria are still struggling to recover from the aftermath of the decline in the price of crude oil, and settle outstanding debt service obligations. To stay afloat, these companies have resorted to debt refinancings and, in some cases, limited equity injection.

With the increase in crude oil price, the FGN’s oil revenues have also increased. Notwithstanding this increase, the FGN has maintained its position on the removal of
subsidy on petroleum products. For instance, subsidy payments were not included in the 2017 budget. However, as the largest importer and supplier of petroleum products in the market (over 90 per cent), the NNPC continues to bear the loss for the high landing costs of petroleum products. NNPC imports petroleum products and sells to the oil marketers who then sell to the end users.

In 2017, in a move towards revamping the Nigerian petroleum industry, the FGN approved two major policies for the sector: the National Gas Policy 2017 (NGP) and the National Petroleum Policy 2017 (NPP). The policies are wide-reaching and address the barriers facing investment and the development of the Nigerian petroleum industry. The NGP replaces the FGN Gas Master Plan 2008. The purpose of the NGP, as set out in the policy document, is to define the FGN’s policy in respect of Nigeria’s natural gas endowment, establish its medium- to long-term targets for gas reserves’ growth and utilisation and record strategies to be pursued to ensure the successful implementation of the policy in accordance with Nigeria’s national socio-economic development priorities. The NPP, which builds on the NGP, is meant to address the issues affecting investment in the Nigerian petroleum industry. The NPP articulates a vision and sets policy goals, strategies and implementation plans for the introduction of an appropriate institutional, legal, regulatory and commercial framework to resolve these issues. The policies are aimed at revamping the Nigerian oil and gas sector. A major focus of the NPP is the need to actively move away from oil as a source of income to oil as a fuel for economic growth. The NPP is expected to be reviewed and updated periodically.

On 28 March 2018, the Petroleum Industry Governance Bill (PIGB) was passed by both chambers of the Nigerian federal legislature (the National Assembly). The PIGB is expected to deal with governance and the institutional framework for the Nigerian petroleum industry. The Bill still has to be assented by the President before it becomes law.

ii Electricity

In the past year, NERC has, despite the outcry for a review, continued to implement the MYTO-2015 electricity tariff that became effective as of 1 February 2016. The tariff, which eliminates all forms of fixed charges, has been criticised as not being cost-reflective. NERC recently issued the Meter Asset Provider Regulations (MAP) 2018. MAP is designed to bridge the widening end-user metering gap in the Nigeria electricity supply industry, with the goal of eliminating ‘estimated billing’. Through MAP, the Discos ceases to have exclusive right to the metering of end-users. Under MAP, a new class of operators, the meter asset providers, would be responsible for the provision, installation, maintenance and the replacement of meters. However, the meter asset providers are expected to liaise with the relevant Discos to ensure compliance with industry standards in the provision of the metering services.

Within the year in review, the Minister of Power, pursuant to the powers of the Minister of Power under EPSRA, issued a directive to NERC declaring certain categories of customers as eligible to buy power directly from the Genco. Following this, NERC issued the Eligible Customer Regulation 2017. This regulation is expected to trigger competition and liberalise the Nigeria electricity supply industry by allowing the eligible customers access to contract directly with the Gencos. The Discos have opposed the new regulation as likely to impact their revenue as these eligible customers constitute the Discos’ high-demand customers. Several eligible customer agreements are currently being negotiated with the Gencos.

At the state level, the Lagos State Government passed into law the Lagos State Electric Power Sector Reform Law 2018. The law is aimed at providing an enabling environment
for generating and delivering up to 3,000MW power in three years though private sector support. The law has been applauded by actors in the industry and is expected to engender similar moves by other states in Nigeria.

VII CONCLUSIONS AND OUTLOOK

With the fluctuation in crude oil price, there have been calls from various stakeholders that the FGN should pursue an active diversification policy to move the Nigerian economy away from its dependency on oil revenues. Following these calls, there are ongoing plans for a massive reform of the Nigerian oil and gas industry. The PIGB is currently awaiting presidential assent. The PIGB, when signed, is expected to create commercially oriented and profit-driven (but government-controlled) business entities and regulators, and improve transparency and accountability. The NPP and NGP have been applauded by actors in the oil and gas industry. However, to realise the laudable objectives of these policies, the FGN must commit to actively pursue and measure the implementation of these policies within the set timelines.

The FGN is expected to continue the electricity industry reforms. Some observers think that the current administration will deregulate and privatise the power transmission business (which is under the control of the TCN wholly owned by the FGN) to attract more foreign direct investment into the electricity industry and enhance competition in the electricity market. There is, as yet, no express communication from the current government that any fundamental changes will be made to the electricity sector.

A major review of the MYTO-2015 is expected within the coming year. This review is expected to address concerns around a cost-reflective tariff and the issue of inflation. On the NERC Eligible Customer Regulation, industry experts are waiting to see how the regulation will be implemented and how the Nigeria electricity supply industry will react, given the threats raised by the Discos.
Chapter 26

PANAMA

Annette Bárcenas Olivardía and Luis Horacio Moreno IV

I OVERVIEW

Since the mid-1960s in Panama, energy related services have been rendered by a government agency called the Hydraulic and Electric Resources Institute (IRHE), which in the late 1990s was restructured into eight companies (one transmission company, three distribution companies and four generation companies) to allow for private investment in distribution and generation. The State continues to hold 100 per cent of the capital stock of the transmission company Empresa de Transmisión Eléctrica, SA (ETESA).

Being one of the fastest growing economies in Latin America, the escalation in the demand of electricity (approximately 5–6 per cent per year) has become a challenge for Panama, whose energy generated in 2017 was 64.8 per cent hydro, 29.4 per cent thermo, 4.3 per cent wind and under 2 per cent solar.

The installed capacity in Panama in 2017 was 3,336.1MW, of which 49 per cent was hydro, 39 per cent thermo, 8 per cent wind, and almost 4 per cent solar.

In 2017, the total energy sales by the distribution companies was 8,474.12GWh.

The three main subsectors of the energy market in Panama are generation, transmission and distribution. Commercialisation is also a regulated activity, but the law prescribes that commercialisation is to be performed together with the distribution activity, except that generators may commercialise their capacity or energy with large customers only.

Electricity generation is rendered in competition. Distribution/commercialisation, on the other hand, is currently limited to three concessionaires with exclusive rights in their areas of service, save for the fact that the distribution activity may be performed by other providers within isolated systems, and also under rural electrification project rules, when the distribution companies close to the project areas decline the option to provide the service.

Law 6 of 1997 dictates that the transmission and integrated operation activities shall only be performed by ETESA, but this rule is included in a provision that seeks to impose restrictions on the simultaneous provision of services. This may be why the National Authority of Public Services (ASEP) has issued a resolution governing the granting of transmission concessions to parties other than ETESA.

The law dictates that ETESA is responsible for the planning of the transmission network expansion, the construction of new assets and reinforcements to the network, as well as the operation and maintenance of the national interconnected system. ETESA is also obliged by law to mediate between generators and distributors by calling and conducting the

1 Annette Bárcenas Olivardía is a partner and Luis Horacio Moreno IV is an associate at Alfaro Ferrer & Ramírez.
public bidding processes necessary to award power purchase agreements to ensure satisfaction of the demand that distribution companies must serve under their corresponding concession contracts.

In 2016, Panama’s government approved the National Energy Plan (PEN), prepared by the National Energy Secretariat (SNE), that defines Panama’s roadmap regarding energy policy for the next 35 years (up to 2050). The PEN is driven by four main pillars that will guide the energy policy of the country, which are:

- **universal access to and reduction of energy poverty**;
- **the decarbonisation of the energy matrix**;
- **reduction and efficient use of energy**; and
- **energy security**.

**II REGULATION**

**i The regulators**

The law assigns functions and tasks to different entities in order to assure the proper functionality of the system. These entities are as follows.

**ASEP**

ASEP is an autonomous governmental entity responsible for regulating public utilities, including electricity services. ASEP is bound to regulate electricity services so as to assure the constant availability of energy, to make it possible to efficiently supply the growing demand in a social, environmental and financially responsible manner. Also, this authority adopts procedures established by law to stimulate competition and is authorised to take measures to impede abuses from market agents who might have a dominant position in a moment in time.

**The Authority for Consumer and Competition Protection (ACODECO)**

ACODECO is an autonomous governmental entity legally empowered to investigate, verify and sanction monopolistic, anticompetitive and discriminatory behaviours and activities by agents of the market generally, including the electric market, among other powers granted by law.

**ETESA**

ETESA is a wholly government-owned corporation that owns the transmission network, and conducts the integrated operation of the electricity system, among other activities. Although ETESA is a regulated entity, like generators and distribution companies that are subject to ASEP’s oversight and supervision, in some respects ETESA can make certain determinations that may effect other agents of the market.

**National Energy Secretariat (SNE)**

The SNE is a governmental entity ascribed to the Ministry of the Presidency, whose primary task is to establish and conduct the energetic policy of the country, within the legal framework, in order to guarantee supply, access, efficient use of energy, as well as to promote its investigation, development, and sustainable growth and progress.
**Wholesale Market Monitoring Group**

Although not an authority *per se*, the Wholesale Market Monitoring Group is formed by the agents of the market, and can act as a consulting body to provide advice to ASEP regarding issues related to the wholesale market.

**Legal framework**

Panama’s main energy legal framework may be summarised as follows:

- **a** Law No. 6 of 1997 (as amended) dictates the institutional and regulatory framework for the provision of electricity public service. This Law is regulated by Executive Decree No. 22 of 1998;
- **b** Law No. 45 of 2004 establishes incentives for the promotion of hydroelectric and other new, clean and renewable sources of energy. This Law is regulated by Executive Decree No. 45 of 2009;
- **c** Law No. 44 of 2011 (as amended) dictates incentives for the development, construction and exploitation of wind power generation plants;
- **d** Law No. 41 of 2012 dictates incentives for the promotion of construction and exploitation of natural gas-based power generation plants;
- **e** Law No. 37 of 2013 dictates incentives for the promotion of construction, operation and maintenance of solar power generation plants; and
- **f** Law No. 42 of 2011 dictates parameters for national policy regarding biofuel and biomass-based power generation.

A significant number of resolutions of ASEP further develop some of these laws in detail. In particular, the Operations Regulation, is a comprehensive instrument governing important operative and technical aspects of the market and the commercial rules of the market.

**ii Regulated activities**

The main services provided by agents of the market in the electricity sector are transmission, distribution/commercialisation and generation. However, there are other forms of participation in the sector that are also regulated, namely:

- **a** large customers (passive or active) who can freely contract their energy needs with other agents of the market;
- **b** companies located abroad, who can perform international exchanges of electricity using to that effect the interconnection network; and
- **c** autogenerators and co-generators who can generate energy for their own consumption, sell excess energy in the national interconnected system and purchase backup services therein.

This section focuses on the regulatory authorisation mechanisms of the three main activities: generation, transmission and distribution/commercialisation.

In general, electricity distribution and transmission activities require concessions issued by ASEP. As to generation activities, depending on the technology used to generate electricity, the service provider may need a concession contract or a licence.
Generation concessions
Any person (individual or legal entity) who intends to construct and operate a hydroelectric or a geothermal generation plant must obtain a concession issued by ASEP, which ultimately takes the form of a concession contract, although the concession right is recognised previously through a resolution of ASEP.

These concessions shall be issued through processes that guarantee public concurrence, in these cases:

a. when ASEP deems necessary to develop a new hydroelectric or geothermal project; and
b. when an interested party presents a concession application to ASEP.

The bid specifications and rules for the concurrence process are dictated by ASEP, and they should reflect objective rules fostering equality and promoting the participation of investors, provided that said rules are not contrary to Law No. 6 of 1997.

As part of the process, ASEP must seek a determination from the Ministry of the Environment as to whether the natural resource needed for the project is suitable for the intended purpose. Eventually, the winning bidder will be required to obtain the approval of the environmental impact study of the project.

The term of these concession contracts may be as long as 50 years, with the possibility to be extended for an equal term. The procedures and requirements for the issuance of a concession and its subsequent formalisation through the subscription of the concession contract are established and regulated by Resolution AN No. 5558-Elec of 31 August 2012, as amended.

Generation licences
Any person (individual or legal entity) who intends to construct and operate an energy generation plant – other than hydroelectric and geothermal – destined for public service (i.e., fuel-based, solar and wind power) must have a licence issued by ASEP for this purpose.

Licences take the form of resolutions issued by ASEP, containing the terms and conditions pursuant to which the licence is granted in each case. No contract is entered with the authority in these cases. The generation capacity of the power plant may not be increased without authorisation from ASEP. To this effect, the licensee should file an application.

Licences shall be granted for a period of up to 40 years. Licensees may only engage in electricity generation activities.

Resolution AN No. 1021-Elec of 19 July 2007 (as amended) regulates the requirements and procedure to obtain a licence. The licensing process has two stages: provisional licence and permanent licence.

The applicant must fill out a special form approved by ASEP for purposes of applying for the licence. A guarantee of US$100 per MW or fraction of capacity to be installed for the power plant, as shown in the form, shall be submitted as well. This guarantee will be returned once the definitive licence is issued. For wind power farms, the guarantee is US$500 per MW or fraction.

The application form requires the applicant to include certain general information of itself, a technical description of the project and also to attach a number of documents that are listed in the form. Some of these documents are required to be filed during the first stage of the process in order for ASEP to issue the provisional licence for the project. The rest can be submitted as part of the second stage of the process, which leads to the issuance of the permanent licence.
With regard to a few of the most important documents required for the licence, the regulation requires:

- **a** a sworn statement of the treasurer of the applicant containing a list of the direct and indirect shareholders of the applicant, that is, showing the controlling interest over 100 per cent of the capital of the petitioner (in the case of investment funds or publicly traded companies, the applicant must list the members of the controlling body of the entity, i.e., the board of directors);
- **b** a letter of solvency and financial capacity, and the ability of the applicant to contribute at least 30 per cent of the investment necessary for the new power plant based on international costs according to the technology to be used and letters of intention of experienced power plant operators (two years) and contractors (five years);
- **c** a letter of viability of connection of the project issued by ETESA or by a distribution company, as the case may be;
- **d** environmental impact study of the project and evidence of approval by the Ministry of the Environment (typically this approval is sought within the 12-month term of the provisional licence);
- **e** construction bond for 10 per cent of the investment required to build the new power plant (required when the definitive licence is issued); and
- **f** performance bond (estimated at US$500 per MW for windpower and US$2,000 per MW for natural gas and solar projects).

The regulation specifies which of the documents required need to be filed as a condition to issue the provisional licence, which is valid for 12 months. The rest of the requirements shall be filed within the 12-month term of the provisional licence. ASEP may extend this term, as well as the terms of milestones contemplated in the definitive licence, based on a justified request of the applicant.

The provisional licence is non-transferable and does not authorise the construction of the power plant.

Once the remainder of the requirements to obtain the definitive licence are filed, ASEP shall issue the definitive licence of the power project.

**Transmission concessions**

Resolution JD-1244 of 10 February 1999 (as amended) governs the award of transmission concessions. Transmission concessions shall be awarded through a concurrence process, unless there are no interested competitors (except for the applicant). In the amendment enacted in 2016, ASEP provided that no concurrence process would be required in the case of companies that intend to build transmission lines and substations that will be transferred to ETESA.

**Distribution concessions**

Currently, most (but not all) of the country is divided into three large distribution areas, each one exploited by a distribution concessionaire that is a mixed-capital company in which the public and private sectors have interests. The participation of the private sector in these entities is the result of the public bidding acts held in the late 1990s after the restructuring of IRHE. Some of the original private equity holders have sold their interest in the companies, and therefore, share ownership has changed in time, but distribution concessions remain in effect under a regime of exclusivity within the service area of each concession.
As indicated before, the distribution activity may be carried out by third parties (other than the three main distribution companies) outside of the exclusivity regime in the case of isolated systems and in the case of projects of rural electrification.

iii Ownership and market access restrictions

No-ownership restrictions

Article 285 of the Panamanian Constitution provides that the majority portion of the capital of private companies of public interest that operate in the country shall be Panamanian, save for the exceptions contemplated in the law, which shall define them.

Further to Article 280 of the Constitution, Article 45 of Law No. 6 of 1997 specifically authorises that companies that render public services in the field of electricity may have majority foreign ownership, pursuant to the provisions of Law No. 6 of 1997.

Law No. 6 of 1997, in turn, expressly allows national or foreign capital companies (private or mixed), to participate in the electricity sector, whether by purchasing shares of state-owned electricity companies, or by obtaining and exploiting concessions or licences.

Land acquisition restrictions

Pursuant to Article 291 of the Constitution, foreign individuals or legal entities or companies whose owners are foreign, in whole or in part, may not acquire ownership of public or private land located within 10 kilometres of the national borders. Therefore, an electricity sector service provider owned directly or indirectly by foreign individuals or entities is prevented from acquiring title over the land referred to above. This rule does not encompass the use of land for an electricity sector project through means other than ownership rights.

Other restrictions

There are other restrictions that are specific for the electricity sector:

a energy generation, transmission, distribution and commercialisation companies located in Panama shall have, as sole purpose in their bylaws, one of the activities listed in Article 1 of Law No. 6 of 1997;

b activities related to the transmission and integrated operation of the interconnected national system will be undertaken by the transmission company (ETESA, as defined in the law);

c commercialisation services may be rendered by distributors, except in the case of generators who might commercialise directly with large customers;

d generation companies and their owners shall be restricted from having direct or indirect control in distribution companies, as well as requesting or applying for new concessions, if by doing so they would directly or indirectly serve more than 25 per cent of the national energy demand;

e the transmission company may not participate in activities related to the generation or distribution of energy, nor in the sale of energy to large clients;

f under certain circumstances, distribution companies and their owners may not participate or control directly or indirectly generation plants in their concession area; and

g distribution companies and their owners may not request or apply for new distribution concessions, if by doing so they would serve directly or indirectly more than 50 per cent of the total number of national clients.
iv  Transfers of control and assignments

In connection with capital stock of a concessionaire or licensee: there are no special requirements to seek approval before transferring direct or indirect ownership of stock of a concessionaire or licensee. However, it is recommended to notify any changes in due course after the change of ownership occurs because one of the requirements to obtain a concession or licence is the list of direct and indirect shareholders of the applicant. There is no special regulation for this filing, which is informative in nature.

In connection with mergers and acquisitions of concessionaires or licensees: there is no specific regulation generally mandating that merger and acquisition transactions relating to electricity sector entities be subject to prior approval of ASEP. ASEP has authority to intervene in the event of practices that hinder competition (i.e., abuse of dominant position), including mergers or acquisitions with such effects.

Parties interested in entering transactions in the electricity sector may submit a voluntary consultation on whether the particular merger or acquisition is permitted.

In connection with assets of concessionaires or licensees used in the provision of electricity services: Law No. 6 of 1997 includes among the duties and obligations of electricity sector players 'to administer and maintain the installations and assets required for the provision of the services'. However, some concession contracts contemplate specific provisions on the ability to dispose of assets required for the service. For example, in the case of generation concessions, they allow for the transfer of assets necessary to provide the service, with the prior notice to ASEP.

In connection with concessions or licences: as indicated before, provisional generation licences are not transferrable. Other licences or concessions would be typically transferrable subject to the prior approval of ASEP.

III  TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i  Vertical integration and unbundling

In the 1990s, prior to IRHE’s restructuring, IRHE performed all three of the main electricity sector activities discussed herein (transmission, distribution and generation). IRHE also acted as ‘regulator’ of the sector in many – if not most – respects. Back in those days, a few private power plants had been authorised by IRHE to operate.

Law No. 6 of 1997 disaggregated these services by:

a  restructuring IRHE into seven different service providers in which the private sector would have stakes, as described before;

b  creating restrictions in the law leading to avoid the provision of services in a way that would permit vertical integration; and

c  creating a clear regime of competition in generation activities, enabling large customers to become players in their own merit and regulating other alternatives for players of the market to participate (i.e., autogenerators and co-generators).

Also, special rules have been dictated for electricity sector players to share infrastructure with other agents of the market through remunerated commercial contracts.

Pursuant to Law No. 6 of 1997, a general rule applicable to all electricity market players is to facilitate access and interconnection of other entities who render public services, or who are large customers of the latter, to lines and substations used in the organisation and provision of the services.
Finally, natural gas projects are a new occurrence, and they began to make an appearance in the electricity forum of Panama not long ago. The first natural gas power plant has not yet come online, but it is expected to do so in the following months. Two others have been authorised to date.

ii  Transmission/transportation and distribution access

As indicated before, concessionaires of the electricity market must facilitate access and interconnection to lines and substations used in the organisation and provision of the services to other entities who render public services, or to large customers. For instance, a distribution company shall permit a generator to connect to the transmission network indirectly through the distribution network’s assets, if required, subject to viability based on technical studies. Another example would be a generator who has installed transmission capacity for itself. Such capacity may be sought by another generator to connect to the grid.

The law does not currently allow for competition in the commercialisation of services to end customers. Regulated customers, which are the vast majority of customers of distribution companies, may only be served by the distribution company in their concession zone, which is under a regime of exclusivity. The remaining customers are large customers, who may negotiate their supply agreements with generators.

The rules encouraging competition, which have mainly focused on generation, have been fruitful, as can be seen judging by the large number of projects (in all technologies) that have been or are being constructed after enactment of Law No. 6 of 1997.

The next step in the promotion of competition appears to be the reduction of restrictions on the activity of commercialisation (referred to below).

iii  Rates

Sales of energy to large customers is subject to a regime of mutually agreed pricing. There are no tariffs to apply.

For sales to regulated customers, the Law requires ASEP to dictate the applicable tariff regime for each activity, which serves as a general framework of methodologies and formulas that the market agents must then apply to produce their own tariffs. The tariff regime approved by ASEP is valid for four years unless corrections are needed in the event of errors.

For distribution, ASEP shall define the profitability rate deemed reasonable for the concessionaire, taking into account the latter’s efficiency, the quality of its service, its investment programme for the period of validity of the tariff formulas and any other factor deemed relevant.

For transmission, costs used to calculate the tariff must enable ETESA to have a reasonable rate of return before taxes, over the fixed net asset, at the original cost. For purposes of this calculation, the law contemplates rules on how to determine a reasonable rate.

iv  Security and technology restrictions

Although Law No. 6 of 1997 does not explicitly regulates topics such as homeland security, law enforcement, protection of critical infrastructure and network security, it does define generation, transmission, distribution and commercialisation of electricity as services of public interest destined to satisfy collective needs of the general public. As a general rule, the state must intervene in such services of public interest in order to guarantee the efficient, continuous and uninterrupted service provision.
The Criminal Code of Panama includes penalties ranging from three to five years of jail time for those who seize movable property destined for electricity public services. Similarly, the Criminal Code also includes penalties ranging from five to 10 years of jail time for those who damage or make useless networks, channels or works destined for the transmission of energy, gas or energy substances.

In general, providers of electricity public service have, among others, the following obligations. They must:

- assure that the service is provided continuously and efficiently, without abuse of dominant position;
- avoid monopolistic or competition restrictive practices;
- provide for the end customers that are entitled to receive the subsidies granted by the authorities;
- divulge the efficient and safe way to use the public service;
- protect the environment in the execution of their daily functions;
- facilitate the interconnection access to other companies or entities providing public services and to their large customers;
- provide collaboration to the authorities in cases of public calamity to avoid harm or injury to the end users;
- register with the regulatory authority and provide notification of commencement of the services;
- respond for damage caused to the end customers; and
- provide clear information to the end customers regarding the services and the costs.

Among the transmission company’s obligations are the following. They must:

- provide for the transmission service as established in Law No. 6 of 1997;
- prepare the generation expansion plan of the interconnected national system;
- prepare the transmission expansion plan for the interconnected national system;
- undertake basic studies required to identify possible hydroelectric and geothermic developments; and
- expand, operate, maintain and provide services related to the national network of meteorology and hydrology.

Among the distribution company’s obligations are the following. They must:

- provide the energy distribution service within its corresponding concession area;
- extend their services to rural areas within its corresponding concession area;
- comply with the terms of the concession agreement, and provide the services in a regular and continuous manner within the concession area;
- expand the distribution networks when required to serve the increase in demand within the concession area; and
- keep the fees for the services public and accessible to the customers.

### IV ENERGY MARKETS

#### i Development of energy markets

Under the law and more specifically under the Commercial Rules of the Wholesale Electricity Market, which is part of the Operations Regulation, two markets are recognised: the spot market and the contract market.
A general rule in Law No. 6 of 1997 obligates distribution companies to enter into power purchase agreements to meet the demand in their concession zone. Currently, ETESA calls and conducts the public bids required to award power purchase agreements (PPAs) intended to satisfy the general obligation of Law No. 6 of 1997. ETESA acts as an intermediary between distributors and generators in said processes.

When IRHE had been just restructured, the initial bids for PPAs were open to participants from all generation technologies. With the passage of time, some bids called only for certain technologies. As a result, there have been solar-only, wind power-only and natural gas power-only bids. Through this contracting policy – which refers only to the moment of procuring the PPA – for the past few years, the government has been trying to reshape the composition of the generation matrix of the country.

In the contract market bids are called for different products, for instance, power-only, power and energy or energy-only. However, again, this refers only to the moment of procuring the PPA.

Dispatch in the market occurs in ascending order of variable cost, regardless of the conditions of a particular PPA.

ii Contracts for sale of energy

Large customers may freely negotiate individual contracts for the purchase of capacity or energy with generators of the market. There are no regulatory requirements limiting pricing or establishing rates.

The parties may agree to include in these contracts an arbitration clause to submit to arbitration by ASEP in the event of disputes; and therefore, only if a party submits a dispute to ASEP would the authority have the ability to intervene to dictate a solution.

There is no natural gas market in Panama. The gas necessary for the large gas power plants being installed will have to be imported.

iii Market developments

Currently, Law Project 573 is being discussed at the National Assembly. If approved, this Law Project would modify Law No. 6 of 1997 in various aspects, including the recognition of the ‘commercialisation’ activity in the energy market outside of the current bounds of the Law. The ‘marketer’ (person undertaking the commercialisation activity) would be allowed to commercialise energy between the distributors, large clients and other market agents, as well as between generators and large clients.

This Law Project anticipates the elimination of the rule that makes it mandatory for all generators with uncompromised capacity to submit bids for PPAs when bids are called, and the abolition of special bids for the purchase of energy by specific technology.

Additionally, this Law Project intends to include a mechanism to provide incentives for the use of renewable energy by including public bids for the purchase of energy and evaluation criteria that penalise CO2 emissions.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

Law No. 45 of 2004 establishes a number of general incentives for the promotion of energy generation systems fuelled by new, renewable and clean sources.
Some of the tax incentives are the following: exoneration of import tax, tariffs, rates, and other contributions caused by the importation of equipment, machines, materials and parts necessary for the construction, operation and maintenance of generation systems fuelled by clean and renewable sources.

There are also tax incentives based on the reduction of tons of CO2 emissions, which may be used for the payment of income tax during the first 10 years counted from the beginning of the project’s commercial operations.

More specific laws for the different types of energy sources regulate the corresponding incentives for each source. Among them are the following:

a. Law No. 44 of 2011 establishes incentives for the construction and operation of wind generation plants;
b. Law No. 37 of 2013 establishes incentives for the construction and operation of solar generation plants; and
c. Law No. 41 of 2012 establishes incentives for the construction and operation of natural gas generation plants.

The PEN, prepared by the SNE as per Law No. 43 of 2011, includes as a short-term project the consolidation and harmonisation of existing regulations regarding renewable energy into one law.

ii Technological developments

Panama is taking its first steps towards being conscientious about smart grids in governmental affairs and in relation to citizens. Perhaps the entity that is the most advanced in taking the first steps towards implementing the concept of a smart city is the Municipality of Panama. While no special regulatory effort appears to be in the pipeline for smart grid technology as it pertains to the electricity sector, it is clear that both ASEP and the SNE are actively joining forces with other government entities such as the Municipality to promote the common goal to incorporate technology to empower citizens.

VI THE YEAR IN REVIEW

The following are among the most relevant occurrences:

a. The much-needed Third Transmission Line is reaching completion and portions thereof have become operational already.
b. A new public bid for the construction of the Fourth Transmission Line with a capacity of 1,280MW by circuit of 500KV with a length of 330 kilometres is under evaluation. The call for the bid is expected to occur during 2018.
c. Law Project 573, which amends Law No. 6 of 1997, is still being discussed and if approved, a more liberalised form of commercialisation activity will be a reality in Panama.
d. The current trend in large power plant investment is natural gas. There are currently three concessions awarded, one of them in advanced stages of construction.
e. Another project that is being discussed is the Colombia–Panama interconnection line through underwater cable with a capacity of 400MW.
VII CONCLUSIONS & OUTLOOK

The Panamanian electricity sector is expected to continue to attract investment. A relatively clear-cut regulation to obtain the relevant concessions and licences is among the strengths of the system.

If the new rules on commercialisation are enacted, the dynamics of the system will change and there must necessarily be a time to adapt to change. The regulator should make sure that clear regulation is in place and proper divulgation is made, to avoid confusion in the applicable rules that pertain to commercialisation with regard to the traditional methods to purchase and sale power and energy.
I OVERVIEW

In 2001, the Philippine Congress passed Republic Act No. 9136, or the Electric Power Industry Reform Act (EPIRA), to:

a. restructure the Philippine electric industry into four major sectors – generation, transmission, distribution and supply;
b. privatise several state-owned assets, which paved the way for the entry of private investors;
c. enable the creation of the wholesale electricity spot market; and

d. enable the introduction of open access and retail competition.

In addition, the implementation of Republic Act No. 9513 (2008), or the Renewable Energy Act (the RE Act), has dramatically increased the entry of green energy alternatives to the power sector by offering several incentives to renewable energy developers, including a feed-in-tariff system. Republic Act No. 10771 (2016), or the Philippine Green Jobs Act of 2016, recently granted further incentives to business enterprises, such as renewable energy developers, that generate and sustain green jobs as certified by the Climate Change Commission created under the said law.

In 2015, the Congress passed Republic Act No. 10886, otherwise known as the Philippine Competition Act (PCA), that created a quasi-judicial body called the Philippine Competition Commission, which has original and primary jurisdiction in hearing and deciding anti-competition cases in all industries, including the energy sector, thus stripping the Energy Regulatory Commission (ERC) of the exclusive authority over anticompetitive behaviours of the energy participants.

II REGULATION

i The regulators

Electric power industry

The power industry in the Philippines is primarily governed by the EPIRA and its Implementing Rules and Regulations (EPIRA IRR), as amended, and the issuances by the Department of Energy (DOE) and the (ERC).
Under the EPIRA, key government agencies and instrumentalities were either created or their powers and functions reorganised, with the aim of fulfilling the mandate of the law.

The DOE is the primary policymaking and implementing body for the industry, with a mandate to supervise and control all government activities pertaining to energy projects.

The EPIRA also created the ERC (in place of the Energy Regulatory Board) as an independent, quasi-judicial regulatory body, that has original and exclusive jurisdiction over all cases contesting rates, fees, fines and penalties it imposes, and over all cases involving disputes between and among participants or players in the energy sector.

The EPIRA likewise mandated the ERC to promote competition, encourage market development, ensure consumer choice and penalise abuse of market power in the electricity industry. Nonetheless, with the passage of the PCA, which similarly granted the Philippine Competition Commission (PCC) jurisdiction to, among other things, conduct inquiries, investigate, hear and decide anticompetitive cases in all industries including the energy sector, both the ERC and PCC now exercise concurrent jurisdiction over anticompetitive cases in the energy sector. The two entities have yet to come up with terms of engagement in handling market abuse cases involving energy stakeholders.

The EPIRA also established the Power Sector Assets and Liabilities and Management Corporation (PSALM) to manage the orderly sale, privatisation and disposal of generation assets, real estate and other disposable assets of the National Privacy Commission (NPC). PSALM was authorised to take title to and possession of those assets transferred to it. The EPIRA mandated that all such assets should be sold through public bidding, with the exception of the Agus and Pulangui hydropower complexes in Mindanao, the privatisation of which was left to the discretion of PSALM in consultation with Congress.

Also created under the EPIRA was the National Transmission Corporation (TRANSCO), a government-owned and controlled corporation that assumed the power transmission functions of the NPC, including the authority and responsibility for the planning, construction and centralised operation and maintenance of ancillary services. Designated as the system operator under the Philippine Grid Code, TRANSCO is responsible for providing open, equal and non-discriminatory access to its transmission system to all electricity users.

Also worth noting are certain private entities that perform key functions for the Philippine power industry:

- the Philippine Electricity Market Corporation (PEMC), a non-stock, non-profit company that manages and operates the wholesale electricity spot market (WESM);

2 Section 37 of the EPIRA.
3 Rule 3, Section 1 of the EPIRA IRR.
4 Section 38 of the EPIRA.
5 In its Order dated 2 February 2017 in ERC Case No. 2015-025MC, the ERC clarified that it no longer has exclusive jurisdiction over market abuse and anticompetitive behaviours in the energy sector.
6 Section 50 of the EPIRA.
7 Section 47(f) of the EPIRA.
8 Section 8 of the EPIRA.

© 2018 Law Business Research Ltd
the National Grid Corporation of the Philippines (NGCP), the private corporation that holds the concession to operate and maintain the power transmission system and sub-transmission system owned by TRANSCO, and that presently acts as system operator.\textsuperscript{9}

\textbf{Other industries}

Both the oil and natural gas industries are subject to regulation by the DOE. Presidential Decree No. 87 (1972), or the Oil Exploration and Development Act (PD87), was passed in 1972 to ‘hasten the discovery and production of indigenous petroleum through the utilization of government and/or private resources’.\textsuperscript{10} PD87 remains the basis for the current service contract system adopted by the Philippine government, through the DOE, to directly conduct exploration and produce indigenous petroleum or to appoint technically competent and financially capable contractors to do this, whether local or foreign.\textsuperscript{11} Presidential Decree No. 1857 (1983) complements PD87 in providing the fiscal and contractual terms of the service contracts, with special consideration for deepwater oil exploration.\textsuperscript{12}

In 1998, Republic Act No. 8479, or the Downstream Oil Industry Deregulation Act, sought to liberalise and deregulate the industry by promoting, among other things, the entry of new participants in the downstream oil industry, and granted the DOE various powers to this end.\textsuperscript{13}

In 2001, the regulation of the natural gas industry was entrusted by the President of the Republic to the DOE,\textsuperscript{14} which promulgated Department Circular No. 2002-08-005, or the Interim Rules and Regulations Governing the Transmission, Distribution and Supply of Natural Gas (the Natural Gas Interim Rules), providing a set of guidelines for the downstream natural gas industry. In 2017, the DOE issued Department Circular No. 2017-11-0012, or the Philippine Downstream Natural Gas Regulation, which establishes the rules and regulations to be followed with respect to siting, design, construction, expansion, rehabilitation, modification, operation and maintenance of the Philippine Downstream Natural Gas Industry Value Chain.\textsuperscript{15}

This chapter focuses primarily on the electric power industry, which has seen more vigorous developments in recent years. Reference is made to the oil and natural gas industries where relevant.

\textbf{ii Regulated activities}

The electric power industry is segregated into four main sectors: the generation, transmission, supply and distribution sectors.

\textsuperscript{9} Republic Act No. 9511 (2008).
\textsuperscript{10} Section 2 of PD87.
\textsuperscript{11} Section 4 of PD87.
\textsuperscript{12} See https://www.doe.gov.ph/presidential-decree-no-1857.
\textsuperscript{13} Section 2 of Republic Act No. 8479 (1998); also see Chapters II, III and IV of Republic Act No. 8479 (1998) for the various powers granted to DOE.
\textsuperscript{14} Executive Order No. 66 (2001).
\textsuperscript{15} Philippine Downstream Natural Gas Industry Value Chain refers to the Downstream Natural Gas Facilities and the operations or activities related thereto that involve LNG importation, storage, regasification, transmission and distribution to customers including the pipeline and its related facilities used to transport indigenous natural gas and the operations of activities related thereto after the point of sale up to the last connection point to the Customers (Rule 4(ii) of the Philippine Downstream Natural Gas Regulation).
The generation of electric power is recognised as a business affecting the public interest and is mandated to be both competitive and open. A generation company is a person or entity authorised by the ERC to operate facilities used in the generation of electricity. The generation business is not regulated and the parties to power (or ancillary services) supply agreements are generally free to negotiate a mutually acceptable tariff; however, one of the parties must be a regulated entity – such as a distribution utility or transmission company – and the negotiated tariff is subject to ERC approval.

In contrast, the transmission of electric power is considered a regulated common electricity carrier business, requiring a national franchise and subject to the rate-making powers of the ERC. The NGCP was issued the national franchise for the operation and maintenance of TRANSCO's power transmission and sub-transmission system, with TRANSCO's oversight to ensure compliance with the concession agreement.

The distribution of electricity to end-users is a regulated common electricity carrier business requiring a national franchise. Distribution of electric power to end-users may be undertaken by private distribution utilities, cooperatives, local government units and other duly authorised entities, subject to regulation by the ERC. Any of these entities can be a distribution utility provided it holds an exclusive franchise area to operate a distribution system in accordance with the EPIRA.

Finally, the supply sector is also regarded as a business affecting the public interest. A supplier is any person or entity authorised by the ERC to sell, broker, market or aggregate electricity to end-users. Except for distribution utilities and electric cooperatives with respect to their existing franchise areas, all suppliers of electricity to the contestable market require a licence from the ERC.

The law also allows for wholesale aggregators – being any person or entity, other than a generation company – to be issued with a certificate of registration by the ERC to sell electricity to distribution utilities. However, considering recent changes in the WESM that removed technical and financial barriers to distribution utilities' participation in the WESM, the ERC discontinued the wholesale aggregator scheme and the Rules for the Registration of the Wholesale Aggregators, as amended.

iii Ownership and market access restrictions

To protect against market abuse and anticompetitive behaviour, the EPIRA prohibits the following persons or entities from holding any interest, whether directly or indirectly, in

---

16 Section 6 of the EPIRA.
17 Section 4(x) of the EPIRA.
18 Section 7 of the EPIRA.
19 Section 2 of Republic Act No. 9511 (2008).
20 Section 22 of the EPIRA.
21 Rule 4(kkkk) of the EPIRA IRR.
22 Rule 8, Section 4 of the EPIRA IRR.
23 On 22 May 2006, the ERC adopted the Rules for the Registration of the Wholesale Aggregators to purposely open an avenue by which distribution utilities, especially small electric cooperatives, would be able to supply from the WESM. (ERC Resolution No. 23, Section 2006).
24 Section 5 of the ERC Rules for the Registration of the Wholesale Aggregators.
any generation company: TRANSCO and its concessionaire (NGCP) and stockholders or officials of TRANSCO or the NGCP, or their relatives within the fourth civil degree of consanguinity or affinity, whether legitimate or common law.26

In addition, the PCA empowered the PCC to prohibit or issue orders to remedy mergers that will substantially prevent, restrict or lessen competition in the relevant market or in the market for goods and services, and therefore impose financial penalties, including the energy sector.27

The EPIRA also states that ‘no company or related group can own, operate or control more than 30 per cent of the installed generating capacity of a grid or 25 per cent of the national installed generating capacity’.28 The ERC determines the installed generating capacity per grid and in the national grid, as well as the market share limitations each year or as often as necessary, based on the maximum capacity of the power plants.29

The business of power generation by itself is not subject to foreign ownership limitations; it is not considered a public utility operation and therefore is not considered a nationalised activity that requires a national franchise.30 The issue of foreign ownership only arises if power generation involves the exploration, development and utilisation of natural resources31 – such as renewable energy – as this activity must be under the full control and supervision of the state. This may only be undertaken jointly with Filipino citizens or corporations or associations 60 per cent of whose capital is owned by Filipino citizens under co-production, joint venture or production sharing agreements.32 In contrast, the transmission and distribution sectors are subject to nationality restrictions as they are considered to be regulated common electricity carrier businesses and thus public utilities. Entities engaged in the transmission and distribution of electricity are required to secure a franchise and a certificate of public convenience and necessity prior to operation.33 The operator must then be a Filipino citizen or a corporation or other entity organised under the laws of the Philippines, at least 60 per cent of the stock or paid-up capital of which must belong entirely to citizens of the Philippines.34

iv Transfers of control and assignments

Parties to a merger (including those in the energy sector) that meet the threshold requirements under the PCA are required to notify the PCC within 30 days of the signing of definitive agreements relating to the merger.35 The PCC may decide to: approve the merger, prohibit

---

26 Rule 5, Section 3, and Rule 11, Section 3 of the EPIRA IRR.
27 Section 12 of the PCA; Section 2.2 of the PCC Rules on Merger Procedure.
28 Section 45(a) of the EPIRA.
29 Guidelines for the Determination of Installed Generating Capacity in a Grid and the National Installed Generating Capacity and Enforcement of the Limits on Concentration of Ownership Operation or Control of Installed Generating Capacity under Section 45 of Republic Act No. 9136.
30 Section 6 of the EPIRA.
32 Article XII, Section 2 of the Constitution.
33 Section 1 of the ERC Rules to Govern the Issuance of Certificate of Public Convenience and Necessity to Entities Engaged in the Transmission and Distribution of Electricity.
34 Section 2 of the ERC Rules to Govern the Issuance of Certificate of Public Convenience and Necessity to Entities Engaged in the Transmission and Distribution of Electricity.
35 Section 2.1 of the PCC Rules on Merger Procedure.
the merger or prohibit the merger subject to conditions that it considers appropriate to remedy, mitigate or prevent the activities that will substantially prevent, restrict or lessen competition.36

Apart from the foregoing competition-related approval, there are generally no restrictions or approvals necessary in the power industry for the transfer of assets, services or control, other than for those entities with legislative franchises, which usually include a clause providing that any change in ownership will require Congressional approval. The distribution and transmission of electric power require a national franchise.37

While the generation sector is not subject to the foregoing restriction, any change in ownership or control of assets and services of a generation company must comply with the ownership threshold on installed generating capacity, as previously discussed.

III TRANSMISSION/TRANSPORTATION & DISTRIBUTION SERVICES

i Vertical integration and unbundling

Transmission sector
The transmission sector in the Philippine power industry essentially remains a monopoly. After open competitive bidding, the operation and management of the transmission system was privatised and transferred from TRANSCO to the NGCP in 2008, as part of the mandated privatisation of TRANSCO under the EPIRA. The NGCP was also awarded the legislative franchise, with a term of 50 years to engage in the business of conveying or transmitting electricity through the high-voltage backbone system of interconnected transmission lines, substations and related facilities.38

Distribution sector
As discussed above, the distribution of electricity to end-users is undertaken by distribution utilities, which may be electric cooperatives, private corporations, government-owned utilities or existing local governments.39 These utilities also hold franchises covering their respective distribution areas.

Supply sector
The supply of electricity to end-users may be undertaken by a retail electricity supplier (RES) or aggregator duly licensed by the ERC upon the implementation of the regime of open access. An RES is a person or entity authorised by the ERC to sell, broker, market or

36 Section 2.1.2 of the PCC Rules on Merger Procedure.
37 See, for instance, Section 6 of Republic Act No. 9511 (An Act Granting the National Grid Corporation of the Philippines a Franchise to Engage in the Business of Conveying or Transmitting Electricity through the High-Voltage Backbone System of Interconnected Transmission Lines, Substations and Related Facilities, and for other Purposes).
38 Republic Act No. 9511 (2008); Section 8 of the EPIRA.
39 Rule 4(cc) of the EPIRA.
aggregate electricity to end-users forming part of the contestable market,\textsuperscript{40} which initially consists of end-users with an average monthly peak demand of at least 750kW for the proceeding 12 months.\textsuperscript{41}

A retail aggregator is a person or entity licensed by the ERC to engage in consolidating the electric power demand of end-users qualified for contestability for the purpose of purchasing and reselling electricity on a group basis.\textsuperscript{42} Retail aggregation is set to begin on 26 June 2018.\textsuperscript{43}

\textbf{ii Transmission/transportation and distribution access}

Consistent with the policy of ensuring transparent and reasonable pricing of electricity in a regime of free and fair competition,\textsuperscript{44} the EPIRA mandates TRANSCO, the NGCP and the distribution utilities to provide open and non-discriminatory access to all electricity end-users to the transmission system and distribution systems.\textsuperscript{45}

A customer seeking to connect to the transmission system must, however, comply with the requirements under the Revised Rules, Terms and Conditions for the provision of Open Access Transmission Service (the OATS Rules), the Philippine Grid Code (PGC) and related issuances for connections to the transmission system.

Further, end-users within the franchise area of a distribution utility intending to connect directly to the transmission system need to secure the prior approval of the ERC. In seeking this approval, it must be shown that the distribution utility is unwilling or unable to adequately service the power requirements of such end user\textsuperscript{46} in deference to the franchise held by the distribution utility covering such area.\textsuperscript{47}

Similarly, an end-user seeking to connect to the distribution system of a distribution utility must comply with the requirements under the Distribution Services and Open Access Rules (DSOAR), the Philippine Distribution Code (PDC) and other related issuances.

The goal of retail competition and open access on distribution wires is to provide end-users forming part of the contestable market – ultimately at household level – with their choice of electricity service providers.

\textbf{iii Rates}

The ERC generally sets the rates that the NGCP and the distribution utilities may charge its customers. In the exercise of its rate-setting functions, the ERC is mandated by the EPIRA to fix such rates such as to allow the recovery of just and reasonable costs and a reasonable return.

\textsuperscript{40} Section 5 of the 2016 Rules Governing the Issuance of Licences to Retail Electricity Suppliers; ‘contestable market’ refers to electricity end-users who have a choice of supplier of electricity as determined by the ERC.  
\textsuperscript{41} Article II, Section 1.1 of the ERC Revised Rules for Contestability.  
\textsuperscript{42} Article I, Section 3 of the ERC Revised Rules for Contestability.  
\textsuperscript{43} Article II, Section 1.2 of the ERC Revised Rules for Contestability.  
\textsuperscript{44} Section 2(c) of the EPIRA.  
\textsuperscript{45} Sections 9(b) and 23 of the EPIRA  
\textsuperscript{46} ERC Resolution No. 48 (2006), as amended by ERC Resolution No. 27 (2010).  
\textsuperscript{47} Batangas II Electric Cooperative Inc. v. Energy Industry Administration Bureau, GR No. 135925, 22 December 2004; Rule 7, Section 1(a) of the EPIRA IRR.
Transmission

The maximum rates that may be charged by the NGCP for the provision of transmission services are subject to the approval of the ERC. In determining the maximum transmission wheeling rates that can be charged by the NGCP, the ERC is guided by the Rules for Setting Transmission Wheeling Rates (RTWR), which provides the methodology and pricing principles to be adopted by the ERC, the annual rate verification and adjustment process to be undertaken, the regulatory processes and timelines, performance indicators, performance targets and reporting arrangements required from the NGCP. The RTWR further provides for a performance incentive scheme, which rewards or penalises the NGCP depending on its compliance with set performance targets and indices.

Distribution

The distribution wheeling rates and connection charges, which may be charged by distribution utilities to end users, are also subject to the approval of the ERC. Different rate-setting regimes govern different classes of distribution utilities.

The rates that electric cooperatives may charge end-users are determined in accordance with the Rules for Setting the Electric Cooperatives’ Wheeling Rates (RSEC-WR). Under the RSEC-WR, electric cooperatives are classified into groups based on the number and consumption of their customers. The rates are then determined based on the operating revenue requirements of the different classes of electric cooperatives.

On the other hand, the maximum distribution wheeling rates to be charged by private distribution utilities operating under performance-based regulations are governed by the 2016 Rules for Setting Distribution Wheeling Rates (2016 Revised RDWR). The 2016 Revised RDWR provides the methodology and pricing principles to be adopted by the ERC; the annual rate verification and adjustment process to be undertaken; the regulatory processes and timelines; and performance indicators, performance targets and reporting arrangements required from the distribution utilities. A performance incentive scheme is incorporated into the RDWR, whereby a qualified distribution utility is rewarded or penalised depending on its compliance with set performance targets and indices.

iv Security and technology restrictions

The operation, maintenance and development of the transmission system are generally governed by the PGC, the OATS Rules and related issuances. Similarly, the operation and maintenance of distribution systems are regulated by the PDC, the Amended DSOAR and related issuances.

48 Section 19 of the EPIRA.
49 Section 1.2 of the RTWR.
50 Section 8.2 of the RTWR.
51 Section 23 of the EPIRA.
52 Section 2.3 of the RSEC-WR.
53 Article 4 of the RSEC-WR.
54 Section 1.2.1 of the 2016 Revised RDWR.
IV ENERGY MARKETS

i Development of energy markets

Wholesale electricity spot market

The EPIRA mandated the establishment of the WESM to provide a mechanism for identifying and setting the price of actual variations from the quantities transacted under contracts between sellers and purchasers of electricity.55

In 2003, the PEMC was organised as a non-stock, non-profit corporation to undertake the preparatory work and initial operation of the WESM. The PEMC currently operates the WESM as the autonomous group market operator pending transition to an independent market operator, pursuant to the EPIRA.

The WESM is currently organised on a grid basis, consisting of three separate markets for Luzon, Visayas and Mindanao. The WESM commenced commercial operations in Luzon in June 2006 and in Visayas in December 2010.56 The Interim Mindanao Electricity Market (IMEM) was launched in 2013 to provide a trading platform for any uncontracted capacity in Mindanao,57 but its operation was suspended by the DOE. On 26 June 2017, WESM in Mindanao was officially launched58 but it is not yet operating commercially. The DOE plans to create a transition committee for the Mindanao WESM,59 which is expected to be commercially operational by the second quarter of 2018.60

The Luzon-Visayas WESM operates on the basis of a gross pool whereby all transactions for the sale and purchase of electricity are channelled through the market. The market network model is used for the purpose of central scheduling, dispatch, pricing and settlement.61

Generation companies submit generation offers, and customers their demand bids for each trading interval of each trading day of the week.62 Market clearing prices63 and dispatch are determined based on the results of the market dispatch optimisation model for a specific trading interval,64 subject to adjustments for bilateral contract quantities declared for dispatch but settled outside the market. The dispatch targets set by the market operator are then implemented by the NGCP, as system operator, through dispatch instructions to the trading participants.65

Other markets

Under the current legislation, provisions have been made for the establishment of a reserves market for ancillary services66 and a renewable energy market (REM) for the trading of

55 Section 30 of the EPIRA.
56 See www.wesm.ph/inner.php/about_us/wesm.
57 IMEM Implementing Rules, DOE Department Circular 2013-05-008.
58 Section 2 of DOE Department Circular No. DC2017-05-0009.
61 Section 3.2.1 of the WESM Rules.
62 Section 3.5.5 and 3.5.6 of the WESM Rules.
63 The price determination methodology used by the market operator is subject to the approval of the ERC (Rule 9, Section 5(d) of the EPIRA IRR).
64 Section 3.3.6 of the WESM Rules.
65 Section 3.8.2 of the WESM Rules.
66 Section 3.3.4 of the WESM Rules.
renewable energy certificates. The commercial operation of the central scheduling and dispatch of energy and contracted reserves in the WESM commenced on 26 November 2015. The implementation of such central scheduling and its protocol shall immediately cease upon the commercial operations of the WESM reserve market. On the other hand, the draft rules governing the REM have been issued by the DOE for comments of stakeholders, but have not yet been finalised.

ii Energy market rules and regulation

The WESM Rules, promulgated by the DOE and formulated jointly with the electric power industry participants, and the WESM Manuals issued pursuant thereto generally govern the operation of the WESM. By express provision of the EPIRA, all electric power industry participants are bound to comply with the WESM Rules relative to transactions in the WESM.

iii Contracts for sale of energy

Electric power industry participants are generally free to enter into bilateral contracts for the supply of electric power, and utility purchases of power are customarily driven by commercial considerations.

Certain limitations on the purchases of electric power through bilateral power supply contracts by distribution utilities are imposed under the EPIRA as a measure against market abuse and anticompetitive behaviour, and to encourage participation by distribution utilities in the WESM:

a contracts with distribution utilities are subject to review by the ERC; and
b distribution utilities are prohibited from sourcing more than 50 per cent of their total demand from an affiliate engaged in generation.

On 20 March 2015, the ERC issued the Resolution Directing All Distribution Utilities to Conduct a Competitive Selection Process (CSP) in the Procurement of their Supply to the Captive Market (the CSP Resolution), mandating distribution utilities to undertake a transparent and competitive selection process before entering into a bilateral agreement for the supply of electric power. The ERC has not yet prescribed a specific form of competitive selection process. Pending issuance by the ERC of a prescribed competitive selection process, distribution utilities may adopt any accepted form of CSP.
Direct negotiation may only be undertaken in the case of two failed competitive selection processes in which the following circumstances exist:

- no proposal was received by the distribution utility;
- only one supplier submitted an offer; and
- competitive offers of prospective suppliers failed to meet the requirements prescribed under the terms of reference, as determined by the distribution utility’s bids and awards committee.

Power supply contracts that have not yet been filed for the approval of the ERC following the effectivity of the CSP Resolution must first undergo a competitive selection process before they can be accepted by the ERC. On 15 March 2016, the ERC restated the effectivity of the CSP Resolution from 30 April 2016.77

iv Market developments

Open access and retail competition for the contestable market of 1MW (minimum) users have been implemented since June 2013. Persons intending to supply electricity to end-users reaching the prescribed minimum threshold of monthly average peak demand are required to secure a licence from the ERC.78

On 12 May 2016, the ERC issued Resolution No. 10, Series of 2016, mandating end-users with an average monthly peak demand of at least 750kW to enter into a retail electricity contract with a retail electricity supplier by 26 June 2017.79 On 26 June 2018, the threshold shall be lowered to cover end-users with an average peak demand of at least 500kW. Distribution utilities are required to submit accurate information on contestable customers that have accounts with the distribution utilities to the ERC and the Central Registration Body on a monthly basis. On the basis of the data submitted by the distribution utilities, the ERC shall issue the Certificates of Contestability.

However, on 21 February 2017, the Supreme Court issued a temporary restraining order enjoining the implementation of various DOE and ERC issuances relating to retail electricity supply and contestable market, including ERC Resolution No. 10, Series of 2016. The DOE and ERC have filed a motion for reconsideration and an Omnibus Motion to seek clarification on scope and coverage of the temporary restraining order, including whether the threshold for contestability may be lowered to 750kW on a voluntary basis. However, these motions remain unresolved as of the time of writing.

Pending the resolution on the motions filed by the DOE and ERC, the DOE has issued Department Circular No. DC2017-12-0013 providing for voluntary participation of end-users with an average monthly peak demand of at least 750kW in the competitive retail electricity market. The same DOE circular lowers the threshold for voluntary participation to 500kW by 26 June 2018, or on an earlier date to be set by the ERC.

77 ERC Resolution No. 1, Series of 2016.
78 Section 4(vvv) of the EPIRA IRR; Section 29 of the EPIRA.
79 Article II, Section 1.1 of ERC Resolution No. 10, Series of 2016.
V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

In 2008, the RE Act, was passed into law to establish a framework to accelerate the development and advancement of renewable energy resources, and the development of a strategic programme to increase its utilisation. To this end, the law included the granting of fiscal incentives to persons engaged in the exploration, development and utilisation of renewable energy resources (RE developers) and the adoption of a feed-in tariff (FIT) system, among others.

The RE Act grants the following incentives to RE developers:

\[ a \] A seven-year income tax holiday from the start of commercial operations, followed by a corporate tax of only 10 per cent of its net taxable income – substantially lower than the regular 32 per cent imposed under Republic Act No. 8424 (1997) or the National Internal Revenue Code.

\[ b \] Duty-free importation of renewable energy machinery, equipment and materials and their parts within 10 years of the issuance of a certification to the RE developer.

\[ c \] Special tax rates on civil works, equipment, machinery and other improvements actually and exclusively used for renewable energy facilities, not exceeding 1.5 per cent of their cost less the accumulated normal depreciation or net book value.

\[ d \] The net operating loss carry-over of the RE developer during the three years from the start of commercial operations may be carried over as a deduction from gross income for the next seven consecutive taxable years immediately following the year of such loss – which is substantially longer than the three-year period under the National Internal Revenue Code.

\[ e \] The sale of power generated from renewable sources of energy are subject to zero-rated value added tax (VAT), as well as purchases by RE developers of locally supplied goods, properties and services.

\[ f \] RE developers who purchase locally produced renewable energy machinery, equipment, materials and parts will be entitled to a tax credit of 100 per cent of the VAT and customs duties that would have been paid had these items been imported.

The RE Act mandates the ERC, in consultation with the National Renewable Energy Board (NREB), to promulgate a FIT system. Thus, on 12 July 2010, the ERC approved and adopted Resolution No. 16, Series of 2010, or the Feed-in Tariff Rules, which established the FIT as a fixed tariff, specific to a technology and size of the renewable energy power plants. In July 2012, the ERC approved the following initial FIT rates:

\[ a \] hydro: 5.90 pesos per kW/h;

\[ b \] biomass: 6.63 pesos per kW/h;

80 Section 3 of the RE Act.
81 Section 15(a) and (e) of the RE Act; Section 27(A) of Republic Act No. 8424 (1997).
82 Section 15(b) of the RE Act.
83 Section 15(c) of the RE Act.
84 Section 15(d) of the RE Act; Section 34(D)(3) of Republic Act No. 8424 (1997).
85 Section 15(g) of the RE Act.
86 Section 15(j) of the RE Act.
87 Section 7 of the RE Act.
88 Sections 2.2–2.3 of the FIT Rules.
The installation targets for renewables were 250MW for biomass, 500MW for solar, 200MW for wind, 250MW for run-of-river hydro and 10MW for ocean power. The installation targets for solar and wind were increased to 500MW and 400MW, respectively, but both increased installation targets have already been fully subscribed. The installation targets for biomass and hydro have not been fully subscribed upon their expiration on 31 December 2017, but the DOE is expected to extend them for two more years.

The RE Act also mandates the NREB to set the minimum percentage of generation from eligible renewable energy resources and determine on which sector the renewable energy portfolio standards (RPS) will be imposed on a per-grid basis. On 22 December 2017, the DOE adopted the Rules and Guidelines Governing the Establishment of the RPS for On-Grid Areas, which prescribes that the share of electricity coming from renewable energy resources shall be based on the aspirational target of 35 per cent in the generation mix by 2030. The minimum annual RPS requirement per mandated participant shall be computed by a team in coordination with NREB, subject to an initial minimum annual increment of 1 per cent to be applied to the net electricity sales of the mandated participant for the previous year.

### ii Energy efficiency and conservation

The DOE has promulgated Implementing Rules and Regulations Directing the Institutionalisation of a Government Energy Management Programme (the GEMP IRR), which mandates the formulation of an energy conservation programme by each government entity to reduce monthly electricity and fuel consumption by 10 per cent. No similar issuances apply to the private sector.

### iii Technological developments

There is no special legislation that promotes or advances particular technological developments in the RE sector. However, some of the incentives provided above that are available to RE developers are also available to manufacturers, fabricators, and suppliers of locally produced renewable energy equipment and components.

### VI THE YEAR IN REVIEW

The continued growth of the renewable energy sector and introduction of new technology characterises the past years for the Philippine energy industry. As of 2016, 32.5 per cent of the total installed capacity of the country is from renewable energy resources. Despite the
The development of significant solar power projects has substantially contributed to the growth of the renewable energy sector. In 2016, solar power made up almost all of the US$1 billion capacity investment as developers competed to avail of the FIT. With the development of solar power projects during the past two years, the Philippines ranked first among developing countries in Asia in terms of the use of solar photovoltaic systems for electricity generation.

Although there are currently no plans to have another round of FIT for solar, development of solar power project continues in the form of distributed energy resources (DERs). Recently, the ERC issued the draft Licensing Rules for Distributed Energy Resources and Microgrid Systems, which aims, among other things, to recognise the integration and entry of DERs into the transmission and distribution system. The emergence of renewable energy systems has also brought an increase in net metering schemes.

Notwithstanding growth in the renewable energy sector, coal-fired power plants continue to account for a substantial share of the country’s energy mix. As of 2016, coal-fired power plants account for 34.6 per cent of the installed capacity and 47.7 per cent of the gross generation in the Philippines.

The energy industry has also met challenges recently, with the suspension of four ERC Commissioners for extending the implementation of the CSP Resolution to 30 April 2016. The suspension of the Commissioners has halted the operations of the ERC because, as a collegial body, it can only act after due deliberation and it requires the presence of at least three Commissioners to constitute a quorum. The Court of Appeals has issued a 60-day temporary restraining order against the suspension of the Commissioners. However, the motion for reconsideration against the suspension order remains unresolved.

VII CONCLUSIONS & OUTLOOK

Power situation

As of 2016, the DOE has identified the total installed capacity as 21,424MW. The DOE projects that the Philippines will need an additional capacity of 43,765MW by 2040, with 70 per cent baseload requirements.

Based on the 2016 power capacity, 21.9 per cent of the gross generation is sourced from natural gas. However, the Malampaya natural gas field, which supplies 50 per cent of the energy requirements for Luzon, is expected to run out of reserves in 2029–2030. In view

of this, the Department of Finance is pushing for new energy sources.\textsuperscript{104} Also, among the strategic directions of the DOE for 2017–2040 is the development of LNG terminals.\textsuperscript{105} In line with this, the Asian Development Bank has entered into a transaction advisory services agreement with Philippine National Oil Co, on the LNG hub project in Batangas. The project shall include a regasification terminal, storage, power plant and other related infrastructure. To provide for rules and regulation governing the downstream natural gas industry, the DOE has issued Department Circular No. DC2017-11-0012.

\textbf{ii} \hspace{1em} \textbf{Increase in power rates}

Electricity rates are expected to rise owing to the provisions of the newly enacted Tax Reform for Acceleration and Inclusion (TRAIN) Law. Under the TRAIN Law, the VAT on wheeling charges was reinstated, resulting in 7 centavos per kWh.\textsuperscript{106} Another provision on the TRAIN Law that increases the power rates is the increase on the tax on coal and the imposition of excise tax on petroleum products.\textsuperscript{107}

\textbf{iii} \hspace{1em} \textbf{Policy initiative}

The President has issued Executive Order No. 30 Series of 2017 to create the Energy Investment Coordinating Council, in order to streamline the regulatory procedures affecting energy projects.\textsuperscript{108} The President has also identified major energy projects for power generation, transmission and ancillary services with the following attributes as projects of national significance:\textsuperscript{109}

\begin{itemize}
  \item \textit{a} significant capital investment of at least 3.5 billion pesos;
  \item \textit{b} significant contribution to the country’s economic development;
  \item \textit{c} significant consequential economic impact;
  \item \textit{d} significant potential contribution to the country’s balance of payments;
  \item \textit{e} significant impact on the environment;
  \item \textit{f} complex technical processes and engineering designs; and
  \item \textit{g} significant infrastructure requirements.
\end{itemize}

However, the DOE has expressed that the enforcement of Executive Order No. 30 is for the next investment cycle: 2020–2021.\textsuperscript{110} Notwithstanding the delay in the enforcement of Executive Order No. 30, investment opportunities in the energy sector of the Philippines remain as the DOE continues to develop programmes on alternative fuels and technologies, energy efficiency and conservation, and renewable energy.\textsuperscript{111}

\begin{flushleft}
109 \ Section 2 of Executive Order No. 30.
111 \ See Philippine Energy Plan 2016–2030.
\end{flushleft}
I OVERVIEW

In recent years, following the publication of European Union directives for the implementation of the electricity\(^2\) and natural gas\(^3\) internal markets, the legislation and regulation of the energy sector in Portugal have undergone significant changes.

From production to supply, both in the electricity and the natural gas industries, all activities must be developed by legally separate entities, except for some specific cases. The liberalisation of these sectors in mainland Portugal has almost been concluded, and with the abolition of end-user energy supply tariffs due to happen on 31 December 2020, all consumers will shift to the liberalised markets.

Generation and supply of electricity and natural gas are free and mostly deregulated activities, while the operation, maintenance and exploration of infrastructures such as transmission and distribution networks, liquefied natural gas (LNG) terminals and storage facilities are regulated activities, with access rates set administratively by the national regulatory authority, the Energy Services Regulatory Authority (ERSE).\(^4\)

Currently, the Portuguese government’s policy for the energy sector is set out in the National Plan of Action for Energy Efficiency 2013–2016 (PNAEE 2016) and in the National Plan of Action for Renewable Energies 2013–2020 (PNAER 2020), both approved by Ministers’ Council Resolution No. 20/2013 of 10 April. The PNAEE 2016 and PNAER 2020 are intended to be tools for a better energy strategy by establishing the means of achieving international goals and commitments\(^5\) assumed by Portugal in matters of energy efficiency and the use of renewable resources, without losing sight of economic rationale and the need to ensure adequate levels of energy prices, which do not prejudice the competitiveness of Portuguese companies or the minimum living standards of the general population.

---

1 Nuno Galvão Teles and Ricardo Andrade Amaro are partners at Morais Leitão, Galvão Teles, Soares da Silva & Associados, Sociedade de Advogados, SP, RL.
4 Taking into account their geographical limitations, electricity and natural gas activities on the archipelagoes of Azores and Madeira continue to be developed by vertically integrated companies, and therefore the considerations that follow refer mainly to mainland Portugal.
5 In the context of the European ‘20-20-20’ measures, Portugal committed to achieve an overall reduction of primary energy consumption of 25 per cent and to have 31 per cent of its gross final energy consumption fuelled by renewable sources.
Given the scarceness of fossil fuel resources in the country and the current economic and financial situation of the country, these Plans of Action focus primarily on the reduction of the country’s energy dependence, the increase of energy generation using renewable resources and the promotion of energy efficiency and sustainable development, namely by:

- ensuring the continuance of measures that guarantee the development of an energetic model with economic rationale, which provides sustainable energy costs;
- ensuring a substantial improvement of the country’s energy efficiency; and
- maintaining the reinforcement to diversify primary energy sources, reevaluating the investments made in renewable technologies and presenting a new remuneration model for more efficient and prominent technologies.

The PNAEE 2016 and PNAER 2020 have the following five major objectives:

- to comply with Portugal’s commitments to establish a greater economic rationale;
- to significantly reduce greenhouse gas emissions;
- to reinforce primary energy sources diversification, thus contributing to enhancing Portugal’s security of supply;
- to improve the energy efficiency of Portugal’s economy, particularly in the state sector, thus reducing public spending and promoting an efficient use of available resources; and
- to improve economic competitiveness by reducing consumption and costs related to companies’ functioning and household economy management, freeing resources to boost internal demand and new investments.

II REGULATION

i The regulators

The national regulatory authority of both the electricity and natural gas industries is ERSE, a public entity with administrative and financial independence. ERSE’s by-laws were enacted by Decree-Law No. 97/2002 of 12 April, and recently amended by Decree-Law No. 212/2012 of September 2012.

ERSE is in charge of regulation, supervision and sanctioning in the aforementioned sectors, from generation to supply. Recently, Law No. 9/2013, which came into force on 28 January 2013, established the Energy Sector Sanctioning Regime, which substantially reinforced ERSE’s sanctioning competence and powers. Later, Decree-Law No. 84/2013 of 25 June revised ERSE’s by-laws, completing the implementation of Directives 2009/72/EC and 2009/73/EC.

Alongside ERSE, the General Directorate of Energy and Geology (DGEG), a state-administered entity with financial independence, has the task of implementing and developing the state’s policies regarding energy matters and the exploitation of geological resources.

As such, and in most cases, the DGEG is the competent entity for granting licences and other administrative authorisations concerning energy-related activities, such as generation or exploration licences.

In summary, while ERSE is the independent national regulatory authority for electricity and natural gas, the DGEG is the body that represents the state on energy matters, also being competent to grant licences and receive the corresponding applications or requests.
Regarding the upstream oil sector, the DGEG, via its oil exploration and production division is the competent authority to, among other things:

a. manage, organise and integrate all data and technical information resulting from oil exploration and production activities and other relevant data;

b. promote and carry out specialised studies aimed at establishing the value of oil resources;

c. promote the oil potential of Portuguese basins throughout the industry;

d. negotiate and ensure the proper procedures to grant (by direct negotiation or public bidding), transfer and annul exploration and production rights;

e. prepare and supervise licences for preliminary evaluation and concession contracts;

f. evaluate work programmes and specific technical projects during the execution of the contracts; and

g. regulate and supervise the activities during the execution of contracts, ensuring that legal provisions and regulations are followed, including those related to health, safety and environmental protection.

In relation to the downstream oil sector, following Decree-Law No. 244/2015 of 19 October, Entidade Nacional para o Mercado de Combustíveis, EPE (ENMC), acting through the members of government responsible for finance and energy matters, is the competent authority to, among other things:

a. monitor, jointly with DGEG, security of supply of the national petroleum system and follow up on the supply conditions concerning raw petroleum and petroleum products, as a function of future consumption necessities;

b. monitor the functioning of the raw petroleum and petroleum products market;

c. give opinions on licensing procedures of large petroleum facilities, notably refining, transportation and storage;

d. approve registration of suppliers of petroleum products; and

e. receive complaints concerning activities in the liquefied petroleum gas value chain.

ENMC also has powers concerning the regulation of biofuels and the constitution and maintenance of oil reserves.

However, the Portuguese state budget for 2017 anticipates the extinction of ENMC and foresees that ERSE shall become the competent entity to regulate the liquefied petroleum gas and fuel sectors. The legal termination of this entity has not, as of yet, occurred.

The core legal framework for the electricity sector is composed of Decree-Laws No. 29/2006 of 15 February and No. 172/2006 of 23 August, and in the natural gas sector, by Decree-Laws No. 30/2006 of 15 February and No. 140/2006 of 26 July (which have undergone significant changes in recent years). The main legal framework for the oil and gas upstream sector is Decree-Law No. 109/94 of 28 April, recently amended by Law No. 82/2017 of 18 August, providing for mandatory consultation of local governments prior to the surveying and exploration of hydrocarbons and, for the downstream sector, Decree-Law No. 31/2006 of 15 February, recently amended by Decree-Law No. 244/2015 of 19 October.

Regulations put into force by ERSE, such as the Commercial Relations Regulation, the Tariffs Regulation, the Quality Standards of Service Regulation and the Infrastructures Operation Regulation, and those put into force by the DGEG, such as the Transmission Regulation, All available at www.erse.pt/pt.
Network Regulation and the Distribution Network Regulation constitute other significant sources of law governing these industries. These Regulations have been recently amended by ERSE (on December 2017).

ii Regulated activities

In the electricity industry, transmission and distribution are activities that are subject to administrative authorisations.

The operation and exploration of the national transmission and distribution networks are awarded by means of concession agreements entered into with the Portuguese state, granting the concessionaires the exclusive right to explore the networks within a determined geographical area, for periods of 50 or 35 years.

Besides the national distribution network,7 there are also municipal distribution networks, mainly composed of low-voltage grids. The right to explore these networks is also granted through concession agreements, but these are awarded by the respective municipalities and are valid for a period of 20 years.

In the natural gas industry, the exploration and production, transmission, distribution and operation of LNG terminals and of LNG storage facilities are also regulated, subject to administrative authorisations.

The operation of the national transmission and distribution networks, of LNG terminals and LNG storage facilities is also granted by means of concession agreements, offering the exclusive right to develop these activities for 40 years within a certain geographical area.

Additionally, there are some local natural gas distribution networks with no physical connection to the national distribution network, which may be operated by obtaining a licence, valid for a period of 20 years. The request for its attribution should be directed to the Minister of the Economy and Employment and delivered to the DGEG’s office.

The right for prospection, exploration, development and production of oil is granted by the Minister of the Economy and Employment through a concession agreement.

Regarding remuneration, aside from production, income and real estate taxes, and some sporadic fees, there is no legal obligation for production sharing, the concessionaire is exempted from paying royalties, and it is free to sell the oil, except in the event of war or public emergency. The concessionaire is also entitled to freely dispose of all findings of natural gas, being exempt from any production taxation.

The concession agreements for the aforementioned activities are granted by means of a public procurement process.

Lastly, licensing for oil downstream activities is not required (other than licensing for the facilities where the activities are being carried out).

iii Ownership and market access restrictions

Electricity generation is a free activity, being subject only to obtaining a generation licence. The licensing entity may vary upon the generation technology or geographical location where the generation plant is to be installed. Prior to entry into industrial exploration, the generation groups of the facility must also obtain an exploration licence, granted after an inspection that ensures they meet all technical and safety conditions to start operating.

7 Which, in general terms, refers to high- and medium-voltage grids.
Generation licences do not have a term, unless the power is generated using public domain water resources, or the generation plant is installed in maritime space that is under sovereign or national jurisdiction, in which case the term of the generation licence will be that of the licence or concession agreement that confers the right to use public domain resources.

The transmission network operators (TNOs) of the electricity and natural gas sectors are subject to a full ownership unbundling regime.

Under this regime, no entity may hold an equity participation greater than 25 per cent of the share capital of the TNO. Also, the TNO or the companies that control it\(^8\) may not, directly or indirectly, exercise control or any rights over companies dedicated to generation or supply of electricity or natural gas. Equally, companies dedicated to generation or supply of electricity or natural gas or companies that control such, directly or indirectly, cannot exercise control or any rights over the TNO.

Subject to certain exceptions that relate to the historical role of the electricity TNO, the TNO is also strictly forbidden from acquiring electricity or natural gas for selling purposes.

In the downstream oil sector, entities that carry out storage and pipeline transport of petroleum or petroleum products must be legally independent from entities that conduct refining, distribution by pipeline or supply of petroleum or petroleum products.

### iv Transfers of control and assignments

The transfer or encumbrance of any assets related to activities granted through concession agreements must obtain prior authorisation from the competent Ministry.

Concentration operations that meet some predetermined conditions must be notified to the Portuguese Competition Authority and are subject to its prior approval.

After being notified, the decision should be issued within 30 or 90 days, depending on whether or not a detailed investigation of the concentration operation is required.

Lastly, changes to the control of assets considered to be ‘strategic’ (which include electricity and gas transmission and distribution assets) are subject to non-opposition of the Portuguese government, if the acquirer is an entity based outside of the European Economic Area.

### III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

#### i Vertical integration and unbundling

Currently, the operation and exploration of the national transmission network of electricity and natural gas is carried out in accordance with the full ownership unbundling regime. This means that the company that operates the national transmission network may not integrate any group of companies dedicated to the generation, distribution or supply of electricity or distribution or supply of natural gas.

Under this context, EDP Energias de Portugal SA, formerly the company that held the monopoly in the electricity industry, was required to spin off any assets related to the

---

\(^8\) The definition of ‘control’ refers to the definition provided for in Council Regulation (EC) No. 139/2004 of 20 January 2004, regarding the control of concentrations between undertakings (the EC Merger Regulation).
transmission network into a separate company, thus forming REN Rede Eléctrica Nacional SA. Similarly, GALP Energia SA was also forced to dispose of its natural gas transmission assets, which are now owned and operated by REN Gasodutos SA.9

In 2012, in line with the latest European directives, the Portuguese legal framework for the electricity and natural gas sectors allows transmission activity to be developed by a vertically integrated company. In this case, however, the transmission system operator must be a legal entity separate from the rest of the companies, forming an independent transmission operator (ITO). The ITO must observe strict independence obligations and comply with several independence criteria to avoid falling foul of discriminatory behaviours, namely those set out in Article 9 of Directives 2009/72/EC and 2009/73/EC. Compliance with such obligations and independence criteria is assured by means of a certification process, monitored by ERSE and the European Commission, and that the ITO must fulfil to develop transmission activity.

The distribution of electricity and natural gas is subject to a legal unbundling regime. This means that operators of distribution networks must be independent from a legal, organisational and decision-making process standpoint from other activities unrelated to distribution. Distribution companies that serve fewer than 100,000 clients are not subject to the legal unbundling regime, but they must still implement accounting and functioning unbundling measures.

Supply activities are also subject to the unbundling regime, implying that they must be legally separate from other activities. The last-resort supplier is also bound by this unbundling regime, even in relation to common suppliers.

The operation of LNG terminals and storage facilities is also subject to the legal unbundling regime. To a lesser extent unbundling requirements also exist in the downstream oil sector (see Section II.iii, above).

ii Transmission/transportation and distribution access

To ensure equal market conditions for all market participants, the concessionaires of transmission and distribution activities in electricity and natural gas must comply with specific public service obligations: to guarantee equal access conditions to all market participants and to abstain from adopting any discriminatory behaviour or practices.

Where facilities for transport by pipeline and storage of petroleum or petroleum products are declared as being in the public interest, holders of such facilities are also obliged to act in a non-discriminatory manner.

The ensuring of equal conditions to all market players for the access and use of infrastructure is intended to create effective market conditions, promoting competition and thus enhancing consumers’ experience in these markets.

iii Terminalling, processing and treatment

The access and use of LNG terminals and storage facilities is also regulated, under the same terms as for distribution networks. Rates are determined by ERSE according to the Tariffs Regulation, and all users must benefit from equal commercial conditions.

---

9 Both companies are wholly-owned by REN Redes Energéticas Nacionais SGPS, SA, a listed company.
The only exception is for storage facilities. Part of the storage capacity is operated under regulated conditions by REN Armazenagem SA, with rates determined by ERSE. The other part of the storage capacity is operated by Galp Energia SA and access to these facilities can be made under a negotiated access regime, with leeway to negotiate access and use terms.

The rates of services rendered by the LNG terminal (reception and unloading of natural gas, liquefaction, storage and loading) are regulated, being established by ERSE according to the terms of the Tariffs Regulation.

iv Rates

Rates for the transmission and distribution of electricity and natural gas are determined by ERSE according to the respective Tariffs Regulation.

ERSE also determines the matters that must necessarily be included in the network use agreement, such as duration, interruption of service conditions, payment methods and terms of resolution, which vary depending on the contracting parties (generators, suppliers, network operators or consumers). The general terms of the network use agreement are submitted to ERSE for prior approval.

The Portuguese tariff system is constructed in such a way that for each regulated activity there is an associated regulated tariff, and the tariff applicable to each client is made up of the total of the various activity tariffs.

Tariffs for the use of regulated infrastructures are based upon the provider’s cost plus a reasonable rate of return, which will determine the operator’s allowed revenue. The reasonable rate of return is also established by ERSE for a certain period.

The allowed revenue and the provider’s cost for the activity of transmission and distribution of electricity is determined in accordance with the Electricity Tariffs Regulation.

The formula used to calculate the allowed revenue of the transmission network operator includes the application of efficiency factors to the provider’s costs, to reward efficient spending and investments, along with incentives for the maintenance and operation of equipment that is at the end of its life.

In the transmission and distribution of natural gas, the formulae used to determine the allowed revenue of the service provider are set out in the Natural Gas Tariffs Regulation.

Although these are not specifically determined in this regulation, it is established therein that the cost of the TNO’s activity will be subject to efficiency incentives to be determined by ERSE.

v Security and technology restrictions

The concessionaires of electricity and natural gas transmission activities are also in charge of managing and monitoring the National Electric System (NES) and the National Natural Gas System (NNGS).

The concessionaires of electricity and natural gas transmission activities have the following responsibilities:

- assuring the long-term capacity of the NES and the NNGS;
- providing information to other network operators to:
  - maintain safe operation;
  - estimate the level of reserves needed for medium-term safety of supply (especially the level of water reserves); and
  - in general, form a central part in the NES and NNGS;
- operating the transmission network; and

© 2018 Law Business Research Ltd
In cooperation with the DGEG, the concessionaire of electricity transmission activity published a Report for Monitoring the Safety of Supply of the NES for 2013–2020. This report describes, *inter alia*, the NES, provides future grid scenarios, planned and installed capacity, and levels of power generation by source.\textsuperscript{10}

**IV ENERGY MARKETS**

i Development of energy markets

The Iberian Electricity Market (MIBEL), a regional, organised electricity market was put in place by Portugal and Spain in July 2007.

One important aspect of MIBEL’s functioning is the principle of reciprocal recognition of agents. Under this principle, if an agent is granted the status of producer or supplier by one country, this implies automatic recognition by the other country, granting equal rights and obligations to that agent.

The management of the Iberian spot electricity market is the responsibility of OMEL, the Spanish division of the Iberian Energy Market Operator.

In the spot electricity market, transactions are executed by the participation of agents on the daily and intraday market that aggregate the Spanish and Portuguese zones of MIBEL. Trading on the daily market is based on a daily auction, with settlement of energy at every hour of the following day.

There are various intraday sessions subsequent to the daily market auction in which agents can trade electric power for the various hours of the day covered by that market. Trading is also done by auction.

The financial settlement of the transactions occurs weekly, and guarantees must be deposited.

Producers, self-producers, external agents (non-resident entities), suppliers, representatives and qualified consumers can be spot market agents.

OMIP is the operator of the Portuguese division of MIBEL and is responsible for the management of the derivatives trading market. OMIP holds a 100 per cent stake in OMIClear, which has the role of clearing house and central counterparty in all operations executed on the market managed by OMIP, also being able to clear trades on the over-the-counter market or even other markets that have, as underlying assets, energy-based products.

On the OMIP trading platform, all elements of the futures contracts are standardised (e.g., volume, underlying asset and minimum price variation). Therefore, when an agent opens a position, it need only choose the contract it will trade, the relevant quantity and the price (except if it is a market offer). A key characteristic of these contracts is that they are marked to market on a daily basis.

The operations carried out on OMIP are registered in trading accounts and simultaneously registered in clearing accounts through which the financial settlement of the contracts is assured.

\textsuperscript{10} Available at www.dgeg.pt.
The recently implemented Iberian natural gas market, MIBGAS, held its first trading session in December 2015. MIBGAS is managed by MIBGAS, SA and offers its users the possibility of trading within-day, day-ahead, balance of month and month-ahead products at an Iberian level.

ii Energy market rules and regulation

The legal framework for the organisation of MIBEL is based on the MIBEL Agreement, signed on 1 October 2004. It establishes the general principles for the organisation and management of MIBEL and, in particular, the framework for the organisation of the spot market and the derivatives market.

The MIBEL derivatives market, because of its financial nature, is directly subject to Portuguese law and jurisdiction and, therefore, to the legislation applicable to this type of market, which is primarily:

- the Securities Code;
- the Securities Market Commission (CMVM) Regulations; and
- the CMVM Instructions.

The derivatives market is under the direct supervision and regulation of the CMVM, in coordination with ERSE.

Notwithstanding the powers granted to the Portuguese authorities, the regulation and supervision of the derivatives market is carried out in conjunction with the equivalent Spanish authorities, the National Energy Commission and the National Securities Market Commission.

In addition, regulation of MIBEL takes place through market rules developed by the market operators, OMIE and OMIP, which have the duty of developing and jointly applying all the market rules.

MIBGAS and trading conducting therein, on the other hand, are governed solely by Spanish law.

iii Contracts for sale of energy

Any entity (producers, suppliers, consumers or other agents from the organised market) registered as a market agent may enter into a bilateral agreement, either for electricity or natural gas.

With respect to the legal and regulatory applicable provisions, the terms of such contracts are dependent upon each market agent’s agreement. The market agents must notify the transmission network operator (as global system manager) of the completion of such an agreement and indicate the term for which it is executed.

iv Market developments

The process of phasing out of end-user regulated electricity and natural gas tariffs is currently under way. Decree-Law No. 75/2012 of 26 March approved the timetable for the gradual phasing out of such tariffs for normal low-voltage electricity consumers, and Decree-Law No. 74/2012 of 26 March also established that for natural gas for either 31 December 2014

11 The Agreement between the Portuguese Republic and the Kingdom of Spain relative to the constitution of an Iberian Electrical Energy Market.
or December 2015 (depending on the contracted power or annual gas consumption). After several extensions, Decree-Law No. 15/2015 of 30 January, and Order No. 97/2015 of 30 March, further pushed back the expiration date for the end of all regulated tariffs to 31 December 2017.

Pursuant to the enactment of recent legislative instruments, the predicted date for the end of all regulated tariffs was once again delayed, this time to 31 December 2020.

During this period, transitory tariffs with a gradually increasing premium component will apply and also be updated quarterly by ERSE.

In the energy supply sector, it is worth noting the set-up of the Logistics Operator for Supplier Switching, created to facilitate electricity and natural gas ‘switching’ procedures for consumers and businesses.

V RENEWABLE ENERGY AND CONSERVATION

In February 2013, the Council of Ministers approved the National Action Plan for Energy Efficiency for the period 2013–2016 (PNAEE) and the National Action Plan for Renewable Energy for the period 2013–2020 (PNAER). The main objective of the PNAEE is to envisage new actions and targets for 2016, integrating the concerns regarding the reduction of primary energy for 2020 contained in the EU policy on energy efficiency.

The PNAEE is currently under review and a draft for the Energy Efficiency Action Plan for the period 2017–2020 has been prepared and submitted to the European Commission (pursuant to the obligations set out under the Energy Efficiency Directive). Notwithstanding, such new action plan has not been formally approved by the Council of Ministers.

The PNAER was also defined in light of the current situation (oversupply of electricity generation due to lower demand) with a view to adapting and mitigating costs. The plan continues to focus on renewable energy sources – very relevant in the promotion of a balanced energy mix – to enhance security of supply and reduce the risk of the price variability of certain commodities and its corresponding implications for the national energy bill.

i Development of renewable energy

With the purpose of reducing energy imports and dependence, and following the enactment of several European directives, Portugal has introduced guaranteed remuneration schemes for renewable electricity generators (i.e., a ‘feed-in tariff’ system), prompting the development of wind and solar generation, as well as cogeneration, in the country.

Nevertheless, in the wake of the financial assistance programme (a memorandum of understanding underwritten by the Portuguese government, the European Union, the International Monetary Fund and the European Central Bank), which ended in 2014, legislative measures seeking to curb guaranteed remuneration were procured, although precautions were taken to avoid impacting significantly on existing feed-in tariffs and undermining the legitimate expectations of the private parties in the market (and including changes that have been negotiated with participants in the renewables sector).

While Decree-Law No. 35/2013 of 28 February reduced the term during which special-regime generators have the right to receive the corresponding feed-in-tariff, the

---

also established the possibility of special-regime generators (except for small hydropower plants) adhering to certain alternative remuneration mechanisms; in general, these allow for an extension of the period during which the special-regime generators receive a special tariff or guaranteed remuneration.

Successive amendments to Decree-Law No. 23/2010 of 25 March (the most recent of which was executed by Decree-Law No. 68/2015 of 30 April), and related regulation thereof, have reduced feed-in-tariffs and the cap on installed capacity (reduced from 100MW to 20MW of installed capacity) for eligibility to benefit from cogeneration feed-in tariffs.

In relation to micro generation of electricity, Decree-law No. 153/2014 has also reduced the guaranteed remuneration for small generation power plants while allowing for self-consumption electricity generation and facilitating the licensing or registration of both.

Pursuant to a recent Ministerial Order (268-B/2016 of the Secretary of State for Energy affairs, enacted on 13 October 2016), it was determined that public funds granted to existing renewable energy projects with guaranteed remuneration (such as EU funds) shall be offset against future feed-in tariff payments. This measure has yet to be implemented by the government.

ii  **Energy efficiency and conservation**

In 2008, the government introduced the PNAEE, a plan of action that establishes the main policies and energy-efficiency measures to be developed to achieve a target of a 10 per cent reduction in the country’s energy consumption. Recently, the PNAEE was revised and the government set new goals to be achieved in matters of energy efficiency until 2016.13 As mentioned above, the PNAEE is currently under review.

After the establishment of the PNAEE, the Energy Efficiency Fund was created,14 which finances the programmes and measures provided for in the plan.

In 2011, the government, by Decree-Law No. 29/2011 of 28 February, created a specific public tender procedure to expedite and facilitate the formation and execution of energy efficiency contracts, to be entered into by the public administration and private companies to implement measures improving energy efficiency in public buildings.

ERSE has tried to ensure that regulation of the sector galvanises actions that contribute to the promotion of energy efficiency. In the Tariffs Regulation for the electricity sector, a competitive mechanism called the Consumption Efficiency Promotion Plan (PPEC) has been established to promote measures for managing demand. In the electricity PPEC, incentives are awarded for the promotion of measures aimed at improving efficiency in electricity consumption through measures taken by suppliers, network operators and organisations that promote and protect the interests of electricity consumers in mainland Portugal and in the autonomous regions, and that are aimed at consumers in different market segments. The actions result from specific measures proposed, subject to a selection process, whose criteria are defined in the Rules for the Consumption Efficiency Promotion Plan. This process allows the selection of the most promising measures for energy efficiency to be

---

13  Council of Ministers Resolution No. 20/2013 of 10 April.

© 2018 Law Business Research Ltd
implemented by the aforementioned promoters, taking into account the amount available in the PPEC annual budget, which is approved at the start of each regulation period for each one of its years.

Decree-Law No. 38/2013 of 15 March transposed into national law a set of provisions relating to the greenhouse gas emission allowance trading scheme, namely Directive 2009/29/EC of the European Parliament and of Council of 23 April 2009. In particular, this Decree states that from 2013 onwards the emission allowances that are not allocated free of charge shall be auctioned and the revenues from the auctions shall be applied in measures that contribute to the development of a competitive low-carbon economy (this mechanism is currently regulated by Order No. 3-A/2014). It is also established that the amounts to be transferred to the SEN should be used to offset the extra costs incurred with respect to the purchase of electricity from special-regime generators.

iii Technological developments

Driven by the growing dependence on oil for energy and by the environmental impact of the use of fossil fuels, Portugal is investing in new energy models for mobility that aim to improve quality of life and reduce pollution.

This has led to the creation of the Electric Mobility Network, an integrated network linking 1,300 charging stations in Portugal, managed by MOBI.E, which will enable electric vehicles to recharge, using a charge card.

Its main goal is to contribute to a more sustainable mobility model, promoting the integration of electric power coming from renewable sources into the functioning and development of cities, and maximising its advantages.\(^{15}\)

Technological advances, the lowering of the cost for solar panels and new energy efficiency rules are also disseminating the use of auto-consumption schemes in several households.

On other developments, smart meters (which enable remote readings of electricity consumption), after successful pilot projects, are now being rolled-out in the entire country by the distribution system operator.

VI THE YEAR IN REVIEW

In 2017 the Portuguese economy enjoyed a strong rebound.

Electricity demand is increasing and so is the number of ‘greenfield’ renewable energy projects seeking to add capacity to the grid, even without guaranteed remuneration schemes. Concretely, several solar power plants with no support schemes are now being developed or constructed and it is envisaged that the electricity generated will be sold in wholesale markets or through bilateral power purchase agreements.

Also as a result, transactional activity in the energy sector was buoyant, with high-profile deals being struck by industrial players and institutional investors alike. Notable transactions include the divestiture of gas distribution assets in Northern Portugal by EDP and the acquisition of minority and majority participations in several wind farm portfolios.

In 2013, the Portuguese government implemented the ‘extraordinary energy-sector contribution’, the revenues from which were intended, primarily, to reduce the tariff deficits

---
being generated in the electricity sector. Following this extraordinary contribution, which continued into 2015 and 2016, the government set up the Fund for the Systemic Sustainability of the Energy Sector, with the goal of creating of policies of a social and environmental nature related to energy-efficiency measures and the reduction of the tariff deficit in the energy sector, and funded in part from the revenues obtained through the special contribution. The Portuguese state budget for 2018 establishes the extension of this extraordinary contribution into 2018.

The successive extensions of this extraordinary contribution have resulted in litigation cases, currently pending in the Portuguese courts.

VII CONCLUSIONS AND OUTLOOK

The Portuguese power market is currently a mature market with a generation mix in which green energies have a significant weight, both in terms of installed capacity and power output. The natural gas market has room for expansion considering that there are still interior regions that do not have distribution networks. However, tepid economic growth and the need to keep grid tariffs low means that ‘connections’ growth in this sector will remain slow in Portugal.

The main challenges in the energy market in Portugal relate to the completion of the liberalisation of the electricity and natural gas industries. Although market efficiency is expected to increase and competition within the market should benefit end users, the full effects of liberalisation are not yet certain.

In what concerns future developments, the European ‘Clean Energy Package’, yet to be rolled out, is expected to have a relevant impact (also in Portugal) on energy efficiency measures, the financing and remuneration of renewable energy projects and energy consumer empowerment.
I OVERVIEW

The year 2017 brought with it significant uncertainty in respect of transformation in the South African energy sector in relation to renewable energy. In February 2017, former President Jacob Zuma announced in his state of the nation address that state-owned power provider Eskom Holdings SOC Limited (Eskom) would sign all outstanding power purchase agreements for renewable energy from bid windows 3.5 and 4 within the coming months. However, 27 contracts totalling US$4.7 billion and covering 2.3GW of renewable energy projects were only signed in the first quarter of 2018, owing to Eskom’s continuous delay tactics and an interdict brought by the National Union of Metalworkers of South Africa together with Transfrom SA.

There was further uncertainty in respect of when the 20 small-scale projects (with capacity between 1MW and 5MW and an aggregate capacity of 100MW) that had been awarded through the bidding process under the Small Scale Renewable IPP Programme would be able to begin operations owing to delays in the small-scale projects reaching financial close. Only 10 of the 20 small-scale projects had been able to obtain the required licences from the National Energy Regulator (as required under the Electricity Regulation Act 4 of 2006). The South Africa government has decided to exempt independent power producers (IPPs) owning generators not exceeding 1MW from obligation to apply and hold a licence (discussed below).

Although coal-fired generation still dominates the energy sector with a net output of 35.6GW (representing 85 per cent of South Africa’s total capacity), at the end of 2017 a total of 3.2GW of renewable energy projects had been constructed and connected to the grid. This has brought the total investments in renewable energy to approximately 195 billion rand under the Renewable Energy Independent Power Production Procurement Programme (REIPPPP). Further, South Africa was ranked 10th among G20 countries for renewable energy investment conditions by Allianz Climate and Energy Monitor.

The South Africa government has been the subject of additional pressure from environmental groups, with various court applications challenging the Department of Energy’s (DOE’s) procurement of the proposed Khanyisa and Thabametsi coal-fired power stations (the projects will add approximately 863MW to the national electricity once operational) owing

---

1 Lido Fontana is of counsel and Sharon Wing is an associate at Covington & Burling (Pty) Ltd.
2 Eskom is the buyer of electricity for these projects.
to alleged concerns regarding their climate impact. It is understood that the government is seeking to engage with various stakeholders in order to assess whether cleaner coal technology can be used in the DOE’s proposed baseload procurement programme.

Unfortunately, there have been no new developments in respect of the expressions of interest called by the South African government during 2016 in relation to the proposed 600MW gas-fired power project alongside one or more state-owned companies. Moreover, a South African court revoked fracking regulations governing proposed shale gas fracking in the Eastern Cape (discussed below). South Africa’s plans in respect of further nuclear power stations also appear to be on hold, given several recent statements from the government that the country cannot afford to develop nuclear power plants. Although the Integrated Resource Plan was approved by Cabinet in 2017, it has been subsequently sent back for processing and is currently expected to be released in August 2018.

II REGULATION

i The regulators

In South Africa, energy regulation is split among three regulators, being:

a the National Energy Regulator (NERSA), established under the National Energy Regulator Act 2004, which regulates electricity, piped gas and petroleum pipelines industries;

b the National Nuclear Regulator (NNR), established under the National Nuclear Regulator Act 1999, which regulates nuclear energy; and

c the Petroleum Agency of South Africa (PASA), established under the Mineral and Petroleum Resources Development Act 28 2002 (MPRDA), which regulates petroleum exploration and production.

Each of these Acts, together with other key legislation regulating the relevant industry (the Electricity Regulation Act 2006 (the Electricity Regulation Act) in the case of electricity; the Petroleum Pipelines Act 2003 in relation to the petroleum industry; the Gas Act 2001 (the Gas Act) as regards piped gas; the Nuclear Energy Act 1999 in the case of nuclear energy; and the MPRDA in respect of petroleum exploration and production) establish the framework for energy regulation in South Africa. That legislation, together with regulations, notices, rules and guidelines issued thereunder grant expansive regulatory power to the regulators, including the powers to issue, amend and revoke licences, as well as to approve tariffs.

ii Regulated activities

Under the Electricity Regulation Act, a licence is required for the operation of each of electricity generation, transmission and distribution facility and in respect of the import, export and trading of electricity (collectively, the Licensed Activities). That Act provides exemptions for licences in respect of (1) any generation plant constructed and operated for demonstration purposes; (2) any generation plant constructed and operated for own use; (3) any non-grid connected electricity supply other than for commercial use; and (4) any other activity relating to the Licensed Activities in respect of which NERSA has determined that a licence is no longer needed. In relation to the last referenced exemption, NERSA may require that persons undertaking such activities nevertheless register the activities with NERSA.
A person obliged to hold a licence in terms of the Electricity Regulation Act must apply to NERSA for the licence in the form and applying the procedure prescribed. The application must be accompanied by the prescribed licence fee. The information required to form part of such an application includes, among other things: (1) a description of the applicant, including the vertical and horizontal relationships with other persons engaged in the operation of the relevant Licensed Activity; (2) the administrative, financial and technical abilities of the applicant; (3) a description of the proposed generation, transmission or distribution facility to be constructed or operated; (4) a detailed specification of the services that will be rendered under the licence; (5) a general description of the type of customer to be served; (6) the tariff and price policies proposed to be applied; and (7) evidence of compliance with the Integrated Resource Plan.\(^4\) The process entails publication of notices of the application in appropriate newspapers or other media, the applicant responding to objections to the application being granted, and culminates in NERSA making a decision on the application within the prescribed period.

In terms of the National Nuclear Regulator Act 1999, no one is allowed to procure a site, construct, operate, decontaminate or decommission a nuclear installation except under the authority of a nuclear installation licence. The process prescribed for the making, consideration and issue of such licences is similar to that outlined above, albeit that the time lines are shorter and an applicant may further be directed to serve a copy of its application upon every municipality affected by the application and such other body or person as the chief executive officer of the NNR determines.

Licences are also required for the storage, transportation and reticulation of gas and petroleum through petroleum pipelines. The licences for the storage, transportation and reticulation of petroleum through pipelines are issued by NERSA. Although the procedure for applying for the licences is similar to that of Licensed Activities, only owners of storage, transportation and reticulation facilities respectively, may apply for licences for the storage, transportation and reticulation of petroleum.

Licences for exploration or production rights in petroleum resources are generally issued pursuant to bidding processes initiated by the Minister of Mineral Resources. The Minister invites applications for exploration and production rights in respect of designated blocks on predefined terms and conditions.\(^5\) Successful applicants are still required to submit applications to PASA for a reconnaissance permit, technical cooperation permit, exploration right or production right. In certain instances, the Minister will upon consideration of PASA’s recommendations either grant or refuse the application. In the event that the application is granted, the exploration right or production right must be registered with the Mineral and Petroleum Titles Registration Office, while the permits must be filed and noted with the Mineral and Petroleum Titles Registration Office. The rights issued by the Minister of Minerals Resources only constitute limited real rights.\(^6\)

### Ownership and market access restrictions

In 2010, much of South Africa's electricity generation capacity was state-owned. At that stage, Eskom, a state-owned utility with a monopoly over the national transmission grid

---

\(^4\) Section 10(2)(a)–(h) of the Electricity Regulation Act, 2006.

\(^5\) Section 73(1) of the MPRDA.

\(^6\) Section 5(1) of the MPRDA.
produced close to 95 per cent of the country’s electricity, while the balance of the country’s electricity was sourced mainly from municipalities. Like electricity generation, transmission and distribution capacity was restricted to the state and state-owned entities.

In 2011, the South Africa government launched the Integrated Resources Plan, which called for the doubling of the country’s electricity capacity from its 2010 level of 238,272GWh using a diverse mixture of energy sources, mainly coal, gas, nuclear and renewables, including large-scale hydro to be imported from other countries in the southern African region.

The REIPPPP has served as the primary vehicle through which the South African government has procured renewable energy from private sector power producers. That programme provides that projects developed thereunder must be 40 per cent owned by South Africans with people of colour holding a minimum of 12 per cent (with a target of 20 per cent), and a minimum of 2.5 per cent ownership by local communities (those communities within a 50km radius of the project). In addition to the ownership requirements, REIPPPP bidders are also required to bid on other non-price factors known as ‘economic development requirements’, which are designed to achieve the government’s Integrated Resource Plan objectives of promoting job growth, domestic industrialisation, community development and black economic empowerment (a programme designed to counter the adverse economic impacts of apartheid by initiating, among other things, ownership and control of capital by South Africans of colour, women and disabled persons (Historically Disadvantaged Persons or HDSA), as well as skills transfer and enterprise development of legal entities owned by HDSAs).

The Coal Baseload IPP Procurement Programme provides that 51 per cent of each project must be owned by South Africans. Ownership criteria for the gas-to-power and nuclear procurement is still unknown. Save as outlined above, there are no foreign ownership or aggregate holdings constraints under the REIPPPP and the Coal Baseload IPP Procurement Programme.

The preliminary information memorandum (PIM) for the Liquefied Natural Gas to Power Independent Power Producer Procurement Programme (LNG-to-Power IPP Procurement Programme) was released on 4 October 2016 by the DOE. The PIM provides insight into the proposed LNG-to-Power IPP Procurement Programme and provides the basic framework being considered by the DOE for the minimum mandatory socio-economic objectives, all of which will be provided in further detail under the request for qualifications (RFQ), which was meant to be issued during November 2016. To date, the RFQ has not been issued and in all probability the RFQ will only be released once the DOE has finalised the contentious updated Integrated Resource Plan, which was released for public comment in December 2016 and was extended to 31 March 2017(discussed below).

The Petroleum and Liquid Fuels Charter, issued under the MPRDA provides a framework for black economic empowerment within that industry. Holders of exploration and production rights are obliged to reserve shareholdings for HDSAs in their respective companies. Companies active in the upstream sector are obliged to reserve participation interest of not less than 9 per cent for HDSAs, while companies in the midstream and downstream sectors must reserve a 25 per cent participating interest for HDSAs. These companies must further make contributions towards the funding of skills development initiatives.
iv Transfers of control and assignments

Transfer of control and the assignment of a licence issued in respect of Licenced Activities, including generation licences issued to IPPs, are restricted by conditions imposed on the licensee by NERSA. Accordingly, each licence must be reviewed on a case-by-case basis to determine what specific approvals are required for its transfer. However, the Electricity Regulation Act generally provides that a licensee may not cede or transfer its powers or duties under a licence to any other person without the prior consent of NERSA. The transfer of control and the assignment of licences issued to IPPs are further regulated by the Implementation Agreement between the South African DOE and the IPP; that agreement provides for, inter alia, government support for the development and financing of relevant IPP projects.

A nuclear licence is not transferable in terms of the National Nuclear Regulator Act 1999.

Regarding the transfer of control and the assignment of a licence or permit in the petroleum sector, the position is as follows: (1) a reconnaissance permit is not transferable, nor does it grant the holder any exclusive right; (2) a technical co-operation permit is not transferable, but the holder of the right has an exclusive right to apply and be granted an exploration right over the area described in that permit; (3) an exploration right is transferable and the holder has an exclusive right to apply for and be granted a renewal of the right, or for a production right, over the area described in that exploration right; and (4) a production right is transferable and the holder has an exclusive right to apply for and be granted a renewal of that production right.

The consent of the Minister of Mineral Resource must be obtained in the event that a holder wishes to cede, transfer, let, sublet, assign, alienate or otherwise dispose of a prospecting right or exploration right or interest in such a right, or a controlling interest in a company that holds such a right (except in the case of a change in controlling interest in a listed company). An application for the Minister’s consent must set out and prove that the transferee has the required technical and financial ability to comply with the obligations imposed on the holder of the exploration or production right.

A licence granted to a person or entity under the Gas Act may not be assigned to another party, is valid for a period of 25 years and may be renewed after the expiry of the licence period.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Electricity

The Independent System and Market Operator (ISMO) Bill was introduced in 2011. The ISMO Bill intended to restructure the electricity supply industry by providing for the establishment of the ISMO as a state-owned company autonomous from Eskom to serve as the dedicated procurer of electricity for onward sale to wholesale off-takers. The ISMO Bill, when established would have removed the operation of the transmission grid from Eskom and allow for easier access to the grid by IPPs.

---

7 Section 15(1)(k) of the Electricity Regulation Act, 2006.
However, the ISMO Bill was suddenly withdrawn in its final stages of being adopted by its sponsor, the DOE, in June 2015.

In 2015, the government had apprised the market that a new ISMO Bill was being drafted; however, a draft has not yet been released for public comment and there is uncertainty if it will in the near future.

Gas
The gas pipeline network comprises the Rompco Pipeline\(^8\) (used to transport gas from Mozambique into South Africa), which is the main pipeline network in South Africa, and several other short-range pipelines, which are privately owned. Owners of these pipelines are compelled under their licence conditions to grant access to third parties on commercially reasonable terms only to the extent that they have uncommitted capacity in these transmission pipelines.

ii Transmission/transportation and distribution access
The transmission of electricity is currently being undertaken exclusively by Eskom. Save for contractual commitments under wheeling agreements with Eskom, there is no obligation on Eskom to provide third-party access to the transmission grid. Eskom distributes electricity directly to customers and to municipalities, who redistribute the same (see Section IV on energy markets, below).

There is currently no regulated framework for use-of-system charges for embedded generators. Some of these generators (primarily IPPs) sell to Eskom through approved power purchase agreements, while others wheel energy to third parties through bilateral agreements with Eskom.

Generators that wish to wheel energy face a number of challenges, including the charges involved, which may render small projects uneconomical; the generator being required to obtain a licence from NERSA to generate and for the wheeling transaction; the generator having to comply with Eskom’s onerous requirements for grid connection; and entering into multiple agreements with various distributors.

Although Eskom has provided guidelines on its website for wheeling costs on its network,\(^9\) it still remains a complicated process. NERSA has said that it is currently working on developing a standardised framework for these arrangements.

The Gas Act provides that a licensee of a gas transmission pipeline must provide access to its transmission pipelines to third parties, while the Petroleum Act provides that a licensee of a petroleum pipeline must provide access to its loading facilities and uncommitted capacity in storage facilities to third parties. These requirements will be provided as conditions on a licensee’s licence. However, a distributor is not compelled to grant access.

iii Rates

Electricity
Eskom’s tariffs are regulated by NERSA under the Electricity Regulation Act. These tariffs are based on Eskom’s costs plus a reasonable rate of return.

---

8 This is a joint venture between South African Gas Development Company Limited (iGas), Companhia Limitada de Gasoduto (CMG) and Sasol Gas Holding Proprietary Limited.
9 www.eskom.co.za/Whatweredoing/Pages/Wheeling_Of_Energy.aspx.
A suite of supply policy guidelines for the integrated national electrification programme 2016/2017 was released by the DOE (the integrated national electrification programme’s objective is to achieve universal access to electricity by 2012, the date of which was changed to 2019 and is one of the pillars of the South African government’s energy transformation strategy, born in the 1998 White Paper on Energy Policy).

The objective of the policy guidelines is to develop and provide a suite of supply frameworks in line with the 1998 White Paper Policy and guidelines, thus providing a uniform set of standardised supply options and connection fees, as well as a uniform approach to electrification tariffs for electrification customers for all licensed entities providing electricity.

Oil and gas

In relation to gas and piped petroleum product, tariffs are negotiated on a commercial basis and then approved by NERSA.

The DoE is mandated to regulate the tariffs applicable to the manufacturing, wholesaling and retailing of petroleum products through the implementation of the Petroleum Products Act 1977 and the responsibility resides with the Controller of Petroleum Products (this is too wide a matter to be discussed in this chapter).

iv Security and technology restrictions

South Africa’s nuclear legislation,\(^\text{10}\) which is based on several international conventions to which South Africa is a party,\(^\text{11}\) provides for the establishment of internationally endorsed protocol on nuclear safety, political and financial risk and ultimate state liability. The NNR is mandated to provide for the protection of persons, property and the environment against nuclear damage as the competent authority for nuclear regulation in South Africa.

The NNR has regulatory requirements developed in accordance with the National Regulator Act, the South African Nuclear Energy Policy (2008), Minimum Information Security Standards and IAEA Nuclear Security Series No. 7. The IAEA Nuclear Security Series No. 7 is the International Atomic Energy Agency implementing guide on Nuclear Security Culture, which prescribes characteristics, attitudes and behaviour of individuals, organisations and institutions in supporting the establishment of effective nuclear security. The development of the regulatory requirements is to assure nuclear security or physical protection systems at nuclear installations or associated actions in South Africa.\(^\text{12}\)

Several of Eskom’s power stations and other facilities, as well as municipality distribution installations, have been designated national key points. National key points are strategic installations, which require heightened state security.

---

\(^{10}\) Nuclear Energy Act 46 of 1999.  
\(^{11}\) For example, the Convention on Nuclear Safety, 1994; the Convention on Early Notification of a Nuclear Accident, 1986; the Convention on Assistance in the Case of Nuclear Accident or Radiological Emergency, 1986; the Convention on Physical Protection of Nuclear Material, 1979. See also: www.nti.org/treaties-and-regimes/treaties/.  
\(^{12}\) www.nnr.co.za/nuclear-security/.
IV ENERGY MARKETS

i Electricity

NERSA is mandated to, *inter alia*, regulate trading activities such as electricity resale (buying and selling). Eskom purchases electricity that is supplied by IPPs to the national grid and in turn sells the electricity to industrial, mining, commercial, agriculture and residential customers in South Africa, some members of the Southern African Development Community and redistributors (municipalities), who in turn redistribute electricity to businesses and households within their areas.

Section 155(6)(a) and (7) Schedule 4B of the Constitution lists electricity reticulation as a competence of municipalities in South Africa. Each municipality is a service authority for the electricity reticulation function for the whole of its jurisdictional area and has the right to set tariffs in respect of its sale of electricity in its areas of jurisdiction. On 30 October 2014, the South African Local Government Association entered into a memorandum of understanding and active partnering agreement with all distributors, including Eskom, to ensure cooperative and collaborative working relationships.

Electricity can also be onsold to multiple customers by persons with bulk supply points, such as bodies corporate and office parks (known as Resellers). These Resellers are ‘non-licensed traders’ of electricity in terms of the Electricity Pricing Policy. Resellers are not required to hold a distribution licence, but they must be registered with the licensed authority (generally a municipality) from which the bulk connection was obtained.

To resell electricity the licensed authority must complete a service level agreement with the Reseller to operate in its area of jurisdiction. The Reseller is also obligated to supply its customers with information on tariffs and tariff structures.

South Africa is part of the Southern African Power Pool (SAPP), which includes several Southern African utilities. While SAPP faces a number of major challenges such as lack of maintenance of infrastructure, high transmission losses and limited funds to finance new investments, the energy volumes traded by Eskom since its inception in 1996 (around 4,500GWh) have increased steadily to over 9,977GWh a year since 2003.

ii Natural gas

The use of natural gas as an energy source has stagnated and is unlikely to be a feature of the South African energy mix (other than gas pipelines) until 2019. Some setbacks that occurred for the gas sector during 2017 are set out below.

*Shale gas*

Exploration right applications were submitted to the Department of Mineral Resources to explore the possibility of a shale gas resource of 485 trillion cubic feet in the Karoo Basin. However, first expropriation licences are only expected, as a minimum, to be issued in 2019 owing to a ruling handed down by the Eastern Cape High Court in *John Douglas Stern v. Mineral of Mineral Resources (2015) EC*, setting aside the decision of the Minister of Mineral Resources to make the Regulations for Petroleum Exploration and Production 2015 (Regulations) (which manages shale gas exploration) on the basis that the Regulations

---

were invalid. The Regulations were passed in terms of Section 107(1)(a) of the Mineral and Petroleum Resources Petroleum Act 28 of 2002, which included the right of the Minister of Mineral Resources to pass regulations in respect of environmental matters. However, the Mineral and Petroleum Resources Development Act 49 of 2008 (the Amendment) subsequently deleted Section 107(1)(a). The Court therefore found that the Minister of Mineral Resources lacked the authority to pass the Resolution as the Resolution was passed after the Amendment. The South Africa government will now have to draft new regulations to manage shale-gas exploration.

600MW gas

No new developments have been made in relation to the expression of interest, which closed on 20 June 2016 for the Gas 600MW IPP Procurement Programme. The IPP Office has said that request for proposals in relation to gas-fired power plants would only be potentially looked at in the first quarter of 2019.

iii Gas pipeline

During 2017, the Industrial Development Corporation approved 218 million rand in loan finance to be used by Tetra4 (the natural gas subsidiary of JSE listed energy company Renergen) to develop a new natural gas project that will span over 187,000 hectares of gas fields across Welkom, Virginal and Theunissen, in the Free State, South Africa. The aim of the project is to produce South Africa's helium and liquefied natural gas instead of importing it, which will result in 107km of pipeline network and associated gas-processing facilities being constructed.

iv Nuclear

The development of nuclear power in South Africa was highly contested during 2017, with little or no progress being made to develop the nuclear new-build programme. It is unclear whether nuclear energy will be included in the energy mix in the much anticipated revised Integrated Resource Plan (IRP).

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

Background

The South African energy sector has undergone extensive transformation in recent years. In August 2011, the government’s DOE launched the REIPPPP, an unprecedented, world-class procurement programme with the audacious goal of the country producing 17,800MW of renewable energy by 2030. This objective was set against a backdrop of the country's then current generation capacity becoming increasingly inadequate to meet the ever rising electricity demand of a growing economy. The inadequacy manifested in Eskom, with a monopoly over generation and transmission capacity, implementing rolling blackouts throughout the country in late 2007 and early 2008. Rolling blackouts resurfaced in 2014 and early 2015. Although widespread load-shedding has not occurred since September 2015, consumer trust in Eskom's ability to deliver reliable power supply is conditioned on a wait-and-see approach.

After the electricity blackouts in 2008, the country decided to draw investor interest by initiating a process to introduce renewable energy feed-in-tariffs (REFIT) to facilitate the
introduction of renewable energy into the power system. In 2009, NERSA published REFITs with proposed tariffs designed to cover generation costs plus a real after-tax return on equity of 17 per cent, fully indexed for inflation.

However, in 2011, NERSA terminated the REFIT programme because the National Treasury was of the opinion that the REFIT approach contravened public finance and procurement regulations. The REFIT programme was subsequently terminated and replaced by the REIPPPP.

The Integrated Resource Plan

The initial IRP sets out the South African government’s strategy for the establishment of new generation and transmission capacity for the country for the period 2010 to 2030. It calls for the doubling of the country's electricity capacity from its 2010 level of 238,272GWh, using a diverse mixture of energy sources, mainly coal, gas, nuclear and renewables, and including large-scale hydro to be imported from other countries in the southern African region. The initial IRP further details how this demand should be met in terms of generating capacity, type, timing and cost. The initial IRP also serves as an input to other government planning functions, inter alia, economic development, funding, environmental and social policy formulation. It is also a process by which the requirement for further investment in electricity generation capacity for South Africa is determined.

At the time that the IRP was initially promulgated, the South Africa government advised that the IRP should be viewed as a ‘living plan’ that would be revised by the DoE every two years to ensure its relevance with regard to (among other things) technological and environmental developments in the global arena. An update to the IRP was provided for public comment in November 2013; however, this document was subsequently gazetted and remains of no binding relevance. On 2 November 2016, the Minister of Energy released drafts of an updated Integrated Energy Plan (IEP) and an IRP on 22 November 2016. The IEP serves as the government’s master plan for the entire energy system, with its focus on the broader objective of reducing the overall energy intensity of the country. The IEP regulates energy industries and promotes electric power investment, greater employer benefits and more favourable environmental impact. The IRP on the other hand, being the subordinated legislation to the IEP, focuses specifically on electricity.

The updated IRP has received more attention due to the South African government (and Eskom) promoting the importance of nuclear power within the overall electricity provision forecasts to 2050. The Minister of Energy extended public consultation to 31 March 2017. This allowed the South African government to make the necessary adjustments and promulgate the updated IRP in 2017, once approved by Cabinet. During the consultation process, major issues, particularly in relation to the base case, were raised. Some critics believe that the cost assumptions for solar PV and wind were too high and that if proper costs were reflected there would be no need to construct a nuclear plant up to 2050. The IRP was approved by Cabinet in December 2017 but was sent back for processing for reasons not disclosed. President Cyril Ramaphosa has announced that the revised IRP will be released in August 2018 after a brief public participation. To date, no further drafts have been provided for public comment.

What is the IPPPP?

The Independent Power Producer Procurement Programme (IPPPP) was introduced as a vehicle for securing private sector investment for the development of new electricity
generation capacity. The 1998 White Paper on Energy Policy identified that IPPs were expected to play a key role in developing and producing new electricity capacity in the country.

The REIPPPP was initiated with a request for proposals in August 2011, in terms of which IPPs were invited to bid in a competitive process.

VI THE YEAR IN REVIEW

i Amendment to the MPRDA
The Mineral Petroleum Resources Amendment Bill [B15D – 2013] (MPRDA Bill) was sent to the National Council of Provinces for public hearings on 10 October 2017. The MPRDA Bill, which was revised by the National Assembly in 2016, did not differ substantially from the MPRDA Bill that was referred to the President for his assent during March 2014 and subsequently referred back to Parliament on the grounds of its being unconstitutional. The MPRDA Bill provides for state participation in any successful minerals and gas or oil development exercises carried out by the private sector that would result in the state receiving a right to free carried interest in all such exploration and production rights. The MPRDA proposes that the South African government be provided with a 20 per cent ‘free carry’ in all new exploration and production rights.

ii Exemption to hold licence
Under the Electricity Regulation Act, NERSA can exempt any activity relating to the Licensed Activities in respect of which NERSA has determined that a licence is no longer needed (discussed above). During 2017, a licensing exemption and registration notice was published in the Government Gazette,16 which exempted independent power producers (IPPs) owning generators not exceeding 1MW from holding a licence; however, the IPPs still need to be registered with NERSA. These rules will mainly focus on the registration and connection process, tariff structures and reporting requirements.

VII CONCLUSIONS AND OUTLOOK

Although there were not many developments during 2017, it was a year that proved that government will buckle under political pressure to ensure that economic growth, stability and foreign investment is achieved. The future looks very positive for renewable energy and the much-anticipated revised draft of the IRP will help understand which energy sector the new South African governments will be supporting in the years to come.

Chapter 30

SPAIN

Antonio Morales

I. OVERVIEW

In Spain the energy sector is highly regulated. Its strategic and technical importance requires a strong regulatory framework that ensures a constant supply of energy at the lowest possible cost and meets all local and European environmental requirements.

This regulatory framework has undergone significant changes in the past decade, mainly imposed by European legislation, with the introduction of the directives for the internal electricity market in 1996 and 2009\(^1\) and for the gas market in 1998 and 2009.\(^2\) During 2013, however, the Spanish government accomplished a structural reform of the energy industry to establish a new regulatory framework to reduce and control one of the main problems of the Spanish energy sector, the ‘tariff deficit’ – the negative correlation between electricity costs and the income obtained from regulated electricity activities.

The reform started with the enactment of Royal Decree-Law 9/2013 of 12 July (RDL 9/2013), whereby certain urgent measures were taken to ensure the financial stability of Spain’s electrical system. The main changes introduced by this regulation aimed to provide the industry with a uniform, transparent and stable regulatory framework, as well as to give economic and financial sustainability to the electricity system and avoid the generation of a tariff deficit. Furthermore, on 27 December 2013, the Electricity Sector Act 24/2013 of 26 December (the Electricity Act 24/2013) was published in the Spanish Official State Gazette. It contained, among other things, the main principles set out in RDL 9/2013 in respect of the remuneration of renewable energy generators. The reform was also completed with a number of royal decrees and further regulations approved during 2014. For instance, the following regulations were enacted at the end of 2013:

\(a\) Royal Decree 1047/2013 of 27 December, which established the methodology for calculating the remuneration for electricity transmission; and

\(b\) Royal Decree 1048/2013 of 27 December, which established the methodology for calculating the remuneration for electricity distribution.

The remuneration scheme established by the Spanish government through the structural reform of the energy industry that started in July 2013 and continued in 2014 deserves particular mention. On 11 June 2014, the regulation on renewable energy electricity generation activity was passed by means of Royal Decree 413/2014 (RD 413/2014), which regulates electricity generation activity using renewable energy sources, cogeneration

---

1 Antonio Morales is a partner at Latham & Watkins LLP.
2 2009/72 of 13 July.
3 2009/73 of 13 July.
and waste. On 16 June 2014, Ministerial Order IET/1045/2014 (MO IET/1045/2014) approving the remuneration parameters for standard facilities applicable to certain electricity production facilities based on renewable energy sources, cogeneration and waste was passed. Those regulations established a new remuneration system for facilities producing electricity from renewable energy sources, cogeneration and waste, which replaces the former remuneration regime.

Furthermore, the gas market has also undergone several changes, specifically with regard to the remuneration framework for regulated gas activities (gas distribution, transmission, regasification and storage activities) that was approved by the Spanish government by means of Royal Decree-Law 8/2014 of 4 July (RDL 8/2014), which approved urgent measures to encourage growth, competitiveness and efficiency. The said regulation was incorporated definitively into the Spanish legal system through the enactment of Act 18/2014 of 15 October (Act 18/2014). This Act included commercial deregulation measures and also established an energy efficiency system in line with EU directives.

During 2015, several new regulations were passed by the government. On 16 January 2015, the Spanish government approved the draft bill that modifies the current Act 34/1998 of 7 October on the Hydrocarbons Sector (the Hydrocarbons Act), by means of which an organised market will be created to encourage competition in the gas sector, allowing other suppliers to enter into restricted markets such as the gas market. This regulation was finally approved on 21 May 2015 through the enactment of Law 8/2015, which amends Act 34/1998 of 7 October, on the Hydrocarbons Sector and establishes certain tax and non-tax measures in respect of the exploration, research and exploitation of hydrocarbons.

On 31 July 2015, Royal Decree 738/2015 was passed, which regulates the production of electricity and the procedure for distributing power in non-mainland territories’ electricity systems.

The most important regulation passed by the government during 2015 was Royal Degree 900/2015 of 9 October, which regulates the administrative, technical and economic requirements for the methods of supplying and generating electricity for self-consumption.

On 28 November 2015, the Official State Gazette published two main regulations: Royal Decree 1073/2015 and Royal Decree 1074/2015, both of 27 November. The first of these, Royal Decree 1073/2015, modifies certain provisions in the Royal Decrees on the remuneration of electricity networks (Royal Decree 1073/2015), specifically Royal Decree 1047/2013 of 27 December 2013 for transmission, and Royal Decree 1048/2013 of 27 December 2013 for distribution, referred to above. Among other aspects, Royal Decree 1073/2015 eliminates the yearly update of unitary values based on the consumer price index, in accordance with Law 2/2015 of 30 March on de-indexing the economy. The second regulation, Royal Decree 1074/2015, modifies certain regulations in the electricity industry to ensure they are in line with the Spanish government’s electricity reforms of the past few years (Royal Decree 1074/2015).

During 2016, the reform of electricity distribution remuneration was concluded. Ministerial Order IET 980/2016 of 10 June established the remuneration of the different distribution companies in accordance with the new legal framework started by the Electricity Act 24/2013.

One of the main amendments passed in 2016 was Royal Decree Law 7/2016 of 23 December on financing the cost of the social tariff and protective measures to the vulnerable consumer of electricity (Royal Decree Law 7/2016), which amended the Electricity
Spain

Act 24/2013. The new financing mechanism allocates social tariff costs to company sectors based on the number of customers of their retail subsidiaries, and opens the possibility for highly vulnerable consumers to avoid the interruption of their electricity supply.

The Energy Efficiency Directive 2012/27/EU of the European Parliament and Council (Directive 2012/27/EU) was partially transposed in Spain by Royal Decree 56/2016 of 12 February (Royal Decree 56/2016) in terms of energy audits, accreditation schemes for energy services providers and energy auditors, as well as promoting energy efficiency in production processes.

During 2017, several regulations were passed by the Spanish government, including, among others:

\[a\] Ministerial Order ETU/120/2017 of 1 February, which determines the way of sending information from the autonomous communities and local entities to the Ministry of Energy, Tourism and Digital Agenda regarding their saving and energetic efficiency programmes implemented under Directive 2012/27/EU;

\[b\] Ministerial Order ETU/130/2017 of 17 February, by virtue of which the remuneration parameters of the renewable energy installations are updated for the semi-regulatory period between 1 January 2017 and 31 December 2019; and

\[c\] Royal Decree 897/2017 of 6 October, which regulates the figure of the vulnerable consumer, social bonus and other protective measures for domestic consumers. Beneficiaries of the old Social Bonus had six months (until 10 April 2018) to establish their status as vulnerable consumers.

In addition, at the ends of 2016 and 2017, three competitive procedures were carried out for the allocation of a specific remuneration regime to electricity producers from renewable energy sources.

Furthermore, within the gas market, Royal Decree-Law 13/2014 of 3 October, by which urgent measures in relation to the gas system were adopted, was partially repealed by ruling dated 21 December, issued by the Spanish Constitutional Court, in particular with regard to the Castor underground natural gas storage facility.

II REGULATION

i The regulators

The framework for power distribution between the state and the autonomous regions is directly established in Article 149(1)(22) and (25) of the Spanish Constitution. The former reserves the ‘authorisation of electrical installations when their use affects another region or the transport of energy out of its territorial scope’ to the state’s exclusive jurisdiction. The latter provides that the state has jurisdiction over establishing the basis of the energy regime. According to this framework, facilities within each region are also authorised, and the legal bases of the energy sector have developed.

The state’s broad jurisdiction in this area is reflected in the basic state legislation, which establishes the sector’s regulatory framework: the Electricity Act 24/2013 replaced and repealed the Electricity Act 54/1997 and amended the Hydrocarbons Act. Since these two laws (as enacted and as amended) are very comprehensive and wide-ranging, in practice there is little space for the autonomous regions to regulate.
The Electricity Act 24/2013 consists of 80 articles and is divided into 10 titles, 20 additional provisions, 16 transitional provisions, a repealing provision and six final provisions, and it introduced, among others, the following legislation:

\( a \) The principle of economic and financial sustainability of the electricity system.

\( b \) Article 14 of the Electricity Act 24/2013 regulates the remuneration of the different activities involved in the supply of electricity. The remuneration system is financed by means of the income obtained from regulated activities and is based on objective, transparent and non-discriminatory criteria. Additionally, Section 7 determines that the Spanish government may establish a specific remuneration for the promotion of production from renewable sources, cogeneration and waste.

\( c \) With regard to generation activity, the Electricity Act 24/2013 eliminated the former distinction between an ordinary and a special regime, establishing different economic regimes in accordance with the technology and the capacity of the generation facilities.

\( d \) Specific rules on the Voluntary Price for the Small Consumer (PVPC) mechanism are set out in the Electricity Act 24/2013. As this reform seeks to guarantee the supply of electricity at the lowest possible price, the PVPC is the highest price that the major electricity retailers may charge certain consumers.

In addition to the above, Act 3/2013 of 4 June created a new regulatory body, the National Markets and Competition Commission (CNMC), which encompasses different supervisory authorities in different sectors: the former National Energy Commission, the National Competition Commission, the Telecommunications Market Commission, the Rail Regulation Committee, the Airport Economic Regulation Commission, and the National Postal Industry Commission.

Within energy matters, Act 3/2013 transferred certain functions, originally developed by the former National Energy Commission, to the Ministry of Industry, Energy and Tourism, such as inspecting, initiating and conducting certain penalty proceedings, responding to claims made by consumers and informing them about their rights and dispute resolution methods, among others.

\( ii \) Regulated activities

The main activities involved in the supply of energy are the following: generation, transportation, distribution and supply (or commercialisation). As natural monopolies, transportation and distribution are considered regulated activities; whereas generation and supply operate in a free-market system.

Royal Decree 1955/2000 of 1 December, as amended by the Electricity Act 24/2013, regulates the regime applicable to transportation, distribution, commercialisation and supply activities. The management of transportation, as a regulated activity, is entrusted to Red Eléctrica de España, which is also the system operator.

Additionally, Royal Decree 1955/2000 states that the construction, expansion, modification and operation of production facilities, as well as transportation and distribution, require certain permissions. This Royal Decree has been mainly modified by (1) Royal Decree 1074/2015 in relation to the guarantees that must be provided in the authorisation process for production facilities; (2) Royal Decree 56/2016, which establishes new authorisation criteria for thermal power stations whose thermal power is greater than 20MW to generate electricity, and also for their substantial renewal, including the obligation of the administrative authorisation applicant to submit a cost–benefit analysis to adapt the planned facility to
Spain

high-efficiency cogeneration; and (3) Royal Decree 897/2017, which introduced a new provision regulating the suspension of supply to consumers that are natural persons in their usual home with contracted power equal to or less than 10kW, by referencing such situations to vulnerable consumers.

Administrative authorisation is needed for the draft technical installation document to be processed in conjunction with the environmental study. An application must be filed with the Directorate-General for Energy Policy and Mining, which is then forwarded with the required documentation to the Ministry of Industry, which makes the decision. If the application is approved, the Ministry will indicate the time within which the application must be submitted for project-implementation approval, which – once approved – allows the owner to construct or establish the installation. The application must be submitted to the industry and energy sub-office where the facility is located. A decision must be arrived at within three months by the Directorate-General for Energy Policy and Mining, specifying a deadline for the construction of the facility.

Once a project is duly implemented, an operating authorisation allows energy to be transmitted to the facilities for commercial exploitation. The application to operate must be submitted to the industry and energy sub-office and should be accompanied by the final certificate of work.

Some autonomous regions have specific regulations for electrical installations, but they follow basically the same administrative procedure as established by the foregoing state regulations.

iii Ownership and market access restrictions

Electricity network operation (transmission and distribution) is subject to significant economies of scale, which gives them an element of natural monopoly, as it is inefficient to introduce competition into these activities. The Electricity Act 24/2013 (which replaces Law 54/1997 of 27 November to, among other concerns, ensure the financial stability of the Spanish electricity industry) establishes an obligation to separate legal and accounting matters within regulated electric activities (transportation and distribution) that are provided under a financial regime. Deregulated activities (generation and supply) are carried out by operators in a free market and their remuneration is being governed by the laws of supply and demand.

Directive 2009/72/CE and its subsequent incorporation into Spanish law go into greater detail on this aspect and impose an obligation on vertically integrated groups to functionally separate their activities to ensure the autonomy of management and decisions of those responsible for the transportation and distribution networks. In addition, it purports to preserve the confidentiality of commercially sensitive information available to those responsible so as not to compromise competition in deregulated activities.

The former Electricity Act 54/1997 and the current Electricity Act 24/2013 and subsequent legislative developments establish and define the role of the different participants in the electricity sector:

Power producers are individuals or legal entities that have the function of generating electricity, as well as building, operating and maintaining generating plants. The distinction between ordinary producers and special-regime producers has been eliminated. The Electricity Act 24/2013 established a unified regulation for the ordinary regime and for the production of electricity from renewable sources, cogeneration

© 2018 Law Business Research Ltd
and waste. Additionally, producers are entitled to temporarily close their production facilities, subject to an administrative authorisation regime, this being one of the main legislative innovations of the Electricity Act 24/2013.

Electricity transporters are companies that have the function of transporting electricity and construction, maintenance and transportation of transformer facilities. As stated above, in Spain, the management of transport activity is entrusted to Red Eléctrica de España, which is also the system operator.

Distributors are those companies that have the function of distributing power, and also building, maintaining and operating distribution facilities designed to establish energy consumption points.

Sellers are legal persons who, by accessing transportation or distribution, have the function of selling electricity to consumers. Among them are ‘last-resort sellers’, appointed by the regulator, which are functionally and legally separate from other companies operating in the sector, and which are responsible for providing energy to consumers benefiting from the ‘tariff of last resort’ set by the government. As noted above, the updated regulation set out new and specific rules on the PVPC.

Consumers are individuals or corporations who buy energy for their own consumption. Consumers who purchase energy directly in the production market are referred to as ‘direct market consumers’.

The market operator (OMI-Polo Español SA, or OMIE) is the company that assumes the management of the bids for and sale of electricity in the daily and intraday power market in exchange for a regulated fixed fee within the territory of the Iberian Peninsula (Spain and Portugal). OMIE is regulated by the Santiago International Agreement, regarding the implementation of an Iberian electricity market (MIBEL) between the Kingdom of Spain and the Republic of Portugal, and subject to the rules and regulations governing Spain’s electricity sector. Half of OMIE’s stock is owned by the Spanish company OMEL, with the other half held by the Portuguese company OMIP SGPS, SA.

The system operator (Red Eléctrica de España) is the company whose main function is to perform activities associated with the technical operation of the electricity system, ensuring the continuity and security of the electricity supply and proper coordination of production and transportation systems.

On 10 October 2015, the Official State Gazette published Royal Decree 900/2015, which regulates the administrative, technical and economic requirements for supplying and generating electricity for self-consumption, establishing a regulatory framework that guarantees the economic sustainability of the system and adequate distribution of system costs.

It also stipulates the tolls and charges payable for self-consumption, in accordance with the Electricity Act 24/2013, which already established that self-consumption must contribute to financing the costs and services of the system to the same extent as other consumers (the criticised ‘tax on the sun’). Specifically, Royal Decree 900/2015 imposes the aforementioned tolls and charges on self-producers, both at a fixed cost according to installed power capacity and at a variable cost according to the electricity self-consumed. The regulation also considers
Spain

a specific surcharge for those who use batteries to store some of the electricity produced by their solar panels. There are two exceptions to this rule whereby consumers are exempt from paying costs:

- consumers on islands; and
- small consumers with a contracted capacity of no more than 10kW.

Accordingly, a record of self-consumption facilities has been created so that system operators and electricity distributors are aware of generation facilities within their networks, and to therefore ensure the correct operation of the electricity system under safe conditions. Royal Decree 900/2015 establishes two categories of self-consumption depending on the size of the facilities: (1) facilities with a capacity generation lower than 100kW, which may feed their excess capacity into the grid, but without receiving any compensation in return; and (2) large producers – facilities with a capacity generation higher than 100kW, which may charge for the excess energy that they feed into the grid, at the current wholesale market price when the energy is provided. Nevertheless, such activity is, from a legal point of view and for tax purposes, equal to production activity and consequently subject to power generation charges and to the 7 per cent tax on energy production.

Lastly, the Royal Decree gives consumers, installers and other agents a period of six months to adapt to its provisions.

The Spanish Supreme Court has issued ruling No. 1542/2017 dated 13 October 2017, by means of which it is stated that self-consumers shall also contribute to the electrical system costs provided that they are connected to the grid. Self-consumers demanded that the obligation imposed by Royal Decree 900/2014 was a kind of ‘levy on the sun’, but our Supreme Court has rejected their petitions.

On 24 December 2016, the Royal Decree Law 7/2016 was published in the Spanish Official State Gazette and amended Electricity Act 24/2013 in relation to the financing mechanism of the cost of the social tariff. It allocates social tariff costs to company sectors on the basis of the number of customers of their retail subsidiaries. The social tariff will cover the difference between the PVPC and a base value that may vary depending on the categories of vulnerable consumers established.

In addition, it creates another group, of ‘severely vulnerable consumers’, whose supply cannot be interrupted, as well as co-financing their invoices by the relevant administration and by the obligated companies of the sector. On 7 October 2017, Royal Decree 897/2017, which further developed Royal Decree Law 7/2016, was published in the Spanish Official State Gazette. Royal Decree 897/2017 defines the vulnerable consumer, associating such customer, as a general rule, with certain thresholds of income given in the Public Indicator of Income of Multiple Effects, based on the number of members that make up the family unit. The thresholds can be increased if special circumstances are proven for one of the members of the family unit.

Additionally, selected groups are recognised as being eligible for the social bonus regardless of their level of income. Within groupings of vulnerable consumers, a higher social bonus is established for severely vulnerable consumers, which are defined by reference to lower income thresholds than those indicated in general terms. It also creates a differentiated category among severely vulnerable consumers, namely, consumers at risk of social exclusion, who are those that are being served by the social services of an autonomous or
local administration. This allows for inter-administrative cooperation, which constitutes an additional mechanism to protect consumers in situations of energy poverty and vulnerability. The three categories defined above will receive the following benefits:

- **a** vulnerable customers, who receive a 25 per cent discount;
- **b** severely vulnerable customers, who receive a 40 per cent discount; and
- **c** severely vulnerable customers at risk of social exclusion (100 per cent discount), and customers accredited by the social services as paying at least 50 per cent of their bills.

### iv Transfers of control and assignments

Royal Decree 1955/2000 also establishes the authorisation process for the transfer of installations. The request for authorisation for facilities transfer must be sent to the Directorate-General for Energy Policy and Mining, enclosing supporting documentation about the applicants. A decision must be rendered by this department within three months (failure to respond positively within three months means the application is deemed rejected), prior to the report of the CNMC. The applicant then has six months to confirm the transfer, following which, provided that it is not formalised, the authorisation will expire. As mentioned before, Royal Decree 1074/2015 amended Royal Decree 1955/2000 in relation to the guarantees that must be provided in the authorisation process of production facilities.

### III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

#### i Vertical integration and unbundling

Energy (electricity or natural gas) is transported from the point where it is generated to the point of consumption by large industrial consumers that are directly connected to the transmission system and to the point of intersection with the distribution networks (substations), through which power is carried to the remaining consumers.

The electricity transmission network is made up of lines of voltage equal to or greater than 220kV, international connection lines regardless of voltage, transformers of 400/220kV, transformer compounds of voltage equal to or greater than 220kV, and other elements of voltage equal to or greater than 220kV. There are also international interconnection facilities connecting Spain with other Spanish territories, which have a voltage transport function lower than 220kV.

Transport networks are developed when new investment is periodically approved by the Ministry of Industry. The construction of network sections included in this planning is regulated, and remuneration is calculated by the regulator in accordance with the approved methodology contained in the regulations, defined in Royal Decree 1047/2013. Law 17/2007 established the single-carrier model, with Red Eléctrica de España as the owner of the entire transportation network. As the system operator, it must comply with the relevant instructions by filing investment plans for future years.

#### ii Transmission/transportation and distribution access

Power distribution brings the energy from the output of transport networks (electricity or gas) to the final consumer. Electrical distribution facilities comprise voltage lines lower than 220kV, which are not considered part of the transport network.

Prior to June 2009, distribution companies were also responsible for servicing a regulated tariff supply to consumers. Since then, regulated supply has disappeared, creating a ‘last-resort supply’ (TUR), which will be managed by ‘suppliers of last resort’, who must
supply electricity at a price no higher than that fixed by the government. At present, specific rules on the current PVPC were set out in the Electricity Act 24/2013. This Act restricted the tariffs to two groups of consumers: (1) consumers considered vulnerable; and (2) consumers who temporarily do not have a supply contract with a free-market retailer and are not entitled to the application of the PVPC. Therefore, the Spanish government will establish by regulations the provisions required to determine the PVPC and last-resort supply, with these being configured as regulated tariffs. Also, the electricity supply will be carried out in accordance with Royal Decree 216/2014 of 28 March, which set out the method for calculating voluntary prices for the small consumer of electrical energy and the legal framework for contracting. Accordingly, the prices introduced by Royal Decree 216/2014, which entered into effect retroactively as of 1 April 2014, apply only to those consumers whose contracted power capacity does not exceed 10 kilowatts. Finally, Ministerial Order ETU/1948/2016 of 22 December, which further develops Royal Decree 216/2014, fixed certain values of the commercialisation costs for referral suppliers to be included in the PVPC for the period 2014–2018.

Distributors must build, maintain and operate power grids linking transport to consumption centres. For the proper development of these functions, distributors have the obligation to expand distribution facilities when needed to meet new demands for electricity, at all times ensuring an adequate service quality level, and differentiating by type of consumption and area. Furthermore, distributors are responsible for supply measurement, applying consumer tolls or access fees.

Distributors are required to keep a points-of-supply database, always maintaining confidentiality. They must send the required customer information to the Supplier Switching Office and provide reports to the transporter about their network incidence and maintenance plans to ensure certainty of supply.

Finally, distribution companies must also provide information to clients, the Ministry of Industry, Tourism and Trade, autonomous communities, the Supplier Switching Office, and the system operator. They must also submit their investment plans annually. Distribution companies, in the exercise of their activities, are entitled to payment by the administration.

Notwithstanding the foregoing, prior to the approval of Royal Decree 222/2008, laying down the remunerations of electricity distribution activity, electricity distributors with fewer than 100,000 customers were covered by a special regulation (established in Transitional Provision 11 of the former Electricity Act 54/1997) with a different financial and regulatory regime from other distributors. Approval of Royal Decree 222/2008 meant that all distribution companies were subject to the same remuneration and policy, therefore removing the previous size differentiation. Royal Decree 222/2008 was subsequently repealed by Royal Decree 1048/2013, which established the methodology for calculating the remuneration of distribution activities.

iii Terminalling, processing and treatment

The Hydrocarbons Act laid the foundations for a reorganisation of the gas system, far removed from the monopoly in which Gas Natural SDG group performed all the activities within the natural gas industry. This Act introduced (1) separation of regulated activities and competition activities, (2) free access for third parties to gas infrastructure, (3) establishment of regulated access charges, (4) progressive full-trade wholesale and retail liberalisation, and (5) regulation of minimum security and strategy.
The Hydrocarbons Act was amended in 2007 by Law 12/2007 of 2 July, which transposed the major changes to the rules of European Union Directive 2003/55/EC (subsequently repealed by Directive 2009/73/CE), to promote the creation of a competitive internal energy market:

- rearrangement of the powers of the different regulatory authorities;
- development of the rules governing access to networks;
- the functional separation of regulated activities;
- regulating the activity supply of last resort;
- creation of the Supplier Switching Office; and
- establishing a schedule of tariff system adaptation and natural gas supply for the supply of last resort.

Directive 2009/73/CE concerning common rules for the internal natural gas market aimed at making a definite contribution to the creation of an internal energy market through the following principles:

- effective separation of network activities from supply and production activities;
- increase of the powers and independence of the national regulators, who must cooperate across a network of energy regulators, but who have the capacity to make binding decisions and impose sanctions;
- the creation of supranational transmission system operators by achieving EU-wide market integration; and
- improvement of the functioning of the gas market and, specifically, greater transparency and access to free storage facilities and LNG terminals.

Furthermore, the Spanish Hydrocarbons Act was amended by Act 11/2013 of 26 July concerning measures to support entrepreneurship and stimulate growth and job creation. This regulation introduced several amendments by virtue of which distribution agreements are more strictly regulated. Therefore, sale agreements within the sector ‘cannot contain exclusivity clauses which . . . set, recommend or affect, directly or indirectly, the retail price of fuel’ and clauses that ‘determine the sale price of fuel with reference to a particular fixed, maximum or recommended price, or any others that contribute to indirect fixing of the sale price’ shall be void and deemed deleted. Additionally, the Electricity Act 24/2013 repealed Article 83 bis of the Spanish Hydrocarbons Act.

As stated above, Royal Decree-Law 8/2014 and Act 18/2014 introduced several measures aimed at ensuring sustainability and accessibility to the hydrocarbons sector through the establishment of a new remuneration framework for gas distribution, transmission, regasification and storage activities. The purpose of the reform was to ensure the principle of financial and economic sustainability, so that the revenues generated by the gas market are used to finance system costs. Consequently, the revenues must be sufficient to cover all system costs; otherwise, measures should be adopted to increase or reduce the equivalent revenues to maintain the costs-revenues balance. Additionally, regulatory periods of six years were established, but subject to revision every three years (sub-regulatory periods of three plus three years).

For gas distribution, remuneration for the aggregate of the distributor’s facilities is linked to the number of customers connected and to the volume of gas supplied.
For gas transmission, regasification and storage activities, this remuneration system established a common methodology for all facilities of the core network, based on the annual net value of the assets, removing any value update or adjustments made during the regulatory period. The remuneration is composed of the following elements:

a a fixed component for the facility’s availability, which includes annual operating and maintenance costs, depreciation and a financial return; and

b a variable component of continuity of supply, which enables the adjustment of imbalances resulting from fluctuations in demand.

Law 8/2015, which was published on 22 May, amends the previous Hydrocarbons Act to bring it more into line with the current situation, to increase competition and transparency in the hydrocarbons sector, reduce fraud, ensure greater consumer protection, reduce costs for the consumer and adapt the rules on infringements and penalties.

With respect to natural gas, the Law seeks to create an organised natural market that offers consumers more competitive and transparent prices, and allows the entry of new suppliers to increase competition. In this regard, the measures introduced by Law 8/2015 can be summarised as follows: a market operator for the organised gas market will also be appointed; any authorised natural gas installer may carry out inspections (this was previously the responsibility of distributors); the entry of new suppliers is encouraged through the mutual recognition of licences to supply natural gas to other EU member countries where there is an existing agreement; and certain measures have been adopted regarding minimum security inventories, giving suppliers greater flexibility at lower cost, without impairing the security of supply, and enabling the Corporation for Strategic Oil Reserves to maintain strategic natural gas inventories.

With regard to the development of fracking, the Law introduces a tax on the value of the extraction of gas, oil and condensates, which establishes a levy of between 1 per cent and 4 per cent on the production of unconventional gas. It also sets a fee of €125,000 to be paid for each inland exploration survey and production well. The Law provides with particular force that the revenue collected from both the tax and the fee shall revert to the autonomous regions and municipalities where the wells are located. Moreover, the companies that hold exploitation concessions must pay 1 per cent of the value of the production to the owners of the land around the wells, even where these areas are intended for an activity other than hydrocarbon extraction.

On 31 October 2015, Royal Decree 984/2015 of 30 October was published, which regulates the organised gas market and third-party access to natural gas system installations. This Royal Decree contains the basic regulations for the operation of this new organised gas market, along with other measures, such as the inspection procedures for gas installations. In compliance with Article 32 of Royal Decree 984/2015, the Organised Gas Market Agents Committee was established on 28 January 2016. This Article regulates the organised gas market and third-party access to natural gas system facilities. The Agents Committee is formed by representatives of the agents, Spain’s National Commission for Markets and Competition (CNMC), the transmission system operator, the market operator and the party responsible for the settlement services.

To sum up, Law 8/2015 provides for the creation of an organised gas market on the Iberian peninsula, and nominates MIBGAS SA as its operator. This mandate is statutorily developed in Royal Decree 984/2015, which regulates the organised gas market and third-party access to natural gas system facilities; in the Resolution of 4 December 2015, issued by the Secretary of State for Energy, which approves the market’s rules, the adhesion
contract and the decisions of the organised gas market; and in Circular 2/2015 of 22 July, issued by the CNMC, which lays down the balancing rules for the gas-system transmission network. The MIBGAS trading platform is used for the purchase and sale of natural gas with physical delivery at the virtual balancing point for within-day, day-ahead, balance-of-month and month-ahead products.

Additionally, the ruling issued by the Spanish Constitutional Court of 21 December declares the unconstitutionality of Articles 2.2, 4, 5 and 6, the first additional provision and the first transitory provision of Royal Decree-Law 13/2014 of 3 October, which adopts urgent measures in relation to the gas system and the ownership of nuclear power plants. Thus, the Spanish Constitutional Court has annulled the compensation procedure for the promoters of the Castor underground gas storage facility, owing to the lack of ‘urgent need’ that would have justified approving a Royal Decree-Law in this regard.

iv Rates
Remuneration for transportation and distribution are administratively established in response to investment costs, operation and maintenance, and network management, according to a calculation model defined by the regulator by royal decree and in accordance with provisions established in the former Electricity Law 54/1997 and the current Electricity Act 24/2013 (Article 14.8). Thus, the remuneration is established by reference to the costs required to build, operate and maintain the facilities complying with the principle of covering the electricity supply at the lowest cost. Accordingly, Royal Decrees 1047/2013 and 1048/2013 establishing the methodologies for calculating the remuneration for transportation and distribution activities have been implemented.

This remuneration methodology is based on the following remunerative principles:

- the accrual and collection of the remuneration generated by transmission and distribution facilities placed into service in year ‘n’ will start from 1 January of year ‘n+2’;
- the remuneration for investment will consist of assets in operation that have not been depreciated. The basis for their financial return will be the net value of the assets;
- the financial rate of return on the assets eligible for remuneration out of the electricity system for transportation and distribution companies will be linked to the yield on 10-year government debt securities on the secondary market plus a suitable spread; and
- the remuneration is determined for each regulatory period, which will last for six years, but the remuneration parameters can be reviewed before the start of each regulatory period.

The remuneration methodology of transportation activity should comprise economic incentives for the improvement of the availability of the facilities and any other goal. In the case of distribution, the remuneration methodology must include the formula for remunerating other regulated functions performed by distribution companies, as well as any incentives that may be appropriate for the improvement of the supply’s quality, reduction of losses, combating fraud, innovating technology and any other goals.

v Security and technology restrictions
Security in relation to transportation facilities of electrical energy is relevant from the perspectives of both industrial safety and security of supply.

Industrial safety is dealt with by Law 21/1992 of 16 July and the Electricity Act 24/2013, and is understood as safety aimed at risk prevention and control, as well as protection against
accidents and disasters capable of causing harm to the population or damage to flora, fauna, property or the environment. Security of supply is dealt with under the sector-specific regulations. The Electricity Act 24/2013 states in this regard that the ‘few basic technical rules needed will be established to ensure the reliability of electricity supply and installations of transport network’.

IV ENERGY MARKETS

i Development of energy markets

According to the Electricity Act 24/2013, electricity production takes place in the electrical power production market in a free-competition regime. The electricity production market is composed of all energy purchase and sale business transactions and other services related to the supply of electricity. It includes forward markets, a daily market, an intraday market, the resolution of system technical constraints, ancillary services and the management of deviations.

The Spanish electricity market has historically offered competitive prices for end users compared with other European markets. The Iberian Electricity Market was started in 2007, and the results of integration in the market have been obvious: while in the second half of 2007 the average price differential between the Portuguese and Spanish electricity systems was €10 per MWh, this fell to €0.3 per MWh by 2010, with identical rates on both sides of the border for the majority of the time.

The operation of the wholesale market at any given time is determined by the mix of generation structure, import capacity, the imperfect meshing of the network, the inelasticity of demand and the system reserve margin. The market-design rules can make this operation more or less efficient, but cannot make up for significant deviations in these factors.

From the opening to competition of the generation market in January 1998 to 2005, almost all of the transactions in wholesale energy were carried out in the pool. Forward markets and bilateral contracts have been developed gradually with the evolution of the regulations. Thus, in recent years, the energy involved in the daily market run by OMIE has ranged between 45 and 55 per cent of demand, with the remainder opting for bilateral transactions.

Despite the reduction in the quantities traded in the daily market, its price still represents the main visible energy price reference and the underlying settlement of bilateral contracts, the over-the-counter (OTC) market and forward markets organised by OMIP.

In this context the significant increase in OTC negotiations on the financial market should also be noted. The volume of energy traded in this market went from 6 per cent of domestic demand in 2007 to 10 per cent in 2010.

The low prices in the Spanish wholesale market compared with their European counterparts have reflected the influence of generation technology’s price takers. As an illustrative example, in the period from December 2009 to March 2010 the market price showed a very substantial fall even below fuel price, reaching an average of €19.6 per MWh in March 2010, reflecting, inter alia, prices of zero euros per MWh for almost 300 hours. One of the main causes of this was a 1.91 per cent reduction in demand, along with growth in wind production coinciding with intense rainfall.

© 2018 Law Business Research Ltd
ii  **Energy market rules and regulation**

Since 1998, the Spanish electricity sector has undergone a major transformation as a result of regulation changes resulting from the adoption of Directive 96/92/EC, the main objective of which was to create an internal market for electricity in the EU by liberalising electricity generation and sale.

The electricity markets are regulated by:

a  a market operator, responsible for the preparation of the daily operation of the system, matching offers and demands, supervised by a committee of representatives of producers, distributors, traders and qualified consumers;

b  a system operator, ensuring continuity and security of supply (Red Eléctrica de España);

c  the Electricity System Commission, which protects consumer interests and ensures the transparency of the whole system;

d  the Industry and Energy Ministry must supervise the correct operation of production activities and consumption of electricity;

e  autonomous communities, which also have direct responsibilities in regulating their electrical systems; and

f  the European Union, which establishes the general framework of the electrical system in all countries of the Union through directives and legal regulations.

Royal Decree 949/2001 (amended by Royal Decree 984/2015 on organised gas market and third-party access), which regulates third-party access to gas infrastructure and establishes an integrated economic system of the natural gas for regulated activities paid under rates, tolls and regulated fees, as amended, also sets out the basic criteria for remuneration of regulated activities, setting tariffs and fees to be paid by individuals for the use of gas installations.


iii  **Contracts for sale of energy**

Participants in the energy market may freely agree the terms of contracts for the sale of electricity to subscribe, subject to the terms and minimum content, under the Electricity Act 24/2013 and its implementing regulations. MIBEL consists of the forward markets managed by OMIP and the daily market and intraday markets managed by OMIE.

Electricity traded through daily and intraday markets is remunerated on the basis of the prices resulting from the balance between supply and demand of electricity offered. In other words, it is a marginal pricing market in which the price and trading volume in each hour are set according to the point of equilibrium between supply and demand. Electricity traded through bilateral contracts or the physical or term market is remunerated on the basis of the price of the firm’s contracted operations in those markets.

iv  **Market developments**

Historically, the energy market has functioned properly, but in recent years a technology-driven influx of price takers has distorted its proper functioning. This has caused a reduction in the wholesale market price, which, together with a reduction in the thermal gap, is not sending the right economic signals to garner investment in new capacity.
This situation will only deteriorate in the future, as the progressive decarbonisation production mix forecasts a greater presence of non-renewables, relegating thermal technologies to the role of providing back-up power, with only a residual role as contributor energy, and jeopardising the recovery of investment. Incentives for investment and the availability of service, established in Order ITC/3127/2011 of 17 November (recently modified by the Ministerial Order ETU/1133/2017 of 21 November and Ministerial Order ETU/971/2017 of 17 October), have not sent sufficient economic signals to encourage investment in new backup power in the region of 500 hours per year, which highlights the need to revise that target.

In particular, a procedure to assist supply security was introduced in 2011 with the aim of ensuring a level of domestic coal consumption according to the provisions of the National Coal Plan (which justifies the operation of these plants for security of supply and capacity for each state to give priority to indigenous sources for up to 15 per cent of production). This regulatory change involves the generation of coal that is bought (10 plants totalling 4,700MW) at a regulated price, while production in the process of withdrawal of the production–demand balance (imported coal and combined cycle) does not receive any compensation. Nevertheless, according to the Framework Agreement for Coal Industry and Mining Districts for the period 2013–2018, the said incentivising mechanisms expired at the end of 2014. The Spanish government proposed renewing the incentives granted to power plants that burned national coal. For that purpose, on 31 March 2015, the Spanish government presented a draft Proposal of Order regulating an incentive for investment in environmental performance improvement for electricity generating facilities from indigenous coal to the Commission on the Monitoring of the Coal Plan for the period 2013–2018. The draft Proposal of Order was subject to prior review by the CNMC and notification to the European Commission. The CNMC issued its report on 30 September 2015, stating that the measures established in the draft Proposal of Order were not justified with regard to the necessity and proportionality of the objective, and expressly pointed out that such measures could fall within the scope of the definition of state aid under European law and thus be duly notified to the European Union pursuant to Articles 107(1) and 108(3) of the Treaty on the Functioning of the European Union. The European Commission responded negatively to the draft Proposal of Order in February 2016.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

The Electricity Act 24/2013 eliminated the former distinction between ordinary and special-regime installations and replaced them with a remuneration system based on the technology and capacity of the generation facilities. Under the former remuneration system, special-regime installations, which include renewable energy sources, were not subsidised in the state budget. Instead, they were included in electricity rates, causing a ‘tariff deficit’; however, it was not only renewable energy premiums that generated a tariff deficit, so did other items, such as regulated tariff billing. In fact, the special-regime premiums caused only one-third of the tariff deficit.

Royal Decree 6/2009, dated 30 April, had previously attempted to limit the increase of the aforementioned general tariff deficit; however, it was not sufficient, given that only a year later further steps needed to be taken by the government and Royal Decree-Law 14/2010 was passed for this purpose. In this context, the purpose of Royal Decree-Law 1/2012 was to limit
the impact of renewable premiums in the tariff deficit, thus reducing costs; in similar terms, Royal Decree-Law 2/2013 aimed to mitigate the tariff deficit by modifying the remuneration system of regulated activities as well as the remuneration formula for special-regime facilities.

In addition, there were several regulatory changes during 2012 and especially during 2013 in relation to energy production from renewable sources, cogeneration and waste.

As stated above, the Spanish government has accomplished a structural reform of the Spanish energy sector, starting with the enactment of RDL 9/2013. This regulation focused on addressing ‘the pressing need to immediately adopt a series of urgent measures that will ensure the financial stability of the national electrical grid and, likewise, the advisability of overhauling the regulatory framework so that it can adapt to the events and situation that define the electricity sector at any given period, with the objective of maintaining the sustainability of the electrical system’.

The RDL 9/2013 regulation abolished the former remuneration system based on a regulated tariff (the only one in existence since RDL 2/2013 was enacted), even for generation facilities in operation at the time this regulation entered into force. It replaced the previous regime with a system in which power plants producing electricity from renewable energy sources, cogeneration and residual waste receive ‘a specific remuneration that is composed of an amount per installed power unit/facility (which covers, where applicable, the investment costs for a standard plant that cannot be recovered from the sale of electrical power), in addition to an amount for the operation itself (which covers, where applicable, the difference between operating costs and the revenue obtained from the market by said standard power plant)’.

This specific remuneration is calculated on the basis of a ‘standard power plant, over the useful regulatory life thereof and based on the business activity that would be carried out by an efficient and well-managed company’. Thus, production facilities receive a ‘reasonable profitability’ based on standardised costs and revenues for a standard power plant.

The provisions contained in RDL 9/2013 relating to the remuneration system for producers of energy from renewable sources, cogeneration and waste were basically carried into the Electricity Act 24/2013. Accordingly, Section 5 of Article 14 of the said Act determines that the remuneration for generation activities includes the following concepts:

\[\begin{align*}
\text{a} & \quad \text{correspondent remuneration for participation in the daily and intraday market for generation;} \\
\text{b} & \quad \text{the system adjustment services required to guarantee a suitable supply to the consumer;} \\
\text{c} & \quad \text{when applicable, remuneration through the capacity remuneration mechanism;} \\
\text{d} & \quad \text{when applicable, additional remuneration for generation activities carried on in the electricity systems of non-peninsular territories; and} \\
\text{e} & \quad \text{when applicable, specific remuneration for the generation of electricity using renewable energy sources, cogeneration and waste.}
\end{align*}\]

RD 413/2014 specifically regulates the remuneration system for facilities generating electricity from renewable energy sources, cogeneration and waste. Thus, power plants producing electricity by these methods may also receive a specific remuneration, in addition to the electricity market price, composed of the following elements:

\[\begin{align*}
\text{a} & \quad \text{‘remuneration according to the investment’, which is an amount relative to the installed power unit or facility, and covers, where applicable, the investment costs for a standard plant that cannot be recovered from the sale of electrical power; and}
\end{align*}\]
‘remuneration according to the operation’, which is an amount relative to the operation itself, and covers, where applicable, the difference between operating costs and the revenue obtained from the market by said standard power plant.

This specific remuneration, that allows power plants producing electricity from renewable energy sources, cogeneration and waste to achieve a reasonable rate of return, is calculated on the basis of a ‘standard power plant, over the useful regulatory life thereof and based on the business activity that would be carried out by an efficient and well-managed company’.

The RD 413/2014 defines the concept ‘reasonable rate of return’ by referencing the pre-tax return on the secondary market average yield on 10-year government bonds for the 24 months prior to May of the previous year as of the beginning of the regulatory period, increased by a differential. Each regulatory period will last for six years, with the first starting on 14 July 2013 and lasting until 31 December 2019.

Notwithstanding the above, those facilities that benefited from a feed-in tariff regime as of 14 July 2013 will receive a reasonable rate of return based on the pre-tax return on the secondary market average yield on the 10 years prior to the entry into force of RDL 9/2013 government bonds, plus 300 basis points. The specific remuneration will be granted to new power plants producing electricity from renewable energy sources, cogeneration and waste, by means of a competitive tendering process respecting transparency, non-discrimination and objectivity principles. Once power plants producing electricity from renewable energy sources, cogeneration and waste have completed their useful regulatory life, they would not be entitled to receive any specific remuneration and would merely obtain the income associated with participation in the electricity market. Lastly, the remuneration parameters based on standardised costs and revenues for a standard power plant are set forth in MO IET/1045/2014. MO ETU/130/2017 updates the retributive parameters of the standard installations applicable to certain electricity production facilities from renewable energy sources, cogeneration and waste for the period between 1 January 2017 and 31 December 2019. Specifically, the following were revised:

- The plotting of real prices against estimations for the first half-period that has elapsed (2014–2016). This reveals a deviation collection entitlement for the price included in the regulation of the years 2014–2016, which will be offset over the remaining useful life of the assets.
- An update to the plotting of prices for the second half-period (2017–2019) and an update to the remuneration parameters for standard installations, applicable from 1 January 2017 onwards.
- An update to the technological indication coefficients, with figures from the past three years.

As stated above, the Spanish government has carried out three competitive procedures (renewable auctions) for the allocation of the referred specific remuneration regime to electricity producers from renewable energy sources, cogeneration and waste:

- First renewable auction: Royal Decree 947/2015 of 16 February set the first call for the provision of the specific remuneration regime to new biomass and wind installations and Ministerial Order IET/2212/2015 of 23 October regulated the procedure for the provision of such specific remuneration regime. Finally, by virtue of resolution dated 18 January 2016, the General Directorate of Energy Policy and Mining awarded 500MW of wind power capacity and 200MW of biomass capacity.
Second renewable auction: Royal Decree 359/2017 of 31 March established a call for up to 3,000MW of installed power for the granting of the specific remuneration regime to new installations for the production of electricity from renewable energies in the peninsular electrical system. Ministerial Order ETU/315/2017 of 6 April approved the procedure for assigning the specific remuneration regime in the call for new installations for the production of electric energy from renewable energy sources. The General Directorate of Energy Policy and Mining awarded through a resolution dated 19 May 2017 the 3,000MW to mainly renewable energy producers from wind and photovoltaic power.

c Third renewable auction: the third call for the additional provision of 3,000MW of installed capacity has been regulated through Royal Decree 650/2017 of 16 June, and Ministerial Order ETU/615/2017 of 27 June, which aimed to introduce the necessary modifications to Ministerial Order ETU/315/2017 to allow its full application to the new auction. By resolution dated 27 July 2017 the General Directorate of Energy Policy and Mining awarded the relevant capacity.

After the three auctions were held, all of the MW of power with available installed capacity were awarded. These results show that the new facilities for the generation of electrical energy from renewable energy sources are configured as a pillar for the achievement of the objectives established in Directive 2009/28/EC of the European Parliament, which promotes the use of renewable energy from renewable sources by 2020, from an environmental point of view and from an economic point of view.

On 1 August 2015, the Official State Gazette published Royal Decree 738/2015, which mainly regulates electricity production activity and the dispatch procedure in non-mainland electricity systems. This Royal Decree establishes a scheme similar to the previous system, with remuneration for fixed costs (which include fixed investment and fixed operation and maintenance costs) and for variable costs (including fuel and variable operation and maintenance costs), and takes into account, within the costs of these systems, the taxes arising from Law 15/2012, on fiscal measures for energy sustainability. Certain aspects of the methodology have been changed to improve the efficiency of the system. The Royal Decree also implements matters already contained in Law 17/2013 of 29 October 2013 to guarantee supply and increase competition in these systems.

The Royal Decree entered into effect on 1 September 2015 and includes, for certain measures, a transitional period that started on 1 January 2012. In accordance with additional Provision 11, the full and final effectiveness of the Royal Decree is subject to the European Commission not raising any objections with regard to its compatibility with Community law.

On 13 February 2016, Royal Decree 56/2016 was published in the Spanish Official State Gazette partially transposing Energy Efficiency Directive 2012/27/EU. Royal Decree 56/2016 sets forth the obligation for large-scale enterprises and groups of companies to carry out energy audits as a measure for organisations to know their situation regarding energy use, and to contribute to the saving and efficiency of energy that is consumed.

It imposes the obligation to carry out energy audits for large-scale companies that meet the following requirements:

- **a** workforce of more than 250 workers; or
- **b** turnover of more than €50 million and a balance sheet exceeding €43 million.
The obligation also applies to groups of companies as defined in the provisions of the Spanish Commercial Code that fulfil the applicable above-mentioned requirements. Small and medium-sized companies are exempt from this obligation.

The energy audits must be performed by qualified energy auditors, and the obligation is subject to inspection by the competent authorities in matters of energy efficiency. The audits must cover at least 85 per cent of the total energy consumption of the obliged company’s facilities located in Spain that are involved in the industrial, commercial and service activities. Such audits must be performed at least every four years from the date of the previous energy audit.

The sanctions for non-compliance include fines of up to €60,000 according to Law 18/2014 approving urgent measures for growth, competitiveness and efficiency.

An Administrative Energy Audit Register will be created in the Ministry of Energy, Tourism and the Digital Agenda, to record the information notified by the companies under the scope of Royal Decree 56/2016. It will be public and free of charge.

ii Energy efficiency and conservation

Objectives and actions on energy efficiency in Spain are part of the policy objectives and progress set by the regions’ institutions. Also, in addition to the objectives approved in the European Council in spring 2007 of reducing greenhouse gas emissions and increasing renewable energy, a target was included of improving energy efficiency by 20 per cent in 2020 in the EU compared with the baseline scenario (the target block is commonly called 20-20-20 targets). Unlike the target for 20 per cent renewables and 20 per cent reduction of carbon dioxide emissions, the efficiency target is not binding and has been distributed by Member States.

In line with European objectives set forth in Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources, the only public reference in a Spanish context has been the 20 per cent target of improving energy efficiency in the government’s ‘Strategy for a Sustainable Economy’ in December 2009, which included a target of 20 per cent reduction in energy usage by 2020 compared with the scenario at that time.


The 2008–2012 Action Plan includes a significant number of structured activities and strategic sectors. The measures carried out are divided into the following categories:

- legislative actions, generally far-reaching, and representing a complex set of recommendations, regulations, rules of functioning, constraints and generally binding rules;
- incentive measures for carrying out audits and analysis of consumption of the technologies used, and promoting investment in equipment to increase energy efficiency; and
- training in good practices, knowledge of available technology, advances and new techniques of management demand, consumption and, in general, the correct use of energy.
Alongside this plan, some of the key energy-efficiency measures stated in the Spanish Action Plan 2011–2020 include those in the transportation, building, utilities and cogeneration sectors.

### iii Technological developments

One of the main goals within the European Union is to fully achieve energy interconnection and, for that purpose, the European Commission passed the Third Energy Package, which came into force in March 2011. The Third Energy Package sought to accelerate investments in energy infrastructure, to enhance cross-border transactions and provide access to diversified sources of energy.

The European Commission considers the connection of ‘energy islands’, that is, Spain and Portugal on the Iberian Peninsula and Estonia, Latvia and Lithuania in the Baltic Sea region, along with the rest of the internal market as a high priority goal.

A recent example of electricity interconnection as technological developments is the new interconnection grid established between and Spain and France. Both countries have recently finished a €700 million project of common interest that doubles the electrical connection capacity between France and Spain. It was co-financed by both countries through the incorporation of the company INELFE (50 per cent owned by Red Eléctrica de España and 50 per cent by Réseau de Transport d’Électricité).

### VI THE YEAR IN REVIEW

As described above, the Spanish energy sector has undergone a broad reform as a consequence of the government’s attempts to reduce the ‘tariff deficit’ and to re-establish a positive correlation between electricity costs and the income obtained from regulated electricity activities. The main reforms during 2017 could be summarised as follows:

- During 2017, two further renewable auctions were carried out by the Spanish government for the awarding of a total installed capacity of 6,000MW, which shows Spain’s commitment to the promotion of renewable energies in order to fulfil the 20 per cent energy production from renewable energies by 2020;
- On 17 February 2017, Ministerial Order ETU/130/2017 updated the remuneration parameters of the renewable energy installations for the semi-regulatory period between 1 January 2017 and 31 December 2019;
- On 6 October 2017, Royal Decree 897/2017 regulated the figures regarding vulnerable consumers, social bonus and other protective measures for domestic consumers; and
- Important rulings were rendered during 2017; in particular:
  - Ruling No. 1542/2017, dated 13 October 2017, issued by the Spanish Supreme Court by means of which it is stated that self-consumers shall also contribute to the electrical system costs provided that they are connected to the grid; and
  - the ruling issued by the Spanish Constitutional Court, dated 21 December, within the gas market, which repealed some provisions of Royal Decree-Law 13/2014 regarding the Castor underground natural gas storage facility.
VII CONCLUSIONS AND OUTLOOK

Spain depends heavily on foreign energy and needs all available resources. Its energy system is still in a state of revision, both in the electricity and gas sectors, which creates uncertainty for international investors, who demand safe, predictable and transparent markets. Additionally, the retrospective effect of certain measures adopted since 2013 (i.e., RDL 9/2013) concerning renewable-energy incentives, along with tax relief, have brought uncertainty to potential investors. The main objectives for the Spanish government in the short term are to shore up the markets and counter this uncertainty, but it is also important to outline definitively the energy mix required over the next 20 years; once defined, this plan should remain in place for that length of time.
Chapter 31

SWITZERLAND

Georges Racine

I OVERVIEW

The Swiss energy sector has its own distinctiveness. Switzerland has been referred to as the ‘water tower’ of Europe; indeed, hydropower accounts for about 59 per cent of electricity production in the country, while nuclear power accounts for about 32.8 per cent. Other conventional thermal and ‘new’ renewable energies, including solar, wood, biomass, wind, geothermal and ambient heat, account for about 8.2 per cent. Despite the country’s high dependence on nuclear energy, the Federal Council has decided to gradually phase out nuclear power. On 21 May 2017, Swiss voters endorsed (by a majority of 58.2 per cent) Energy Strategy 2050, thereby paving the way for a new Federal Energy Act (the Energy Act). The new law and related ordinances came into force on 1 January 2018, setting forth extensive measures to reduce energy consumption, increase energy efficiency and promote renewable energy. The new law bans building new nuclear power plants but allows existing plants to operate for as long as they meet safety standards. This followed an earlier referendum on 27 November 2016, by which Swiss voters rejected (by a majority of 54.2 per cent) the introduction of a cap on the lifetime of existing nuclear power plants in Switzerland, and the Swiss Federal Council’s decision of 4 May 2016 to indefinitely delay the full liberalisation of the Swiss electricity sector.

The Swiss electricity market has been described as being highly fragmented owing to the number of market participants. Such a high number is peculiar, considering the size and population of the country. Electricity represents approximately 25 per cent of Swiss energy consumption, while oil and gas represent about 50.6 per cent and 13.5 per cent respectively. Coal, wood, industrial waste and other renewable energies constitute the remaining 10.3 per cent. Switzerland produces neither oil nor gas. As such, this chapter focuses on the electricity industry.

---

1 Georges Racine is a partner at HFW. He would like to thank Nick Wright for his assistance in researching materials for this chapter.


II REGULATION

i The regulators

The Swiss energy institutional framework comprises a number of federal offices, regulatory authorities and specialised agencies. The Federal Office of Energy (SFOE) is the office responsible for all questions relating to energy supply and energy use. It sits under the Federal Department of the Environment, Transport, Energy and Communications (DETEC), which is responsible for ensuring sustainable development and the provision of basic public services in the interests of society, the environment and the economy.

The SFOE pursues the following objectives:

a it creates the necessary conditions for ensuring a sufficient, well diversified and secure energy supply that is both economical and ecologically sustainable;

b it imposes high safety standards in the areas of production, transportation and distribution of energy;

c it sets out to promote efficient energy use, increase the proportion of renewable energy in the overall energy mix and reduce the level of carbon dioxide emissions; and

d it promotes and coordinates energy research and supports the development of new markets for the sustainable supply and use of energy.

A number of commissions support the SFOE, including the Energy Research Commission (CORE), the Commission for Radioactive Waste Disposal (CRW), the Administrative Commission of the Decommissioning Fund and the Disposal Fund for Nuclear Installations (ACDFDFNI), the Nuclear Safety Commission (NSC) and the Commission for Connection Conditions for Renewables Energies (CCRE).

The CORE assists with the formulation of guidelines governing energy research and the implementation of research findings. Its members represent the industrial sector, the energy industry, universities and various energy agencies and research institutions in Switzerland.

The CRW is an independent body that is responsible for advising the SFOE and the Federal Nuclear Safety Inspectorate (ENSI) (see below) on geological aspects of nuclear waste disposal.

The two funds administered by the ACDFDFNI were established to secure the necessary financing for the disposal of radioactive waste and spent-fuel elements, and the decommissioning of nuclear installations after their shutdown.

As an advisory body for the Federal Council, DETEC and ENSI, the NSC examines fundamental issues relating to nuclear safety and may submit comments for the attention of the Federal Council and DETEC regarding reports by ENSI on nuclear safety. It took over the duties of the former Federal Commission for the Safety of Nuclear Facilities on 1 January 2008.

The CCRE advises cantonal authorities and the SFOE on the formulation of recommendations and enforcement tools for the implementation of connection conditions for independent producers.4

The Federal Office for the Environment (SFOEN), which also sits under DETEC, plays an important role alongside the SFOE. It is responsible for ensuring that natural resources are used sustainably, that the public is protected against natural hazards, and that the environment is protected from unacceptable adverse impacts.

---

In accordance with DETEC’s sustainability strategy, the SFOEN pursues the following goals:

- long-term preservation and sustainable use of natural resources (land, water, forests, air, climate, biological and landscape diversity) and elimination of existing damage;
- protection of the public against excessive pollution (noise, harmful organisms and substances, non-ionising radiation, wastes, contaminated land and major incidents); and
- protection of people and significant assets against hydrological and geological hazards (flooding, earthquakes, avalanches, landslides, erosion and rock falls).

In order to achieve these goals the SFOEN has been assigned the following responsibilities:

- environmental monitoring to provide a sound basis for the management of resources;
- preparation of decisions, to secure a comprehensive and coherent policy of sustainable management of natural resources and prevention of natural hazards; and
- implementing the legal foundations, supporting enforcement partners and providing information on the state of the environment and on the appropriate use and protection of natural resources.\(^5\)

The Federal Electricity Commission (ElCom) is the independent regulatory authority for the electricity sector. It is responsible for monitoring compliance with the Federal Electricity Act and the Federal Energy Act, taking all necessary related decisions and pronouncing rulings where required.

When the new Electricity Supply Act entered into force on 1 January 2008, ElCom was formally entrusted with the task of supervising the liberalisation of Switzerland’s electricity market. As an independent regulatory authority at the federal level, ElCom is responsible for securing the smooth transition from a monopoly situation in the electricity supply sector to an electricity market based on the principles of competition. ElCom’s duty is to ensure that the liberalisation of the market does not result in excessive tariff increases and that the network infrastructure is properly maintained and expanded in order to guarantee an adequate supply of electricity.

ElCom has been entrusted with extensive judicial powers to effectively perform its various duties. It monitors compliance with the provisions of the Electricity Supply Act and the Energy Act, and can pronounce legally binding decisions and rulings as necessary.

The specific duties of ElCom are to:

- verify the electricity tariffs of customers who do not have free access to the network, as well as the remuneration paid for the input of electricity into the grid. It is authorised to prohibit unjustified increases in electricity prices, and may order the reduction of excessively high tariffs, taking action on the basis of complaints or in its official capacity;
- mediate and pronounce rulings on disputes relating to free access to the electricity network;
- rule on disputes relating to cost-covering remuneration of electricity input that is to be paid to producers of electricity from renewable energy sources;
- monitor supply security and the condition of the electricity networks;
- in the case of shortfalls in cross-border transmission lines, to regulate the allocation of network capacities and coordinate its activities with the European electricity market regulators; and

ensure that the transmission network is handed over to the national system operator (Swissgrid) according to schedule.

ENSI is the national regulatory body with responsibility for the nuclear safety and security of Swiss nuclear facilities. It is an independent body constituted under public law.

ENSI is supervised by an independent board elected by the Federal Council and reports directly to it. Its regulatory remit covers the entire life of a facility, from initial planning, through operation, to final decommissioning, including the disposal of radioactive waste. Its remit also includes the safety of staff and the public and their protection from radiation, sabotage and terrorism. ENSI is also involved in transport of radioactive materials to and from nuclear facilities and in the continuing geo-scientific investigations to identify a suitable location for the deep geological disposal of radioactive waste.6

ii Regulated activities

Articles 76 and 89–91 of the Swiss Federal Constitution address energy matters and bind the Confederation and the cantons to provide a satisfactory, diversified, secure, economic and environmentally compatible energy supply.

According to the Constitution, the Confederation is in charge of determining the principles of the use of all domestic and renewable energies in particular, as well as legislating in certain specific areas such as nuclear energy, hydropower generation and transmission and delivery of electricity. Legislation concerning all other areas is to be provided by the cantons. Consequently, energy laws can vary considerably among cantons.

At the federal level, the principal pieces of legislation are:

a energy: the new Energy Act;
b hydropower: the Hydropower Act 1916 and the Water Protection Act 1991;
c electricity: the Electricity Act on Electric Facilities for Low and High Voltage 1902 and the Electricity Supply Act 2007;
e CO2: the CO2 Emission Reduction Act 1999 (the CO2 Act); and

Enacted by the Federal Council on 1 November 2017, the new Energy Act took effect on 1 January 2018. Three new ordinances and a series of revisions to other ordinances also took effect on 1 January 2018. The aims of the new Act are to ensure:

a the economic and environmentally sound provision and distribution of energy;
b economical and efficient use of energy; and
c transition to renewables, especially domestic renewables.

The Federal Electricity Supply Act, which was adopted by Parliament in 2007, provides for an opening of the market in two stages, starting on 1 January 2009. In the first five years (2009–2013), only end-consumers with an annual consumption of more than 100,000kWh per site were granted free access to the market. Households and other small-scale end consumers were also supposed to be able to freely choose their electricity supplier as of 1 January 2014,

7 Article 1 of the new Energy Act.
but that full market liberalisation has been delayed, due to the main objective of market liberalisation – the creation of a competitive and secure electricity supply with transparent pricing – not having been achieved.

Negotiations between the EU and Switzerland to enter into a comprehensive long-term energy treaty began at the end of 2007. The primary aim of such an accord (obtaining this agreement is considered one of the top priorities for Switzerland) would be the mutual access to the free energy market. The negotiations, which were at an advanced stage, came to a halt immediately following the adoption by the Swiss people (9 February 2014) of the Swiss popular initiative ‘Against Mass Immigration’.

### Policy

The Swiss Federal Constitution, the Energy Act, the CO2 Act, the Nuclear Energy Act and the Electricity Supply Act are all integral parts of the instruments defining a sustainable and modern Swiss energy policy. In addition to legal instruments, the energy policies of the federal government and the cantons are both based on the presentation of energy perspectives as well as on strategies, implementation programmes and the evaluation of energy-related measures at the municipal, cantonal and federal levels.

Energy policy was only anchored in the Swiss Federal Constitution in 1990, when provisions were added stipulating that the federal government and the cantons are obliged to use their competences to ensure an adequate, broad-based, secure, economical and ecological energy supply, and the economical and efficient use of energy. This comprehensive list of requirements places high demands on energy policy at the federal and cantonal levels, while demonstrating how difficult it is to find suitable solutions.

Since 1990, all cantons have drawn up their own energy legislation and regulations, and with the enactment of the Federal Energy Act and the Federal Energy Ordinance on 1 January 1999, the Federal Council fulfilled the mandate it had received following the approval by the electorate of the energy provisions in 1990.

The energy perspectives as drawn up by the Federal Council have served as a basis for all political decisions in the energy field and have been reviewed and updated regularly since the establishment of the General Energy Plan in the mid-1970s.

On 4 May 2016 the Federal Council confirmed that it was indefinitely delaying the full liberalisation of the Swiss electricity market. Due to the economic and political implications of full liberalisation, the Federal Council launched a public consultation process, which took place between 8 October 2014 and 22 January 2015. Following its review of the report on the consultation process and in light of the conflicting views expressed therein, the Federal Council has indicated that full liberalisation will depend on:

a. the evolution of the energy pact with the European Union;
b. the progress achieved with Energy Strategy 2050;
c. the prevailing market conditions; and
d. the revision of the Federal Electricity Supply Act.

Since the adoption of Energy Strategy 2050 and the new Energy Act coming into force, there has been renewed discussion of market liberalisation, notably a report by the SFOE in
November 2017 and a motion supported by the Federal Council and SFOE in December 2017. It is expected that liberalisation will go hand-in-hand with the establishment of a strategic reserve.8

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling
The most significant change in the structuring of the transmission and distribution grid in the Swiss electricity market has been the gradual liberalisation in the past decade of the high-voltage transmission network, and more specifically the separation of the transmission network from other core elements in the electricity market such as distribution, power generation and trading.

The liberalisation of the transmission network was facilitated in large part by the foundation of Swissgrid in 2005 as the Swiss transmission system operator (TSO) and the gradual transfer since then of operational responsibility and legal ownership of the network to Swissgrid.

The transfer of the transmission grid to Swissgrid has consolidated the network (which was previously split up into eight control areas) into one zone covering the entire country. The combined Swiss transmission system is now 6,700km long and connects to transmissions systems of neighbouring countries at over 40 points.9

On 1 January 2009, the number of Swissgrid shareholders increased overnight from eight electricity companies, directly or indirectly majority-owned by the Swiss cantons (Alpiq AG, Alpiq Suisse SA, Axpo Power AG, Axpo Trading AG, BKW FMB Energie AG, CKW AG, ewz and Repower AG) to 17 shareholders as part of the opening up of the previously closed system. There are now over 30 electricity generators and distributors that share ownership of Swissgrid.10

The Swiss Electricity Supply Act mandated that the transfer of the transmission network from the original owners to Swissgrid be completed by the end of 2012. By the beginning of 2013, most of the network components had been transferred with the remainder completed at the beginning of 2015.

The separation of the transmission network from vertically integrated generation and supply companies occurred in three separate stages (principally between January 2009 and January 2015):

a separation of accounting functions from distribution, production and trading activities; 
b legal separation and restructuring of operating entities into subsidiaries; and 
c transfer of legal ownership of the network to national operator Swissgrid.11

Swissgrid now owns and operates the Swiss transmission system and has overall responsibility for ensuring security of supply. Its main areas of responsibility are:

a the transportation of electricity from the producing power plant to the end consumer via regional and local distributors; and

b the trading of electricity exported and imported from the rest of Europe.

11 The transfer to Swissgrid was registered in the commercial register on 3 January 2013.
To regulate the behaviour of Swissgrid and other players in a newly liberalised market, the Swiss Transmission Code was introduced in December 2013 as a regulatory mechanism to define the technical and organisational principles governing the Swiss transmission system.¹² The regulations govern the relationship between Swissgrid and the distribution system operators, power generators and end consumers, as well as other market players and defines the minimum requirements for the operation, use and connection to the Swiss transmission system.

Due to Switzerland’s central location in Europe, approximately one-third¹³ of all electricity flowing through the Swiss transmission network is transmitted from one neighbouring country to another. Swissgrid coordinates its transnational activities through its membership of the European Network of Transmission System Operators for Electricity.

Swissgrid is also part of the TSO Security Cooperation, an initiative between 13 TSOs to ensure secure energy supplies among its members. The initiative brings together a standing security committee and uses a joint real-time information system (the Real-time Awareness and Alarm System) and shared IT platform to meet its main objective of increasing security on Europe’s high voltage transmission network.¹⁴

Swissgrid has been a shareholder of the auction platform Capacity Allocation Service Company since 2010, which acts as a service company and single point of contact for the implementation and operation of the power transmission capacity allocation between counties in Europe.

**ii Transmission/transportation and distribution access**

The Electricity Supply Act stipulates that electricity grid operators must allow power generators access to the transmission and distribution network. The expenses incurred for making these connections are borne by the individual generators. Power generators of electricity from renewable sources (particularly hydropower) are given priority when it comes to allocating capacity on the grid.

Swissgrid must also by statute allow other regulated third parties access to the grid without discrimination, on a transparent and non-discriminatory basis. Access to the network may be denied, however, for ‘legitimate business reasons’, including when the safe operation of the network could be endangered or when the network is congested.

**iii Rates**

Swissgrid sets the rates for use of the transmission grid. These are subject to provisions of the Electricity Supply Act and also to review by ElCom. The legislation stipulates that the tariffs (for all distribution and transmission grids) shall not exceed the recoverable costs, fees and royalties. Recoverable costs consist of the operating and capital expenditure associated with Swissgrid’s operation of the grid.

ElCom acts as a price monitor and regulator for the Swiss transmission network operated by Swissgrid. ElCom is vested with the power to order reductions and to prohibit tariff increases.

---

¹³ 25TWh of 78TWh in 2014, according to Swissgrid (2015).
¹⁴ https://www.tscnet.eu/about-tsc/.
ElCom takes a proactive approach to its price monitoring duties and has ordered the lowering of grid usage tariffs on several occasions, notably in four consecutive years from 2009 to 2012. These tariff reduction orders were, however, struck down by the Federal Supreme Court in 2013. The method by which ElCom calculates tariffs was subject to another Supreme Court Ruling in 2016, which is expected to have a significant impact on how ElCom is able to regulate tariffs in future.

ElCom also rules as a judicial authority on general disputes relating to network access and tariffs. ElCom monitors electricity supply security and regulates issues relating to international electricity transmission and trading.15

Swissgrid sets the tariffs for use of the grid in accordance with statutory requirements and publishes them at the end of March annually.16

Swissgrid effected reductions in tariffs for 2018, attributing this reduction to the ‘drop in operating costs brought about by Swissgrid’s ongoing efforts to increase efficiency’.17 In March 2018, Swissgrid announced that in 2019 the tariff for system services will decrease by 25 per cent (when compared with 2018) and that grid usage tariffs will be up to 21 per cent lower than in 2018.18 Lower ancillary costs are made possible, according to Swissgrid, as a result of lower operating costs and control reserve power costs. Swissgrid attributes these lower costs to the increase in the number of providers, leading to more competition.

Swissgrid’s grid usage tariff19 (charged to the distribution system operators directly connected to the transmission grid) is split up in three components:

\[
\begin{align*}
& a \quad \text{working tariff (the energy component);}
& b \quad \text{power tariff (the power component); and}
& c \quad \text{fixed basic tariff (per weighted outflow point).}
\end{align*}
\]

The working tariff is calculated on the basis of the active energy consumed by end consumers directly connected to the transmission grid, and in the case of a grid operator (of which there are more than 800 in Switzerland), the active energy used by end consumers connected to its grid and all lower-level grids. The actual active energy being consumed is multiplied by the working tariff published by Swissgrid.20

The power tariff is calculated on the basis of the annual average of the actual monthly ‘quarterly-hour’ peak demand values used by each end consumer directly connected to the transmission grid and by end consumers connected to its grid and all lower-level grids. Deductions are made for the energy required for a power plant’s own consumption and the pump energy used by pumped storage power plants (if declared by the grid operator directly connected to the transmission grid).

---

19 The grid use tariff covers the cost of renewal, development and maintenance of the transmission grid, as well as of operations and monitoring via the control centres.
If a customer (either end customer or distribution system operator) has feed-out points into the transmission grid, then the tariff calculation is based on the ‘quarter-hourly’ netted values after the appropriate deductions are made. Similar deductions are made to take into account the energy required for power generation and pump energy.

For the fixed basic tariff calculation, each feed-out point for a grid distribution operator is weighted using the ‘K-factor’, where the share of energy being fed out is considered in relation to a formula based on the sum of energy being fed in and out; from an average taken over the previous 12 months.21

The grid usage tariff is therefore the result of the following formula:

\[\text{a} \times \text{b} + \text{c}\]

\(a\) multiplying the energy volume by the working tariff;
\(b\) multiplying the monthly peak output by one twelfth of the power price; and
\(c\) multiplying the number of weighted feed-out points by the fixed basic tariff per weighted feed-out point.

Swissgrid estimates that in 2019 the average Swiss household will pay a total of 45 francs towards the cost of the transmission grid. Swissgrid forecasts that 5 per cent of electricity price paid by end consumers will go towards the operation and maintenance of the national transmission grid in 2019 and that 47 per cent of costs will be attributed to the distribution grids. 22

iv Security and technology restrictions

The most significant technology restrictions (and sources of vulnerability) on the Swiss transmission and distribution grids are caused by the fact that most of the network is 40 to 50 years old (and only a third of the network dates from after 1980). Until 2013, planning for the development and expansion of the network was carried out at a local level and therefore considerable work remains to be done to modernise the grid.

Additionally, the limited number of transfer points on national borders with main trading partners Germany, France, Italy and Austria (approximately 40) means that capacity is limited and congestion can occur. The Strategic Grid 2025 is an initiative put in place with the main objective of upgrading the grid in order to ensure that it is technically secure, environmentally friendly and economically efficient.23

Swissgrid acts as the single point of contact for other national TSOs and foreign electricity distributors in the negotiation and scheduling of cross-border supply to fill gaps in the Swiss domestic supply. Swissgrid also facilitates capacity auctions for cross-border supply.

Swissgrid is responsible for the safe operation of Switzerland’s high-voltage network from two linked control rooms, operational around the clock and every day of the year. 24

Swissgrid controls a comprehensive IT infrastructure from which it is able to map a real time model of the Swiss transmission network from approximately 40,000 data points. Thousands of measurements and switch positions from the network are collected and processed in cycles of less than 20 seconds. With these many data points, the system is unquestionably vulnerable to cyberattacks.

The Swiss Federal IT Steering Unit is tasked with implementing a national strategy for the general protection of Switzerland against cyber risks.\textsuperscript{25} Produced annually, the latest report on progress was published in 2016.\textsuperscript{26} The report does not, however, contain any specific policy for dealing with cyber threats to the electricity grid.

Swissgrid has established a new technology business unit in order to design and implement a digitisation and automation strategy.\textsuperscript{27} The Swissgrid research and development unit is tasked with developing new technologies for the efficient transmission of electricity, including the new ‘smart grid’ and ‘super grid’ initiatives. The R&D unit also provides support for third-party innovation projects through sponsorship deals and partnership programmes.\textsuperscript{28} This is part of the Strategic Grid 2025 initiative. This has led to the implementation of the first smart grid system by Romande Energie in September 2017, and the banding-together in August 2017 of 11 energy companies to form the Smart Grid Switzerland Association.\textsuperscript{29}

\section*{IV ENERGY MARKETS}

\subsection*{Development of energy markets}

The decision by the Federal Council to indefinitely delay the full liberalisation of the electricity market followed an earlier announcement on 7 March 2016 by major hydropower producer ALPIQ of its intention to divest up to 49 per cent of its hydropower portfolio with a total installed capacity of 5.2GW. The stake for sale represents roughly 8 per cent of the total Swiss hydropower production or 5 per cent of Switzerland’s total power production.

The sale process initiated by ALPIQ, though now suspended, is a testament to the challenges facing Swiss hydropower producers. Under Energy Strategy 2050, the share of hydropower is expected to be well over 50 per cent. Yet for the time being, hydropower producers are struggling. Wholesale prices remain low and the Swiss franc remains strong. Profitability of Swiss power plants has come under strain due to:

\begin{enumerate}
  \item high subsidies for new renewable energies (e.g., wind and solar power);
  \item low prices for primary energies (e.g., oil, gas and coal);
  \item the stagnation of the world economy;
  \item lower carbon dioxide taxes; and
  \item high duties.
\end{enumerate}

Producers like ALPIQ lack access to end consumers in the non-liberalised segment of the Swiss market, while their traditional clients (including power distributors and large-scale consumers that benefit from partial liberalisation) have been buying abroad.

The Swiss energy market comprises several hundreds of players, including a small number of major consortia with vertically integrated operations, and about 80 power producers, who differ considerably in terms of size and operations. The vast majority of market players are publicly owned regional and local utilities that distribute electricity to

\begin{itemize}
  \item \textsuperscript{25} www.isb.admin.ch/isb/en/home/themen/cyber_risiken_ncs.html.
  \item \textsuperscript{27} https://swissgrid.ch/en/home/about-us/newsroom/newsfeed/20160115-01.html.
  \item \textsuperscript{28} https://www.swissgrid.ch/en/home/about-us/research-development.html.
  \item \textsuperscript{29} https://romande-energie.ch/espace-presse/communiques-de-presse/110908-communique-fr.
their local municipalities. Only some of these regional and local distributors can produce electricity. The largest utilities are responsible for approximately 80 per cent of the power production and 90 per cent of the energy supplied in the country.

ii Contracts for sale of energy

As there is no power exchange in Switzerland, Swiss trading companies trade on the Powernext in Paris, the Energy Exchange in Austria and the Leipzig-based European Energy Exchange.

The Dow Jones Swiss Electricity Price Index (SWEP), which was initiated by Aare-Tessin AG für Elektrizität and Elektrizitäts-Gesellschaft Laufenburg AG, and launched in cooperation with Dow Jones in March 1998, provides price indications for over-the-counter electricity trading in Switzerland for next-day delivery. The SWEP is the volume-weighted average of the profile adjusted price for hour 12 of all transactions having an impact on hour 11am to 12pm, also taking into account the Index for the past 20 days.30

On 30 October 2013, Elcom gave its green light to an accord between Swissgrid and the European power exchange EPEX Spot. This accord paved the way for the introduction of market coupling at the Swiss border, which is expected to make power trading more efficient. As a power exchange, EPEX Spot is already overseeing short-term electricity wholesale trade in Switzerland.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

Historically, Switzerland’s longest-serving and most important source of renewable energy has been hydropower, but the ‘new’ renewables including solar, wood, biomass, wind, geothermal and ambient heat also play an increasingly important role in today’s Swiss energy mix. Such role will be accelerated with the endorsement by the Swiss people of Energy Strategy 2050. The revised Energy Act that will come into force on 1 January 2018 specifically aims to increase the use of renewable energy, especially from domestic sources, in addition to securing an economic and ecological supply and distribution of energy and using energy economically and efficiently. To that effect, it sets forth specific goals and measures, including the following:

a the domestic production of hydroelectric power will be increased to 37,400GWh by 2035, while domestic electricity production from other renewable sources will be increased to 4,400GWh by 2020 and 11,400GWh by 2035;

b the current feed-in compensation for energy from renewable sources (i.e., solar, wind, biomass and geothermal energy) will be extended until 2022, and large-scale hydroelectric power plants and photovoltaic and biomass power plants may obtain subsidies until 2030;

c subsidies for local renewable sources and energy efficiency measures will be financed by increases in the grid fee;

d promotion of the construction and expansion of power plants, by declaring that renewable sources use is a national interest equal to the protection of nature and heritage; as a result, it will become more difficult to object against new power plants by referring to nature and heritage protection;

30 http://www.stromkosten.de/maerkte/swiss-electricity-price-index-swep/.

© 2018 Law Business Research Ltd
the cantons will have to provide fast approval procedures for the construction and expansion of power plants;

recourse to the Federal Supreme Court regarding disputes over planning approvals for power plants, will be possible only for legal issues of fundamental importance; and

the right to use self-produced energy will be expanded.

ii Energy efficiency and conservation

The new Energy Act, which came into force on 1 January 2018, also presents goals and measures targeting energy saving and efficiency, including the following:

a a substantial reduction in energy and electricity consumption is to be achieved by 2035. Compared to the 2000 figures, average energy consumption per person per year is to be reduced by 16 per cent by 2020 and 43 per cent by 2035. Average electricity consumption per person per year is to be reduced by 3 per cent by 2020 and 13 per cent by 2035;

b the existing subsidy programme for energy building refurbishments is to be continued after 2019. The subsidies will be increased and partly financed from revenues of the carbon dioxide (CO2) tax. In addition, tax deductions for such refurbishments will be extended;

c as of 2021, the average CO2 emission of new passenger cars must be reduced to 95g of CO2/ km (currently 130g of CO2/km). The average CO2 emission of delivery vans and light-duty vehicles must be reduced to 147g of CO2/km; and

d the existing mechanical electricity meters are to be replaced by smart metering systems that provide more specific data and allow efficient electricity supply and consumption.

In 2017, 25 million francs in subsidies was available for electricity saving proposals, through a competitive tender process. In 2018, 50 million francs has been made available, paid for by the surcharge on transmission costs of high-voltage grids.

On 16 August 2017, the Federal Council adopted two proposals to approve the signing of an agreement to link the carbon market in Switzerland to the Emissions Trading Scheme (ETS). Once ratified by the EU and Switzerland, the proposed agreement will provide for fungibility of EU (1,800 million tonnes) and Swiss (5 million tonnes) carbon allowances. It is expected that the earliest the proposed agreement could take affect is 2019, which would follow amendment of the CO2 Act.

VI THE YEAR IN REVIEW

The major development in the Swiss energy sector in the last 12 months or so has been the legislative response to the public endorsement of Energy Strategy 2050 by public referendum on 21 May 2017. As a result of that vote, the landscape has changed in respect of Swiss energy law, through the enactment in November 2017 and coming into force of the new Energy Act on 1 January 2018. The past several months has also seen engagement and preliminary agreement with the EU on the trading of carbon credits, and potential for a reawakening of the project to liberalise the Swiss electricity market (certainly at committee level in the Swiss Parliament). While existing nuclear plants are to remain in use as long as they are considered

 safe, the new Energy Act strongly favours home-grown renewables and provides continued support for large-scale hydropower through state subsidies. Most notably, following the adoption of Energy Strategy 2050, ALPIQ, which owns and operates 18 hydropower stations in Switzerland, has decided to suspend plans to divest 49 per cent of its hydropower portfolio.

VII CONCLUSIONS AND OUTLOOK

The tremors of Fukushima are still fresh in the minds of the Swiss policymakers more than seven years after the disaster. This has led to a shift of public opinion against nuclear power and towards renewables, in particular renewables that contribute to the Swiss economy. In the current market, renewables, including capital-intensive hydropower projects, require state subsidy to be viable when compared with less clean alternatives. It remains to be seen whether the intention of and subsidies provided for in the Energy Act will be sufficient to improve the commercial viability in the longer term of hydropower as against other forms of energy production.
Chapter 32

TURKEY

Okan Demirkan, Melis Öget Koç, Gökçe İldiri and Cihan Mercan

I OVERVIEW

Following the elections held in Turkey in November 2015, Mr Berat Albayrak was appointed as the Energy and Natural Resources Minister. Minister Albayrak has since adapted the same policy as that of his predecessor, and declared that in the long term Turkey aims to (1) increase its general energy storage capacity; (2) increase storage obligation rates for imports; (3) use different energy storage options; and (4) support investments in the energy sector, with a particular focus on renewable energy. In the past decade, Turkey increased its installed capacity from 39,800MW to 80,546MW (as of July 2017) and Turkey’s energy consumption increased from 160 billion kWh to 293 billion kWh. The minister further announced that Turkey is planning to make an investment of 18 billion Turkish liras to strengthen the infrastructure of its electricity supply system network in the coming five years. As it did in 2015 and 2016, Turkey continues to take concrete steps to meet energy demands and to keep increasing the figures until 2023. In addition to relevant targets for electricity and natural gas, Turkey is also planning to enact a separate coal law, considering the specific needs of operating coal mines and the use of coal to meet energy demands. This shows that, while focusing on renewable energy investments, Turkey will continue to use coal as an energy resource in its energy strategies. All in all, Turkey aims to stop being an energy importer and start exporting energy in the coming years.

Turkey’s strategy and targets for 2023 are:

a. increasing total installed power to 120,000MW;
b. increasing the share of renewable energy sources to 30 per cent;
c. maximising the use of hydropower;
d. increasing wind-power installed capacity to 20,000MW;
e. installing power plants with 1,000MW of geothermal and 5,000MW of solar energy;
f. extending the length of electricity transmission lines to 60,717km;
g. reaching a power distribution unit capacity of 158,460MVA;
h. extending the use of smart grids;
i. raising the natural gas storage capacity to 11 billion m3;
j) establishing an energy stock exchange with a diversified product range, which has been achieved;
k) commissioning nuclear power plants; and
l) increasing coal-fired installed capacity to 30,000MW.4

Establishment of an energy stock exchange with a diversified product range was among these targets. In line with this approach, the new Electricity Market Law5 (EML) enacted in 20136 provided that this energy stock exchange market would be administered through a company called EPİAŞ.7 EPİAŞ was established on 12 March 2015 in line with the EML, to support market liberalisation, ensure transparency and help maintain a healthy balance between national energy supply and demand.

Turkey has become one of the fastest growing energy markets in the world, paralleling its economic growth over the past 15 years. Energy demand in Turkey is estimated to increase by approximately 6 per cent per annum until 2023.8 In any case, because of insufficient petroleum and natural gas sources, Turkey is still dependent on imports. According to EMRA’s petroleum and natural gas market reports prepared for 2016, Turkey imports petroleum mainly from Iraq (23.09 per cent), the Russian Federation (19.38 per cent), Iran (17.32 per cent), India (9.95 per cent), and natural gas from the Russian Federation (55.48 per cent), Azerbaijan (14.65 per cent) and Iran (17.42 per cent), in addition to its long-term liquefied natural gas (LNG) imports from Nigeria (2.76 per cent) and Algeria (9.69 per cent).9

With the enactment of the Natural Gas Market Law10 (NGML) in 2001, the Petroleum Pipeline Corporation (BOTAŞ)11 lost its monopoly in natural gas importation, distribution and sales. However, BOTAŞ maintains its key market position, as it owns and operates the natural gas transmission network and still imports approximately 81.02 per cent of the natural gas consumed in Turkey,12 and 100 per cent of natural gas export from Turkey is still made by BOTAŞ.13 In accordance with the NGML, on 30 November 2005, BOTAŞ transferred an existing agreement for the import of 4bcm per year of natural gas from Russia

---

4 The current coal-fired installed capacity is 17,300MW.
5 Entered into force on 30 March 2013.
6 In addition to the EML, many long-awaited regulations entered into force in 2013 in line with EML, such as the Electricity Market Licence Regulation, the Electricity Market Distribution Regulation and the Electricity Market Connection and Use of the System Regulation.
7 Enerji Piyasaları İşletme Anonim Şirketi.
9 These percentages only relate to natural gas imports under long-term purchase agreements, but Turkey also imports spot LNG. EMRA has granted spot LNG import licences to 41 natural gas import companies other than BOTAŞ. These companies may import spot LNG to Turkey. However, since 2009, there have been only two natural gas import companies importing spot LNG to Turkey. One is BOTAŞ and the other is Ege Gaz AŞ. In 2016, the latter imported 0.252bcm spot LNG, a negligible volume given Turkey’s total imported spot LNG volume of 2.123bcm in 2016.
11 The Petroleum Pipeline Corporation, BOTAŞ is a state-owned company.
to four other natural gas import companies with a tender process. These four natural gas import companies were Shell Enerji AŞ, Bosphorus Gaz Corporation AŞ, Enerco Enerji Sanayi ve Ticaret AŞ and Avrasya Gaz AŞ. In addition, after the expiry of the natural gas purchase agreement with Gazprom Export LLC (Gazprom) on 31 December 2011, BOTAŞ did not renew this agreement owing to the restrictions imposed by Provisional Article 2 of the NGML limiting BOTAŞ’s monopoly. Hence, following the expiry of BOTAŞ’s natural gas purchase agreement with Gazprom, EMRA was permitted to grant import licences to market players for the same volume of natural gas (from the same country). In this case, four natural gas import companies gained the right to import 6bcm per year to Turkey through the Russia–Turkey Natural Gas Pipeline. These companies were Akfel Gaz Sanayi ve Ticaret AŞ, Bosphorus Gaz Corporation AŞ, Batı Hattı Doğalgaz Ticaret AŞ and Kibar Enerji Dağıtım Sanayi AŞ. These developments are a step forward in terms of liberalising Turkey’s natural gas market.

As per the High Planning Council’s decision on 16 December 2016, Turkey aims to reach a 5bcm working gas capacity in the long run within the scope of the Tuz Gölü (Salt Lake) Natural Gas Underground Storage Project, which was initiated on 10 February 2017. The current capacity of the Tuz Gölü (Salt Lake) Natural Gas Underground Storage Facility is 1bcm. In addition, recently, the Silivri Natural Gas Storage Facility, with a working capacity of 2.84bcm, was taken over by BOTAŞ to ensure seasonal supply-demand balance and supply security.

Turkey enacted a new Turkish Petroleum Law in 2013, abolishing the former Petroleum Law. Then, the Turkish Petroleum Law Implementation Regulation entered into force in early 2014. An amendment law proposing substantive changes to the Natural Gas Market Law (the Draft Amendment Law) was prepared in 2012 and submitted to the Turkish Grand National Assembly (the Turkish Parliament) on 4 August 2014, within the 24th legislative session (2011–2014). However, the draft amendment law has not been enacted within the said legislative session, so it became void at the end of that legislative session. Accordingly, at the time of writing, these amendments still have not been enacted. On the other hand, another amendment to the NGML came into effect on 17 June 2016, which will be explained in detail in Section II, infra.

In line with Turkey’s substantial demand potential and its renewable energy targets, Turkey has also introduced the Regulation on Generating Electricity Without a Licence; the Regulation on Documentation and Support of Renewable Energy; the Regulation on Technical Evaluation of Solar Energy.

---

16 Ibid.
18 Entered into force on 11 June 2013.
19 Entered into force on 22 January 2014.
20 Entered into force on 2 October 2013.
21 Entered into force on 1 October 2013.
22 Entered into force on 9 October 2016.

© 2018 Law Business Research Ltd
Based Licence Applications;\textsuperscript{23} the Communique on Wind and Solar Measurements for Preliminary Licence Applications;\textsuperscript{24} and the Contest Regulation on Pre-Licence Applications Regarding Generation Facility Based on Solar and Wind Energy.\textsuperscript{25}

II REGULATION

i The regulators

The MENR is responsible for preparing and implementing energy policies, plans and programmes in coordination with its affiliated institutions. EMRA is responsible for regulating and supervising the operation of the electricity, downstream petroleum and downstream natural gas markets.\textsuperscript{26} It exercises its powers through EMRA’s board.\textsuperscript{27} With its competence to regulate and supervise the energy markets, EMRA has the following duties:\textsuperscript{28}

\begin{enumerate}
\item issuing licences;
\item drafting, amending, enforcing and auditing performance standards, as well as distribution and customer services;
\item setting out the pricing principles indicated in the law; and
\item maintaining the development and performance of infrastructure for implementation of new power trading and sales methods.
\end{enumerate}

The primary legislation for the electricity market is the EML and the Electricity Market Licence Regulation.\textsuperscript{29} While the Petroleum Market Law,\textsuperscript{30} the Liquefied Petroleum Gas Market Law\textsuperscript{31} and the Petroleum Market Licence Regulation\textsuperscript{32} govern downstream petroleum activities, the NGML and the Natural Gas Market Licence Regulation\textsuperscript{33} govern downstream natural gas activities. As for the upstream market, the TPL governs upstream oil and gas activities,\textsuperscript{34} and the Law on Transit Passage through Petroleum Pipelines\textsuperscript{35} (the Transit Law) governs the transit passage of oil and gas.

ii Regulated activities

Electricity

To conduct any one of the following market activities, companies must obtain a licence from EMRA: generation, transmission, distribution, wholesale, retail, market operation, import, and export.

\textsuperscript{23} Entered into force on 30 June 2017.
\textsuperscript{24} Entered into force on 17 June 2014.
\textsuperscript{25} Entered into force on 13 May 2017.
\textsuperscript{26} The General Directorate of Petroleum Affairs is the regulatory authority responsible for upstream market.
\textsuperscript{27} The Energy Market Regulatory Board.
\textsuperscript{29} Entered into force on 2 November 2013.
\textsuperscript{30} Entered into force on 20 December 2003.
\textsuperscript{31} Entered into force on 13 March 2005.
\textsuperscript{32} Entered into force on 17 June 2004.
\textsuperscript{33} Entered into force on 7 September 2002.
\textsuperscript{34} Under the TPL, the definition of ‘petroleum’ includes both crude oil and natural gas.
\textsuperscript{35} Entered into force on 29 June 2000.
In order to conduct electricity generation activities, companies must obtain a generation licence from EMRA. Only limited liability partnerships and joint stock corporations established in Turkey can obtain electricity generation licences. There are no restrictions in terms of foreign shareholding in electricity market companies in Turkey.

Obtaining a preliminary licence is a prerequisite for obtaining a generation licence for applicants. A preliminary licence is issued for a specific term, to those having submitted an application to EMRA to conduct electricity generation activities. The preliminary licence’s purpose is to enable the applicant to obtain the necessary permits, approvals and licences, as well as to acquire ownership or usufruct rights to the land where the generation facility is to be located, during the application’s evaluation. The Electricity Market Licence Regulation determines the detailed requirements of the regulatory approval process to obtain a preliminary licence and generation licence. The term of a preliminary licence will be determined by EMRA, depending on source type and installed capacity. The term can vary between 24 months and 36 months.

The new Regulation on the Amendment to the Electricity Market Licence Regulation36 separates preliminary licence applications for renewable energy resource areas (RERAs) from those made by other entities generating electricity. Under the Electricity Market Licence Regulation, generation licences are granted for a term of 10 to 49 years. However, the term of generation licences granted for a RERA cannot exceed 30 years. The Regulation on the Amendment to the Electricity Market Regulation also sets forth procedures to be followed for obtaining a preliminary licence for a RERA. In addition, individuals or legal entities generating electricity for their own needs, and having facilities or equipment that does not operate in parallel to the transmission and distribution network, are not required to obtain a licence, as long as they remain disconnected from the transmission and distribution networks and do not engage in wholesale or retail activities.

In this respect, the EML defines the market activities that may be conducted without a licence. Under the EML and the Regulation on Generating Electricity without a Licence, generation facilities with an installed capacity of up to 1MW of renewable energy resources are exempt from this licensing requirement. Moreover, if a company generates more electricity than it consumes, the surplus may be sold in the same distribution region in which it is generated, within the scope of the Renewable Energy Resources (RER) Support Mechanism. The Council of Ministers is authorised to increase the maximum installed capacity for a renewable energy plant to operate without a licence, up to 5MW. Certain amendments to the Regulation on Generating Electricity without a Licence came into force on 23 March 2016, 22 October 2016, 15 May 2017 and 17 January 2017. Pursuant to these amendments, a maximum capacity of 1MW per transformer centre can be allocated to individuals or legal entities generating solar or wind energy (excluding rooftop installations), regardless of the number of consumption facilities owned by that individual or legal entity. When calculating the 1MW limit, both the individual or legal entity or entities in which such persons have direct or indirect control are considered as the same person. These amendments introduced a minimum self-consumption ratio, which places a maximum limit for the excess energy that can be sold to distribution companies. Accordingly, the installed capacity of unlicensed wind and solar generation facilities cannot exceed 30 times the capacity of the consumption unit associated with the generation unit.

36 Entered into force on 24 February 2017.

© 2018 Law Business Research Ltd
Among other significant changes, the new amendments introduced certain share transfer restrictions. Accordingly, shareholders of companies that applied for grid connection for unlicensed electricity generation projects (based on solar and wind energy) are prohibited from transferring any of their shares in these companies. The prohibition period applies from the date of application until the temporary acceptance date. The Regulation on the Amendment to the Electricity Market Licence Regulation\(^\text{37}\) provides certain exceptions to the above limitation: this limitation will not apply to: (1) changes in the shareholding structure of publicly listed legal entities with regard to their publicly listed shares, and changes in the shareholding structure of legal entities with publicly listed shareholders, with regard to the publicly listed shares of these shareholders; (2) direct or indirect changes in the shareholding structure of the relevant legal entity, due to exercise of pre-emption rights by the entity’s shareholders; (3) indirect changes in the shareholding structures of the relevant entities, resulting from changes in their foreign shareholders’ shareholding structures; and (4) direct or indirect changes in the shareholding structure of the relevant entity, caused by a public offering of the entity’s shares or the shares of its direct or indirect shareholders.

**Downstream petroleum and natural gas**

The following downstream petroleum market activities require a licence: refining, processing, lubricant oil production, storage, transmission, eligible consumer, bunker delivery, distribution, transportation, and dealership.

Under the NGML, the following activities require a licence: import; export; transmission; storage; wholesale; distribution; and sale, distribution and transmission of compressed natural gas.

### iii Market restrictions

#### Petroleum

In the downstream petroleum market, a distributor’s market share cannot exceed 45 per cent of the total domestic petroleum market and a distributor’s sales via its own dealers (i.e., dealers owned by the distributor) cannot exceed 15 per cent of that distributor’s total domestic market share.

Another restriction regarding distributors and dealers derives from the Competition Board interventions. According to Article 5 of the Competition Authority’s Block Exemption Communique on Vertical Agreements, non-compete undertakings for indefinite terms or those exceeding five years can no longer be granted a block exemption from the prohibition of agreements, concerted practices or decisions that restrict competition in a specific market. According to the Competition Board’s latest decisions, all personal or real rights related to dealership agreements (such as loan contracts, equipment contracts and long-term lease contracts and long-term usufructs) must be limited to five years.

#### Natural gas

Under the NGML, import companies cannot conclude new natural gas purchase agreements (except for LNG) with countries that currently have existing natural gas sale and purchase agreements with BOTAŞ. The barrier to market entry is actually even higher, because under EMRA’s Board Decree No. 725 (Decree No. 725), EMRA must obtain BOTAŞ’s opinion

---

\(^{37}\) Entered into force on 22 October 2016.
on whether or not such import activity will affect the performance of BOTAŞ’s obligations arising out of its existing contracts (in BOTAŞ’s capacity as a natural gas importer). In addition, Decree No. 725 requires consultation with BOTAŞ (in its capacity as a transmission system operator) on the technical suitability of the proposed importation through BOTAŞ’s transmission network.

The Draft Amendment Law proposing important changes to the NGML, which became void at the end of the 24th legislative session, was going to abolish the prohibition on import companies from concluding new natural gas purchase agreements with countries that currently have existing natural gas purchase agreements with BOTAŞ. Although it did not enter into force, we believe that the said draft law is still a useful tool for understanding the government’s intentions for the future. In any case, another amendment to the NGML came into effect on 17 June 2016. Prior to this amendment, the NGML and the Natural Gas Market Licence Regulation required import licence holder applicants to (1) conclude lease contracts with storage licence holders to ensure storage of 10 per cent of their annual gas import or (2) to obtain a commitment from storage licence holders confirming that they will have such storage capacity within the following five years. However, the current total capacity of the storage facilities in Turkey was below 10 per cent of the nation’s annual gas import amount. With the above amendment to the NGML, EMRA became authorised to change the commitment amount, and set the applicable storage commitment percentage at 6 per cent. A similar obligation is imposed on wholesale licence applicants. Accordingly, wholesale licence holders must take the required storage-related measures within five years of the issuance of the licence, which may be extended if the total capacity of the storage facilities in Turkey is not sufficient after five years of the issuance of the licence.

Under the NGML, no company can sell natural gas corresponding to more than 20 per cent of the estimated national consumption levels determined by EMRA. Moreover, importers cannot import more than 20 per cent of estimated national consumption.

iv Transfers of control and assignments

In the electricity market, in general, licence transfer is not permitted under the Electricity Market Licence Regulation. However, with EMRA’s approval, legal entities holding an electricity generation licence are permitted to transfer rights and obligations related to their licences (1) to another legal entity by way of merger or spin-off; and (2) to another legal entity established under the same shareholding structure. Furthermore, legal entities holding an electricity generation licence may transfer the generation facility to another legal entity seeking to conduct electricity generation activities, by way of sale, transfer or lease, subject to EMRA’s approval. Correspondingly, the legal entity acquiring the generation facility must obtain a new generation licence from EMRA, before such transfer.

In addition to the above-mentioned transactions, the Electricity Market Licence Regulation provides the possibility of granting step-in rights to banks and financial institutions that provide loans to licence holders, allowing them to request licence transfers from EMRA. The transferee will undertake all obligations of the former licence holder under the loan agreement.

These types of transactions are not considered as ‘licence transfer’. The transaction mentioned in item (2), above, and the transactions relating to project financing allow the transferee to obtain a generation licence that maintains the terms and conditions applicable to the former licence.
The Electricity Market Licence Regulation also sets forth certain share transfer restrictions as stated in the Electricity section (Section II.ii). Under Article 6 of the EML and Article 19 of the Electricity Market Licence Regulation, direct or indirect changes in shareholding structure or share transfers (aside from certain exceptions set forth under the Electricity Market Licence Regulation) are forbidden within the preliminary licence period. EMRA may cancel a preliminary licence if such a transaction occurs.

After obtaining a generation licence, the following share transfers are subject to EMRA’s prior approval:

a. direct or indirect acquisition of shares representing at least 10 per cent of the licence holder company’s share capital (5 per cent if the company is publicly traded);

b. share transfers resulting in a change of the company’s control, regardless of the change in the shareholding percentage of the shares; and

c. share pledge for legal entities holding a generation licence, the tariffs of which are regulated.

Similar to the restrictions in the electricity market, licence transfer is not permitted in the natural gas market under the Natural Gas Market Licence Regulation. However, with EMRA’s approval, legal entities holding a licence are permitted to transfer rights and obligations related to their licences to another legal entity by way of merger. This transaction is not considered to be a ‘licence transfer’.

In addition, the Natural Gas Market Licence Regulation provides the possibility of granting step-in rights to banks and financial institutions that provide loans to licence holders, allowing them to request licence transfers from EMRA. The transferee will undertake all obligations of the former licence holder under the loan agreement. Furthermore, the Natural Gas Market Licence Regulation also sets forth certain share transfer restrictions. In the natural gas market, licence holders must obtain EMRA’s approval for any of the following transactions:

a. direct or indirect acquisition of 10 per cent or more shares (5 per cent or more in publicly held companies) in licence holding companies by an individual or a legal entity;

b. any transaction in relation to shares, resulting in any shareholder’s shares exceeding 10 per cent or decreasing below 10 per cent in licence holding companies;

c. any transaction in relation to 10 per cent or more shares (5 per cent or more in publicly held companies) in natural gas storage licence holding companies, regardless of whether a shareholder’s shares exceed 10 per cent or decrease below 10 per cent;

d. any transaction resulting in acquisition of the right to vote in the licence holder company;

e. share pledges;

f. creating or lifting privilege over shares; and

g. merger, in accordance with Article 43 of the Natural Gas Market Licence Regulation.
III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Electricity

TEİAŞ conducts all of Turkey’s electricity transmission activities. The distribution network is divided into 21 regions, with a different distribution company in each region. All of these companies have recently been privatised. TEDAŞ no longer operates any distribution companies, but continues to own the distribution assets.

The shareholders of distribution utilities can own the newly established retail sales utilities’ shares. However, distribution utilities cannot purchase administrative and support services from companies under the parent company’s control. Additionally, retail sales companies and distribution utilities must use different physical premises and information system infrastructures.

Natural gas

Under the NGML, market participants active in more than (1) one market activity or (2) a single market activity in more than one facility, must keep separate accounts for each activity or facility. Cross-subsidisation between accounts is prohibited. In addition to this account separation, companies holding distribution licences must also maintain separate accounts for their natural gas sale and transportation activities.

Although the NGML provided that BOTAŞ was to be unbundled, beginning in 2009, BOTAŞ has not yet been divided into separate legal entities. However, under the NGML, BOTAŞ must keep separate accounts for its transmission, storage and import activities.

ii Transmission/transportation, distribution and storage access

Electricity transmission and distribution

TEİAŞ is required to meet individual and company demands for connection to the transmission network. In cases where system connection and use of the system by generation companies are possible, the licence holder and TEİAŞ or the distribution licence holder must conclude connection and system usage agreements.

Petroleum transmission and storage

Companies holding distribution or storage licences cannot discriminate among third parties of equal status for access to transmission and storage networks. Transmission and storage licence holders that have spare capacity in their facilities must meet the transmission and storage demands of third parties if these demands conform to, inter alia:

- the tariff of the licence holder;
- the capacity of the relevant facility; and

© 2018 Law Business Research Ltd
the minimum amount in the tariff of the licence holder.

**Natural gas transmission and distribution**

Companies holding distribution or transmission licences cannot discriminate among third parties of equal status for access to transmission and distribution networks. Licence holders may only decline third-party access requests if:

- **a** their capacity is not sufficient;
- **b** they cannot perform their existing obligations otherwise; or
- **c** they may be ordered to pay significant financial compensations owing to their existing contractual obligations.

If an applicant undertakes to cover the expenses to overcome the lack of capacity or connection situations, access cannot be denied.

Distribution companies must connect all consumers within their region. A connection agreement must be concluded between the distribution company and consumers, and the technical connection and service lines must be established.

**LNG and natural gas storage**

In Turkey, there are two underground natural gas storage facilities: the Silivri Underground Natural Gas Storage Facility and the Tuz Gölü Underground Natural Gas Storage Facility owned and operated by BOTAŞ. The first phase of the Tuz Gölü Underground Natural Gas Storage Facility was completed and came into service in February 2017. The second phase of the project is still under construction and, according to the MENR’s official website, this phase will be completed in 2020. In addition, there are two LNG terminals: the BOTAŞ Marmara Ereğlisi LNG Terminal in Tekirdağ and the Ege Gaz Aliaga LNG Terminal. Recently, EMRA also categorised floating liquefied natural gas (FLNG) activities as ‘storage’. In addition, EMRA issued the first FLNG licence to Etki Liman İşletmeleri AŞ for a floating storage and regasification unit in Aliaga, İzmir and issued the second FLNG licence to BOTAŞ for a floating storage and regasification unit in Dörtyol, Hatay. These natural gas storage facilities are operational. That said, the natural gas storage capacity is still not sufficient, considering the annual national consumption. In addition to the above, on 30 September 2016, a consortium consisting of three companies, Tekfen, Tesisat and HMB, signed two agreements with licence holders Tören Doğalgaz Depolama ve Madencilik Anonim Şirketi and Gaz Depo ve Madencilik Anonim Şirketi to supply, construct and operate an underground natural gas storage facility in Mersin as part of the Tarsus Underground Storage Project.\(^41\)

Companies holding storage licences must provide storage services to users in an objective and fair manner. In principle, except for the exclusive grounds mentioned above for distribution and transmission networks, companies must accept storage requests. On the other hand, in practice, there are only nine storage licences in force.\(^42\) As the current storage capacity is insufficient, third-party access is practically impossible.\(^43\)

---


\(^{42}\) The last natural gas storage licence was issued on 9 November 2017, in relation to BOTAŞ’ floating storage regasification unit in Dörtyol, Hatay.

\(^{43}\) EMRA is fully aware of the existing storage conditions in Turkey. Considering the current circumstances, EMRA does not strictly monitor the performance of storage-related obligations and, in practice, does not impose penalties on market participants even if the obligations are not met.
iii Tariffs

Electricity

EMRA is responsible for regulating connection and use, including transmission and distribution tariffs, in the electricity sector. Licence holders, the tariffs of which are regulated, must prepare and submit their tariff proposals to EMRA annually. EMRA must complete the examination and evaluation of these proposals before the effective date of the relevant tariff.

Natural gas

As it does in the electricity market, EMRA regulates connection tariffs, storage tariffs and tariffs pertaining to the control of transmission and dispatch in the natural gas market. Companies using the gas transmission system are subject to connection tariffs. Fees can be determined freely between the parties, provided that EMRA's connection tariff principles are reflected in the relevant connection agreements.

iv Security and technology restrictions

There are various pieces of legislation in Turkey dealing with the security of energy infrastructure facilities. Turkey is also a party to international agreements and forums regarding the security of critical infrastructure facilities.

IV ENERGY MARKETS

i Development of energy markets

In Turkey, supply licence holders can conduct electricity trading activities. Electricity traders must either conclude a bilateral electricity purchase agreement with another licence holder or contribute to the organised markets themselves, to participate in the electricity market.

As for natural gas, since there is no energy exchange in Turkey yet, gas trading is physical and regulated in each separate licence and the Network Operation Manual of BOTAŞ. However, the newly introduced Regulation on the Natural Gas Organised Wholesale Exchange Market provides that a natural gas organised wholesale exchange market will be established on 1 April 2018. At the time of preparation of this review, the system for this new exchange market is in testing stage.

In Turkey, gas trading is conducted by four types of licence holders: production lease, import licence, export licence and wholesale licence.

Under the NGML, a company holding an import licence does not need a separate wholesale licence to perform natural gas wholesale activities.

---

44 e.g., the Transit Law; the General Directorate of BOTAŞ, Technical Security and Environment Regulation on Construction and Operation of Crude Oil and Natural Gas Facilities; the Turkish Criminal Code; the Petroleum Market Law; the NGML; and the BOTAŞ Transmission Network Operation Principles.
45 e.g., NATO and Critical Infrastructure Facilities; the Convention on Nuclear Safety; the Energy Charter Treaty; the INOGATE Project (Interstate Oil and Gas Transport to Europe); the Convention on Cybercrime; the OSCE Strategy Document For the Economic and Environmental Dimension; and the Decision on Protecting Critical Energy Infrastructure from Terrorist Attacks.
46 i.e., wholesale, export, import and retail sales.
47 The licence holder can conduct petroleum trade. However, it cannot conduct natural gas trade without a wholesale licence.
ii Energy market rules and regulation
In addition to the EML and the Electricity Market Licence Regulation, electricity trading is particularly regulated by the Regulation on Electricity Market Balancing and Settlement.\(^{48}\)
The Regulation on Electricity Market Balancing and Settlement sets forth the principles and procedures regarding the day-ahead market and real-time balancing of the active electricity demand and supply, as well as settlement of trade in these markets. On the other hand, natural gas trading is regulated under the provisions set forth in each separate licence and the Network Operation Manual of BOTAŞ.

iii Contracts for sale of energy
Electricity is traded mostly through bilateral agreements on an over-the-counter basis. Agreements are not subject to EMRA’s approval and, thus, all commercial terms and conditions are freely negotiable. Electricity can also be traded on a day-ahead and real-time basis.

As for natural gas, suppliers and consumers must conclude private law contracts to participate in natural gas trading. A natural gas sale agreement is the primary agreement executed within the framework of natural gas sale and purchase activities.

In addition to a natural gas sale agreement, the following agreements must be concluded by the parties: operation agreements, system connection agreements and lease agreements.

iv Market developments
Turkey aims to create a liberal and competitive energy market and increase investment opportunities by establishing an energy exchange market. Aside from this, Turkey’s involvement in international oil and gas pipelines significantly supports its aim to become, in the short term, a regional energy hub.

International oil and gas pipelines
The transit passage of oil and gas through Turkey is governed by the Transit Law. However, for the Transit Law to apply as the legal regime of a transit pipeline, there must be an international agreement regarding that pipeline. The Transit Law, the international agreement (generally an intergovernmental agreement (IGA)) and the project agreements apply as the legal regime to the transit pipeline.

In addition to ‘transit’ pipelines through Turkey (e.g., the BTC Pipeline and the contemplated TANAP\(^{49}\)), there are pipelines that transport oil or gas to or from Turkey. These are non-transit pipelines, such as the Kirkuk–Yumurtalık Crude Oil Pipeline. The legal regime applicable to these pipelines is either in the form of a Council of Ministers’ Decree (pursuant to the former Petroleum Law\(^{50}\) (PL)) or an IGA signed specifically for that pipeline.

There are currently two international crude oil pipelines in Turkey:
\(a\) the Baku–Tbilisi–Ceyhan (BTC) Crude Oil Pipeline, transporting crude oil from Azerbaijan to Ceyhan, Adana (transit); and
\(b\) the Kirkuk–Yumurtalık Crude Oil Pipeline, transporting crude oil from Iraq to Adana (import).

\(^{48}\) Entered into force on 14 April 2009.
\(^{49}\) The Trans-Anatolian Natural Gas Pipeline.
\(^{50}\) Entered into force on 16 March 1954.
Currently, the following pipelines exist for the import or export of natural gas:

- the Baku–Tbilisi–Erzurum Pipeline, transporting natural gas from Azerbaijan’s Shah Deniz gas field (Stage I) to Turkey (import);
- the Blue Stream Natural Gas Pipeline, transporting natural gas from Russia to Turkey through the Black Sea (import);
- the Interconnector Turkey–Greece, transporting natural gas between Turkey and Greece (export);
- Russia–Turkey Western Route Natural Gas Pipeline crossing Ukraine, Romania and Bulgaria to Turkey; (import); and
- Iran–Turkey Natural Gas Pipeline, transporting natural gas from Iran to Turkey (import).

The following contemplated projects will make Turkey a true oil and gas transport hub:

- TANAP, to transport natural gas from Azerbaijan’s Shah Deniz gas field (Stage II) to Europe, through Turkey. This pipeline is currently under construction;
- the Trans Adriatic Natural Gas Pipeline Project, to transport natural gas from Turkey to Southern Italy and further to Europe through Greece and Albania;
- the Trans Caspian Natural Gas Pipeline Project, to transport natural gas from Turkmenistan to Erzurum, Turkey and possibly to Europe;
- the Mashreq–EU Natural Gas Pipeline Project, to transport natural gas from the Mashreq countries to Turkey, Iraq and the EU;
- Turkey–Bulgaria Natural Gas Pipeline Project, to transport natural gas from Turkey to Bulgaria;
- the Northern Region of Iraq–Turkey Natural Gas Pipeline Project, to transport natural gas from the Northern Region of Iraq to Turkey; and
- the Turkish Stream Natural Gas Pipeline, which will replace the South Stream Project and transport gas from Russia across an offshore section under the Black Sea to Turkey and from there onto European markets. On 10 October 2016, Turkey and the Russian Federation signed an IGA for construction of the Turkish Stream pipeline. This pipeline is currently under construction.

V  RENEWABLE ENERGY AND CONSERVATION

i  Development of renewable energy

In recent years, investments in electricity generation from renewable energy sources have increased greatly. One of Turkey’s targets is to increase the share of electricity generated from renewable energy sources to 30 per cent by 2023. This is expected to entail the increase of wind-power installed capacity to 20,000MW, as well as the installation of new power plants, with 1,000MW of geothermal and 5,000MW of solar energy.

Incentive regime

The principles and procedures to be applied on the utilisation of renewable energy resources for the purpose of generating electrical energy are mainly governed by the Law on the

51 Under the IGA signed for the Interconnector Turkey–Greece, it is possible to use this pipeline for import as well. However, it is currently used only for export.
Utilisation of Renewable Energy Resources for the Purpose of Generating Electrical Energy\(^{52}\) (the RER Law). The renewable energy resources covered by the RER Law are wind, solar, geothermal, biomass, biogas (including landfill gas), wave, stream, tidal, river and arc-type hydroelectric generation facilities with a reservoir area of less than 15 kilometers. In January 2011, the RER Law underwent a significant set of amendments, upon which the feed-in tariffs and other incentives were introduced. With the amendments in January 2011, the RER Law established a renewable energy support mechanism (RERSM). This mechanism includes price, terms, procedures and principles regarding the payments to be made to individuals generating energy using renewable energy resources within the scope of the RER Law.

In order to achieve Turkey's 2023 target of increasing the share of renewable energy sources to 30 per cent, the EML and the RER Law were amended on 4 June 2016. In addition to these amendments, the Regulation on Certification and Supporting of Renewable Energy Resources (the RERSM Regulation) was also amended on 29 April 2016 (to become effective as of 1 May 2016). Before the amendments, power plants within the scope of the RERSM Regulation were subject to a system in which the generated energy was sold to the market operator without a generation limitation or a risk regarding the price or amount of energy generated. In addition, power plants were free of obligation regarding the balance mechanism. Therefore, they did not have to pay any imbalance expenses. The RER Law guaranteed the prices in terms of US cents, and access to loans were relatively easy due to predictable cash flows. Power plants operating under the RERSM portfolio system could sell all of their products to a market operator, and did not have to engage in any market activity. With the amendments in the RERSM Regulation, power plants within this regulation's scope may now sell the generated energy directly to the free market. In return for sales income, they will pay the RERSM income to the market operator, EPİAŞ.

The RER Law provides that the prices in Schedule I (see below) will apply for 10 years for those generation facilities subject to the RERSM and commissioned until 31 December 2020.\(^{53}\)

<table>
<thead>
<tr>
<th>Type of facility</th>
<th>Prices applicable (US$ cent/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydroelectric</td>
<td>7.3</td>
</tr>
<tr>
<td>Wind</td>
<td>7.3</td>
</tr>
<tr>
<td>Geothermal</td>
<td>10.5</td>
</tr>
<tr>
<td>Biomass (including landfill gas)</td>
<td>13.3</td>
</tr>
<tr>
<td>Solar power</td>
<td>13.3</td>
</tr>
</tbody>
</table>

The RER Law further provides that renewable energy facilities can, subject to a Council of Ministers' Decree, benefit from certain tax incentives, such as customs duty and VAT. Additional incentives are provided if domestic equipment is used in facilities commissioned before 31 December 2020.

\(^{52}\) Entered into force on 18 May 2005.

\(^{53}\) Although the initial date set in the RER Law was 31 December 2015, a Council of Ministers' Decree dated 18 November 2013 extended the incentive term until 31 December 2020.
ii Energy efficiency and conservation

Under the Energy Efficiency Law, the EECC regulates energy efficiency activities. This law sets forth several mandatory obligations. It also includes provisions regarding energy efficiency education and awareness.

The Energy Efficiency Law requires industrial entities to appoint an energy efficiency controller. These entities must inform the GDRE of their annual energy consumption. Furthermore, industrial businesses may (1) voluntarily submit projects that increase efficiency or (2) conclude agreements with the GDRE, undertaking to reduce their consumption levels by at least 10 per cent, in return for certain incentives.

iii Technological developments

Renewable energy is a developing sector in Turkey. Although Turkey has remarkable potential in terms of renewable energy resources, there is currently insufficient legislation encouraging technological developments in the renewable energy sector.

VI THE YEAR IN REVIEW

i Privatisations

Following the completion of the privatisation of all state-owned electricity distribution companies in 2013, Turkey has been focusing on the privatisation of generation assets. In recent years, Turkey privatised several electricity generation assets owned by EÜAŞ. Below is a summary of privatisations that have been completed by 1 April 2018:

<table>
<thead>
<tr>
<th>Power plant</th>
<th>Privatisation year</th>
<th>Approximate bid value (millions of Turkish liras)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Orhaneli and Tunçbilek TPP</td>
<td>2015</td>
<td>521</td>
</tr>
<tr>
<td>Soma B TPP</td>
<td>2015</td>
<td>685</td>
</tr>
<tr>
<td>Manavgat HPP</td>
<td>2016</td>
<td>370</td>
</tr>
<tr>
<td>Fethiye HPP</td>
<td>2016</td>
<td>128</td>
</tr>
<tr>
<td>Karacaören 1 and Karacaören 2 HPP</td>
<td>2016</td>
<td>515</td>
</tr>
<tr>
<td>Kadıncık 1 and Kadıncık 2 HPP</td>
<td>2016</td>
<td>864</td>
</tr>
<tr>
<td>Doğankent, Kürttin ve Torul HPP</td>
<td>2016</td>
<td>1,225</td>
</tr>
<tr>
<td>Sanlıurfa HPP</td>
<td>2017</td>
<td>247</td>
</tr>
<tr>
<td>Adıgüzel ve Kemer HPP</td>
<td>2017</td>
<td>341</td>
</tr>
<tr>
<td>Almus – Kölküce HPP</td>
<td>2017</td>
<td>750</td>
</tr>
<tr>
<td>Yenice HPP</td>
<td>2017</td>
<td>130</td>
</tr>
<tr>
<td>Suçatı, Değirmendere, Karaçay and Kuzuculu HPP</td>
<td>2017</td>
<td>30</td>
</tr>
<tr>
<td>Anamur, Bozyazı, Menderençay, Silifke and Zeyne HPP</td>
<td>2018</td>
<td>9</td>
</tr>
<tr>
<td>Menzelet-Kılavuzlu HPP</td>
<td>2018</td>
<td>1,276</td>
</tr>
</tbody>
</table>

55 The Energy Efficiency Coordination Committee.
56 e.g., the use of labelled equipment in industrial companies and buildings.
57 The General Directorate of Renewable Energy.
58 This Article only includes certain significant developments until 1 May 2017.
59 The state generation entity.
In addition to the privatisation of electricity generation assets, the tender for privatisation of İGDAŞ is also expected. Furthermore, on 28 December 2016, the Privatisation Administration approved the privatisation of TP Petrol Dağıtım AŞ, a petroleum distribution company, for 490 million liras.

**ii EPIAŞ**

The EML introduced the ‘market operation activity’, to be conducted by a newly incorporated company, namely EPIAŞ. EPIAŞ was incorporated on 12 March 2015 and obtained a market operation licence on 1 September 2015. EPIAŞ’s purpose is to lead the development of organised energy exchange markets in Turkey; to supervise and manage these energy exchange markets in an effective, transparent and reliable manner; to create added value to national economy by maximising the trading volume in the energy sector; and to provide a transparent and competitive environment for both domestic and foreign investors. TEİAŞ and Borsa İstanbul (BIST) each hold 30 per cent of the corporation’s total shares, with the remaining 40 per cent held by various major market participants, namely, private energy companies. Under this shareholding structure, TEİAŞ and BIST hold Class A and Class B shares, whereas private energy companies hold Class C shares. Upon its incorporation, EPIAŞ started conducting the market operation activities of organised wholesale electricity markets (including day-ahead market activities), other than those operated by the BIST stock exchange and TEİAŞ. TEİAŞ continues to conduct balancing activities.

**iii Pending projects**

The Akkuyu Nuclear Power Plant, in Mersin, is the first nuclear power plant in Turkey, and is not yet operational. The Akkuyu Nuclear Power Plant is planned to have four power units with capacity of 1,200MW each and a total capacity of 4,800MW. The EIAR of the project was approved by the MEU on 1 December 2014. The generation licence for the project is issued to be effective as of 15 June 2017 and the licence will be valid for 49 years. The Turkish Atomic Energy Authority issued the construction licence on 2 April 2018 and construction was started by a ceremony with the participation of Mr Recep Tayyip Erdoğan and Mr Vladimir Putin. It is expected that its first unit will be operational in 2023.

In May 2013, Turkey signed an IGA with Japan for the construction and operation of a nuclear power plant in Sinop. This US$20+ billion project will be constructed and operated by the consortium formed by Mitsubishi Heavy Industries, Itochu and GDF Suez. The discussions regarding the memorandum of understanding (MoU) between Turkey and Japan regarding the Sinop Nuclear Power Plant Project were concluded and the MoU was delivered to the Japanese Embassy for signature in August 2014. The IGA and the MoU (along with the draft HGA) were published in the Official Gazette on 10 April 2015 and became a part of Turkish legislation. The project participants recently started to conduct the feasibility studies on site for realisation of the Sinop NPP.

Following the success of the Baku–Tbilisi–Ceyhan Crude Oil Pipeline, Turkey became the obvious candidate for hosting pipelines transporting petroleum and natural gas from the

---

60 Istanbul’s natural gas distribution company.
62 Environmental impact assessment report.
63 The Ministry of Environment and Urbanisation.
Caspian to Europe. In line with this approach, Turkey and Azerbaijan signed an IGA for the construction and operation of the TANAP. Attached to the IGA is a HGA signed between Turkey and the TANAP project company. The Turkish government places great importance on this project, which will be the longest energy pipeline in the region at approximately 2,000km. On 24 July 2014, Turkey approved the EIAR prepared for the TANAP project. In September 2014, the Turkish Parliament approved:

a. the memorandum of understanding between the Republic of Turkey and the Republic of Azerbaijan regarding the TANAP system; and  
b. the text of amendment to the HGA between the Republic of Turkey and the TANAP project company.

The Council of Ministers’ Ratification Decrees for these two texts were published in the Official Gazette on 21 October 2014. The construction works started on 17 March 2015 with the ground laying ceremony, which was attended by Turkish, Azerbaijani and Georgian presidents.65

In January 2013, Turkey and the UAE signed an IGA for what was going to be the largest foreign direct investment in Turkey to date, with a value of approximately US$12–14 billion. The project entailed the construction and operation of a coal-based power plant,66 in Turkey’s Afşin-Elbistan region. The project was initially planned to start in mid-2013. However, because of other priorities, in August 2013, TAQA decided to defer its investment decision. After TAQA deferred its investment decision, companies from the State of Qatar, Japan, China and South Korea started to compete for this project.

iv  Shale gas

In recent years, along with the rising of the importance of shale gas in the world, importance has been given to searching for shale gas in Turkey. For this purpose, Sarıbuğday-1 in 2012, Konacik-1 in 2013, Aკçay-1 in 2014 and Çeşmekolu-1 and Çakıcı-1 wells in the Trakya Region in 2015 and 2016 respectively were opened in Southeastern Anatolia. Studies are under way to evaluate data obtained from the wells. Apart from the South-Eastern Anatolian region, it is also believed that there are significant amounts of available shale gas in the Hamitabat and Mezardere areas of the Thracian region, which have yet to be taken into the scope of the operating agreement, but which may be put on the agenda in the coming period.67

v  Solar and wind-based energy generation licence applications

Significant developments have also been witnessed in renewable energy investment since 2015. EMRA received applications for solar-based energy generation licences between 1 and 7 April 2015. Although the designated total capacity for solar-based generation licences is 600MW, applications were submitted for nearly 8,900MW. Thus, several contests will be organised in different regions to decide who will obtain the generation licence in the relevant region.

65 According to the final version of the shareholders agreement, signed in March 2015, while BOTAŞ holds 30 per cent stakes in the TANAP project company, BP holds 12 per cent. Southern Gas Corridor Closed Joint Stock Company holds the remaining stakes.  
66 With a capacity of up to 8,000MW.  
Below is a summary of the contests held in 2014 and 2015, and the respective regions:

<table>
<thead>
<tr>
<th>Packages</th>
<th>Date</th>
<th>Districts</th>
</tr>
</thead>
<tbody>
<tr>
<td>First package</td>
<td>12 May 2014</td>
<td>Elazığ</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Erzurum</td>
</tr>
<tr>
<td>Second package</td>
<td>29 January 2015</td>
<td>Siirt–Batman–Mardin</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Şanlıurfa–Diyarbakir</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Antalya</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Muğla–Aydın</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Denizli</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Burdur</td>
</tr>
<tr>
<td>Third package</td>
<td>30 January 2015</td>
<td>Konya 1</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Konya 2</td>
</tr>
<tr>
<td>Fourth package</td>
<td>28 April 2015</td>
<td>Adana–Osmaniye</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Sivas</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Kayseri</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Niğde–Nevşehir–Aksaray</td>
</tr>
<tr>
<td>Fifth package</td>
<td>29 April 2015</td>
<td>Kahraman-Maras–Adıyaman</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Malatya–Adıyaman</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Van–Ağrı</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Bitlis</td>
</tr>
<tr>
<td>Sixth package</td>
<td>30 April 2015</td>
<td>Karaman</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Mersin</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Isparta–Afyon</td>
</tr>
</tbody>
</table>

In addition, on 13 May 2017, the new Contest Regulation on Pre-Licence Applications Regarding Generation Facility Based on Solar and Wind Energy\(^{68}\) entered into force and superseded the old regulations. Under the new regulation, the contests will not be carried out on applicant’s contribution rate basis. Instead, the minimum offer over the prices indicated in the RER Law Schedule I will be considered. Under the Contest Regulation on Pre-Licence Applications Regarding Generation Facility Based on Solar and Wind Energy, the date and place of contests will be determined by TEİAŞ, in the event of multiple applications for a specific field.

Following enactment of the new regulation, the first contests were held for wind-based energy generation licences (for allocation of 710MWe capacity) on 21 and 22 June 2017 and the second contests were held (for allocation of 2,110MWe capacity) on 27 and 28 December 2017 in Istanbul.

---

\(^{68}\) Entered into force on 13 May 2017.
The TPL (PL)\(^\text{70}\) entered into force on 30 May 2013 and replaced the former Petroleum Law dated 1954. The new law divides Turkey into two petroleum districts, namely, onshore and offshore. It requires entities to obtain:

- a survey permit;
- an exploration licence; or
- an exploitation licence, depending on the type of upstream petroleum activity they wish to pursue.

The term of the exploration licence has been set at five years for onshore and eight years for offshore activities. The terms of these licences may be extended up to nine years for onshore and 14 years for offshore exploration licences. As for exploitation licence, this type of licence is granted for 20 years and it may be extended twice, each time for 10 years.

Petroleum right holders are allowed to export 35 per cent for onshore and 45 per cent for offshore of the crude oil or natural gas produced in the fields discovered after 1 January 1980. The remaining volume and the total of the crude oil and natural gas produced in the fields discovered before 1 January 1980 must be reserved for the needs of the state. Furthermore, the TPL states that a state share corresponding to 12.5 per cent of the petroleum produced by exploration or exploitation must be paid to the state.

**VII CONCLUSIONS AND OUTLOOK**

Considering economic expansion, rising per capita income, positive demographic trends and the rapid pace of urbanisation that are the main drivers of Turkey's growing energy demand, Turkey's energy demand is estimated to increase by approximately 6 per cent each year. 

---

\(^{69}\) Although these enactments took place in 2013, we will provide brief information on them in this chapter because of their importance.

\(^{70}\) The long-awaited TPL was enacted in 2013, replacing the PL after nearly 60 years.

\(^{71}\) Entered into force on 21 November 2007.

\(^{72}\) Entered into force on 31 March 2017.

\(^{73}\) Entered into force on 8 April 2017.

\(^{74}\) Entered into force on 5 April 2017.
year until 2023. Because of this increase in energy demand, the Turkish energy market has been experiencing vast changes. These changes include liberalisation, attracting private sector participation and the establishment of a competitive market.

Turkey’s long-term energy policies and strategies will keep Turkey’s focus on diversifying its energy resources. At present, domestic resources provide approximately 26 per cent of the total energy demand, the remainder being imported. Turkey’s costs for importing crude oil and natural gas are currently as high as US$56 billion. This accounts for more than half of the country’s foreign trade deficit. Because of insufficient domestic energy generation, Turkey’s primary goal is to strengthen its security of supply. Turkey aims to diversify its energy supply routes and sources, such as nuclear energy, and to increase the share of renewable energy.

Turkey’s importance in the energy markets is not just increasing as a growing consumer with a huge domestic market, but also as an energy transit hub. Although Turkey has limited energy resources, its position is critical for petroleum and natural gas trade between the East and the West, as it lies between energy-demanding European countries and energy-rich eastern countries. Turkey is a natural transit country for the maritime and pipeline transportation of gas and oil. Accordingly, international crude oil and natural gas pipelines and pipeline projects hold great importance and improve Turkey’s role as a reliable transit country.
I OVERVIEW

The United Arab Emirates (UAE) is a federation of the seven emirates of Abu Dhabi, Dubai, Sharjah, Ajman, Fujairah, Ras Al Khaimah and Umm al-Quwain. The city of Abu Dhabi in the emirate of Abu Dhabi is the federal capital. Abu Dhabi is the largest emirate by area (making up about 86 per cent of the country’s area) and the richest in terms of oil resources. Dubai is the second-largest emirate by size (accounting for about 5 per cent of the country’s total area) and the largest by population. Together, Dubai and Abu Dhabi account for about two-thirds of the country’s population and form the core of its economy.

The UAE’s economy has traditionally been dominated by the petroleum industry but successful efforts at economic diversification have reduced the share of the oil and gas sector in the country’s GDP to 25 per cent. The UAE has an open economy with one of the highest per capita incomes in the world and a sizeable annual trade surplus. The currency is freely convertible and funds can be freely repatriated. The country’s free zones – offering 100 per cent foreign ownership and zero taxes – are a major conduit for foreign investment in the country. The geographical location of the UAE, situated at the tip of the Arabian Peninsula, makes it a central trading post connecting the Far Eastern economies with the Middle East, Africa and Europe. With modern communication and thriving ports, the UAE has emerged as an important trading hub between the Indian sub-continent, Europe, Africa and the Middle East.

The powers of the federal and the emirate governments are enumerated in the State Constitution of 1971. Although the country’s government is based on a federal structure, the individual emirates enjoy considerable economic and political autonomy and each emirate largely pursues its own economic policies. Even though Article 120 of the UAE Constitution gives the federal government exclusive legislative and executive jurisdiction over electricity services in the country, in practice the larger emirates of Dubai and Abu Dhabi, to some extent Sharjah, and more recently the northern emirate of Ras Al Khaimah, formulate and implement their own electricity policies. Hence, although there is a Federal Ministry of Energy (which formulates and implements the federal electricity policies), federal legislation on electricity is fairly limited.

Because of the significance of Abu Dhabi and Dubai within the Federation, this chapter focuses primarily on the electricity sector in these two emirates, in addition to the federal laws and policies on electricity.
The generation, transmission and distribution of electricity in the UAE is dominated by four water and power authorities. Three of these authorities are owned by the governments of the emirates of Dubai, Abu Dhabi, and Sharjah, whereas the authority that operates in the smaller northern emirates is federally controlled. These state-owned authorities serve as the exclusive purchasers and distributors of electricity in the respective emirates. While the private sector has been allowed to participate in the generation of electricity, transmission and distribution is performed exclusively by state-owned authorities.

Abu Dhabi and Dubai currently have the most active private sector participation in the energy sector. In line with extant regulations, private participants can own up to 40 per cent economic interest in electricity generation plants in Abu Dhabi and up to 49 per cent in Dubai. There has been speculation regarding the introduction of a privatisation policy by the federal government for the northern emirates; however, no formal announcement has been made so far.

Currently, only Dubai and Abu Dhabi have enacted laws creating specialised regulatory bodies for the electricity sector. These consist of the Dubai Supreme Council of Energy (DSCE), the Dubai Regulation and Supervision Bureau (the RSB Dubai) and the Regulation and Supervision Bureau of Abu Dhabi (the RSB). The Federal Ministry of Energy & Industry (Ministry of Energy) regulates the sector at the federal level and works in conjunction with the Federal Electricity and Water Authority (FEWA) to implement the federal government’s electricity policy in the northern emirates.

Increasing population growth and urban development has been responsible for electricity demand in the UAE to grow at double-digit rates, and demand is expected to continue to grow at about 10 per cent annually for the next decade because of increasing population growth and industrial development. There is currently insufficient power generation capacity in the northern emirates of the UAE, and demand in these emirates is being met by construction of additional capacity as well as the supply of power from the larger emirates through the Emirates National Grid (ENG). Some industrial projects have not been able to secure sufficient power supply and have had to resort to captive power generation.

A number of major power projects, both in the field of conventional and renewable energy, are under development to meet the country’s existing and future electricity needs.

II REGULATION

i The regulators

Federal

The Ministry of Energy, the primary regulator at the federal level, was formed pursuant to Federal Decree No. 3 of 2004 by merging the Ministry of Petroleum and Mineral Resources with the Ministry of Electricity and Water. In 2008, the Ministry of Energy was restructured pursuant to Cabinet Resolution No. 11 of 2008 making it responsible for establishing policies for the water and electricity sectors in the UAE and ensuring that other authorities and companies in the state comply with its policies. A separate directorate for the electricity sector was established within the Ministry of Energy, called the ‘Department of Electricity and Desalinated Water’.
In 2014, the federal government further restructured the Ministry of Energy to introduce three new departments:

- the Clean Energy and Climate Change Department;
- the Rationalisation and Energy Usage Efficiency Department; and
- the Regulation and Control Department.

The restructuring was intended to create a more specialised and robust central regulatory authority at the federal level. However, the Ministry of Energy has had little influence in directing policy and implementing projects in the larger emirates of Abu Dhabi and Dubai and remains focused on assisting the smaller emirates in meeting their growing electricity demand.

FEWA, which was established pursuant to Federal Law No. 31 of 1999 (amended by Federal Law No. 9 of 2008) (the FEWA Law), is the dominant player in the northern emirates and engages in all segments of the market, including generation, transmission and distribution. The Ministry of Energy has announced a strategic energy plan to develop the federal government’s electricity services by attracting private investment in the sector.

**Abu Dhabi**

Until recently, Abu Dhabi’s electricity sector was regulated under Law No. 2 of 1998 Concerning the Regulation of Water and Electricity Sector, as amended by Law No. 19 of 2007 and Law No. 12 of 2009 (Abu Dhabi Electricity Law). The RSB has been responsible for implementing the legal framework and its authority includes the power to:

- issue licences to conduct regulated activities;
- monitor licensees and ensure compliance with terms of licences issued; and
- make regulations as it sees fit for the regular, efficient and safe supply of electricity in the emirate.

The Abu Dhabi Water and Electricity Authority (ADWEA) owns (either wholly or as majority shareholder) and controls, either directly or indirectly, the entities responsible for the generation, transmission and distribution of electricity in the emirate. Both RSB and ADWEA were established under the Abu Dhabi Electricity Law.

Pursuant to Federal Law No. 11 of 2018 (issued by the Ruler of Abu Dhabi in February 2018) (the DOE Law), ADWEA and RSB seem to have been replaced with a newly established Department of Energy (DOE). From publicly available information, it appears as though all the employees, assets and liabilities of ADWEA and RSB have been transferred to the DOE and that DOE is henceforth expected to be responsible for carrying out all the functions that were previously being carried out by ADWEA and RSB. However, the DOE Law has not yet been gazetted and is not available in the public domain (including in its draft form), and therefore it is unclear how the transition between the roles of ADWEA, RSB and DOE is envisaged, and the implications thereof.

**Dubai**

Dubai’s legislation on the electricity sector was historically limited to Dubai Law No. 1 of 1992 (the DEWA Law), as amended by Decree No. 13 of 1999 and Decree No. 9 of 2011,
establishing the Dubai Electricity and Water Authority (DEWA). Dubai has since enacted a number of laws to modernise and open the sector to private investment. Two new regulatory bodies have been created: the DSCE,\(^3\) established under Dubai Law No. 19 of 2009 (DSCE Law), as the apex regulator for the energy sector, and RSB Dubai, established pursuant to Dubai Executive Council’s Resolution No. 2 of 2010, as the specialist regulatory authority for the electricity sector.

As the primary regulator of the energy sector, the DSCE regulates the exploration, production, storage, transmission and distribution of petroleum products (natural gas, liquid petroleum, petroleum gases, crude oil) and electricity. It ensures that the energy and electricity sources satisfy the current and future demands of the emirate of Dubai at affordable prices. The DSCE also proposes any and all initiatives related to the energy sector, which includes the privatisation of its electricity assets and implementing the provisions of Dubai’s Law No. 6 of 2011 Regulating the Participation of the Private Sector in Electricity and Water Production in the Emirate of Dubai (the Dubai Electricity Privatisation Law).

RSB Dubai is authorised to regulate the electricity sector subject to the supervision of the DSCE. RSB Dubai is mainly responsible for regulating, licensing and supervising the electricity generating service providers, facilities and properties. It also determines and establishes standards and controls for electricity generation in the emirate and proposes legislation governing the electricity sector in Dubai.

As with the other emirates, the main player in the electricity market is DEWA, Dubai’s state-owned integrated power generation, transmission and distribution authority.

**Sharjah**

Sharjah created its own electricity authority in 1995, known as SEWA (established pursuant to Sharjah Emiri Decree No. 1 of 1995, as amended by Emiri Decrees No. 2 of 2000, No. 46 of 2006 and No. 20 of 2008), which is authorised to ‘own, manage, operate and maintain’ power stations and electricity transmission lines. As with the other emirates, SEWA is responsible for the generation, transmission and distribution of electricity in Sharjah. SEWA is authorised to determine electricity prices and connection fees, which are subject to approval by the Ruler of Sharjah.

**Northern emirates**

FEWA is responsible for the generation, transmission and distribution of electricity in the northern emirates of Ajman, Ras Al Khaimah, Fujairah and Umm al-Quwain.

**Ras Al Khaimah**

On 10 March 2013, the Ruler of Ras Al Khaimah issued an Emiri Decree No. 4 of 2013 on the Establishment of the Ras Al Khaimah Electricity and Water Authority (RAKEWA) (the RAKEWA Law). This authority is tasked with the regulation, management, operation and maintenance of power stations, water desalination plants, electricity distribution and transport networks in the emirate. The new authority is also responsible for controlling prices of electricity and water in the emirate. Most importantly, the authority is responsible

---

3 Member organisations of the DSCE are DEWA, Dubai Aluminium Company Ltd, Emirates National Oil Company, Dubai Supply Authority, Dubai Petroleum Establishment, Dubai Nuclear Energy Committee, Dubai Municipality, Department of Petroleum Affairs and the Road and Transport Authority.
for fulfilling the electricity needs of the emirate, planning for the generation, transport and
distribution of electricity in the emirate and managing the government’s investments in the
sector.

RAKEWA is to be managed by a board appointed by the Ruler of Ras Al Khaimah,
to be headed by a chairman. The board is authorised to issue regulations relating to the
electricity sector, which shall be binding on all entities involved in the electricity and water
sectors in the emirate.

Despite the establishment of RAKEWA, FEWA continues to own, manage and operate
the electricity resources situated in the emirate and is the de facto authority on ground. The
RAKEWA Law does not contain any provisions for the transfer of assets from FEWA
to RAKEWA and it is presently unclear whether RAKEWA will replace FEWA in Ras Al
Khaimah or if the two authorities will operate jointly in the emirate.

ii Regulated activities

All activities connected to the generation, transmission and distribution of electricity in the
UAE are regulated and require specific licences from the relevant regulatory authorities.

Under the Abu Dhabi Electricity Law, regulated activities include electricity generation,
transmission, distribution and supply to premises. Any person or entity intending to carry
out these activities is required to be licensed by the RSB Dubai.

Under the Dubai Electricity Privatisation Law, regulated activities include ‘any activity
related to generating electricity . . . for the purpose of supplying to the Transmission System
with produced electricity’ (the transmission system is owned and operated by DEWA). All
activities relating to electricity generation, transmission, distribution and supply of electricity
are considered regulated activities in Dubai and require a licence from RSB Dubai.

iii Ownership and market access restrictions

As indicated earlier, Abu Dhabi has allowed private sector participation of up to 40 per cent
in its power generation sector. In furtherance of its legislative policies in this regard, in
2015 Dubai awarded 49 per cent of the ownership of phase 1 of Hassyan, a 2,400MW
clean coal power plant, to a consortium led by Harbin Electric International and ACWA
Power (Hassyan Clean Coal Project). At the federal level, while FEWA has since recently
been inviting bids from private entities, private sector participation has yet to gather speed
in the northern emirates. UTICO (a private sector utility company engaged in electricity
generation, transmission and distribution) in Ras Al Khaimah and Emirates Sembcorp Water
& Power Co – ESC (a joint venture between ADWEA and a private sector entity, operating
a hybrid desalination and power plant by the name of Fujairah F1 Independent Water and
Power Plant) in Fujairah are a few examples of private sector partnerships in the northern
emirates.

Under Federal Law No. 2 of 2015 on Commercial Companies (the Companies Law), foreigners are permitted to own up to a maximum of 49 per cent of a UAE company (other than in the free zones) and the majority 51 per cent is required to be owned by UAE nationals. The

4 Federal Law No. 2 of 2015 on Commercial Companies abrogated Federal Law No. 8 of 1984 (as amended).
power sector is no exception to this requirement and even if 100 per cent private ownership were to be allowed in the power sector, a privately owned power generation, transmission or distribution company would need to be majority locally owned.

Although this restriction is a deterrent to foreign investment, it is not an insurmountable hurdle as informal arrangements exist to enable the foreign investor to transfer 100 per cent beneficial interest in local companies to themselves. It is common for foreign investors to enter into side agreements with the local majority-owning partners by virtue of which the foreign shareholders assume management powers and at the same time transfer to themselves the economic interest in the shares held by the local. The local shareholder is usually paid a fixed fee as part of this arrangement for acting as a local sponsor. The authorities in the UAE have so far tolerated this practice, and as long as there is no dispute between the parties, the arrangement works to the benefit of all shareholders. The enforceability of these side agreements is questionable and untested in the local courts. Although the local partner could, in theory, take over the business by revoking the side agreements, the arrangement works well in the vast majority of cases and offers a practical way forward for foreign investors wishing to do business in the UAE.

Although the UAE free zones allow for 100 per cent foreign ownership, the free zone companies are not allowed to conduct business outside the free zones and within onshore UAE. To date, there are no power generation, transmission or distribution companies in any of the free zones in the UAE. Electricity rates are subsidised throughout the UAE and it is therefore not viable for private producers to construct power plants within the free zones. Furthermore, the state-owned authorities in the emirates of Dubai and Abu Dhabi have sufficient capacity to meet present and anticipated future needs, and this has therefore not necessitated private investment in the sector in the free zones.

The UAE’s electricity laws themselves do not impose any specific ownership restriction on foreign investors in the UAE, nor do they necessarily require government participation in the sector. As a matter of policy, in Abu Dhabi, although two or more foreign joint venture partners are permitted to own up to 40 per cent of a project company, the RSB ensures that a foreign entity does not own more than 25 per cent of the market by capacity.

Most power companies in the UAE (with some exceptions such as UTICO) are either wholly or majority owned by the federal or respective emirates’ governments, and the sector is dominated by the state-owned water and electricity authorities. Of these, the DEWA and ADWEA, being the largest two, account for about 95.4 per cent of the UAE’s gross generated electricity. As of the figures available for 2016, ADWEA accounts for approximately 62.1 per cent of the UAE’s gross generated electricity (at 80,527 GWh), DEWA for 33.3 per cent (at 43,092 GWh), Sharjah Electricity and Water Authority (SEWA) for 4.4 per cent (at 5,684 GWh) and FEWA for about 0.2 per cent (at 293 GWh).

**Abu Dhabi**

ADWEA was established pursuant to the Abu Dhabi Electricity Law, and is responsible for all matters relating to formulation, development and implementation of policies for the electricity sector in Abu Dhabi, including privatisation. As mentioned previously, pursuant to the DOE Law, ADWEA and RSB seem to have been replaced by the DOE but the shift of roles and authority between these three entities is still not clear.

---

5. ADPC has the following subsidiaries: Abu Dhabi Water and Electricity Company; Abu Dhabi Transmission and Dispatch Company; Al Mirfa Power Company; Abu Dhabi Distribution Company; and
ADWEA wholly owns the Abu Dhabi Water and Electricity Company (ADWEC), the single buyer of water and electricity in Abu Dhabi, and Abu Dhabi Transmission and Dispatch Company (TRANSCO), the main transmission company in the emirate. To date, a number of independent water and power producers (IWPPs) have been established as joint-venture arrangements between ADWEA and various international power companies as BOO (build, operate, own) projects, which include:

*a* Arabian Power Company;

*b* Emirates CMS Power Company;

*c* Emirates SembCorp Water and Power Company;

*d* Fujairah Asia Power Company;

*e* Gulf Total Tractebel Power Company;

*f* Ruwais Power Company;  

*6* Shuweihat Asia Power Company PJSC;  

*7* Shuweihat CMS International Power Company;  

*T* Taweelah Asia Power Company; and

*m* Mirfa International Power & Water Company.

The ownership of the IWPPs is split 60:40 between ADWEA (or its subsidiaries) and the foreign investor. The project companies are usually structured as joint stock companies incorporated in Abu Dhabi. The most common ownership structure is one in which ADWEA incorporates an intermediate holding company to own a 60 per cent stake, which is in turn held 10 per cent by ADWEA and 90 per cent by the Abu Dhabi National Energy Company PJSC (also known as TAQA).  

Earlier this year, ADWEA invited private sector entities to submit expressions of interest to participate in a US$1.2 billion water desalination plant in Abu Dhabi, with operations anticipated to commence in October 2021.  

The project will be built in the Al Taweelah Power Complex, 45 kilometres north of Abu Dhabi, and produce 200 million gallons of water per day using reverse osmosis technology.
**Dubai**

DEWA was established as an independent public authority owned by the government of Dubai, responsible for the development and provision of utilities in the emirate. DEWA is managed by a board of directors whose members are appointed by Emiri decree.

DEWA is an integrated supplier owning and operating in all segments of the electricity market in Dubai. DEWA owns and operates 12 plants in the emirate whose individual capacities vary between 400MW to 2,200MW, with a total installed capacity of 10,000MW. Although the Dubai government wants to promote private investment in its electricity generation sector, to date, all of the power generation capacity of Dubai, except for captive power produced by certain entities (e.g., Dubai Aluminium Company Ltd), is owned by DEWA.

In 2011 Dubai passed the Dubai Electricity Privatisation Law, which is broadly modelled on the Abu Dhabi Electricity Law. The Dubai Electricity Privatisation Law authorises DEWA to establish project companies, by itself or in collaboration with third parties, for the generation of electricity. In 2015, Dubai Law No. 22 of 2015 on Regulating Partnership between Public and Private Sectors in Dubai (the Dubai PPP Law) was enacted, which governs the regulatory framework of public–private partnerships in Dubai. The Dubai PPP Law aims to encourage private sector participation in the development of projects. It sets out, *inter alia*, the terms of partnerships between the public and private sector and conditions for approval of prospective projects.

To date, several independent power projects (IPPs) have been launched in Dubai. The first IPP is Al Hassyan 1 IPP, a 1,500MW gas-fired power plant, for which bids were solicited in December 2011. The project has, however, been deferred indefinitely.

In 2015, a consortium of ACWA Power and TSK Electronica y Electricidad SA won the bid to set up a 200MW photovoltaic plant (Shuaa Solar PV Project) in the second phase of the Mohammed bin Rashid Al Maktoum Solar Park10 (Solar Park) on the IPP model. The project has been operational since April 2017.

Subsequently, the Hassyan Clean Coal Project was launched by DEWA and the consortium of ACWA Power and Harbin Electric was awarded the project.11 In 2016, the major engineering procurement and construction contract for the Hassyan Clean Energy Project was awarded to Harbin Electric International and General Electric. The project is proposed to be operational by 2023.

Another development in 2016 was the selection of the consortium led by the Abu Dhabi Future Energy Company (Masdar), including the Spanish companies FRV (Fotowatio Renewable Ventures) and Gransolar Group for construction of the 800MW third phase of the Solar Park on the IPP model. The first phase of the project (200MW) is expected to be operational in the first half of 2018, followed by the second phase (300 MW) in 2019, and the third phase (300MW) in the first half of 2020.

10 The special purpose vehicle set up to establish the project is Company Shuaa Energy 1, in which DEWA is a 51 per cent stakeholder and the remaining 49 per cent is held by the consortium of ACWA and TSK.

11 The special purpose vehicle set up to establish the project is Hassyan Energy Phase 1 PSC, in which DEWA is a 51 per cent stakeholder and the remaining 49 per cent is held by the consortium of ACWA and Harbin.
As the fourth phase of the Solar Park, DEWA released an expression of interest in October 2016 to build the largest concentrated solar power project in the world of 700MW (CSP), based on the IPP model. The project has been awarded to ACWA Power and Shanghai Electric and is proposed to be commissioned in stages, starting from Q4 of 2020.

In addition to the above, Mohd Abdulla Haji Yousuf Khoory & Co LLC (trading as Union Paper Mills) was granted an electricity generation licence in November, 2016 in relation to a 3MW biomass boilers' facility at Al Quoz, Dubai.

In March 2017, Al Ghurair Resources Oils & Proteins LLC was granted a licence by RSB Dubai to generate electricity from an up to 8MW coal plant in Jebel Ali.

**Northern emirates**

FEWA is authorised under the FEWA Law to establish private power generation plants in the northern emirates. A number of projects are presently under development in these emirates but these are primarily owned in the public sector.

FEWA acts as the single point of sale for all power generated in the northern emirates. Electricity transmission and distribution networks within the northern emirates are also primarily owned and operated by FEWA. However, recently, TRANSCO has expanded its operations to assist FEWA in planning, developing and operating its water and electricity transmission assets in the northern emirates. In addition to FEWA, certain private power companies such as UTICO are involved in the generation, transmission and distribution of power in the emirate of Ras Al Khaimah.

In September 2017, FEWA invited expressions of interest from potential developers for the development of a 1.8GW coal-fired power plant in Umm al-Quwain or Ras Al Khaimah on the PPP model. The project has not yet been awarded to any bidder.

**iv Transfers of control and assignments**

Any transfer of control or assignment of an interest in an IWPP requires the consent of the relevant regulator.

Under the Abu Dhabi Electricity Law, a licence may not be transferred unless it specifically permits its transfer. Prior consent of RSB is required for any transfer (including the creation of security over assets of the licence holder), and the consent may be subject to such conditions as the RSB may consider appropriate.

Under the Dubai Electricity Privatisation Law, licensed entities are not permitted to transfer or assign their licences without the prior approval of RSB Dubai. In addition, licensed entities may not dispose-off, sell, lease or otherwise transfer, including granting of a security interest over, their 'main assets' without prior approval from RSB Dubai. Main assets are those movable and immovable assets necessary to conduct the regulated activities and operate the electricity generation facilities.

In addition, the Companies Law contains a statutory pre-emptive right in favour of existing shareholders in the case of limited liability companies and joint stock companies.
III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

The electricity transmission and distribution networks in the UAE are firmly owned and controlled by the state-owned water and power authorities, each of which enjoys a monopoly in its particular area of operation. These authorities are vertically integrated and operate in all three segments of the market.

Abu Dhabi

ADWEA’s wholly owned subsidiary TRANSCO operates Abu Dhabi’s transmission networks. TRANSCO supplies electricity from the generation companies to the two distribution companies of Abu Dhabi, each of which is also wholly owned by ADWEA. These are:

a Abu Dhabi Distribution Company (ADDC), which operates in the city of Abu Dhabi and the western region of the emirate; and

b Al Ain Distribution Company (AADC), which operates in Al Ain city and the surrounding areas.

In response to the power shortages faced in the northern emirates, TRANSCO has become involved in the planning, development and operation of electricity transmission networks in the northern region. TRANSCO’s involvement, given its resources and experience, coupled with ADEWA’s supply of its excess power, has largely alleviated the power problems faced by these emirates in the past.

Dubai

DEWA is the sole purchaser of electricity in Dubai and presently owns all the generation, transmission and distribution capacity of the emirate.\(^ \text{12} \) DEWA’s transmission and distribution network is constantly being expanded as new real estate and industrial projects are set up across Dubai.

Over the past few years, DEWA has further enhanced the electricity transmission networks of the emirate. This includes construction of substations at Jebel Ali (December 2012), the International Media Production zone (February 2013), the Dubai Marina (May 2013), Seih Al Dahl (February 2014) and Dubai Academic City (2016). As of 2016, DEWA had 21 400kV substations, 222 132kV substations, 111 33kV substations and 31,961 11kV and 6.6kV substations. In February 2017, DEWA announced its plans to build 97 new 132/11kV substations over the next three years to be located at the Solar Park, and other locations to support the expansion of other power plants in Jebel Ali and Al Aweer. This was followed by an announcement by DEWA in April 2017 of its plans to build three new 400kV substations over the next three years. DEWA is also currently building three new 132/11kV substations with 45 kilometres of high voltage (132kV) cables for the World Expo 2020. The substations are named Sustainability, Mobility and Opportunity after the three subthemes of the Expo. The first of these substations (named Mobility) was commissioned in January 2018.

\(^ {12} \) As of 2016, DEWA operates a network of overhead lines (1,125 kilometres of 400kV, 413 kilometres of 132kV and 113 kilometres of 33kV lines) and underground cables (23 kilometres of 400kV, 1800 of 132 kV, 2,052 kilometres of 33kV and 29,384 kilometres of 6.6 and 11kV lines) that are, in turn, connected to a distribution system of lower voltage substations and distribution lines.
**Sharjah**

SEWA is the sole purchaser of electricity in Sharjah and presently owns all the generation, transmission and distribution capacity of the emirate.

Because of the increased demands in electricity and energy, SEWA has recently embarked on improving and expanding its electricity transmission and distribution network on a large scale. SEWA has commissioned and inaugurated the Al Khan power transmission and distribution station (worth 105 million dirhams) in 2016, to ensure the reliability of power supply throughout areas such as Al Khan, Al Nahda and Al Taawun in Sharjah and has announced its plans of building three 132kv and five 33kv distribution stations in 2017.

**Northern emirates**

FEWA performs many of the same functions in the northern emirates with respect to electricity distribution and transmission as TRANSCO in Abu Dhabi and DEWA in Dubai. The northern emirates have been suffering insufficient power and electricity generation. For this reason and because of increased demand for electricity, FEWA has announced a number of new projects to expand and improve its electricity network. The notable projects\(^\text{13}\) are as follows:

- In May 2013, FEWA signed two contracts with the Saudi National Contracting Company Limited to commission a 33/11kV transmission station and upgrade a number of 33/11kV and 132/33/11kV stations in the western region (Ajman and Umm Al Quwain), the central and eastern region (Fujairah and Dibba) and the northern region (Ras Al Khaimah);

- In 2016, FEWA inaugurated Al Hamra substation in Umm al-Quwain and plans future expansion of the same. In the same year, FEWA signed a memorandum of understanding with Siemens for the construction of a 2.2GW plant in the northern emirates to enhance electricity generation and distribution and another memorandum of understanding with Mitsubishi Electric for the installation of a number of 132/33/11KV substations in the northern emirates; and

- In October 2017, FEWA invited bids from the private sector for the construction of a 132/33/11kV substation and cable works to be positioned in the Northern Emirates.

**Emirates National Grid**

The ENG project was launched in 2001 under a Cabinet Resolution No. 79/4 of 2001 ‘On the National Project of Linking the Power Grids’ to connect and enable sharing of power between the UAE’s seven emirates. The ENG project was launched by the Ministry of Energy with the purpose of enhancing integration between the various electricity and water authorities in the UAE, each of which contributed proportionately to the capital investment required to build the ENG. The ENG is owned by the following authorities in the proportions stated below:

- ADWEA: 40 per cent;
- DEWA: 30 per cent;

---

\(^{13}\) Other plans include: building four new power stations, expanding the current electricity network, building 25 new power plants, expanding 17 power plants and completing 23 power stations within 2016. It is expected that at least five power plants will be built in Umm al-Quwain, 10 in Ras Al Khaimah and five in Fujairah.
c FEWA: 20 per cent; and

d SEWA: 10 per cent.

Dubai and Abu Dhabi’s power grids were connected by the ENG in the middle of 2006, whereas SEWA’s connection to ENG was completed in May 2007. Connection to the remaining northern emirates transmission networks was completed in April 2008.

On account of its larger production capacity and extensive distribution network, ADWEA has increasingly been assisting the other emirates in meeting their power demand. ADWEA exported about 13,664GWh of electricity to other emirates via the ENG in 2012, up from 12,228GWh in 2011. Renewable energy sources such as solar and nuclear power will increasingly contribute to the ENG. Currently, the solar power is transmitted to the ENG from Shams 1 solar power plant and plans are under way for nuclear energy and further solar power to be transmitted from the Barakah nuclear energy power plant and photovoltaic panels respectively.

**The Gulf Cooperation Council (GCC) Grid**

The UAE is also connected to the rest of the GCC through the GCC Grid, through which it can trade electricity with the remaining GCC countries. About 56MW (peak time) of electricity was exported by Abu Dhabi to the GCC Grid in 2011 whereas 7MW (peak time) was imported in 2012. Ideas have been put forward to expand power grids to Egypt and European networks (through Turkey) and trade energy beyond the GCC region.

**ii Transmission/transportation and distribution access**

**Abu Dhabi**

The Abu Dhabi Electricity Law requires ADWEC to purchase all power produced within the emirate. Although the Abu Dhabi Electricity Law contemplates private ownership in all segments of the electricity supply chain, so far private ownership has been limited to generation only.

**Dubai**

The Dubai Electricity Privatisation Law prohibits a licensed entity from selling electricity to any entity other than DEWA.

**iii Rates**

**Abu Dhabi**

ADWEC, being the single buyer of electricity in the emirate of Abu Dhabi, purchases electricity from the power producers under long-term power and water purchase agreements (PWPAs) and sells it to the distribution companies via annual bulk supply tariff (BST) agreements. The distribution companies pay ADWEC the BST for the electricity purchased and receive revenue from their customers and a subsidy from the government. TRANSCO is paid a transmission use of system (TUoS) charge by the distribution companies.

The components making up the electricity tariff in Abu Dhabi are the following:

a BST, which is the charge paid by the distribution companies to ADWEC for its generation costs (in turn paid by ADWEC to power producers).

b TUoS, which is the charge paid by the distribution companies to TRANSCO for use of its transmission network.
c Distribution use of system, which is the fee that the distribution companies charge for use of their distribution network.

d Sales cost, or the cost incurred by the distribution companies for serving customers for meter reading and billing.

e Government subsidy, consisting of direct payments from the government to the distribution companies. The quantum of the subsidy allows the government to determine the electricity tariffs for different classes of consumers. The higher the subsidy, the lower the tariff charged.

The electricity tariff is determined by adding components (a) to (d) and subtracting (e).

The rates charged by the state-owned power companies (ADWEC, TRANSCO, ADDC and AADC) are subject to government control, exercised via the RSB. The RSB sets their revenue target on the basis of which the control prices are determined. The remainder of the revenue is paid as a subsidy by the government to the distribution companies. All transactions between the power sector companies and any related tariffs are required to take place on the basis of their economic costs. This helps the government keep subsidies to a minimum.

The BST is calculated for each calendar year on the basis of parameters prescribed by the RSB. The calculation of BST requires the estimation of the costs for procuring and dispatching electricity generation to meet the forecasted demand. Starting 2012, the structure of the BST comprises three components (expressed in fils per kWh) charged on an hourly basis for electricity purchased at different times of the day, for ‘Fridays’ and ‘non-Fridays’ and in different months of the calendar year. These three components are:

a a system marginal price charge estimated to indicate the short-term marginal costs (excluding backup fuel (BUF) costs) of providing units at different times of the day;

b a BUF levy charge estimated to reflect the additional costs associated with the burning of backup fuel rather than primary fuel; and

c a high-peak period charge assessed to cover the costs associated with the estimated capacity payments and charged only in the peak demand occurring months of June to September, inclusive.

The TUoS charge paid to TRANSCO covers the investment, operation and maintenance costs of the infrastructure of the transmission systems, excluding assets that are dedicated entirely to a particular customer. These include substations, overhead lines, cables and associated equipment. TUoS charges also cover the costs of the economic scheduling and dispatching of electricity generation.

The rates payable to the power generation companies are determined on the basis of the PWPAs entered by them with ADWEC. These PWPAs are further discussed below.

Contracts for power generation are awarded based on a competitive bidding process after the government invites tenders to meet the emirate’s power generation requirements. The bidding process is managed by ADWEA starting from pre-qualification of bidders and issuance of request for proposals through to selection of the successful bidder.

Electricity rates paid by consumers in Abu Dhabi are subsidised. In fact, UAE nationals benefit from even greater subsidies than those given to expatriate workers. The rates payable in Abu Dhabi were substantially revised in 2015 with the introduction of a slab tariff scheme and an increase of 40–60 per cent in the applicable rates. The rates as published by the RSB on its website for 2018 are divided according to consumer categories as follows:

a UAE nationals (flats): 6.7 fils per kWh until 30kWh/day, 7.5 fils post 30kWh/day;
With effect from 1 January 2018, VAT at the rate of 5 per cent has been implemented in the UAE pursuant to Federal Law No. 8 of 2017 (the VAT Law). Under the VAT Law, the 5 per cent VAT is payable by consumers on their electricity and water consumption. However, VAT is not applicable in respect of the municipality fee levied by the power companies in the respective emirates.

**Dubai**

The DEWA Law empowers the board of directors of DEWA to control electricity prices charged by DEWA, subject to the Ruler’s approval; however, since the promulgation of the DSCE Law, the electricity prices have been determined by the DSCE and DEWA now sets its prices in accordance with the DSCE’s directives. The DSCE Law empowers the DSCE to impose a ‘definite tariff based on cost when necessary’. The DSCE is also authorised to approve fees and tariffs on the services offered to the public by ‘energy service providers’ (meaning the power generation, transmission and distribution companies).

In 2011, Dubai passed Executive Council Decision No. 16 of 2011 on the Approval of the Electricity and Water Tariff in the emirate of Dubai (the Dubai Tariff Decision), which sets out the electricity and water tariffs for Dubai. The Dubai Tariff Decision provides for a slab tariff scheme and authorises DEWA to add the ‘fuel price difference’ to the electricity tariffs charged to consumers. The consumers are divided into (1) industrial (2) residential; and (3) commercial. UAE nationals are subject to tariff rates equal to roughly one-third of the rate applied to other residential consumers.

DEWA has since 2011 increased electricity rates and pursuant to the Dubai Tariff Decision, introduced a variable fuel surcharge in its electricity tariff. The electricity tariff in Dubai now comprises the electricity consumption charges, the fuel surcharge and meter charge. The fuel surcharge component requires consumers to pay for any fuel cost increases using 2010 fuel prices as the benchmark, thereby passing on the risk of international fuel price fluctuations to the consumer. This has enabled the company to increase revenues, reduce demand growth and earn higher profits. The present fuel surcharge rate applicable in the emirate of Dubai is 6.5 fils/kWh. Since the introduction of the VAT Law, 5 per cent VAT is payable on the consumption of electricity and water in Dubai. As mentioned previously, VAT is not applicable in respect of the housing fee, sewerage fee and irrigation fee that DEWA collects on behalf of the Dubai Municipality. Knowledge fee and innovation fee are also exempted from VAT.14

---

IV  ENERGY MARKETS

i  Development of energy markets

The electricity market for private power producers in the UAE is comprised of the state-owned water and power authorities each of which acts as the single point of sale in their respective areas of operation.

Contracts for power generation are awarded on the basis of a competitive bidding process, administered by ADWEA in Abu Dhabi, DEWA in Dubai, SEWA in Sharjah and FEWA in the northern emirates.

ii  Energy market rules and regulation

Under the Abu Dhabi Electricity Law, ADWEC is required to contract with power producers for the purchase of all production capacity from licensed operators in the emirate. ADWEA is authorised to allow ‘by-pass sales’ from power producers directly to eligible consumers provided that:

- the first independent commercial power generation project in the emirates shall have commenced commercial operations;
- the majority of the shares in the company are privately owned; and
- the RSB issues a report stating that the energy market in the country is stable enough for it to be in the public interest that the sale of electricity by producers to eligible consumers be permitted.

To date, no ‘by-pass sales’ of electricity have been allowed by ADWEA in Abu Dhabi and all existing producers in the emirate are required to sell their production exclusively to ADWEC.

Similarly, power producers in Dubai are obligated by law to sell their entire production capacity to DEWA.

All power generation companies in the northern emirates and Sharjah are required to sell their power production to FEWA or SEWA respectively.

iii  Contracts for sale of energy

ADWEC pays the generation companies the tariff agreed under the PWPAs. The PWPA serves both as a grant of concession and offtake agreement.\(^\text{15}\)

The PWPAs usually have a term of about 20 to 25 years from the commencement of commercial operations. Payments to IWPPs by ADWEC under PWPAs comprise three main components:

- capacity (or availability) payments covering the fixed costs of the plant (return on capital, depreciation and fixed operating and maintenance costs);
- operation and maintenance costs, paid when plant is available for production irrespective of whether and how much the plant produces; and
- output (or energy) payments for variable operation and maintenance costs, payable only for the electricity actually produced by the plant and dispatched.

The primary fuel used in the power generation sector in the UAE is natural gas, accounting for 90 per cent of all production. As is often the case in such models, fuel costs are pass-through,

---

and ADWEC is required to procure and supply fuel to the electricity producers under the Abu Dhabi Electricity Law. ADWEC acquires the natural gas from two sources, the Abu Dhabi National Oil Company and Dolphin Energy Limited (purchased from Qatar via a pipeline connecting both states) for onward supply to the power producers.

Power plants are required to stock diesel oil and crude oil as backup fuel. According to the standard PWPAs, generation companies have to stock up enough backup fuel for their plants to run at full capacity for seven days.

PWPA payment rates under some of the agreements are subject to annual indexation against US and UAE inflation or the US$/dirham exchange rate.

ADWEC is required by the standard PWPAs to pay certain other supplemental payments to the IWPPs, such as start-up, shut-down costs and backup fuel costs. Some PWPAs may also have provisions for payment by the relevant party of liquidated damages for delay in performance and of interest on late payments.

To date, DEWA has only signed three power purchase agreements:

a the first with a consortium led by ACWA Power and TSK, for the Shuaa Solar PV Project;

b the second with a consortium led by Harbin Electric International and ACWA Power for the construction of phase 1 of the Hassyan Clean Coal Project; and

c the third with Masdar, for the 800MW third phase of the Solar Park.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

High energy use, encouraged by subsidised energy prices and the construction of energy intensive industries such as aluminium smelting has resulted in the UAE having one of the highest per capita carbon footprints in the world. The development of renewable energy is therefore crucial in reducing the country’s carbon footprint and diversification of its economy away from fossil fuels. The UAE has announced that it aims to produce at least 7 per cent of electricity from renewable sources by 2020.

A number of showcase projects have been launched in Abu Dhabi and Dubai to kick-start the development of renewable energy in the country.

Abu Dhabi

Abu Dhabi established Masdar\(^\text{16}\) to spearhead the emirate’s renewable energy initiative. Masdar City, a project of Masdar on the outskirts of Abu Dhabi city, is proposed to be run entirely on renewable energy as a zero carbon emissions city. Masdar City has also won the rights to host the headquarters of the International Renewable Energy Agency.

Masdar currently produces 17,500MWh of electricity annually; at its solar photovoltaic power plant located at the Masdar City for supply of clean power to the project. It has also launched a carbon capture and storage project in the UAE.

---

\(^{16}\) Masdar is a wholly owned subsidiary of Mubadala Development Company, one of the Abu Dhabi government’s main investment arms.
Most significant is Masdar's 100MW solar power plant\(^\text{17}\) at Madinat Zayed, which was inaugurated on 17 March 2013. Known as Shams 1, it is one the largest parabolic trough power stations in the world. This project is expected to be followed by the Shams 2 and Shams 3 solar power projects. Among other sustainable projects launched by Masdar in the UAE are Masdar City's 10MW solar PV array in Abu Dhabi, Masdar City's 1MW rooftop installations, a 100MW photovoltaic plant in Al Ain, a 30MW onshore wind farm on Sir Bani Yas Island, a grid-connected solar photovoltaic panel on Murawah Island, the Um Al Zomul solar photovoltaic plant, and a 543kWp photovoltaic plant that delivers energy to Rashid Abdullah Omran Hospital. With the success of its pilot project involving the installation of solar photovoltaic cells on 11 school and government buildings across the emirate, Masdar proposes to further expand the installation of solar panels to reduce dependence on hydrocarbon fuels.

Masdar is also actively expanding its international investments in clean renewable energy; some of its projects include the Seychelles wind power project (6MW), the Mauritania solar power project (15MW), Spain's Gemasolar (20MW), Valle 1 and 2 solar power projects (100MW), United Kingdom's Dudgeon offshore wind farm (402MW), Jordan's Tafile Wind Farm (117MW), Bayouna solar power project (200MW), Egypt's Siwa solar photovoltaic plant (10MW), Samoan wind farm on the island of Upolu (1,500MW), Serbia's Tesla wind farm (158MW), Tonga's Vava'u island solar power project (512KW), Scotland wind farm (30MW) and the Noor 1 and Noor 2 solar photovoltaic plants (250MW) in Morocco. Masdar is also a 20 per cent stakeholder in the London Array wind farm in the United Kingdom, which produces 650MW of electricity. In partnership with the International Renewable Energy Agency, the Abu Dhabi government also granted US$57 million in loans to Argentina, Cuba, Iran, St Vincent and the Grenadines and Mauritania to finance renewable energy projects. Masdar is also involved with the UAE-Pacific Partnership Fund in developing renewable energy projects in the Pacific Islands. Currently, four new solar projects are under way in the countries of Kiribati, Fiji, Tuvalu and Vanuatu. An agreement was signed between Masdar and New Zealand to develop a solar photovoltaic power plant (1MW) in the Solomon Islands.

E.ON Masdar Integrated Carbon, a joint venture between E.ON and Masdar, develops and invests in carbon abatement projects in industry, power and oil and gas across Africa, Asia and the Middle East under the UN’s clean development programme.

A 100MW waste-to-energy facility is currently under development in Abu Dhabi (near the Mussafah Sea Port) by TAQA, in co-ordination with the Centre of Waste Management (Tadweer). The plant was scheduled to be up and running by 2017 but there is no update on its current status.\(^\text{18}\)

**Dubai**

The DSCE developed the Dubai Integrated Energy Strategy 2030 and Dubai Clean Energy Strategy 2050\(^\text{19}\) to enable Dubai to become a global centre for clean energy and green

\(^{17}\) The project company, Shams Power Company, is 80 per cent owned by Masdar and 20 per cent by Total SA.


\(^{19}\) The Dubai Clean Energy Strategy 2050 was announced by the Dubai Supreme Council of Energy as part of its participation in the World Future Energy Summit held in Abu Dhabi in January 2017. The Dubai
economy. In line with these strategies, Dubai aims to diversify its energy sources so that by 2030 it can fulfil 25 per cent of its energy demand from solar energy, 7 per cent from nuclear energy, 7 per cent from clean coal and 61 per cent from natural gas. By 2050, Dubai aims to fulfil 75 per cent of its energy demands from renewable energy sources.

As part of these strategies, in January 2012, Sheikh Mohammad Bin Rashid Al Maktoum, the Ruler of Dubai, launched the Solar Park. The Solar Park is expected to have a total installed capacity of 5,000MW by 2030. The project is being implemented by the DSCE in Dubai and managed and operated by DEWA. The first phase 13MW solar photovoltaic plant and substation was completed in 2013, followed by the second-phase Shuaa Solar PV Project in April 2017. The 800MW third phase was awarded by DEWA in June 2016 to a Masdar-led consortium and is expected to be operational in three phases commencing this year. DEWA also awarded the CSP project, as the fourth phase of the Solar Park to ACWA Power and Shanghai Electric, in September 2017.

In July 2013, Dubai launched a waste-to-energy conversion project through a landfill gas recovery plant at the waste collection site in Al-Qusais. To date, this is the first landfill in the region to run its entire operation with electricity generated from landfill gas. In due course, the plant is expected to increase capacity from its current 1MW to 20MW by 2020. Plans to implement a similar project in the Jebel Ali landfill are also proposed by the government.

In 2013, DEWA and DSCE established Etihad Energy Service Company (EtihadESCO), which will serve, notably, to retrofit existing buildings and lower the water and energy consumption of such buildings.

DEWA has launched the Shams Dubai Initiative, which aims to encourage energy efficiency by equipping residential and commercial buildings with solar panels and connecting the panels to DEWA's electricity grid. In 2014, in line with this initiative, the emirate of Dubai issued Executive Council Resolution No. 46 of 2014 Concerning the Connection of Generators of Electricity from Solar Energy to the Power Distribution System in the emirate of Dubai (Resolution 46) to encourage the generation of electricity using solar panels. Resolution 46 enables DEWA consumers to supply power to DEWA's grid by connecting their solar panels and the power supplied to DEWA can then be adjusted against the consumer's electricity bill.

In 2015, Dubai established the Dubai Green Fund (Fund), worth US$27 billion, which provides easy loans to investors in the clean energy sector. DEWA will provide the seed capital for the Fund, with additional investment from the private sector, international banks and large investment companies.

In 2016, DEWA inaugurated one of the largest single rooftop arrays in the Middle East and North Africa region, a 1.5MW direct current photovoltaic generation project at the Jebel Ali Power Station, and successfully connected it to DEWA's grid.

Currently DEWA is working to develop an Innovation Centre, equipped with the latest renewable and clean energy technologies to raise awareness on sustainability, while enhancing national capabilities and increasing competitiveness. The Innovation Centre will be equipped with the latest clean and renewable energy technologies, and will serve as a museum and exhibition for solar energy. The centre will also feature two solar testing facilities, the first will specialise in testing PV solar panels, while the second will focus on CSP. The centre is currently testing 30 photovoltaic panel types from global specialist manufacturers.

Clean Energy Strategy 2050 intends that 7 per cent of Dubai's total power output will come from clean energy by 2020, 25 per cent by 2030 and 75 per cent by 2050.
Dubai has also established the Dubai Carbon Centre of Excellence, responsible for encouraging and developing strategies towards reducing the emirate’s dependence on carbon fuels and reducing carbon emissions.

In January 2018, DEWA signed a memorandum of agreement with the GCC Interconnection Authority and the Belgian Dredging, Environmental & Marine Engineering Group towards building a 400MW pumped hydro storage power station in the Arabian Gulf, with a storage capacity of approximately 2,500MWh.

The Dubai Municipality also announced the world’s largest waste-to-energy project in the emirate’s Al Warsan area, in early 2018. The plant is designed to treat 1.82 million tonnes of solid waste annually, with a total capacity to generate 185MW of electricity. Construction of the plant is proposed to begin mid-2018 and be completed in time for Expo 2020.

**Sharjah**

Like Dubai, Sharjah launched SEWA 2020 Vision in 2016 to enhance power efficiency in sustainable development. SEWA intends to reduce power and water use by at least 30 per cent over the next five years (i.e., by 2020). To achieve this vision, SEWA has launched various projects, which include: setting up the first electric-vehicle charging station, completing a solar-powered road lighting project in Al Saja’a and Al Barashi, and replacing the current electrical infrastructure with modern facilities such as a smart metering system and networks to save energy.

Bee’ah and Masdar have formed a joint venture under the name of Emirates Waste to Energy Company (EWEC) to develop waste to energy plants across the Middle East. The first project being undertaken by EWEC is in Sharjah to establish a facility with the capacity to treat more than 300,000 tonnes of municipal solid waste a year, and with a power generation capacity of 30MW. EWEC and SEWA entered into a power purchase agreement in May 2017 for this project.

**Northern emirates**

In 2014, UTICO, a privately owned utility company, called for the construction of a new 40MW solar plant in Ras Al Khaimah. UTICO has also collaborated with Shanghai Electric to set up a clean-coal power plant project (270MW) in Ras Al Khaimah. Both projects have been deferred indefinitely.

Recently, FEWA installed 11,000 smart electricity and water metres in Ajman. Additionally, in 2016, FEWA announced a 1.3 billion-dirham funding budget to improve the electricity network in the northern emirates. FEWA is expected to expand 17 power stations and construct 25 power distribution stations in Umm Al-Quwain, Ras Al Khaimah and Fujairah.

In 2017, the Ministry of Climate Change and Environment signed a memorandum of understanding with Masdar and Bee’ah for developing a waste-to-energy conversion facility to serve Ras Al Khaimah and Fujairah.

**UAE renewable energy prospects**

Although the UAE’s recent steps towards developing more renewable energy projects in the country are commendable, the projects launched so far will fulfil only a small part of the country’s total energy requirements. Despite the announcement to produce 25 per cent of the country’s total energy requirements from renewable sources by 2030, the UAE has not set itself a mandatory renewable energy target. The UAE’s electricity demand is expected to
grow at close to 10 per cent for the next decade, which will require a substantial increase in conventional gas and diesel-powered plants. Furthermore, most conventional power plants in the UAE also host water desalination plants, making the development of such additional capacity crucial in fulfilling the country’s growing water requirements. The country’s primary focus is therefore expected to continue to remain in developing conventional power and water desalination plants.

To encourage private investment in renewable energy, the government needs to enact formal legislation to regulate the development of renewable energy. A subsidy for renewable energy sources combined with a feed-in tariff that guarantees that electricity generated from renewable sources will be purchased for a minimum price can be introduced as a further incentive.

Nonetheless, recent initiatives in the field of renewable energy have made the UAE one of the most dynamic and exciting markets for renewable energy in the region.

**Nuclear energy**


The UAE aims to produce a significant part (approximately 9 per cent) of its electricity from nuclear technology. The UAE released a nuclear policy in 2008 and has since then promulgated a regulatory framework for development of nuclear energy in the country. In addition to collaborating with the IAEA and the World Association of Nuclear Operators, the UAE has signed cooperation agreements with France (2008), Korea (2009), the United States (2009), the United Kingdom (2010), Australia (2012), Canada (2012), Russia (2012), Argentina (2013) and Japan (2013) for the development of peaceful use of nuclear energy.

The Federal Authority for Nuclear Regulation (FANR), the federal nuclear energy regulator headquartered in Abu Dhabi, was established in 2009 under Federal Law No. 6 of 2009 Concerning the Peaceful Use of Nuclear Energy. The FANR is tasked with the responsibility of setting up the procedures and measures to be followed for the development of nuclear technology in the UAE. The FANR has issued regulations governing, *inter alia*, licensing, site location, design, construction, commissioning and operation, as well as standards for safety, transportation and storage facilities, radioactive waste management and physical protection of nuclear materials. The UAE has also created the International Advisory Board (IAB), an independent body consisting of independent international experts on nuclear energy who will offer guidance to the country’s nuclear programme on compliance with international safety, security and proliferation standards. The IAB is presently chaired by Hans Blix, the former IAEA Director General.

The UAE has been making rapid strides in establishing its first nuclear power station, the Barakah Nuclear Energy Plant (Barakah), in Abu Dhabi. The Emirates Nuclear Energy Corporation (ENEC), an Abu Dhabi government-owned company established by Federal Law No. 21 of 2009, is constructing Barakah, which will have a total capacity of 5,600MW. The project consists of the construction and installation of four 1,400MW reactors. As of
September 2017, the project is 84.92 per cent complete and is proposed to be operational by 2020. Once the four reactors are online, the facility will deliver up to a quarter of the UAE’s electricity needs.

In 2016, ENEC signed a deal with TRANSCO to transmit nuclear power generated from Barakah through TRANSCO’s power lines to the ENG.

ii Energy efficiency and conservation

The UAE has one of the highest rates of electricity consumption per capita. This high usage is encouraged by the electricity and water subsidies given by the government to its citizens and in certain emirates to foreign expatriates. Dubai has progressively reduced and removed most of its electricity subsidies and Abu Dhabi is contemplating similar measures. Efficiency in energy usage is now being recognised as one of the key issues in trying to meet the country’s growing energy needs in a sustainable manner.

In 2010, Abu Dhabi imposed a mandatory rating system for construction of energy-efficient buildings in the emirate under the Estidama initiative. Starting from September 2010, all new development communities, private buildings and villas in the emirate are required to meet the minimum of one-pearl rating. All government led projects have been mandated to meet a two-pearl rating (the highest being a five-pearl rating). Masdar City, an eco-city project within Abu Dhabi, plans to expand its community and target a four-pearl Estidama rating to set an example as the leading energy efficient community.

The Dubai government has also enacted the ‘Green Buildings Regulations’ to encourage sustainable building practices. These regulations are enforced by the Dubai Municipality and apply to all new buildings constructed (including changes or additions to existing buildings) in the emirate. To this end, RSB Dubai has licensed nine energy service companies to retrofit more than 30,000 buildings in the emirate of Dubai to make them more energy efficient. Recently, the Emirates Green Building Council issued the technical guidelines for retrofitting existing buildings.

In 2016, Dubai and Sharjah launched projects to replace current infrastructure with energy efficient facilities. Both emirates are currently replacing street lights with LED lights. In Dubai, existing buildings are currently being retrofitted by Etihad ESCO while Sharjah is replacing and renovating its cables and meters.

To attract foreign private investment in the sector, Dubai has created a free zone dedicated to the development of green technologies and energy conservation, and known as the Energy and Environment Park (EnPark). EnPark is also Dubai’s first master-planned community built on sustainable principles. In 2015, EnPark combined with another free zone, Dubiotech, to create Dubai Science Park.

Through recent investment in its transmission system, DEWA succeeded in reducing the percentage of line losses in its electrical network to 3.26 per cent in 2016 from 6.28 per cent in 2001 and has simultaneously increased the efficiency of its energy generation by 22 per cent between 2006 and 2014. As part of its demand growth management strategy, DEWA has introduced a slab tariff that has been successful in reducing demand growth to 3 per cent despite a 5 per cent growth in end users in 2011. FEWA also has a slab tariff in place for the northern emirates whereas ADWEA is proposing to launch a similar tariff structure in the near future.
iii Technological developments

Masdar has established the Masdar Institute of Science and Technology (MIST), a state-of-the-art research centre and university, in partnership with Massachusetts Institute of Technology. MIST is a graduate-level university that aims to provide solutions to issues of sustainability, focusing on advanced energy and sustainable technologies, through research.

Although it is a brand new institute, according to its website, over 30 research projects are currently under way, covering solar beam down, innovation ecosystems, smart grids and aviation biofuels. In addition, according to its website, a number of patents are already pending registration.

MIST is likely to play a leading role in development of advanced technologies in the UAE in the coming years.

In 2015, Masdar launched Masdar Solar Hub, a solar testing and research and development hub for photovoltaic and solar thermal technology. In the same year, DEWA Innovation Centre, which consists of a laboratory for research and development in clean energy, was inaugurated.

Once completed, the Solar Park is expected to include, inter alia, the following: a centre for innovation equipped with the latest renewable energy technologies, a research and development centre to conduct tests in relation to social and industrial needs for renewable energy; two test technologies for photovoltaic panels and concentrated solar power; a solar testing facility; and a training centre and special conference centre for the exchange of information.

As of 2018, DEWA has signed a memorandum of understanding with Siemens to kick-off a pilot project for the region’s first solar-driven hydrogen electrolysis facility at DEWA’s outdoor testing facilities at the Solar Park in Dubai.

VI THE YEAR IN REVIEW

The UAE has seen double-digit increase in the demand for electricity in recent years and is expected to continue seeing rapid growth in the coming years.

To meet this growing demand, Abu Dhabi and Dubai have allowed private power companies to participate in its energy sector for a number of years. Following the enactment of the Dubai Electricity Privatisation Law in 2011, Dubai awarded the construction and partial ownership of a number of projects on the IPP model, including the Hassyan Clean Coal Project and the ACWA-NSK solar power plant. FEWA has followed Abu Dhabi and Dubai’s example and permitted private sector participation in its electricity network with the participation of UTICO in the electricity network of Ras Al Khaimah and its future plans commencing 2017. However, it seems as though transmission and distribution networks will continue to be owned mainly by the state-owned monopolies and the status there is unlikely to change in the foreseeable future.

The UAE is recognising the need for the efficient use of energy and electricity and is currently revamping its existing infrastructure. In addition to the construction and expansion of power stations, the UAE is involved in other projects such as replacing street lights with LED lights, renovating cables and meters, and retrofitting existing buildings. Consideration has also been given to connecting renewable energy sources to the electric grid. These projects are in line with Dubai Law No. 6 of 2015 on Protection of the Electricity Grid and Public Water Systems in the Emirate, which is intended to protect the electricity and water transmission and generation infrastructure in Dubai.

© 2018 Law Business Research Ltd
High subsidies and heavy reliance on fossil fuels for generation have resulted in the UAE having one of the highest per capita carbon footprints in the world. There is growing recognition that the energy demand cannot be met only through investment on the supply side, and that demand-side management programmes and energy conservation measures are equally important in matching demand with supply. Reduction in subsidies over time (and increases in electricity tariffs) coupled with the introduction of slab tariffs in Dubai and the northern emirates have helped curb demand growth in these areas and relieved pressure on the sector. Because of the effectiveness of the slab tariff introduced by DEWA, Abu Dhabi is also proposing to introduce a slab tariff in the near future.

Green building regulations and a mandatory rating scheme have been introduced in Dubai and Abu Dhabi respectively to encourage energy conservation. In accordance with these regulations, the Emirates Green Building Council in Dubai has further issued the Technical Guidelines for Retrofitting Existing Buildings.

The country has set itself the goal of ensuring 25 per cent of its energy requirements in 2030 (and 75 per cent in 2050) are met from renewable sources. To meet these targets, a number of projects have been launched.

Dubai has recently inaugurated a solar energy park that will, on completion in 2030, have the capacity to produce 5,000MW of electricity. This park is also expected to have testing facilities with the latest renewable energy technologies and special conferences to develop the solar energy sector.

Abu Dhabi has launched the zero carbon emissions and zero waste Masdar City project to be powered exclusively by renewable energy sources and to attain a four-pearl Estidama rating to set an example as the leading energy efficient community in the UAE. Masdar, the owner of the project, continues to develop various other renewable projects within the UAE and internationally.

Dubai has established a Dubai Green Fund and established Etihad ESCO, which is expected to contribute towards the development of the renewable energy sector and an energy efficient community.

A specialist regulatory body for the nuclear energy sector has been created. New regulations governing various segments of the nuclear chain are being developed and issued. Construction work on the Barakah nuclear power plant is currently under way in the emirate of Abu Dhabi, and commissioning is expected in 2020. An agreement was also signed in 2016 to transmit nuclear power to the ENG.

Although efforts at diversification are commendable, the sector looks set to continue to be dominated by the existing players. With growing demand for electricity across the UAE, the authorities are continuing to invest significantly in hydrocarbon-based power generation facilities, which are increasingly being supplemented by development of alternative and renewable energy.

VII CONCLUSIONS AND OUTLOOK

As seen above, in addition to the drive towards privatisation, notable developments towards energy diversification and introduction of renewable sources have taken place. These developments, however, currently remain restricted to the government sector despite the various initiatives that were launched to permit private sector participation.

The state-owned monopolies in the various emirates are likely to continue to dominate the sector in the foreseeable future. The requirement under the Companies Law to maintain
majority ownership in local hands means that foreign private investors will have to work with the local water and power authorities as junior partners or, when full private ownership is permitted within the sector, with local partners as the majority shareholders.

Although Abu Dhabi and Dubai have seen foreign investment in the electricity sector for a number of years, the other emirates are increasingly beginning to recognise the benefits of encouraging private sector participation. This change in attitudes is driven principally by the increased demand in electricity on account of population and economic growth, as well as the current low oil prices, which have reduced the availability of government funds compared with previous years.

The energy sector in the UAE is likely to continue seeing rapid changes and as the economy continues to grow, demand is likely to create opportunities for private investment in the sector. Although, the GCC Grid has not taken any significant steps in the last few years, the completion of the GCC Grid and its proposed expansion to Egypt and European countries (through Turkey) will create further opportunities for private sector investment in the sector by enabling cross-border trading of power. Furthermore, in line with diversifying energy sources and preserving energy, the UAE is expected to continue its projects such as retrofitting buildings, establishing solar parks and energy efficient communities, which will require the investment and research capabilities of the private sector. Despite the encouragement for private investment in alternative energy sources and energy efficiency measures, investment in the sector looks likely to continue to be led by the state-owned water and power authorities.
Chapter 34

UNITED KINGDOM

Munir Hassan and Filip Radu

I OVERVIEW

The United Kingdom has one of the most mature and dynamic electricity and gas markets. The country was a pioneer in the drive towards liberalisation, starting with the Energy Act 1983 that opened up the supply markets. The liberalisation was later bolstered by an ambitious privatisation programme in the late 1980s and 1990s, which led to the creation of wholesale markets where generators could sell electricity in real time. At present, the markets are fully liberalised and privatised.

The United Kingdom has since pushed an energy agenda focused on decarbonisation, demonstrated by the country’s national 2020 renewable energy targets, which exceed those required under the European Renewable Energy Directive. This has resulted in strong growth for renewable generation over the past decade with subsidies providing attractive returns and investment opportunities. In the wake of the 2008 financial crisis, government policy has given increased attention to lowering the cost to consumers. In addition, concerns about the intermittent nature of renewable generators and their growing share of the generation profile of the United Kingdom have shifted policy focus towards ensuring security of supply. The result has been a reconfiguration of subsidy support mechanisms, with the twin aims of (1) lowering the cost of new technologies; and (2) incentivising the construction of baseload generation. This regulatory shift, together with the uncertainty resulting from Brexit, has led to a slowdown in growth for new renewable projects and a converse increase in activity in the secondary market for operational renewable assets. However, there is sustained optimism in the energy sector, particularly in relation to emerging technologies such as battery storage (especially co-located with existing renewable projects), and the opening up of transmission (onshore and offshore) projects to private investors.

II REGULATION

i The regulators

Gas and Electricity Markets Authority (GEMA)

GEMA is the regulator of both the gas and electricity markets in Great Britain (GB). The Utility Regulator for Northern Ireland, an independent non-ministerial government...
department, regulates the electricity and gas markets in Northern Ireland. Its duties are to protect the short and long-term interests of electricity, gas, water and sewerage consumers with regard to price and quality of service; promote a robust and efficient water and sewerage industry; deliver, where appropriate, high-quality services; promote competition, again where appropriate, in the generation, transmission and supply of electricity; and to promote the development and maintenance of an economic and coordinated natural gas industry.

For the GB market, similar duties are performed by GEMA. GEMA consists of a panel of individuals appointed by the Secretary of State for a specified term of not less than five years, but it is independent of government and has no stakeholder participation. GEMA’s duties are set out in the Gas Act 1986 (as amended) (Gas Act), the Electricity Act 1989 (as amended) (Electricity Act), and the Utilities Act 2000 (as amended) (Utilities Act), and it has powers in relation to granting and administering licences, as well as concurrent authority with the Competition and Markets Authority (CMA) on the application and enforcement of certain competition rules. GEMA operates through its office, the Office of Gas and Electricity Markets (Ofgem), to which it delegates the day-to-day administration of its functions. Ofgem is therefore often more commonly referred to as the regulator in common parlance.

GEMA’s objectives are enshrined in the relevant sections of the Gas Act and the Electricity Act. While these are varied and at times inconsistent, GEMA’s principal objective is to protect the interests of existing and future consumers in relation to electricity and gas, and, wherever appropriate, to achieve this by promoting effective competition.

On a day-to-day basis, Ofgem exercises GEMA’s powers to grant and modify the conditions of licences, to monitor the activities of gas and electricity companies, and, where necessary, takes enforcement action to ensure these companies comply with their statutory and licence obligations. Ofgem also exercises GEMA’s power to impose financial penalties on licence holders for breaches of such obligations.

The regulatory framework is responsive to changes in the market through Ofgem’s ability to modify the licence conditions. This is done through industry code modification panels. Appeals in respect of such modifications can be made to the CMA.

GEMA also has the power to modify the various industry codes. This power is conferred by the relevant licence condition under which a network operator (e.g., National Grid Electricity Transmission plc (NGET) or National Grid Gas plc (NGG)) is required to ‘own’ the code in question, and currently is not subject to any specific statutory constraints.

**CMA**

The CMA is the United Kingdom’s lead competition and consumer body established under the Enterprise and Regulatory Reform Act 2013 (ERRA). GEMA, as energy regulator, has concurrent powers with the CMA with regard to the energy sector. The ERRA requires sectorial regulators, including GEMA, to consider applying competition law before using their sector-specific powers. The provisions of the Competition Act 1998 and the Enterprise Act 2002 (Enterprise Act) as amended by the ERRA dealing with anticompetitive practices play a particularly important role and are jointly applied and enforced by GEMA and the CMA.

To improve the effectiveness of these concurrent powers, the CMA is required under the ERRA to publish an annual report, in consultation with the sector regulators, on how the cooperation under the joint competition powers has worked.

Under the Enterprise Act, the CMA may investigate the functioning of competition within a market in the United Kingdom as a whole (as opposed to targeting specific actions of
companies) and open an investigation where it has reasonable grounds for suspecting that any feature, or combination of features, of this market restricts or distorts competition in the supply or acquisition of any goods or services. In the case of the gas and electricity sector, Ofgem may refer a market to the CMA for a market investigation or the CMA may direct Ofgem to transfer the case to it. The CMA conducted an extensive energy market investigation and on 24 June 2016 published its final findings and remedies. Although it found the wholesale electricity market was generally ‘working well’, it identified two aspects of the regulatory regime that adversely affected competition, namely: (1) the absence of locational charging for transmission losses; and (2) the mechanism for allocation of Contracts for Difference. Following the final CMA decision, Ofgem published on 3 August 2016 a strategy for the implementation of the CMA remedies and then issued its detailed implementation plan on 9 November 2016.

The CMA also has powers to hear appeals in relation to price controls set by Ofgem for network companies (price controls are explained further below in Section III). Two such appeals were brought in 2015 by (1) British Gas Trading Limited (BGT); and (2) Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc (together ‘NPg’) in respect of the RIIO-ED1 price controls set by Ofgem. The result was the dismissal of two out of the three grounds of appeal for NPg and four out of five grounds of appeal for BGT.

Health and Safety Executive (HSE)

The HSE is the national independent regulator with regard to health and safety of GB. It was established under the Health and Safety at Work Act 1974 and is responsible for the regulation and enforcement of workplace health and safety in GB and for producing guidance and carrying out research in relation to occupational risks.

In Northern Ireland the role is performed by the Health and Safety Executive for Northern Ireland.

Office for Nuclear Regulation (ONR)

The ONR is responsible for the regulation of nuclear safety and security, including through nuclear site licences, across the United Kingdom. The ONR is also responsible for regulating the transport of nuclear materials and ensuring that safeguards obligations for the United Kingdom are complied with. The ONR reports to the Department for Work and Pensions, although it also works closely with the Department of Energy and Climate Change.

Environment Agency

Responsibilities in relation to environmental regulation in GB have largely been devolved to governments in each of England, Wales and Scotland. For example, in England, the Environment Agency is a non-departmental public body sponsored by the Department for Environment, Food and Rural Affairs. It is responsible for protecting and improving the environment and promoting sustainable development in England.

In Wales, since April 2013, environmental and other natural resources-related matters have been the responsibility of Natural Resources Wales. The role of the environmental agencies regarding electricity is limited to pollution-related matters, so mainly relate to

---

3 https://www.gov.uk/cma-cases/energy-market-investigation.
conventional generation and nuclear, although additional environmental matters also arise in relation to consenting. The Environment Agency in England is also responsible for limiting and preparing for the impacts of climate change.

In Northern Ireland, the Northern Ireland Environment Agency is the body responsible for the protection conservation and promotion of the national environment.

**Department for Business, Energy and Industrial Strategy (BEIS) and the Department for the Economy (DFE)**

While not regulators, BEIS (in respect of GB) and DFE (in respect of Northern Ireland) are government departments responsible for setting the policies affecting the UK electricity and gas markets. The Secretary of State for Business, Energy and Industrial Strategy is responsible for making decisions, setting policy and implementing legislation affecting the sector and is accountable on matters including security of supply and sustainability in the GB energy sector. BEIS is responsible for formulating UK energy policy, which is implemented through legislation. In addition, there are some regulatory powers that are reserved to the Secretary of State directly. For example, the Secretary of State is authorised to make orders under the Electricity Act granting exemptions from the requirement to hold a licence, where certain criteria are met.

The corresponding government ministry in Northern Ireland is DFE, which assumed most of the roles and responsibilities of the former Department of Enterprise, Trade and Investment.

**ii Regulated activities**

The regulatory framework in GB operates through a system of legislation, licences and industry codes with an independent regulator responsible for the regulation of the sector and for enforcing any breaches of the rules. In the case of both electricity and gas, there is a prohibition on carrying out the licensable activity without a licence (unless an exception applies).4

Licences are granted by the Secretary of State, by way of Ofgem, to the entity carrying out the particular activity. In line with European Third Energy Package rules, a licensee may not hold a transmission, distribution or interconnection licence if it already holds another licence.

The regulatory regime for gas has recently undergone reform through the development of the European Union-wide Network Codes. Regulation (EC) No. 715/2009 provided for the establishment of Network Codes to help facilitate cross-border network access and market integration. Changes to the electricity sector are also under way pursuant to Regulation (EC) No. 714/2009 regarding harmonising the technical, operational and market rules governing the electricity grids; however, the European Commission has proposed in its latest fourth ‘winter package’ to recast this Regulation. Under this latter EU legislation, ACER and ENTSO are developing European Union-wide codes and guidelines for matters such as

---

4 There are criminal sanctions for breaching these requirements unless covered by an exemption (Electricity (Class Exemptions from the Requirement for a Licence) Order 2001 (SI 2001/3270)).
system operation (adopted), balancing activities (adopted), demand connection (adopted), grid connection for generators (adopted), capacity allocation and congestion management (adopted), and forward capacity allocation (adopted), among others.5

**Electricity**

Unless an exemption applies, a licence is required for the following specified activities under the Electricity Act:

- a generation;
- b participation in transmission (defined to cover both the operation and ownership activities);
- c distribution;
- e supply; and
- f participation in the operation of an electricity interconnector.

From September 2012, providing smart metering services also requires a licence. The position regarding electricity storage is currently unclear, although Ofgem is working with industry stakeholders to develop a regulatory definition for this technology (see more in Section VI, below).6

**Gas**

As with electricity, the Gas Act makes it an offence for an entity without a licence to carry out any gas transportation, interconnection, gas shipping, supply or smart metering (unless an exemption applies). For example, a licence to transport provides the right to convey gas through pipeline systems, while an interconnector licence gives the licensee the right to operate the cross-border transportation of gas. The activity of gas shipping consists of buying gas from producers or importers and arranging for its transport (with gas transporters) via a pipeline system to a gas supply point, to then sell it on to gas suppliers. Gas storage is subject to regulation but is not separately licensed.

A licence on its own does not give an entity the right to carry out other activities such as develop a project. Separate rights need to be secured in relation to land rights, planning requirements, decommissioning, etc., and the licensee would need to comply with other relevant legislation. In practice, this means obtaining authorisations from other regulatory bodies noted above (e.g., the HSE).

**iii Ownership and market access restrictions**

There are no energy-specific restrictions on foreign investment or ownership of energy companies or assets in the United Kingdom. However, an additional certification process

---

5 For a full list of the EU-wide electricity codes and guidelines, as well as their status, see http://ec.europa.eu/energy/node/194.
requires Ofgem to assess, in consultation with the European Commission, whether foreign
ownership or control poses a security of supply risk (Electricity and Gas (Internal Markets)
Regulations 2011).

In a similar vein, the unexpected decision to delay sign-off on final approvals for
Hinkley Point C announced by the Conservative government in 2016 demonstrates that the
executive branch has indirect levers for ensuring control over ownership of national critical
infrastructure. In this instance, the government pointed to concerns over spiralling costs
and security of supply to delay the signing of the final contracts, particularly the Contract
for Difference awarded to Hinkley Point C securing the price of its output at £92.50/MWh
(double the wholesale price at the time). In the event, the government approved the project;
however, it proposed new legal safeguards mainly through a mechanism that will allow it
to prevent any transfer of ownership in UK critical infrastructure without its consent or
knowledge, including that of EDF in Hinkley Point C (in this case through its holding of a
‘golden share’).

iv Transfers of control and assignments
There are no specific restrictions on control in a licence but assignments require prior written
consent of the licensing entity. This is likely to require the incoming party to satisfy the
Secretary of State that it is able to meet the licence obligations, and follows a similar vetting
process as that for a new applicant. In practice, transfers are usually effected by transfer of the
company that holds the relevant licences. The transmission, distribution and interconnection
licences include obligations to ring-fence the regulated asset, which provides an additional
level of control to Ofgem.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Electricity

The GB market was privatised in the early 1990s and has been fully unbundled, thus serving
as a model for many other markets. In GB the legal separation of electricity supply and
distribution activities was introduced by the Utilities Act as part of further restructuring of
the market. As a result, distribution and supply are treated as separate licensed activities and
 licences may in principle not be held by the same person.

Under the provisions of the Third Energy Package, transmission system operators
(TSOs) must be certified as complying with ownership unbundling. This means that
transmission interests (ownership and operation of transmission systems) must be separate
from generation and supply activities. As the UK position did not readily fit within the
Third Package model but was considered sufficiently well developed and independent to meet
the aims of the Third Package, a derogation applies in relation to vertically integrated UK
TSOs pursuant to Article 9(9) (Section 10E (4), the Electricity Act). Scottish Hydro Electric
Transmission plc (SHETL) and Scottish Power Transmission Limited (SPTL), the Scottish
owners, were granted certification on grounds of Article 9(9) subject to certain conditions
and information-sharing restrictions.
Gas
A single regulatory framework applies across GB in respect of the gas sector. Under the Gas Act there is no distinction between gas transmission and distribution activities: both activities are dealt with by the provisions relating to gas transportation.

ii Transmission/transportation and distribution access

Electricity

Transmission and distribution
In 2005, the British Electricity Trading and Transmission Arrangement (BETTA) introduced a single transmission system for the whole of GB and divided the transmission role between a GB TSO, currently NGET, on the one hand, and the existing transmission system owners on the other. Both activities – transmission operator and owner – are licensable and the transmission owners are required by law to make their respective transmission systems available to the TSO, which is responsible for the real-time balancing of supply and demand.

The Electricity Act imposes a duty on transmission licence holders to develop and maintain an efficient, coordinated and economical system of electricity transmission; and to facilitate competition in the supply and generation of electricity. This primary obligation is supplemented by detailed provisions in the respective transmission licences dealing with issues such as compliance with industry codes, charging methodology and non-discrimination.

NGET, a private company listed on the London Stock Exchange, is the holder of the transmission licence and owner of the transmission network in England and Wales, as well as being the TSO for the whole of GB. NGET is also the designated system operator for electricity interconnectors, where it performs system operator to system operator functions.

The respective transmission networks in northern Scotland and southern Scotland are owned by SHETL and SPTL. In Northern Ireland, the TSO is System Operator Northern Ireland and Northern Ireland Electricity owns the transmission assets.

There is also a market for offshore transmission owners (OFTO) with increasing participation. Ofgem has granted a number of licences for electricity transmission connections to offshore wind farms following competitive tenders. The regulator is currently running the OFTO Tender Round 5 process for which ITTs were issued in April 2016 in relation to the Dudgeon, Race Bank and Rampon offshore wind farms and an EPQ was launched for Galloper and Walney Extension. The OFTO Tender Round 6 process is expected to commence in 2018, potentially for the Hornsea, East Anglia and Beatrice offshore wind farms. To date, there are 14 operational OFTOs in place (having a total investment value of approximately £3.1 billion) with a collective capacity of four.

Ofgem is currently working on developing competitive tenders for the design, procurement, construction and operation of new, separable, and high-value onshore transmission assets (designated as Competitively Appointed Transmission Owners or CATOs). The first tender was projected to run in the early part of 2019; however, Brexit has delayed the development of the legislative framework (owing to limited parliamentary time) and there is no clear indication as to when this may be completed. However, Ofgem has been considering whether the current legislative framework allows for the development of alternative models for the competitive delivery of new, separable, and high-value onshore
transmission assets. Consequently, and as part of the necessary transmission reinforcement and connection works that NGET is required to carry out in respect of the Hinkley Point C nuclear project, Ofgem has consulted on two potential models to enable competition:

a. a ‘competition proxy’ model where Ofgem would set the Transmission Owner’s (TO) allowed revenue for a project in line with the outcome it considers would have resulted from an efficient competition for construction, financing and operation of the project; and

b. a ‘special purpose vehicle’ (SPV) model where the incumbent TO would run a competition for the construction, financing and operation of the project through a project specification.

Transmission and distribution are largely regulated through a series of industry codes. NGET has the licence obligation to maintain and administer various industry codes dealing with the operation and use of the transmission system, including the Connection and Use of System Code (CUSC), the Grid Code and, in conjunction with ELEXON, the Balancing and Settlement Code (BSC).

The CUSC sets out the main rights and obligations in relation to the connection to, and use of, the NETS, along with additional provisions on some ancillary and balancing services. The Grid Code deals in detail with matters such as connection conditions, operational liaison and safety coordination, and all material technical aspects relating to connections to, and the operation and use of, the transmission system. The governance of balancing and settlement arrangements is set out in the BSC, to which all generation or supply licensees must be party.

Access

Pursuant to its licence, NGET must not discriminate between any persons or class or classes of persons in the provision of use of the system or in the carrying out of works for the purpose of connection to the transmission system.

Distribution Network Operators (DNOs)

The electricity distribution system in GB is organised along geographic lines with various regional monopolies. England and Wales are divided up between 12 DNOs, while there are only two DNOs in Scotland and one DNO in Northern Ireland. As at April 2018, the DNOs active in GB are owned by the following six groups: Electricity North West Limited, Northern Powergrid, SSE, SP Energy Networks, UK Power Networks, and Western Power Distribution. The DNO in Northern Ireland is Northern Ireland Electricity. Each DNO holds an electricity distribution licence and owns and operates the local electricity distribution system.

Pursuant to the Electricity Act, DNOs must develop and maintain an efficient, coordinated and economical system of electricity distribution and facilitate competition in the supply and generation of electricity. As with transmission, the electricity distribution licence conditions subject the DNOs to obligations such as non-discrimination in the provision of use of system and connection to system; safety and security; and use of system and connection to system charges.

Similar to the obligations of NGET under its transmission licence, under the terms of their distribution licence conditions, DNOs are each required to maintain and comply
with the Distribution Code dealing with technical aspects relating to connections to and the operation and use of the licensee's distribution system, and one of the objectives of the licences and the codes is to facilitate competition in the generation and supply of electricity.

Access
Under the Electricity Act, DNOs have an obligation to make a connection between their distribution system and any premises when requested to do so by the owner of the premises or an authorised electricity supplier. Pursuant to the licences, DNOs must not discriminate between any persons or class or classes of persons in the carrying out of works for the purpose of connection to the licensee’s distribution system, or in the provision of use of the system, and must on application made by any person offer to enter into an agreement for use of the distribution system.

Gas
Transportation
The GB gas transmission network, the National Transmission System (NTS) – a high-pressure pipeline system that transports gas from entry terminals to various gas distribution networks (GDNs) and large industrial customers – is owned and operated by NGG. However, in May 2005, the Uniform Network Code (UNC) enabled companies other than NGG to own gas networks.

The UNC, which is maintained by the Joint Office of Gas Transporters, is the contractual framework that forms the basis of arrangements between the owners and operators of the gas transportation systems in GB and the users of those systems. Similar to the CUSC, the UNC is given effect by a Shipper Framework Agreement, in the form of a contract between a gas transporter and an individual shipper user, by virtue of which they agree to be bound by the provisions of the UNC. In addition to entering into a Shipper Framework Agreement, to become a shipper user under the UNC an applicant must satisfy certain admission requirements including the need to hold a gas shipper licence under the Gas Act.

Within their authorised area, gas transporters must develop and maintain an efficient and economical pipeline system for the conveyance of gas and, in so far as it is economical to do so, are under a duty to provide connection to that system and to convey gas. Additionally, the Gas Act imposes a general duty to facilitate competition in the supply of gas, and to avoid any undue preference or undue discrimination when connecting premises, or a pipeline system operated by an authorised transporter, to any pipeline system operated by the transporter, or in the terms on which the transporter undertakes the conveyance of gas by means of such a system.

The Gas Act is supplemented by detailed provisions on charging for connection and transportation services, standards of performance and system development obligations in the individual licences held by gas transporters.

Distribution
Similarly to the electricity distribution system, gas distribution in GB is organised along geographic lines. There are eight GDNs in GB covering different geographic regions, which are medium and low-pressure pipeline systems. Four of the GDNs (East Midlands, West Midlands, North West England and East of England (including North London)) are owned by Cadent (formerly part of NGG), while the remaining four GDNs are owned and operated
by Northern Gas Networks Limited (North East England (including Yorkshire and Northern Cumbria)), Wales & West Utilities Limited (Wales and South West England) and SGN (Scotland and Southern England (including South London)). On 8 December 2016, NGG announced it had agreed to sell a 61 per cent equity interest in its gas distribution business to a consortium made up of Macquarie Infrastructure and Real Assets, Allianz Capital Partners, Hermes Investment Management, CIC Capital Corporation, Qatar Investment Authority, Dalmore Capital and Amber Infrastructure Limited/International Public Partnerships. Similarly, on 17 October 2016, SSE announced it agreed to sell a 16.7 per cent equity stake in Scotia Gas Networks Limited (SGN) to wholly owned subsidiaries of the Abu Dhabi Investment Authority (ADIA), for a headline consideration of £621 million.

There are also a number of smaller gas transportation networks connected to the GDNs and owned and operated by six independent gas transporters (IGTs). The IGTs compete with each other and the GDN owners to provide gas transportation services. Unless an exemption applies, each IGT and GDN owner is required to hold a gas transporter licence.

Access

Under the Gas Act, gas transporters must, following any reasonable requests for connection, grant access to their pipeline system, in so far as it is economical to do so, convey gas by means of that system to any premises and comply with any reasonable request to connect to a pipeline system operated by another authorised transporter.

Access to the gas network is provided on an entry-exit basis instead of on a point-to-point basis. As access rights comprise entry and exit capacity at entry and exit points, shippers are required to book entry capacity and exit capacity to flow and take gas (there are relatively few entry points – principally gas terminals at which gas is landed from offshore fields).

iii Rates

For electricity, the rates payable for connection to and use of the transmission system are set out in NGET’s charging statements. The charges are broadly made up of the following:

a transmission network use of system charges: to recover the revenue for the transmission system owners, that is NGET, the Scottish transmission owners, OFTOs, and in future CATOs;

b balancing services use of system charges: to recover the cost of balancing the transmission system, and which depend on the amount of balancing required; and

c connection charges: to recover the cost of installing and maintaining connection assets used by the party connecting to the transmission system. It takes into account the asset value, asset age and maintenance costs. Connection charges are not normally paid by generators in the United Kingdom (England and Wales).

On 13 March 2017, Ofgem launched a consultation focused on review of residual charges both at transmission (TNUoS charges) and distribution (DUoS charges) level (for more information see Section VI, below). Residual charges are intended to top up and make up for any deficit in the revenues allowed to be recovered by network companies after forward-looking charges have been levied. In contrast, forward-looking network charges are intended to send signals to market for matters such as where to place generation, fuse size, etc., but these are not being reviewed at the moment.
Price control

Ofgem regulates the prices for regulated assets pursuant to the licence terms of the given gas or electricity licensee. The current price control model is known as RIIO (Revenue =Incentives+Innovation+Outputs). These RIIO price controls set out the revenue that the network companies are allowed to recover and what they are expected to deliver, as well as specifying details of the regulatory framework over the eight years from 2013 to 2021 for transmission and gas distribution, and from 2015 to 2023 for electricity distribution.

The RIIO price controls are established against framework objectives set by Ofgem, against which the network companies present a business plan detailing how they intend to meet the objectives. The business plans are evaluated and approved by Ofgem. The process places major value on stakeholder engagement in the decision-making, efficient investment in services, innovation in networks and reduction of carbon outputs.

Additionally, in its final report on the energy market investigation the CMA has proposed a transitional price cap for customers on prepayment meters from 2017–2020 and this has been implemented by Ofgem. In addition, since February 2018, Ofgem has extended this price cap to vulnerable customers who receive the Warm Home Discount (WHD). This driver behind this further change is to extend the scope of the existing prepayment meter safeguard tariff to protect circa one million consumers who receive WHD.

iv Security and technology restrictions

While there are no specific security and technology restrictions in GB, concerns around national security, cybersecurity and data processing come up in the context of electricity and gas markets. These are typically dealt with through bilateral contracts and protocols.

IV ENERGY MARKETS

i Development of energy markets

Electricity

GB was among the pioneers of electricity sector liberalisation from the mid-1980s, when the Energy Act 1983 created the requirement for the state-owned area boards to offer private generators access to their networks and to purchase the power they generated. Since 1991, the electricity market was privatised and the parties are now free to trade on the basis of bilateral contracts.

Northern Ireland operates a separate wholesale electricity market with a pool system, the Single Electricity Market (SEM), which is integrated with the wholesale electricity market in the Republic of Ireland. A distinct market therefore operates across the island of Ireland; however, the SEM is currently undergoing significant changes to make it compliant with the European Target Model and these changes are intended to fully take effect in October 2018.

Gas

Gas trades, subject to licensing requirements, can be traded by gas shippers within the NTS and at exit points on the gas system. This is usually done on the basis of standard-term contracts and in line with the requirements of the UNC.

The regulatory regime for gas has recently undergone reform through the development of the European Union-wide Network Codes. Regulation (EC) No. 715/2009 provided for the establishment of Network Codes to help facilitate cross-border network access and
market integration. These Network Codes were thought necessary because of the increased interconnection and trade between EU countries and the need to manage gas flows. These Codes further inform the trading of gas.

ii Energy market rules and regulation

Energy market rules are largely set out in industry codes such as the Grid Code, the CUSC and the BSC. Compliance with these is governed through licence conditions.

The BSC is particularly relevant for market trading. It seeks to ensure that total electricity generation and demand are balanced in real time, through a balancing mechanism operated by National Grid. It also quantifies imbalances between the amounts of electricity traded and the actual electricity generated or consumed, and regulates how these are paid for through a post-event imbalance settlement process operated by ELEXON. The BSC contains the rules and governance arrangements for the balancing mechanism and imbalance settlement processes. These arrangements, and the scope of the BSC, were subsequently extended to Scotland in April 2005 under the BETTA. Most electricity trading is done on the basis of industry standard contracts (Grid Trade Master Agreements (GTMAs) or an International Swaps and Derivatives Association Master Agreement with a GTMA index) or by way of bespoke power purchase agreements between generators and suppliers.

Electricity trading is also subject to market transparency regulation and requires disclosure of price-sensitive information to the market. The Regulation on Wholesale Energy Market Integrity and Transparency, initially adopted in December 2011, extends the concept of the Market Abuse Directive to physical gas and power, and requires market participants to disclose physical inside information, and to avoid attempted and actual market manipulation and abuse. More recently, the Markets in Financial Instruments Directive II has significantly narrowed the exemptions currently available to commodity derivatives trading firms to ensure that ‘participants on commodity derivatives markets [are] subject to appropriate regulation and supervision’. It is worth noting that although the United Kingdom voted to leave the European Union, the government has given assurances that it will continue to implement EU legislation until the Article 50 procedure and the transitional period are completed, and thereafter, a proposed Great Repeal Bill will incorporate EU law into national legislation.

iii Contracts for sale of energy

Generators, electricity suppliers, electricity traders and large customers can enter into commercially negotiated contracts to buy and sell electricity. The volumes (not commercial details) of the resulting trades are notified to the system and market operators, and any failure to achieve these notifications (called imbalances) are priced and settled. Trading takes place on a half-hourly basis with gate closure – set one hour ahead of real time – and participants notifying the system operator of their intended final physical position. After this point, no further contract notification can be made and settlement is based on positions at gate closure.

iv Market developments

There are a number of changes affecting the UK energy and gas markets. For example, in electricity transmission in GB, there are plans to introduce competitive auctions or models to build new onshore transmission lines. Ofgem is also continuing to run auctions for competition in offshore transmission.
There has also been a rise in the number of new entrants to the electricity supply markets. This is in line with government aims to decrease the dominance of the ‘Big Six’ vertically integrated utilities in the domestic supply market.

The introduction of the GB capacity market in 2013 has also given rise to more attention being paid to demand-side response and how it is able to provide security of supply during times of system stress. In this respect, National Grid has launched a new demand-side response product, namely the Demand Turn Up ancillary service (for which 138.6MW has been purchased for spring/summer 2017). The service is procured by National Grid and was introduced in 2016 to encourage large energy users and generators to either increase demand (i.e., take energy off the network) or reduce generation.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

The UK has a long-established renewable energy policy. At the national level, the UK, via the Climate Change Act 2008, has committed to a reduction of greenhouse gas emissions by 34 per cent by 2020 and 80 per cent by 2050 in comparison with 1990 levels.

The current main driver for renewable energy policy in the UK is the EU Renewable Energy Directive (RED).\(^7\) The RED aims to reduce the EU’s dependency on fossil fuels and to foster low-carbon and sustainable energy generation. EU Member States agreed under the RED to jointly achieve a target of 20 per cent of energy consumption from renewable sources by 2020. Beyond the 2020 renewable targets, EU countries agreed in 2014 on a policy framework for 2030 including targets for a 40 per cent cut in greenhouse gas emission, 27 per cent share on renewable energy consumption and at least 27 per cent reduction on energy use.\(^8\) However, pursuant to the 2014 policy framework agreement, the European Commission has put forward an amendment proposal to the RED that would, among other things, replace nationally binding 2020 renewables targets with an EU-wide target of 27 per cent renewable energy by 2030. Other amendments would seek to extend national renewable support mechanisms to projects in other member states (which the UK states may not be compatible with the principle of subsidiarity) and boost the proportion of renewable energy used for heating, cooling and transport.\(^9\) The RED amendment proposals are set to enter into force on 1 January 2021 (i.e., post the UK’s exit from the EU in early 2019) and as previously stated, until the Brexit Article 50 procedure is complete, the UK will continue to implement and observe EU law as normal. After the UK’s exit from the EU is effected, the entirety of EU legislation will be enshrined in national law by means of what the government calls a Great Repeal Bill. Renewables targets will, however, remain unaffected regardless of the final Brexit position as the UK’s national renewables and decarbonisation targets exceed those imposed at EU-level. However, the government’s focus on achieving industrial growth post-Brexit may render decarbonisation targets secondary to those of ensuring security of supply for large industrials. Not least, exit from the EU could potentially allow the UK to

---


8 For more information on the EU 2030 Energy Strategy see https://ec.europa.eu/energy/node/163.

pursue an even more ambitious energy policy given that EU rules on state aid would cease to apply (however, the UK may still have to observe EU state aid rules to secure unrestricted access to EU markets).

**Contracts for Difference**

In the UK electricity sector, the main support for renewables is through Contracts for Difference (CfDs), which were introduced in 2013 by the Energy Act 2013 as part of the United Kingdom’s Electricity Market Reform (EMR) programme. Prior to its introduction, the main support measures available for low-carbon generation were in the form of the Renewables Obligation (RO) for large-scale, and Feed-in Tariffs (FiTs) for small-scale projects.

CfDs are 15-year contracts entered between a government-owned company, the Low Carbon Contracts Company, and the eligible low-carbon generators. The CfD mechanism works by setting a fixed price (strike price) thus reducing the generator’s exposure to electricity prices volatility and consequently the cost of capital of the investment. The first allocation round for CfDs took place in October 2014 and contracts were awarded to 27 projects in February 2015. The second allocation round for CfDs for the 2021/22 and 2022/23 Delivery Years took place in April 2017 and 11 projects were successful in obtaining contracts. The government estimated that the capacity delivered under the second allocation round cost up to £528 million per year less than it would have in the absence of competition. The third allocation round is currently planned to be held in the spring of 2019 for less established technologies (e.g., remote Scottish island wind).

**Renewables Obligation**

Support for renewable generation via the RO scheme was introduced in England and Wales in 2002 and administered by Ofgem. The RO scheme imposes an obligation on electricity suppliers to source a fraction of their electricity from renewable generation, and compliance with this obligation is shown by obtaining RO certificates issued to generators accredited on the scheme (with the number of certificates issued varying depending on the technology and the value of each certificate being broadly maintained through terms, such as a buyout price, set from time to time by the electricity regulator).

The RO has been closed to all new generation from the end of March 2017, but the process of closure has been implemented gradually through a series of legislative amendments, which imposed a cap on biomass, closed support to solar PV (large-scale on March 2015, and small-scale on March 2016) and closed support for onshore wind in May 2016. Early closures are subject to provisions of specific grace periods.

**FiTs**

The FiTs scheme was introduced to promote the deployment and use of small-scale (5MW and below) renewable and low-carbon generation. The FiTs scheme began operation on 1 April 2010 and is administered by Ofgem, which accredits generators, maintains the Central FiT Register of the accredited installations and monitors the reaching of deployment caps as well as compliance with the scheme.

---

Payments under the scheme are administered and performed by FiT licensees – suppliers that join the FiT scheme either compulsorily (those supplying more than 250,000 domestic users) or voluntarily – which then pass on costs to consumers. A fixed payment is made under the FiT scheme for electricity that is generated on-site, the ‘generation tariff’, and another payment for any unused electricity that the generator exports to the grid, the ‘export tariff’.

Major changes to the FiT scheme were introduced at the end of 2015, including a reduction of tariffs, the introduction of quarterly deployment caps coupled with a default degression mechanism and an overall FiT budget limit.

ii  **Energy efficiency and conservation**

Until recently, the CRC Energy Efficiency Scheme was a mandatory carbon emissions reduction scheme that applied to large non-energy-intensive organisations. This was scrapped in March 2016 with effect from the end of the 2018/2019 compliance year.

The Climate Change Levy (CCL) is a tax on energy delivered to non-domestic consumers that aims to incentivise increased energy efficiency. The government has introduced a 100 per cent exemption from CCL for energy used in certain energy-intensive (metallurgical and mineralogical) industrial processes. Further, Climate Change Agreements are voluntary agreements that allow eligible energy-intensive sectors to receive up to 90 per cent reduction in the CCL if they agree to meet certain energy efficiency targets.

Separately, the government has introduced the Renewable Heat Incentive (RHI) scheme aimed at promoting energy efficiency through encouraging renewable heat. The RHI is aimed towards levelling the cost of renewable heat with that of heating from fossil fuels. The RHI was first introduced in November 2011 for non-domestic heating and subsequently expanded to include domestic heating support. Duration of support is 20 years for the former and seven years for the latter category. On 12 October 2017, the government put forward proposals to reform the RHI with a view to increasing the focus of the scheme on increased adoption of various technologies such as biomethane and heat pumps.

iii  **Technological developments**

The electricity and gas sectors continue to attract much interest in the development of technologies. For several years, the UK government encouraged the development of industrial carbon capture and storage (CCS) and is funding a four-year co-ordinated research, development and innovation programme into CCS technologies. However, in late 2015 the government announced it was cancelling funding for a UK Carbon Capture and Storage (CCS) Commercialisation competition which would have made available £1 billion capital funding for the design, construction and operation of the UK’s first commercial-scale CCS projects.

The UK government has also set up a Low Carbon Innovation Co-ordination Group to support innovation in energy technologies to meet the climate change goal of an 80 per cent reduction in greenhouse gas emissions by 2050. The group aims to maximise the impact of UK public sector support for low-carbon technologies.

The UK is emerging as a market leader and pioneer in the battery storage industry. According to an All Party Parliamentary Group on Energy Storage, the deployment of 12GW of battery storage by the end of 2021 is achievable and would encourage post-Brexit growth.\footnote{http://www.r-e-a.net/upload/energy_storage_appg_report_dec_2017--large--final.pdf.}
VI THE YEAR IN REVIEW

Although the UK market has had to cope with significant uncertainty resulting from Brexit negotiations and the government’s somewhat related focus on reducing costs, the energy market has thus far demonstrated significant resilience to those developments. That is not to say that concerns and risks are behind us, as the true costs of issues such as Brexit will only truly emerge when the complete suite of exit and future trade agreements are fully settled, ratified and implemented.

The UK continues to enjoy a strong pipeline of interconnectors that benefit from the support of Ofgem and BEIS; however, it remains to be seen to what extent these will reach completion given uncertainties caused by Brexit not only in the UK but also in neighbouring countries. A recent example of negative impacts caused by enduring uncertainties relating to the UK’s future relationship with Europe is the French regulator’s decision to suspend approvals for new France-UK interconnectors projects (i.e., those that have not already been approved) until there is greater clarity in that respect.

The closure of the RO scheme in 2017, coupled with the sparsity of new CfD allocation rounds, has had an impact on new build renewable projects. The RO has historically been responsible for delivering much of the UK’s renewable new build generation and supported 69.1TWh or 23 per cent of UK electricity generation between April 2015 and April 2016, which is in stark contrast to the 1.8 per cent of generation supported by FiTs. Although CfDs were promoted as the instrument intended to replace the RO, the market has not seen the two mechanisms as like-for-like, especially given that CfDs are currently open only to those less established technologies. That said, appetite for developing renewables remains strong as indicated by the oversubscription of bids for the second CfD allocation round where bids received equated to 10 times the value of the final contracts awarded.

In contrast to the decrease in new build renewables, a prominent feature of the past year has been the regulator’s and the government’s increasing focus on flexibility and reliability. This is reflected in the latest T-4 Capacity Market auction for which results were announced in February 2018, where the level of support dropped to its lowest ever level (£8.40/Kw) and continued the trend of existing closed cycle gas capacity taking the lion’s share of the pot (followed by existing nuclear, CHP, interconnectors and coal/biomass). An encouraging feature of this latest Capacity Market auction was that storage and demand side response had a strong showing, winning a significant proportion of contracts. What has not happened, however, is the long-awaited arrival of new gas peaking plant, which is, ironically, an indictment of and results from the very low levels of support under the Capacity Market achieved through competition.

As touched on previously, Brexit has proven to be a much more complicated and extensive exercise than many would have thought only a year ago. As a result, there has been limited parliamentary and, indeed, ministerial time available for the development of new schemes such as CATOs. This has not prevented Ofgem from trying to devise methods (e.g., in relation to transmission reinforcements carried out by NGET in respect of Hinkley Point C) that emulate competition in transmission assets as closely as possible. It remains to

---

12 For example, CfDs are open to technologies in Pot 2 (which includes offshore wind) but not Pot 1 (which includes onshore wind and solar or Pot 3 (biomass).
be seen to what extent such ad-hoc competitive models will be fit for purpose and deliver sufficient savings to justify any disruption or delays they may cause to critical infrastructure projects.

The UK regulatory and legal framework for energy remains a guiding light for many developing countries wishing to inject competition into their electricity and gas markets. This is reinforced, for example, by the regulator’s and government’s efforts to define and integrate battery storage within the regulatory arrangements so as to maximise the efficiencies that technology can bring. However, in a move that would have surprised many if not most just a few years ago, the general election in 2017 coupled with stagnating wages (and living standards generally) prompted both the Conservative and Labour parties to include in their election manifestos price caps on rising energy costs for consumers. In the event, the Conservative government that emerged from the election decided to implement a much less ambitious price cap covering only those consumers with prepayment meters, which was later extended to also include those receiving the Warm Home Discount. Such caps were supported by the conclusions of Professor Dieter Helm’s ‘Cost of Energy Review’ (commissioned by the government), which also proposed a much more ambitious overhaul of the UK’s energy markets; however, the government has yet to decide how to take those proposals forward (if at all).

In terms of networks, the highlight of the past year has been Ofgem and the government’s announcement of their plans to legally separate the system operator role performed by National Grid from its other capacity of being a transmission owner. The stated aim of this move is to help ‘keep household bills down by working to ensure and enable more competition, coordination and innovation across the system’.

Challenging weather conditions, particularly in the winter, have led some to query the ability of the UK’s gas infrastructure to adequately deal with demand (and therefore price) spikes. This issue has been compounded by the closure of key gas storage assets such as Centrica’s Rough facility (which provided close to 70 per cent of the UK’s gas storage capacity). That said, an increasingly booming and maturing global LNG market, coupled with the opening of new LNG terminals at Teesside and Port Meridian, may allay some of the concerns relating to security of supply.

VII CONCLUSIONS AND OUTLOOK

In one sense, it would be sensible to expect the near-to-medium term to be a period of significant regulatory and legislative change; however, there is a real prospect that the diaries of ministers and regulators will be too crowded out by Brexit for any meaningful and considered changes to the current framework to be put forward.

As previously mentioned, the report on the cost of energy commissioned by the government and prepared by Professor Dieter Helm contained a comprehensive set of proposals aimed at radically changing many of the structures, mechanisms and frameworks that currently support the UK’s energy ecosystem. As part of that review, and among many other proposals, it was suggested that the Capacity Market and CfDs are merged into a unified equivalent firm power capacity auction to give further support to renewables development, possibly in recognition of the fact that CfDs did well to reduce costs but are not sufficiently
incentivising new build renewables. The government has put out to consultation many of Professor Helm’s proposals and market participants are awaiting final decisions in that respect.13

More generally on renewables, it is important that a distinction is made between technologies such as onshore wind and offshore wind. The former, owing to increasingly onerous planning restrictions and activism, are not expected to grow significantly in the foreseeable future; however, there is an entirely different (success) story for offshore wind, a technology for which the UK remains a leading global player. That said, the opening up of the third CfD allocation round to remote Scottish island onshore wind may mean that that technology has a future in places where its energy benefits far outweigh the aesthetic displeasures it may cause. In addition, the cost decreases being achieved for certain technologies (e.g., onshore wind, solar) may mean that grid parity is soon reached and a subsidy-free environment becomes something that is achievable without sacrificing climate change objectives due to subsidy-related cost pressures.

Another development that promises to be of interest to many market players is the progress through parliament of the government’s Domestic Gas and Electricity (Tariffs Cap) Bill, which seeks to put in place much wider price caps on electricity and gas suppliers’ tariffs than the ones currently imposed by Ofgem for vulnerable consumers. We have already started to see potential divestment and consolidation of players in the supplier market as a result of this increasingly interventionist and price control-oriented approach taken by the government in the supply markets.

Finally, it remains to be seen what progress Ofgem will make in its efforts to create a wider role for DNOs by extending the scope of their role to that of Distribution System Operators, who may have an additional role in balancing and managing an increasingly dynamic embedded generation market.

---

Chapter 35

UNITED STATES

Eugene R Elrod, Michael J Gergen, Natasha Gianvecchio, J Patrick Nevins and David L Schwartz

I OVERVIEW

Energy regulation in the United States is complex, broad and enforced by a variety of federal and state governmental entities. Further, it is continually evolving in response to global, national and regional events, supply/demand balance and other market shifts, political dynamics and priorities, and technological advances. As such, this chapter is intended to be an overview of the nature and scope of energy regulation and markets.

II REGULATION

i The regulators

Multiple federal and state agencies, departments and other governmental entities regulate US energy development, and the ownership, control and operation of electric energy, natural gas and oil production, gathering, transmission/transportation and distribution of energy resources, including with respect to the rates, terms and conditions of wholesale and retail services, as well as energy market rules.

The Federal Energy Regulatory Commission (FERC) is an independent federal regulatory agency established by the United States Congress initially as the Federal Power Commission to license hydroelectric facilities and regulate wholesale sales of electric energy and natural gas and the transmission of electric energy or transportation by pipeline of natural gas in interstate commerce. Subsequently, FERC’s authority was expanded to include the regulation of interstate shipments of certain liquid fossil fuels via pipelines, including crude oil, petroleum products and natural gas liquids, such as propane and ethane. FERC’s authority is granted, and limited, by statutes, as amended over time, including the Federal Power Act of 1935 (FPA), the Natural Gas Act of 1938 (NGA), the Public Utility Regulatory Policies Act of 1978, the Natural Gas Policy Act of 1978, the Interstate Commerce Act of 1887, the Energy Policy Acts of 1992 and 2005, the Public Utility Holding Company Act of 2005 and the Department of Energy (DOE) Organization Act of 1977.

The Nuclear Regulatory Commission (NRC) is an independent federal regulatory agency established by Congress to formulate policies and regulations governing nuclear reactor and materials licensing and safety. The NRC’s authority is also granted, and limited, by statutes, including the Atomic Energy Act of 1954, as amended, and the Energy Reorganization Act of 1974, as amended.

1 Eugene R Elrod, Michael J Gergen, Natasha Gianvecchio, J Patrick Nevins and David L Schwartz are partners at Latham & Watkins LLP.
The DOE is an executive department created in 1977 via the DOE Organization Act whose current mission ‘is to ensure America’s security and prosperity by addressing its energy, environmental and nuclear challenges through transformative science and technology solutions’. The DOE is led by the Secretary of Energy, a member of the President’s cabinet. FERC is within the DOE, and, under the DOE Organization Act, the DOE and FERC sometimes have overlapping and sometimes have separate authorities under their relevant organic statutes, including the FPA and the NGA. For example, under the NGA, the DOE is responsible for issuing authorisations to import and export natural gas to and from the United States, including liquefied natural gas (LNG). At the same time, under the NGA, FERC is responsible for issuing authorisations to construct and operate LNG import and export terminals.

Numerous other federal agencies and departments regulate certain aspects of the US energy industry, including the Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (PHMSA) and Maritime Administration, Environmental Protection Agency, the Army Corps of Engineers, the Commodities Futures Trading Commission, the Federal Trade Commission, and the United States Departments of Agriculture, Interior, State, Commerce and Justice. The production and gathering of crude oil and natural gas, the siting and construction of energy facilities (except hydroelectric and natural gas facilities regulated by FERC), and the distribution and retail sale of electric energy and natural gas are generally governed by individual state regulatory agencies. In many states, public utility regulation is carried out by public service commissions or public utility commissions (PUCs) or municipal agencies (or both). The jurisdiction of these state-based and locally-based regulatory agencies over energy companies is created by state constitutions and statutes and, like most state regulation in the United States, is also subject to the supremacy of the US government under the United States Constitution and federal statutes, except in certain limited circumstances.

ii Regulated activities

Many aspects of energy development, generation, production, transmission/transportation, and distribution in the United States are subject to some type of federal or state regulation.

FERC regulates the rates, terms and conditions of wholesale sales of electric energy in interstate commerce and the transmission of electric energy in interstate commerce. FERC also regulates the rates, terms and conditions of natural gas and oil pipeline transportation services. Entities making sales of FERC-jurisdictional products or services obtain rate approval from FERC. FERC rates for electric transmission and interstate natural gas transportation and storage are typically either cost-based (i.e., based on the costs of providing the product or service including a reasonable return on equity investment) or market-based (i.e., negotiated or market-determined). Rates for petroleum pipeline transportation services may be based on historical and projected costs; and most pipeline rates are adjusted based on changes in a producer price index that measures the average change over time in the selling prices received by US producers for their output (plus a FERC-specified adjustment). FERC also regulates entities subject to its jurisdiction with respect to matters that may affect rates, including with respect to accounting, record-keeping and reporting, and, with respect to companies regulated under the Federal Power Act, direct issuances of securities and direct and indirect transfers of control over FERC-jurisdictional facilities.

Under the NGA, FERC is authorised to approve the construction and operation of new (and abandonment of existing) interstate natural gas pipeline and storage facilities and,
as discussed previously, LNG import and export terminals. Owners of natural gas facilities authorised by FERC (but not LNG terminals) may call on a federal power of eminent domain to condemn land on which to site approved facilities. As a condition to the construction of new natural gas pipeline and storage facilities, FERC may require natural gas companies to, among other things, conduct an ‘open season’, during which potential customers may subscribe to transportation or storage capacity on a non-discriminatory basis and existing customers may turn back capacity that may result in the downsizing or elimination of the new facilities. In exercising its rate jurisdiction over electric transmission facilities and oil pipelines, and in conjunction with its open access requirements, FERC has also required open seasons for some or all new or expanded capacity on certain electric transmission and oil pipeline facilities.

The NGA was amended in 2005 to expedite the licensing process for the construction of interstate natural gas pipelines and storage facilities, and to clarify and modify FERC’s review and approval of the construction and operation of LNG import and export terminals. The 2005 amendments also codified FERC’s existing policy of ‘light-handed’ regulation of LNG terminals by prohibiting FERC from regulating the rates, terms, and conditions of service for LNG terminals, but only until January 2015. Since passage of this date, FERC has not exercised any authority to regulate the rates, terms and conditions of service of LNG facilities, and instead has continued to allow LNG import and export terminals to charge market-based rates and to operate without imposing open access requirements. Under the FPA, FERC also has siting approval authority with respect to hydroelectric generating facilities to be constructed on navigable waterways. In 2005, Congress also gave FERC ‘backstop’ siting authority under the FPA to issue permits for the construction of transmission lines when the DOE designates important ‘national interest electric transmission corridors’ (NIETC) for geographical areas experiencing transmission constraints or congestion that adversely affects consumers, although the scope of FERC’s backstop siting authority and the DOE’s NIETC designation authority under the FPA remains unclear as a result of judicial decisions in the US Courts of Appeals.

PHMSA regulates the safety of most US pipelines and LNG terminals. Although PHMSA is responsible for enforcement of US laws setting minimum pipeline and LNG safety standards, PHMSA allows states to assume inspection and enforcement authority if the state has adopted the federal minimum standards into law.

Pipelines located in US waters on the Outer Continental Shelf are subject to regulation by the US Department of Interior. Prior to the Deepwater Horizon oil spill in the Gulf of Mexico in 2010, the Department of Interior’s offshore pipeline responsibilities were carried out by the Minerals Management Service; however, in 2010, these responsibilities were transferred to a new agency, the Bureau of Ocean Energy Management, Regulation and Enforcement, and then transferred again in 2011 to two new bureaus: the Bureau of Ocean Energy Management and Bureau of Safety and Environmental Enforcement (BSEE). Offshore pipelines located within three miles of the United States are also often subject to state regulation.

State PUCs generally regulate the distribution and delivery of electricity and natural gas to retail customers, including rates, terms and conditions for retail sales and distribution of electric energy and natural gas, and the safe and reliable delivery of electricity and natural gas to retail customers in the state. State PUCs may also regulate rates and operating conditions
for intrastate natural gas pipelines and storage services and for intrastate deliveries of liquid fossil fuels by pipeline. Siting approvals for the development and construction of new energy facilities are often required at the state or local government level.

iii Gathering, terminalling, processing, and treatment of natural gas and oil

In states where natural gas and oil exploration and development is active, state agencies often possess regulatory authority over gathering (typically the collection and movement of resources by pipeline from production wells to a centralised processing station or other central collection point) of natural gas and oil. Many states have adopted rateable take and common purchaser statutes, which generally require gatherers to take or purchase, without undue discrimination, production that may be tendered to the gatherer for handling or sale. These statutes are generally enforced by PUCs only when a complaint is filed. The processing and treatment of natural gas and the storage and terminalling of oil are generally not regulated. However, FERC may regulate a gathering or processing line if it determines that the primary function of the line is the transmission (not gathering) of gas; and it may regulate an oil pipeline terminal or storage facility if it determines the facility is a necessary component of the pipeline's transportation function.

Regulation of the safety of natural gas gathering and processing facilities largely depends on the location and configuration of the facilities. Some facilities may be unregulated; others may be regulated by one or more state and federal agencies, to include the PUC, PHMSA, BSEE and the Occupational Safety and Health Administration.

iv Ownership, market access restrictions and transfers of control

The Committee on Foreign Investment in the United States oversees foreign investment in existing companies and assets in the United States, with the President having ultimate authority to deny foreign investment that may adversely affect national security. Other than with respect to nuclear energy, there is little restriction on foreign ownership of energy assets in the United States under US energy-specific laws and regulations.

FERC approval is generally required for the direct transfer of natural gas facilities subject to FERC’s jurisdiction, to include transfers that spin down or partially remove facilities from FERC’s jurisdiction (or reduce current services). In reviewing a proposed direct transfer of interstate natural gas facilities, FERC must determine whether the ‘abandonment’ of the facilities by the transferor is consistent with, and the ownership and operation of the facilities by the transferee ‘is or will be required by’ the ‘present or future public convenience and necessity’. In both cases, FERC applies a public interest test that considers matters such as the effect of the transfer on competitive conditions and existing customers and services, including rates.

FERC also regulates the direct and indirect transfer of control over electric transmission and generation facilities. In reviewing a proposed transfer of electric transmission or generation facilities, FERC must determine whether the transaction is consistent with the public interest, including the effect on competition, the effect on rates and the effect on regulation. FERC also considers whether the transaction would result in the cross-subsidisation of a non-utility affiliate of a public utility or the pledge or encumbrance of utility assets for the benefit of a non-utility affiliate of a public utility.

PHMSA requires operators of regulated facilities to provide notice of certain transfers, name changes, acquisitions and divestitures no later than 60 days after the event. New
operators must also be fully in compliance with PHMSA regulations, including drug-testing, recordkeeping and operator ID requirements, upon owning or operating an active or idled pipeline.

Certain states also require that entities obtain PUC approval prior to the direct and, in some jurisdictions, indirect transfer of assets subject to the jurisdiction of the PUC. While many state statutes require PUCs to evaluate whether a proposed transaction is consistent with the public interest, PUCs vary as to whether they interpret their jurisdiction as requiring a showing that the transaction will not result in net harm to the public or a showing that the transaction will provide net benefits to the public.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration, unbundling and open access

Over the past four decades, the federal government and many state governments have sought to replace traditional forms of cost-based regulation of services provided by vertically integrated monopolies with regulation designed to promote open access and competitive market forces.

Natural gas sector

Prior to the mid-1980s, the natural gas industry was fairly rigidly structured into three parts: 

- producers that sold natural gas to pipeline companies;
- pipeline companies that resold and delivered that natural gas to distributors on a ‘bundled’ basis (combining the commodity cost of the natural gas with the cost of transportation service); and
- distributors that sold natural gas to retail customers.

Certain large industrial and electrical generating companies bought natural gas directly from producers or pipelines. And many local distributors had, in response to shortages in the 1970s, entered into long-term ‘take or pay’ contracts with pipelines for firm delivery of natural gas supplies for their customers. When gas prices fell in the 1980s, these distributors contracts required payment for minimum volumes at the historic, higher prices. In an effort to address this issue, and open natural gas markets to widespread competition, FERC issued Order No. 380 in 1984 voiding contractual requirements that distributors purchase minimum quantities of natural gas from pipelines. The next year FERC issued Order No. 436 encouraging voluntary ‘unbundling’ of pipelines (i.e., transportation services not tied to purchases of natural gas from the transporting pipeline or its affiliates). A few years later Congress passed the Natural Gas Wellhead Decontrol Act of 1989, lifting price controls on sales of natural gas by producers. FERC then adopted rules effectively deregulating the price of all other wholesale sales of natural gas. These orders were followed by FERC’s landmark ‘restructuring’ order (Order No. 636) in 1992. Order 636 enhanced natural gas market competition by imposing new open access rules, requiring interstate pipeline and storage providers to offer unbundled transportation services at tariff rates on non-discriminatory terms and conditions set by FERC, promoting development of market hubs, allowing flexible use of receipt and delivery point rights and release of firm transportation and storage rights, among other reforms. Also in 1992, the NGA was amended to effectively eliminate DOE
permitting procedures associated with all natural gas imports, and exports to free-trade nations (coinciding with an agreement reached under the North American Free Trade Agreement to remove gas tariffs between the US, Canada, and Mexico).

FERC has continued to implement reforms to liberalise US natural gas markets by requiring compliance with new standards of conduct that prohibit transmission function personnel from communicating non-public, competitively sensitive information to marketing personnel, requiring interstate natural gas pipelines to phase in standards adopted by the North American Energy Standards Board for internet-based information systems (to facilitate more efficient and transparent scheduling, reporting and use of available pipeline capacity), developing secondary markets for transportation services, market centres and customers’ rights to segment transportation capacity into forward and backward hauls and to use secondary receipt and delivery points on pipeline systems on a non-firm basis, and modifying scheduling timelines to facilitate improved gas-electric coordination. During these same periods, many states also modified the exclusive retail franchises of distributors to permit open access competition in the retail sale of natural gas, while continuing to regulate natural gas utility distribution services provided under exclusive franchises. These reforms led to highly competitive natural gas sales markets in the United States, where only pipeline transportation and distribution services, and certain storage services, are subject to rate regulation.

**Electric sector**

The electric sector in the United States was also dominated by franchised monopolies. Prior to the early 1990s, vertically integrated electric utilities with monopoly retail franchises owned and controlled most of the facilities used for the generation, transmission and distribution of electricity within their franchised service territories. Many vertically integrated utilities were widely traded stock corporations, although some were owned by the US or state governments. Numerous municipally owned or cooperatively owned utilities also distributed electricity at retail, although these publicly owned utilities were typically smaller and more likely to be dependent on investor-owned utilities for transmission services to access generation located outside their service territories.

In 1978, Congress enacted the Public Utility Regulatory Policies Act to encourage the deployment of renewable and energy-efficient technologies by requiring electric utilities to purchase electric power from generating sources using advanced technologies and eliminating all restrictions on the ownership of qualifying generating facilities. Non-utility companies demonstrated a high level of interest in building new power plants, which led in 1992 to Congress’s elimination of all ownership restrictions on facilities generating electricity for sale at wholesale. At the same time, both the federal government and many states began to liberalise their wholesale and retail electricity markets, including state efforts to have state-regulated public utilities divest some or all of their electric generation and federal efforts to make bulk power transmission facilities and distribution facilities available to others on an open access basis.

As part of the 1992 legislation, Congress amended the FPA to authorise FERC to order interstate transmission-owning public utilities to provide any electric utility, federal power marketing agency, or any other person generating electric energy for wholesale sales open and non-discriminatory access to their transmission facilities. As envisioned by Congress,
such open access would allow bulk power consumers and suppliers to enjoy the benefits of
competition in bulk power markets, as well as in those downstream retail power markets
liberalised by states.

In 1996, FERC issued Order Nos. 888 and 889 to establish the foundation for
the development of competitive bulk power markets by directing that bulk power
transmission services be provided on an open access basis that is just, reasonable and not
unduly discriminatory or preferential. Order No. 888 required that all FERC jurisdictional
transmitting utilities in the United States file a *pro forma* open access transmission tariff
(OATT) and functionally unbundle their wholesale power services from their wholesale and
retail transmission services. Order No. 888 also encouraged transmitting utilities to convey
operational control of their transmission facilities to independent system operators (ISOs) or
other independent regional transmission organisations (RTOs), which led to the formation
of ISOs and RTOs in regions including the large majority of electrical load in the United
States.

The *pro forma* OATT requires transmitting utilities to provide open, not unduly
discriminatory, access to their transmission system to transmission customers and addresses
the terms of transmission service, including the terms for scheduling service, curtailments
and the provision of ancillary services. Transmitting utilities are permitted to vary from the
required *pro forma* terms of service if FERC finds that their proposed variations are equally
or more conducive to the OATT’s open access objectives. Order No. 889 required codes of
conduct governing how participants in the wholesale power markets should interact with
transmission service providers and the establishment of electronic bulletin boards (open access
same-time information systems) for the posting of details regarding available transmission
capacity.

Since Order Nos. 888 and 889, FERC has issued a range of major orders updating and
expanding its open access policies to address such matters as: the formation of and participation
in RTOs; *pro forma* procedures and agreements for interconnection of generation to the bulk
power grid; changes to the *pro forma* generator interconnection procedures and agreements
to facilitate interconnection of wind generators; general rules to facilitate more open and
transparent planning and use of wholesale transmission facilities; and most recently, general
rules regarding transmission planning and cost allocation. FERC continues to consider
whether reforms to its open access policies are necessary to eliminate possible barriers to the
integration of wind, solar and other variable energy generation resources, as well as energy
storage (e.g., batteries) and distributed energy resources, and to respond to market changes,
including the growing deployment of small distributed generation resources, such as solar
photovoltaic installations.

FERC’s Order No. 1000 adopted significant reforms of FERC’s transmission planning
and cost-allocation rules established previously in Order No. 890. Order No. 1000 sought
to address significant recent changes in the bulk power industry, including an increased
emphasis on integrating renewable generation and reducing congestion, by implementing
new policies to push transmission providers and planners to seek the most reliable, efficient
and cost-efficient solutions. The major reforms of Order No. 1000 include:

- requiring each public utility transmission provider to participate in a regional
  transmission planning process that produces a regional transmission plan and regional
  and interregional cost allocation methods for planned projects;
requiring each public utility transmission provider to amend its OATT to describe procedures for considering transmission needs driven by public policy requirements established by state or federal laws or regulations, such as state renewable portfolio standards;

removing from FERC-approved tariffs and agreements any federal right of first refusal for incumbent utilities to build and own certain new transmission facilities; and

improving coordination between neighbouring transmission planning regions.

Order No. 1000 also provides that transmission upgrade cost allocations must be roughly commensurate with the benefits received. FERC required public utility transmission providers to begin making filings with FERC during 2012 that proposed revisions to their transmission planning processes under their respective OATTs to comply with Order No. 1000. Throughout 2013, FERC issued orders regarding some of these compliance filings in which it accepted and rejected various proposed revisions, including rejecting a number of proposals to retain certain types of rights of first refusal for incumbent transmission providers to build-and-own transmission projects eligible for socialised cost recovery. Various aspects of Order No. 1000, including its directives on cost allocation and rights of first refusal, were appealed to the US Court of Appeals for the District of Columbia (DC Circuit). In August 2014, the DC Circuit issued a unanimous decision affirming Order No. 1000. FERC continues to face significant challenges regarding Order No. 1000, its cost allocation principles and the implementation of those principles.

Over the past several years, the US electricity industry has evolved to become more dependent on natural gas caused by relative decreases in natural gas prices along with increasing environmental regulations under various federal laws leading to coal plant retirements. In addition, the increasing rate of penetration of intermittent renewable generation resources often requires natural gas fuelled generation as a reliability backstop. The increasing reliance on natural gas for electricity generation, together with severe weather experiences across the United States in recent years, have continued to put pressure on the existing natural gas transportation infrastructure and highlighted several issues with respect to how the natural gas and electric industries interact. After several years of technical conferences and public comments on these issues, in April 2015, FERC issued Order No. 809, entitled ‘Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities’, adopting proposals submitted by an industry forum to modify the scheduling practices used by interstate natural gas pipelines to schedule natural gas transportation service and provide additional contracting flexibility to firm natural gas transportation customers through the use of multiparty transportation contracts and revised nomination timelines. FERC also directed each FERC-jurisdictional RTO and ISO to propose tariff revisions to coordinate its day-ahead energy market with the scheduling practices adopted in Order No. 809 or to show cause why its existing scheduling practices need not be changed.

Oil and liquids sector

Unlike interstate natural gas pipelines, oil pipelines engaged in interstate commerce have been regulated as common carriers (not public utilities) since the Interstate Commerce Act was extended to oil pipelines in 1906. As common carriers, oil pipelines must provide service to all customers without ‘undue discrimination’ or ‘undue preference’ to any customer, including affiliated customers. The prohibition on undue discrimination and preference
extends to periods when the pipeline is in ‘pro-rationing’, namely, the situation in which the pipeline must curtail specific shipments when customers’ nominations exceed available capacity.

For most of the twentieth century, the vast majority of oil pipeline mileage was owned by major oil companies with vertically-integrated production, transportation, refining and distribution operations. This situation began to change, however, in the latter part of the century in light of two developments. First, a change in US tax laws in the 1980s allowed companies engaged in (among other sectors) the transportation and storage of natural resources to be organised as master limited partnerships (MLPs), which provide certain tax advantages to their investors and, hence, make investments in those sectors financially attractive. Second, in 1996, FERC began issuing declaratory orders that approved then-novel rate and tariff structures that enhanced pipeline developers’ ability to finance new pipelines. Specifically, when new or expanded oil pipeline capacity has been offered to all prospective shippers in a FERC-approved ‘open season’, FERC’s orders provide advance regulatory approval of pipelines’ long-term contract (‘committed’) rates and tariff structures that need not be supported by cost data. These two developments facilitated the development of pipelines by independent entities. Today, while many pipelines are still owned by vertically-integrated oil companies, tens of thousands of oil pipeline miles are also owned by non-integrated companies.

ii Rates

Economic regulation of most of the bulk power transmission system in the continental United States is administered by FERC, including regulation of the rates, terms and conditions for the transmission of electric energy in interstate commerce. Most FERC-regulated transmission services are provided at embedded cost-of-service rates that provide a return of investment as well as a FERC-determined reasonable rate of return on common equity. FERC also has permitted ‘merchant’ transmission projects (i.e., transmission that is not included in a cost-of-service rate base) to charge negotiated rates for transmission service.

In 2005, Congress amended the FPA to direct FERC to develop rate incentives to encourage certain transmission development. In 2006, FERC issued regulations to provide on a case-by-case basis a variety of cost-of-service rate incentives for new transmission projects that improve reliability or reduce cost. These incentives include incentive rates of return on equity for new investment, use of a hypothetical capital structure during construction, full recovery of prudently incurred construction work in progress in rate base during construction, full recovery of prudently incurred costs of abandoned projects, and accelerated depreciation. To obtain one or more of these incentives an applicant must show that there is a nexus between the incentive being sought and the risks associated with the investment being made.

Since 2000, FERC has also permitted certain merchant transmission projects to charge negotiated rates for transmission service under OATT-based transmission service agreements. Initially, FERC required merchant transmission facilities to hold open seasons for the full capacity of a planned project. Beginning in 2009, FERC permitted certain merchant transmission project developers to allocate some portion of transmission capacity (generally not more than 75 per cent) through pre-subscription to ‘anchor customers’, who provide upfront or assured ongoing payments through long-term transmission service agreements to facilitate project construction. The remaining project capacity not committed to anchor customers will be made available to later customers selected through an open season process detailed in the project’s OATT and these customers will be entitled to obtain service under
terms and conditions generally comparable to those available to anchor customers. Since 2013, FERC has permitted merchant transmission developers to avoid formal open season requirements and allocate up to 100 per cent of the capacity on a transmission project to a single customer, including an affiliate, if the developer broadly solicits interest in the project from potential customers and demonstrates to FERC that it has satisfied certain solicitation, selection and negotiation process criteria.

Rates for interstate natural gas transportation and storage are generally based on costs, including a reasonable return. Rates for service are established for new facilities when FERC certifies construction. Pipelines may change the rates based on a showing that a new cost-based rate is ‘just and reasonable’, and FERC or other affected parties may require prospective rate adjustments by showing that the existing rates are unjust and unreasonable.

In 2009, FERC began a systematic and in-depth review of cost and revenue information that must be filed annually by pipelines, leading to the initiation of rate investigations of certain pipelines based on data suggesting that these were over-earning. FERC has continued initiating such investigations, typically targeting a few pipelines once each year or every other year. Most recently, in connection with changes in US tax law, FERC has initiated proceedings requiring reporting of updated cost and revenue data and has indicated that it will initiate rate investigations where these data suggest over-earning (unless the pipeline files to voluntarily reduce its rates).

Pipelines and storage companies are permitted to offer discounts below the maximum, cost-based rates approved by FERC (also referred to as the ‘recourse rates’) in order to meet competition. Any rate discounts offered by an interstate natural gas company must be offered on a non-discriminatory basis to all similarly situated customers. Between rate cases, the natural gas company must bear the cost of any revenue shortfalls attributable to discounts (i.e., it cannot charge higher rates to other customers to make up revenues lost because of discounting). Interstate pipelines and storage companies may also negotiate rates for services either above or below the recourse rate, as long as the customer retains the option to take service under the recourse rate. Independent storage companies are often permitted to charge competitive market-based rates based on a demonstration that they do not have significant market power.

For interstate deliveries, FERC jurisdictional pipelines that transport fossil fuel liquids (oil pipelines) may charge cost-based rates; or they may charge market-based rates if adequate competition is proven to exist in the pipeline’s origin and destination markets. FERC-regulated oil pipeline rates may be changed annually based on the US Producer Price Index for Finished Goods, plus a margin established by FERC every five years (currently 1.23 per cent). If, however, oil pipeline indexed rates become significantly higher than a cost-based rate, or any annual increase is substantially greater than actual cost increases, FERC may adjust the rates. FERC allows greater flexibility in rates, terms and conditions of service for interstate service using new or expanded oil pipeline capacity if offered to all shippers and prospective shippers in an open season. FERC permits oil pipelines to offer priority service (i.e., service not subject to pro-rationing during normal pipeline operations) for up to 90 per cent of new capacity if contract (‘committed’) shippers pay a premium over ‘uncommitted’ (walk-up) rates, and all shippers had an opportunity to contract for the new capacity in an open season.

iii Security and technology restrictions

Prior to 2005, the United States relied on voluntary compliance by participants in the bulk power industry with reliability requirements for operating and planning the bulk power
system coordinated through the North American Electric Reliability Corporation (NERC) and various related regional entities. In 2005, Congress responded to a widespread August 2003 blackout throughout the northeastern and midwestern United States (and parts of Canada) by amending the FPA to provide for a system of mandatory, enforceable reliability standards to be developed by a FERC-certified ‘electric reliability organisation’ (ERO), subject to review and approval by FERC. For purposes of approving and enforcing compliance with reliability standards, FERC has jurisdiction over the FERC-certified ERO, any regional reliability entities, and all users, owners and operators of the bulk power system, including public and governmental entities not otherwise subject to FERC jurisdiction under the FPA. FERC certified NERC as the ERO and in various subsequent orders has defined the bulk power system and approved a number of reliability standards proposed by NERC.

Federal law sets minimum safety standards for all natural gas and hazardous liquids pipelines, and provides for regulation of these facilities by PHMSA. PHMSA regulates pipeline facilities pursuant to its pipeline safety programme, which is implemented in cooperation with the states. Although PHMSA has the authority to regulate all interstate pipelines, it may allow a state to act as its agent, subject to certain limitations. Also, states adopting laws meeting or exceeding the federal minimum safety standards may obtain a certification from PHMSA to regulate intrastate pipelines. If a state’s law does not meet the federal minimum safety standards, PHMSA may decertify the state or exercise backstop authority to inspect and enforce federal pipeline safety laws. States are permitted to adopt and enforce standards that are more stringent than the federal minimum standards, which in many cases are overseen by each state’s PUC. The security of LNG waterfront facilities and deepwater ports is regulated by the US Coast Guard pursuant to a number of federal laws, including the Maritime Transportation Security Act, the Ports and Waterways Safety Act, the Magnuson Act and the Deepwater Port Act.

Federal law and agency-specific regulations require that owners and operators of energy facilities protect facility sensitive security and critical energy infrastructure information from disclosure to the public, including electronic copies of such information stored in company operating systems, databases and computers. The United States has not currently adopted mandatory cybersecurity standards for pipelines, storage facilities or LNG terminals, although in response to growing concerns about cybersecurity and recently reported cyberattacks on major pipelines, new legislation and new rules are being considered and a new DOE Office of Cybersecurity, Energy Security, and Emergency Response was established in 2018. The electric, natural gas and oil industries are voluntarily implementing measures to maintain security and are cooperating with federal agencies to develop and implement safeguards.

IV ENERGY MARKETS

i Development of wholesale electric energy markets

Throughout certain regions in the United States, ISOs and RTOs operate transmission facilities and administer organised wholesale electricity markets. FERC has prohibited any one set of market participants (including transmission owners) from controlling decision making within an ISO or RTO. FERC’s Order No. 2000 imposed significant regulatory requirements upon ISOs and RTOs regarding the independence of an energy market administrator, the performance of the energy markets and the elimination of discrimination. FERC left considerable discretion to market participants to determine an ISO’s or RTO’s governance structure, geographical scope and type of market services.
The following ISOs and RTOs are currently operating: PJM Interconnection, LLC (PJM), New York Independent System Operator Inc. (NYISO), ISO New England Inc (ISO-New England), Midcontinent Independent System Operator Inc (MISO), Electric Reliability Council of Texas (ERCOT), Southwest Power Pool and California Independent System Operator Corp (CAISO). Of these RTOs, only ERCOT is not subject to FERC’s regulatory oversight, as ERCOT is deemed to be electrically isolated from the rest of the transmission grid in the continental United States.

Each ISO and RTO offers different energy products in its organised markets. While all of the existing ISOs and RTOs administer some form of bid-based markets for one or more energy products (i.e., where the highest price bid for the marginal quantity of supply that satisfies the quantity demanded in any relevant period sets the market price for the product within that applicable region, node or zone), some provide real-time and day-ahead markets, while others do not. In addition, some of the ISOs and RTOs offer forward markets for the sale of capacity (i.e., the ability to produce electric energy) separate from other energy products. Such forward capacity markets are structured differently in each RTO and ISO and the details associated with the ancillary service markets for these ISOs and RTOs differ as well. Each market has an independent market monitor, as FERC required by Order No. 719, but the nature and scope of the market monitors’ roles differ. RTOs and ISOs that are interconnected to one another have special joint operating arrangements relating to the ‘seams’ between them. Moreover, CAISO has established and made available to other electric grids in the western United States that are neither RTOs nor ISOs a western Energy Imbalance Market (EIM) that on a regional basis can automatically balance supply and demand and dispatch least-cost energy resources on a short-term basis. This system is intended to assist California and other states in the western United States to better manage and share their generation capacity reserves and integrate intermittent renewable generation resources. Electric grids in eight western states are active participants in the western EIM.

ii  Wholesale energy market rules and regulation

Each RTO and ISO develops its own market rules through the market participants’ stakeholder approval process. Market rules for all RTOs and ISOs must be filed with and approved by FERC prior to implementation, except for ERCOT, which is subject to the exclusive jurisdiction of the Public Utility Commission of Texas. The independent market monitor within each RTO and ISO provides independent oversight over certain market issues, including with respect to market concentration issues.

iii  Contracts for sale of electric energy at wholesale

The US electricity markets have a long history with bilateral power purchase and sale contracting at wholesale. Even where market participants are located within an applicable RTO or ISO (i.e., bidding or offering into the organised wholesale markets and scheduling flows through the RTO or ISO), market participants often enter into bilateral energy and capacity contracts as a means of hedging the volatility of market prices or providing a reliable source of supply. Bilateral contracts can be in the form of physical purchases and sales or financial settlements. Some contracting parties use standardised industry form agreements, such as those developed by the Edison Electric Institute or the International Swap and Derivatives Association, and others negotiate individualised contracts. Physical sales of
energy, capacity and ancillary services products in the wholesale markets are subject to FERC jurisdiction and associated contracts must either be filed with FERC or reported through electric quarterly reports.

iv  

Natural gas and oil markets

Unlike in the electricity sector, there are no formal FERC-approved organised wholesale markets for oil and natural gas. Interstate natural gas pipelines are required to operate secondary markets for the transportation services they offer. Under FERC’s rules, any shipper that has contracted for firm transportation service on a natural gas pipeline may release its contracted capacity to other shippers, either by publicly posting the availability of the pipeline capacity on an electronic bulletin board maintained by the pipeline and accepting offers for it, or, if certain criteria are met, in a privately negotiated, but publicly posted, transaction with prices capped at the pipeline’s tariff rate. Also, to facilitate the development of natural gas markets, FERC has liberalised some of its rules designed to prevent shippers from capitalising on a pipeline’s market power. Generally, FERC requires shippers to hold title to the natural gas they ship on interstate pipelines and prohibits shippers from buying natural gas at a receipt point and reselling the natural gas to the same company after transportation at the delivery point in a prearranged ‘buy-sell’ transaction. To allow brokers to aggregate transportation capacity and natural gas supplies, and to use transportation services more efficiently, FERC allows exceptions to its shipper-must-have-title rule under qualifying asset management arrangements. FERC also grants waivers of its shipper-must-have-title, buy-sell and capacity release rules when necessary to facilitate transfer of pipeline capacity in certain circumstances involving asset sales or corporate restructuring. It is unlawful for ‘any entity’ (not just regulated companies) to engage in a course of business or omission, or mislead, with intent to affect a FERC-jurisdictional market. Violation of FERC’s market rules exposes the actor to the potential for significant civil penalties and enforcement action by FERC.

Given the limited scope of its jurisdiction over oil pipelines under the ICA, FERC historically has refrained from involvement in crude oil marketers’ use of interstate oil pipelines – except to insure that the pipelines’ rates, terms and conditions of service for all shippers are ‘just and reasonable’. In November 2017, however, in response to a petition for declaratory order, FERC ruled that a marketing affiliate of an oil pipeline may not use its capacity on the pipeline to engage in ‘buy-sell’ transactions in which the price differential between the points of purchase and resale is less than the pipeline’s filed rate between those two points. That ruling is currently the subject of further review by FERC in response to requests for rehearing and clarification. Also, in February 2018, certain petitioners asked FERC to develop standards of conduct for oil pipelines similar to those applicable to the transportation and marketing functions of natural gas pipelines, and which FERC is currently considering.

v  

Retail energy market regulation

Retail energy markets are regulated at the state and local levels. Across much of the United States, retail consumers of electricity and natural gas buy electricity and natural gas from local utilities, many of whom remain vertically integrated, at rates and under terms and conditions set by local regulators. Beginning in the mid-1990s there was a move in some states to unbundle commodity generation or natural gas service from distribution services and allow retail consumers to purchase these commodity services from competitive retail suppliers. Between 1995 and 2002, a large number of states, including California, Texas
and most of the states in the northeastern United States, introduced retail competition for electricity and natural gas, and in some instances required local utilities to divest or formally separate their electric generation, as part of industry reforms generally referred to as ‘electricity restructuring’. These restructuring efforts also included various mechanisms to provide short-term savings to retail consumers as well as mechanisms to protect consumers from market volatility in the wholesale markets and requirements that distribution utilities serve as a provider of last resort for retail consumers who cannot (or do not choose to) obtain commodity service from a competitive supplier. At the same time, in many states, distribution utilities were required to charge prices for commodity service at levels above projected market prices to create a competitive opening for other retail suppliers.

During 2000 and 2001, there was an extended period of extreme volatility in wholesale electricity and natural gas markets in the western United States, which had a severe negative impact on the financial conditions of the restructured utilities in California and ultimately compelled the state of California to become a significant buyer of last resort in the wholesale electricity markets and ended retail competition for most retail consumers in California. After the California electricity crisis, further efforts at electricity restructuring at the retail level in the United States largely came to a standstill and retail competition was suspended or rescinded in several states. As of early 2018, 16 states and the District of Columbia allow for retail competition. However, regulators in one of these states, New York, took action in early 2016 to limit retail competition for the majority of residential and small commercial customers by requiring retail suppliers to serve mass-market customers under contracts that either guaranteed certain customer cost savings or guaranteed a portion of retail supply from renewable energy sources. This action to limit retail competition was vacated by a state court. In late 2016, regulators in New York initiated a proceeding to determine if retail suppliers should be completely prohibited from serving their current product offerings to mass-market customers. As of early 2018, this proceeding is still pending. Since the early 2000s, a number of states have allowed for the creation of community choice aggregation (CCA) arrangements, whereby a local entity, often an entity created by a local government, can aggregate the buying power of individual retail customers within a defined local jurisdiction to secure alternative energy supply arrangements. This alternative energy supply is delivered to participating retail customers by the already existing electric distribution utility. The presence of CCA arrangements has increased significantly since 2014, especially in California, where utility regulators have estimated that as much as 25 per cent of retail electric load served by the state’s investor-owned utilities will participate in these arrangements by the end of 2018, and as much as 85 per cent will participate within the next decade.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

The United States does not have comprehensive policies regarding the development of renewable energy. Rather, the federal government provides or has provided various targeted tax incentives and financing support programmes, while a large number of states have implemented renewable portfolio or clean energy standards and net metering, tax incentives and installation cost rebate programmes for distributed renewable generation resources. There have been a series of unsuccessful efforts by Congress to mandate a federal renewable or clean energy standard, most notably in the comprehensive greenhouse gas (GHG) cap and trade and clean energy legislation that passed in the House of Representatives in 2009.
The Environmental Protection Agency also issued regulations regarding CO2 emissions from new and existing electric generating facilities (the latter referred to as the ‘Clean Power Plan’), which would limit the rate of emissions of CO2 per MWh of generation output, and the Clean Power Plan proposes in part increased generation output from renewable energy resources, as well as avoided fossil fuel-fired generation output from end-use energy efficiency measures, as compliance mechanisms. In February 2016, the US Supreme Court issued a stay, halting implementation of the Clean Power Plan pending the resolution of legal challenges to the programme in court. The new Trump administration took initial steps in early 2017 to reverse or revoke the Clean Power Plan, though final steps to unwind the Clean Power Plan are expected to require regulatory actions that in and of themselves will take a year or more and are expected to be subject to legal challenges that may not be resolved before the next presidential election in 2020.

The federal government provides or has provided various tax incentives for renewable energy, including:

a. a production tax credit (PTC) (per energy generated) for wind, geothermal, biomass and some other renewable energy resources (not including solar and fuel cells) for a period of 10 years from the date the renewable energy facility is placed in service;

b. an investment tax credit (ITC) (based on qualified project costs) for a wide range of renewable energy resources (including solar and fuel cells) and for combined heat and power generation; and

c. special accelerated depreciation rules that provided five-year depreciation for a range of renewable energy resources placed in service from 2008 to 2012.

The PTC was first implemented under the Energy Policy Act (the EP Act) of 1992, and was extended to include projects that commence construction prior to 1 January 2020, with a phase down in the credit amount for projects commencing construction after 31 December 2016. The ITC was first implemented under the EPAct of 2005 and was most recently extended until 2022, with a gradual step down of the credits between 2019 and 2022. The American Recovery and Reinvestment Act (ARRA) allowed taxpayers eligible for the PTC to take the ITC in lieu of the PTC for projects installed in 2009 through 2013 (2009 through 2012 for wind). ARRA also allowed taxpayers eligible for the ITC (including those taking the ITC in lieu of the PTC) to receive a cash grant from the US Treasury Department in lieu of the ITC for projects for whose construction commenced by the end of 2011, although projects not yet placed in service were subject to reduced cash grants under an automatic sequestration law that took effect in early 2013, affecting expenditures by the federal government. The federal government estimates that as of July 2012 it provided approximately US$13 billion in cash grants for over 45,000 renewable energy projects, although the majority of the funding was awarded to larger wind projects.

The DOE operated various loan guarantee programmes for clean energy projects established under Title XVII of the EPAct of 2005 and ARRA, Sections 1703 and 1705. ARRA provided the DOE with guarantee authority under Section 1705 for commercial projects employing renewable energy systems, electric power transmission systems, or leading-edge biofuels, and appropriations to cover federal credit subsidy costs (i.e., loan loss reserves) of up to US$2.5 billion for projects that commenced construction by 30 September 2011. Accordingly, the DOE issued approximately US$16 billion in full or partial guarantees for 31 renewable energy projects (predominantly solar projects) between September 2010 and September 2011. The DOE has not closed on a loan or loan guarantee for a renewable
energy project since September 2011, although the federal government reported that as of January 2013, the DOE had US$2.3 billion in remaining loan guarantee authority for energy-efficiency and renewable energy projects, and was then considering using US$2 billion of the remaining loan guarantee authority for loan guarantees requested by eight active applications. In December 2013, as part of the Obama administration’s Climate Action Plan, the DOE issued a solicitation making available up to US$8 billion in loan guarantees under Section 1703 to support innovative advanced fossil energy projects that avoid, reduce or sequester GHGs. In February 2014, the DOE issued two loan guarantees under Section 1703 for approximately US$6.2 billion to two entities involved in the development and construction of a nuclear power plant in Georgia. In July 2014, the DOE issued a solicitation making available up to US$4 billion in loan guarantees under Section 1703 (made up of US$2.5 billion in guarantee authority and approximately US$170 million in remaining appropriations to cover credit subsidy costs) to support innovative renewable energy and efficient energy projects. In August 2015, the DOE issued supplements to this solicitation and another outstanding solicitation regarding advanced fossil energy projects to clarify both that the DOE will accept and consider applications for ‘distributed energy projects’ and that state-affiliated financial entities, including state green banks, may submit applications for eligible projects and participate in distributed energy projects as lenders or co-lenders, equity providers, or offtakers (i.e., entities purchasing the energy output of the projects).

More than half of all states and the District of Columbia have renewable energy portfolio standards or goals requiring retail electric utilities to deliver a certain amount of electricity from renewable or clean energy resources. These standards and goals vary greatly across the states, both in terms of their levels and target dates (generally between 10 per cent and 30 per cent by no later than 2020, though some states have higher target levels; e.g., 50 per cent by 2030 in California and New York, 100 per cent by 2045 in Hawaii) and what types of energy resources qualify (e.g., fuel cells, waste energy, combined heat and power (CHP), in-state versus out-of-state resources). Some states also have specific requirements or ‘carve-outs’ for specific energy resources such as solar or distributed generation. Many of these states also allow utilities to comply with their standards through the purchase of tradable renewable energy credits (though there are no national or regional markets for these credits in large part because of the significant differences among states’ standards).

More than 40 states and the District of Columbia have established net metering policies that allow retail electricity consumers who own or host distributed renewable generation resources (predominantly solar electric systems) to supply excess generation to their retail electricity supplier in exchange for credits against their retail electricity bills over 12-month and sometimes longer periods. Typically, generation resources eligible for net metering arrangements cannot be sized at levels greatly in excess of a retail consumer’s peak demand. In recent years, a number of states have taken steps to revisit or revise their net metering policies in response to concerns by retail electric utilities that crediting excess generation supplied back to them at their full retail rate did not accurately reflect the costs and benefits to their other retail customers of distributed solar electric systems being interconnected to their transmission and distribution systems. Notably, while regulators in California, the state in the United States with the largest market for distributed solar electric systems, in early 2016 retained most of the existing net metering tariff for new net metering customers, they also set in motion a process to redesign residential rates for electricity, through mandatory time-of-use rates for newly installed distributed solar electric systems participating in net metering programmes, that could reduce the economic attractiveness of such systems. In
other examples, regulators in Hawaii closed the state’s largest electric utility’s net metering programme to new participants, while regulators in Nevada approved a new net metering tariff that lowered the existing retail credit and imposed higher fixed charges, including initially for existing customers, though they later restored the prior tariff for existing customers. A number of states also offer various tax incentive and rebate programmes for distributed renewable generation resources. Most notably, California provides a property tax exclusion for certain solar resources as well as installation cost rebates or performance-based payments for solar and certain other renewable resources (e.g., wind, fuel cells and CHP).

As discussed above, many of the federal tax incentive and financing support programmes have ended or will end no later than the end of 2021, though some of these programmes could be extended by Congress, as has been the case in past years, and has been proposed in various pieces of legislation. However, given current fiscal concerns and related political disagreements over the nature and role of federal financial support for clean energy, the prospects for such legislation remain unclear. At the same time, state-based renewable portfolio standards, as well as net metering, tax incentive and rebate programmes for distributed renewable generation resources appear poised to remain in place, at least in part, for the foreseeable future (and as discussed in Section VI, below, California not only strengthened its renewable portfolio standard during 2011, it also implemented its own GHG cap and trade programme beginning in 2012, which is intended, in part, to support greater deployment of renewable generation resources). Moreover, a number of states and local governments are actively considering establishing, and since 2011 a few states and one local government, most notably the state of New York, have established, public–private partnership clean-energy financing entities, commonly referred to as ‘green banks’, to support deployment of renewable energy and energy-efficiency projects.

ii Energy efficiency and conservation
The United States has a limited set of comprehensive policies regarding promotion of energy efficiency for electric appliances and energy efficiency standards for federal buildings and properties. In addition, the federal government has various targeted grants and financing support programmes as well as tax incentives for energy efficiency investments. Moreover, as discussed above, the Environmental Protection Agency’s Clean Power Plan proposes in part avoided fossil fuel-fired generation output from end-use energy efficiency measures as a means to comply with proposed limits on CO2 emissions from existing generating facilities.

A large number of states have similar types of programmes (many of which are supported in whole or in part by funds provided by the federal government) and a large number of states have energy efficiency portfolio standards, similar in concept to a renewable energy portfolio standard, that require retail electric utilities to reduce their total retail sales, peak retail sales, or both, by certain amounts by target dates. Some states combine their renewable and energy efficiency portfolio standards. A number of states have also combined their energy efficiency portfolio standards with retail utility rate ‘decoupling’ policies to allow utilities to recover of and on their fixed costs regardless of reduced retail sales resulting from energy saving efforts. Certain states have implemented or will soon implement financing support programmes for end-use energy efficiency investments, including ‘on-bill’ financing or repayment programmes that allow retail utilities or third parties to finance the full cost of end-use efficiency investments for a retail utility customer and then recover of and on these investments through special charges included on the customer’s retail utility bill. A similar type financing arrangement is possible under federally authorised property-assessed clean
energy (PACE) bonding authority for local governments, which use PACE bond proceeds to finance the upfront costs of energy efficiency investments in homes and small businesses and have the loans secured by an annual assessment on the home or business property tax bill, although this programme has so far generally been limited to commercial properties because of federal home mortgage insurance policies.

FERC’s Order No. 745 was adopted in 2011 to encourage demand responsiveness through market pricing mechanisms. In Order No. 745, FERC required that the RTO and ISO organised wholesale electricity markets adopt market rules that treat demand reduction (i.e., ‘negawatts’) in the same way as generation supply alternatives (i.e., megawatts (MW)) for the purpose of bidding into the markets; however, the RTOs and ISOs were still given flexibility as to how to implement these market incentives. RTOs and ISOs began proposing revisions to their market rules to FERC during 2011 to comply with Order No. 745 and FERC acted on a number of these compliance filings during 2011 and 2012. Order No. 745 was challenged before the DC Circuit on a number of grounds, including that the substance of Order No. 745 exceeds FERC’s jurisdiction under the FPA, as it seeks to regulate retail sales of electricity by requiring RTOs and ISOs to pay retail customers for not consuming electricity at retail. In a decision issued in May 2014, the DC Circuit vacated Order No. 745, holding, among other things, that FERC did not have jurisdiction to issue Order No. 745 because demand response is part of the ‘retail market’, which is exclusively within the states’ jurisdiction to regulate. In January 2016, the Supreme Court issued a decision upholding Order No. 745 and FERC’s ‘affecting’ jurisdiction under the FPA to regulate demand response transactions in the organised wholesale electricity markets. The Supreme Court held that RTOs’ and ISOs’ payments for demand response commitments directly affect wholesale rates and that in addressing demand response practices, FERC has not transgressed its jurisdictional boundary by regulating retail sales. The Supreme Court also approved a ‘common-sense construction’ of the FPA’s language, previously adopted by the DC Circuit, that FERC’s affecting jurisdiction is limited ‘to rules or practices that “directly affect the [wholesale] rate’” (emphasis in original).

VI THE YEAR IN REVIEW

i Electricity

Similar to its efforts regarding demand response, FERC has this year considered various reforms to the market rules for RTOs and ISOs to encourage the participation of new or different types of resources. For example, in February 2018, FERC issued Order No. 841, which is intended to remove barriers to the participation of electric storage resources in the organised wholesale electricity markets administered by RTOs and ISOs by requiring them to establish a participation model of market rules that, recognising the physical and operational characteristics of electric storage resources, facilitates their participation in the organised markets. At the same time, FERC opened a proceeding to explore questions related to the participation of distributed energy resource aggregations in the organised markets.

Following severe weather in 2013–2014 in the eastern portion of the United States, when demand was high and generation supply was unavailable for a variety of reasons, both ISO-New England and PJM sought to improve generator reliability during these periods by significantly revising their forward capacity markets. ISO-New England’s new capacity market rules, referred to as ‘performance incentive’ or ‘pay for performance’ were adopted in 2014, and PJM’s proposal, referred to as ‘capacity performance’, was adopted in June.
2015. All capacity resources that clear ISO-New England’s market became subject to pay for performance requirements beginning with the delivery year that commences in June 2018. All capacity resources that clear the PJM market will be subject to capacity performance requirements beginning with the delivery that commences in June 2020. Both programmes eliminate most of the excuses for non-performance during a delivery year and increase the penalties for non-performance, as well as the financial assurances required to be posted by proposed generating facilities.

In October 2015, the Supreme Court agreed to hear a federal pre-emption case involving the effort by some states to subsidise the construction of new electric generating facilities through long-term power purchase arrangements mandated by the states. In those cases, the states’ load-serving entities were participants in PJM’s capacity market, and the subsidised generating facilities would receive the out-of-market compensation conditioned on their clearing the PJM capacity market. This issue came to the Supreme Court as a result of litigation in 2013 and 2014 before lower federal courts that held that procurement programmes in Maryland and New Jersey for the construction of new generation capacity violated the Supremacy Clause of the US Constitution because they impermissibly intruded on FERC’s exclusive jurisdiction under the FPA over wholesale sales (i.e., sales for resale, including PJM’s capacity market). The case involving the Maryland procurement programme was decided by the US Court of Appeals for the Fourth Circuit (the Fourth Circuit), while the case involving the New Jersey procurement programme was decided by the US Court of Appeals for the Third Circuit (the Third Circuit). In April 2016, the Supreme Court issued a decision affirming the Fourth Circuit’s decision holding that ‘Maryland’s program sets an interstate wholesale rate, contravening the FPA’s division of authority between state and federal regulators.’ The Supreme Court further provided that ‘States may not seek to achieve ends, however legitimate, through regulatory means that intrude on FERC’s authority over interstate wholesale rates, as Maryland has done here.’ At the same time, the Supreme Court provided that its holding was ‘limited’ and need not and did not ‘address the permissibility of various other measures States might employ to encourage development of new or clean generation, including tax incentives, land grants, direct subsidies, construction of state-owned generation facilities, or re-regulation of the energy sector’. Shortly after issuing its decision affirming the Fourth Circuit striking down Maryland’s programme, the Supreme Court declined to review the Third Circuit decision striking down New Jersey’s programme.

On a related front, in May 2017, FERC staff and two FERC commissioners held a technical conference with the three northeastern RTOs and ISOs (i.e., PJM, ISO-NE and NYISO), market participants and market experts to discuss issues regarding how FERC might respond to state policies that subsidise certain market resources (such as the ‘Zero Emission Credit’ (ZEC) compensation mechanisms discussed below) and as a result may have adverse impacts on the intended operation of the organised wholesale electricity markets. At the technical conference, both ISO-NE and PJM indicated they were considering submitting proposed changes to their market rules to better accommodate state policies in ways that would avoid or minimise the potential adverse impact of these policies on the intended operation of their organised markets. In August 2017, in response to a request from the Secretary of Energy, the staff of the DOE issued a study in August 2017 regarding the wholesale electricity markets and grid reliability in which they found that the wholesale markets, especially the organised markets administered by RTOs and ISOs, are operating in a manner that may result in the premature retirement of ‘baseload’ coal-fired and nuclear generation facilities that may be needed to ensure the reliability and the resiliency of the
bulk power grid. In turn, in September 2017, the Secretary of Energy acted under little-used authority under the DOE Organization Act to submit a proposed rule at FERC that directed FERC to consider requiring certain RTOs and ISOs to establish tariff mechanisms providing for the purchase of energy from generation resources and the recovery of costs and a return on equity for such resources located in an RTO/ISO with an energy and capacity market that are able to provide essential reliability resources and that have a 90-day fuel supply on-site. In the FERC proceeding to address the Secretary’s proposed rule, the proposed rule was heavily commented on by large number of parties in the FERC proceeding and engendered substantial opposition from a wide-range of parties (including an ad hoc bipartisan group of former FERC chairs). In early January 2018, FERC, with the unanimous vote of all five of its commissioners, issued an order terminating its proceeding to address the proposed rule and initiated a new proceeding to evaluate the resilience of the bulk power grid in the footprints of the RTOs and ISOs. In January 2018, ISO-NE submitted a proposed change to its capacity market rules with FERC, referred to as the ‘Competitive Auctions with Sponsored Policy Resources’, to provide for a new two-stage capacity auction in which existing capacity resources that clear the first-stage auction and have resulting capacity obligations can transfer their capacity obligations to new sponsored policy resources that did not clear the first-stage auction in a second-stage substitution auction and permanently exit the capacity market. In March 2018, FERC issued an order approving this proposed change, though the order approved by a divided vote of the five FERC commissioners (with two dissenting votes and a concurrence). In March of 2018, one company submitted an application with the Secretary of Energy to declare that an emergency exists in PJM within the meaning of FPA Section 202(c) with respect to a threat to energy security and reliability. The application seeks to direct that certain nuclear and coal-fired generation facilities in PJM (including the company’s nuclear and coal-fired generation facilities, which the company asserts are at risk of retirement) enter into contracts and all necessary arrangements with PJM, on a plant-by-plant basis, to generate, deliver, interchange and transmit electric energy, capacity and ancillary services to maintain fuel diversity and grid dependability and resiliency within the PJM region. This effort is highly controversial, is being opposed by PJM and many other market participants (including the owners of some of the nuclear and coal-fired generation facilities that are the subject of the application) and will likely lead to significant litigation.

At the state level, during 2017 a few states continued efforts to consider the restructuring or transformation of the distribution and use of electricity at the retail level, including efforts to accommodate or encourage the greater deployment of distributed energy resources – distributed generation and storage, demand response, and end-use energy efficiency. Most notably, regulators in New York continued their efforts to implement their ‘Reforming the Energy Vision’ (REV) initiative, that calls for ‘animating markets’ at the distribution level so that retail customers and third parties (e.g., energy service companies, retail suppliers, demand-management companies) can monetise the economic values that distributed resources can provide to the overall electric system in New York. This initiative also tasks the electric distribution utilities in New York with acting as ‘distributed system platform’ providers, who together will furnish a state-wide platform that will deliver uniform market access to retail customers and distributed energy resource providers, and who will also act as an interface between customers at the distribution level and the NYISO. As part of this initiative, regulators also directed the electric distribution utilities to propose demonstration projects involving third-party market participants and demonstrating business models and customer engagement for distributed energy resources and to propose a ‘Distributed System
Implementation Plan’. In a series of proceedings, regulators in New York are considering a wide range of issues relating to the REV initiative, including changes in their ratemaking practices for the electric distribution utilities, establishment of a new benefit–cost framework for electric distribution utility expenditures on investments in distributed system platforms, procurement of and a ‘value stack’ compensation model for distributed energy resources, and energy efficiency programmes, development of community distributed generation and CCA arrangements, changes in net metering programmes, a reassessment of New York’s approach for encouraging the deployment of large-scale renewable energy generation, the development of a US$5 billion ‘Clean Energy Fund’ that will in part support the New York Green Bank and a solar electric incentive programme, and the development of a ‘Clean Energy Standard’ to succeed New York’s RPS (which expired at the end of 2015) that requires that 50 per cent of the electricity consumed in New York to come from clean energy sources by 2030. Regulators have indicated that changes in their ratemaking practices for electric distribution utilities should result in utility earnings that depend on a utility’s success in creating value for its customers and achieving regulatory policy goals, such as increased deployment of distributed energy resources and reduced emissions of GHGs, and they issued an order in 2016 adopting a suite of ratemaking changes for electric distribution utilities, including providing them with the ability to earn revenues from:

a. the achievement of alternatives that reduce their capital spending and provide definitive consumer benefits;
b. market-facing platform activities; and
c. transitional outcome-based performance measures.

Relating to the Clean Energy Standard, regulators in New York also established a ‘Zero Emission Credit’ (ZEC) compensation mechanism to subsidise the continued operation of certain existing nuclear generation facilities in New York that face competitive difficulties in the NYISO markets. Regulators in New York concluded that the continued operation of these facilities is necessary for New York to achieve its clean energy policy goals. Legislators in Illinois established a somewhat similar ZEC compensation mechanism directed at certain existing nuclear generation facilities in Illinois that face competitive difficulties in the PJM and MISO markets. Both the New York and Illinois programmes take into consideration the revenues that existing nuclear facilities receive in the energy and capacity markets in the determination of the ZEC payment. Legislators and regulators in other states in the United States are considering similar types of compensation mechanisms, though, as of early 2017, the compensation mechanisms in New York and Illinois are being challenged both in federal courts on constitutional grounds relating to federal pre-emption under the FPA and as being in violation of the dormant commerce clause and before FERC on grounds relating to the continuing lawfulness under the FPA of forward capacity market rules in the NYISO and PJM. FERC is considering mechanisms to include carbon pricing (or other mechanisms to implement state policy goals) in an RTO bid-based market. Notably, the NYISO and utility regulators in New York began a process in 2017 to work with electric industry stakeholders to develop a carbon pricing mechanism for use in the wholesale electricity markets administered by the NYISO. If such a mechanism is developed, it will have to be filed with and approved by FERC before it can be implemented.

Since 2016, a number of states in the northeast US have taken initial steps to promote the development and deployment of offshore wind generation resources. In late 2016, the first offshore wind generation facility in the US, a 30MW facility located off of Rhode
Island’s Block Island, began commercial operation. In June 2017, electric distribution utilities and utility regulators in Massachusetts issued a request for proposals for at least 400MW and possibly as much as 1,600MW of offshore wind generation resources with scheduled commercial operation dates before 1 January 2027. In late 2017 and early 2018, utility regulators and policymakers in New York, New Jersey and Connecticut announced that they intend to commence solicitation processes for significant amounts of offshore wind generation. Utility regulators in Connecticut issued a request for proposals in early 2018. New York is expected to issue an initial request for proposals by the end of 2018, with a subsequent request to follow in 2019.

On 1 June 2017, President Trump announced that he planned to have the United States withdraw from the Paris Agreement.

ii Natural gas and fossil fuel liquids pipelines, LNG terminals and rail transportation of crude oil

As gas production in the United States has grown dramatically in recent years, the interstate pipeline industry has proposed and constructed, with the approval of FERC, large amounts of new infrastructure to serve the new production and transport the gas to markets. In 2016, for instance, FERC certificated approximately 17.6 billion cubic feet per day of new pipeline capacity. Pipeline certificate proceedings have increasingly been heavily contested, with significant opposition to many projects from certain environmentalist organisations and landowners. These organisations have challenged projects at FERC and, in many cases, appealed FERC’s rulings to the courts.

In June 2014, the DC Circuit ruled that the FERC had violated the National Environmental Policy Act of 1970 (NEPA) by improperly ‘segmenting’ its review of four proposed expansions of the pipeline system of Tennessee Gas Pipeline Company in the northeastern United States. FERC regarded the proposed expansions as four separate projects because each resulted in a measurable increase in the pipeline’s overall capacity and therefore provided substantial independent utility. The individual proposed projects were reviewed individually by the FERC and then constructed in rapid succession between 2010 and 2013. The DC Circuit found that the projects were ‘physically, functionally, and financially connected and interdependent’ and should all have been reviewed by the FERC at the same time as ‘connected’ projects under NEPA, and that the FERC should have considered the ‘cumulative impacts’ of all four projects together before approving any one of them. The DC Circuit remanded the case, which involved one of the already built and operating segments, to FERC, but it did not vacate FERC’s order. This decision allowed the pipeline segment to continue to operate while FERC supplemented its environmental analysis. On remand, FERC conducted a supplemental environmental review and reaffirmed its approval of the challenged pipeline project. The DC Circuit’s decision is significant in three respects: (1) although challenged many times, FERC had not previously lost an appeal of a natural gas pipeline case under NEPA; (2) the decision creates uncertainty as to when proposed pipeline projects must be reviewed together, as many proposed projects affect other proposed projects; and (3) the court allowed the pipeline to operate despite its finding that FERC had violated NEPA. In August of 2017, the DC Circuit vacated and remanded FERC’s orders approving the Southeast Market Pipelines project for failure to evaluate the effects of downstream GHG emissions associated with non-jurisdictional power plants receiving fuel from the project, or to explain why it could not do so. FERC re-approved the project after providing a
supplemental analysis, including disclosure of an upper estimate of emissions from the power plants, but without assessing those impacts using the social cost of carbon tool – with two of the five FERC Commissioners dissenting.

Also in 2017, a number of state regulators responsible for issuing water quality determinations under the Clean Water Act withheld or denied certifications for FERC pipeline projects, leading to litigation in a number of courts. The leading case involved a New York State water quality certification for Millennium Pipeline's Valley Lateral pipeline. After New York State failed to act within the one-year time frame set by the statute, the project obtained a ruling from FERC finding that the state waived its certification authority under that statute. New York appealed to the Second Circuit arguing that it had one year from the date a 'complete' application is filed to act, while FERC countered that the one-year period begins when the application is initially filed. The Second Circuit sided with FERC. In another case involving Constitution Pipeline, the Second Circuit declined to decide a challenge to New York's failure to issue a water quality determination, instead requiring that the pipeline first seek a waiver from FERC. FERC subsequently denied the pipeline's waiver request because the state agency had acted within one year of receipt of the most recently filed application, after the initial application was voluntarily withdrawn and resubmitted by the pipeline. Constitution's requests for rehearing by FERC of its decision and for Supreme Court review of the Second Circuit decision are pending.

With respect to oil pipelines, FERC has continued to allow more flexibility with respect to rates, terms and conditions of service for committed shippers on new and expanded oil pipeline capacity when that capacity is offered to all potential shippers in an open season process. Among other approvals, FERC has allowed committed shippers to negotiate rates not supported by cost of service, and to have priority to future available capacity and future expansion projects following the open season. FERC has also approved tiered rates for shippers based on the size of their volume commitments and acreage dedications. Other FERC orders, however, have defined the limits of FERC's flexibility, including orders denying priority service to shippers that enter into contracts after (but not during) an open season, and orders refusing to pre-approve uncommitted shipper rates for new and expanded oil pipelines unless pursuant to a formal rate filing made shortly before service commences. In 2015, FERC also determined that the transportation by pipeline of denatured fuel ethanol in interstate commerce is subject to its jurisdiction.

In July 2016, the DC Circuit issued a decision that ultimately may have broad rate implications for the interstate pipeline industry. In United Airlines v. FERC, 827 F.3d 122 (DC Cir 2016), the DC Circuit sided with pipeline shippers that challenged FERC's income tax allowance policy. FERC's income tax allowance policy, in place since 2005, allowed US MLPs and other pass-through entities that hold interests in regulated oil and natural gas pipelines to include in rates an income tax allowance if their partners or members have actual or potential income tax obligations on the partnership's or other pass-through entity's income. In United Airlines, the DC Circuit concluded that FERC had acted arbitrarily and capriciously when it permitted the pipeline in question to include an income tax allowance in its rates, because FERC had failed to demonstrate that its income tax allowance policy together with its use of a discounted cash flow methodology to determine return on equity would not permit the pipeline's limited partnership owners to double-recover their income taxes through the pipeline's rates. The DC Circuit vacated FERC's orders authorising the pipeline's rates, and remanded the case to FERC for further proceedings. In its decision, the DC Circuit held that FERC is free to continue to provide partnerships and other pass-through entities with an
income tax allowance if it either provides a sufficient explanation that its current policy does not result in double-recovery of taxes for such entities, or takes another approach to assure there is no double-recovery. In response to the *United Airlines* decision, FERC issued a Notice of Inquiry (NOI) in December 2016 and received two rounds of comments in response to the NOI. In March 2018, FERC ruled on the issue on remand, announcing in its ruling and in a revised policy statement that FERC will no longer permit MLPs to recover an income tax allowance in cost-based rates because such recovery allows an impermissible double recovery of income taxes. Going forward, FERC announced that other pass-through entities may be allowed to recover the income tax allowance in cost-based rates, but only if they address the double recovery concern expressed in *United Airlines* and the revised policy statement. The same day, FERC issued orders initiating a rulemaking and another NOI to evaluate whether the recent lowering of the US corporate tax rate from 35 to 21 per cent should be reflected in individual oil and gas pipelines’ cost-based rates, or trigger other changes to rates in response to recent changes in US tax laws. FERC’s proposal, if adopted in a final rule, would require gas pipelines to submit informational reports showing the impact of lower corporate tax rates and the disallowance of taxes for MLPs in their cost-based rates. FERC’s orders encourage gas pipelines either to reduce their rates voluntarily by initiating limited, ‘single issue’ rate proceedings, or to provide justification why their rates should not be reduced. FERC reserves the right to investigate potential over-recovery by gas pipelines that do not voluntarily reduce their rates. Oil pipeline rates, according to FERC’s proposal, will be reduced through FERC’s next round of five-year indexing adjustments in 2020, to be effective 1 July 2021. Pipeline partnerships impacted by these orders are expected to pursue rehearing, reconsideration and, if necessary, appeal. Rate changes that result from FERC’s orders would affect only a pipeline’s maximum, cost-based rates. Other gas pipeline rates, including market-based rates, negotiated rates, discounted rates that remain below any reduced maximum rate for gas pipeline transportation, and settled or committed rates for oil pipelines, generally would not be affected.

Since 2013, FERC has approved the construction and operation of 10 large-scale LNG terminals, nine for the export of LNG produced from natural gas originating in the continental United States and one for the import of LNG to the Commonwealth of Puerto Rico. Two of these projects have completed construction and are exporting cargos from the lower 48 United States. Five LNG export projects are under construction (including expansions of existing facilities or construction of new facilities). Three approved projects have yet to begin construction. In 2017, the Maritime Administration approved the first proposed floating liquefaction LNG export project pursuant to the Deepwater Port Act. Although the project is approved, it is not yet under construction.

Almost all of the FERC orders approving these LNG projects were appealed to the DC Circuit by the Sierra Club and similar non-governmental environmental organisations. These appeals concerned both project-specific issues and common issues regarding FERC’s NEPA review as related to more general, ‘indirect’ and ‘cumulative’ environmental impacts. Among the common issues were claims that approval of new LNG terminals will induce additional US natural gas production for export, thereby increasing demand for natural gas and increasing its price in the US, resulting in the increased use of coal rather than natural gas to generate electricity. These groups also asserted that approval of LNG exports would contribute to increased GHG emissions from downstream end-use of natural gas. In a series of separate opinions issued by the DC Circuit during the latter half of 2016, the Court affirmed FERC’s orders approving four large-scale LNG terminals, holding that the
environmental review did not have to address the alleged indirect and cumulative effects of the LNG exports in upstream and downstream markets, in part because the DOE has sole authority to authorise the export of natural gas and LNG. The DC Circuit also held that FERC adequately considered the environmental effects of the LNG terminals, together with any other past, present or likely future actions in the same geographic area.

In early 2016, FERC denied the applications to construct the Jordan Cove LNG export terminal in southwest Oregon and the related Pacific Connector Pipeline. FERC found that the proponents of the Pacific Connector Pipeline had presented only general evidence as to natural gas demand in an effort to prove a need for the pipeline, but no evidence of subscriptions for its services. In the absence of more tangible evidence, FERC determined that the project was not in the public interest because the proven benefits of the project did not outweigh the detriment to approximately 630 landowners, including 54 intervenors, whose property would be disturbed by the pipeline. FERC also determined that the LNG export terminal is not feasible without the pipeline. The project’s proponents sought rehearing (essentially reconsideration) of FERC’s order, which FERC denied, and later filed a new application with supplemental support demonstrating market support for the pipeline.

In August 2014, the DOE announced a change in its policy regarding the processing of export applications to streamline its process by linking the timing of its final action on an application to follow the completion of environmental reports by FERC and other agencies. The DOE also issued reports supplementing the environmental analysis of LNG export terminals, including an analysis of the effect of LNG exports on GHG emissions and a new study of the estimated economic consequences of LNG exports (up to the equivalent of 20 billion cubic feet of natural gas per day or approximately 168 million tonnes per year) that found that such additional exports would be marginally beneficial to the US economy. In September 2014, the DOE issued a notice of change in its procedures for changes in control affecting applications and authorisations to export or import natural gas. The new procedures allow for authorisation holders to file a notice or statement of a change in control within 30 days of such a change in control. For changes in control related to existing authorisations or pending applications for authorisations to export to non-FTA countries, the DOE will consider properly submitted protests of such changes in control but the DOE will take no action unless it determines that the change in control renders the underlying authorisation at issue inconsistent with the public interest.

The DOE has authorised 10 large-scale LNG projects to export LNG to all countries not specifically prohibited from receiving LNG from the United States (i.e., countries not subject to United States trade sanctions), including countries without free trade agreements to which the United States is a party, that require national treatment for trade in natural gas (non-FTA countries). DOE issued such a non-FTA export authorisation in April 2017 that followed its prior precedent, indicating that there was no change in policy with the new administration. Numerous other companies proposing to develop LNG export projects have applied to FERC and the DOE for similar authority and their applications are pending. Environmental groups filed challenges to many of the DOE’s orders authorising exports of LNG (similar to those lodged against FERC’s orders) in the DC Circuit. In a series of orders issued in 2017, the DC Circuit rejected all arguments that DOE failed to adequately consider the cumulative and indirect impacts associated with induced upstream gas production and downstream GHG emissions. The DC Circuit held that DOE’s ‘environmental addendum’ and a life cycle analysis assessing currently available data (filed and noticed for public comment in each proceeding) was a sufficient assessment of the environmental effects of

© 2018 Law Business Research Ltd
DOE’s orders. The effect of these appellate decisions in the LNG and Southeast Market Pipelines proceedings is to increase overall transparency associated with natural gas sector GHG emissions, but perhaps not to the extent desired by some advocates who prefer use of the social cost of carbon tool for measuring the impact of increased GHG emissions. The orders serve as precedent for future FERC and DOE actions approving natural gas facilities and exports.

Presidential Permits are required for the construction and operation of facilities that cross the international borders of the United States, including facilities for the transmission or transportation of electricity, natural gas, crude oil and petroleum products between the United States and Canada or Mexico. The authority to issue Presidential Permits has been delegated by the President to the Secretary of Energy for electricity, the FERC for natural gas and the Secretary of State for crude oil and petroleum products. Historically, there has been little controversy about the issuance of Presidential Permits, and more than 100 cross-border energy facilities were in operation as of 2015. FERC and the Secretary of Energy, acting through the DOE, have continued to receive and, after consultation with the Secretary of Defense and the Secretary of State, approve Presidential Permits for natural gas and electricity facilities in the ordinary course. At the Department of State, however, the Presidential Permit process for the Keystone XL pipeline has not followed a similar pattern. The Keystone XL pipeline is intended to transport heavy crude oil and diluted bitumen produced from Western Canadian oil sands and light crude oil produced in the Bakken shale formation (the Bakken) in the United States to refineries in the US Midwest. Much of this oil is transported by rail today. An application for a Presidential Permit for the Keystone XL pipeline was filed with the Department of State in May 2012; however, the application was strongly opposed by environmental groups and the Secretary of State in the Obama administration did not issue a decision on the then-pending application. In February 2015, Congress passed a bill approving the Keystone XL project and deeming all statutory environmental requirements to have been satisfied. However, President Obama vetoed the bill, and a vote to override that veto in the US Senate failed in March 2015. In November 2015, the Secretary of State in the Obama administration denied the application for the Presidential Permit for the Keystone XL pipeline, finding that the pipeline would only marginally benefit the US economy and energy security, but would ‘significantly undermine [the United States’] ability to continue leading the world in combating climate change’. In March 2017, the State Department in the new Trump administration reversed course and granted the application for the Presidential Permit for the Keystone XL pipeline, making a determination that issuance of the Presidential Permit ‘would serve the national interest’. Despite the State Department’s issuance of the Presidential Permit, many regulatory and legal steps remain for the Keystone XL pipeline. The Presidential Permit grants permission to ‘construct, connect, operate and maintain’ the pipeline facilities at the international border between the US and Canada, and therefore applies to only 1.2 miles of pipeline. The remaining miles of Keystone XL pipeline in the US have been approved by other regulatory bodies, including state regulators in Montana, South Dakota and Nebraska. However, Nebraska’s approval requires an alternate route that adds 63 miles to the pipeline. In January 2017, President Trump signed a Presidential Memorandum directing the Secretary of Commerce, in consultation with all relevant executive departments and agencies, to develop a plan under which all ‘new pipelines, as well as retrofitted, repaired or expanded pipelines, inside the borders of the US’, use materials and equipment produced in the US ‘to the maximum extent possible and to the extent permitted by law’. The Presidential Memorandum directed the Secretary of Commerce to submit such a plan within 180 days
of the date of the memorandum. As of the date of publication, the Secretary of Commerce has not submitted such plan. In March 2017, the White House clarified that the Presidential Memorandum will not apply to the Keystone XL pipeline, because the Keystone XL pipeline does not constitute a ‘new’ pipeline under the Presidential Memorandum.

In response to a series of highly publicised accidents involving trains carrying crude oil produced from the Bakken Formation, including the July 2013 derailment of a 72-car train carrying Bakken crude oil that resulted in 47 fatalities and extensive property damage in Lac-Mégantic, Quebec, US federal and state regulators have taken numerous steps to improve the safety of the rail transportation of crude oil. The North Dakota Industrial Commission issued new conditioning standards in December 2014 that among other matters established operating standards for crude oil conditioning equipment and prohibited operators from blending lighter hydrocarbons into crude oil before shipment. PHMSA and the Federal Railroad Administration (FRA) have proposed or undertaken a range of additional regulatory actions aimed at increasing the safety of rail transportation of hazardous materials, including the transportation of crude oil by rail. PHMSA and the FRA issued a comprehensive final rule in May 2015 that includes more stringent construction standards for rail tank cars built after 1 October 2015. Depending on the type of tank car, existing tank cars must be replaced or retrofitted within three or five years. The final PHMSA/FRA rule also includes mandates for using advanced braking and performing routing analyses, and makes permanent the provisions of an emergency order issued by DOT in April 2015 imposing a speed limit of 40mph in ‘high-threat’ urban areas for crude oil trains containing at least one older-model tank car. The speed limit for all other crude-by-rail service will be restricted to 50mph, in line with the speed limit railroads voluntarily adopted in 2013. The final rule requires sampling and testing programmes for all unrefined petroleum-based products, including crude oil, and certifications that hazardous materials subject to the programme are packaged in accordance with the test results, but does not require oil companies to process their products to make them less volatile before shipment, as had been proposed by certain safety advocates.

PHMSA also regulates the safety of pipelines and, following several pipeline accidents, has adopted more stringent safety standards for pipelines. Under agreements with certain state agencies, PHMSA allows the state agencies to administer federal safety standards for interstate pipelines. States are permitted to adopt stricter standards for state-regulated pipelines and several have done so in recent years. Effective as of 25 October 2013, PHMSA adopted new rules increasing the maximum administrative civil penalties for violation of the pipeline safety laws and regulations after 3 January 2012 to US$2 million for a related series of violations. State agencies have imposed even greater penalties. In April 2015, the California Public Utilities Commission approved the largest penalty it has ever assessed by ordering Pacific Gas & Electric Company (PG&E) shareholders to pay US$1.6 billion for the unsafe operation of its gas transmission system, including the pipeline rupture in San Bruno, California in 2010 that resulted in eight fatalities and extensive property damage. In July 2014, the US Attorney for the Northern District of California filed a separate criminal indictment against PG&E alleging obstruction of the National Transportation Safety Board’s investigation of the San Bruno incident and knowing and willful violations of the Pipeline Safety Act (PSA). The PG&E case was tried in federal district court during the summer of 2016. In August 2016, the jury in the federal district court case found PG&E guilty of five felony counts of violating the PSA and one felony count of obstructing a federal investigation. In sentencing proceedings in January 2017, the federal district court ordered the company to pay a maximum fine under the PSA of US$3 million, placed the company on probation for
five years, ordered the company to complete 10,000 hours of community service (including 2,000 hours by high-level personnel), and ordered the establishment of a court-appointed monitor. Congress passed legislation in 2016 amending the PSA and reauthorising PHMSA’s pipeline safety programme through 2019. However, the legislation did not revise the standard for criminal liability under the PSA for pipeline safety violations, despite some senior DOT officials advocating a lower liability standard – from ‘knowingly and wilfully’ to ‘recklessly’.

Meanwhile, PHMSA continues to review and revise its existing pipeline safety standards. Among its most significant recent regulatory proposals are two companion rules addressing pipeline safety and integrity, one applicable to hazardous liquid pipelines (which include crude oil and natural gas liquids pipelines) and another applicable to natural gas pipelines. The October 2015 proposal governing hazardous liquid pipelines would have extended existing integrity management requirements to previously-exempt pipelines and would have imposed additional obligations on hazardous liquid pipeline operators that are already subject to existing integrity management requirements. The proposal also would have required operators to evaluate annually the protective measures they have implemented on pipeline segments that operate in ‘High Consequence Areas’ where pipeline failures have the highest potential for human or environmental damage, would have established shorter repair timelines for critical pipeline repairs, and would have tightened the standards for pressure tests. PHMSA issued a final rule in January 2017, just prior to inauguration of the newly elected US president. The final rule modified certain aspects of the proposed rule to address concerns expressed by the regulated industries during the comment period, but retained key aspects of the rule regarding expanded inspection, leak detection, and reporting requirements. The rule was withdrawn in late January 2017.

In April 2016, PHMSA published proposed revisions to its pipeline safety regulations applicable to onshore natural gas transmission and gathering pipelines. The proposed rule would significantly broaden the scope and strength of PHMSA’s safety regulations by adding new assessment and repair criteria for natural gas transmission pipelines and by extending such protocols to pipelines located in newly designated ‘Moderate Consequence Areas’ where an incident would pose a risk to human life. In addition, the proposed rule would, among other things, modify assessment and repair criteria for pipelines inside and outside High Consequence Areas, provide additional direction to pipeline operators on how to evaluate internal inspection results, expand mandatory data collection and integration requirements for integrity management, and require a systematic approach for verifying a pipeline’s maximum allowable operating pressure (MAOP) and reporting of MAOP exceedances. The April 2016 proposal would also revise the definition of gathering lines, and repeal an exemption for natural gas gathering line reporting requirements. The proposed changes regarding gathering lines in particular have received opposition from industry. In January 2017, the Gas Pipeline Advisory Committee convened a meeting to discuss the proposed revisions, which would extensively modify Part 191 and Part 192 of the federal pipeline safety regulations applicable to gas transmission and gathering pipelines. Additional meetings were held in 2017 and are expected to be held through June 2018 to discuss, among many other technical requirements, the application of the new regulations to gathering lines. The resulting rule or rules are likely to issue in mid-to-late 2018.

Responding to the high-profile leak of methane gas from the Southern California Natural Gas Company’s Aliso Canyon/Porter Ranch underground storage field in October 2015 and calls from the Obama administration to act, PHMSA issued an Advisory Bulletin in February 2016 addressing the operation of underground storage facilities used for the
storage of natural gas. In the Advisory Bulletin, PHMSA recommended that all operators of underground natural gas storage facilities have processes, procedures, mitigation measures, periodic assessments and reassessments, and emergency plans in place to maintain the safety and integrity of all wells and associated storage facilities, whether those facilities are operating, idled, or plugged. PHMSA specifically instructed operators to review their operations to identify the potential for leaks and failures caused by corrosion, chemical damage, mechanical damage or other material deficiencies in piping, tubing, casing valves, and associated facilities.

On 22 June 2016, the US Congress enacted the Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2016. Among other things, the act required PHMSA to issue, within two years, minimum safety standards for underground natural gas storage facilities. In addition, the PIPES Act allowed states to adopt more stringent safety standards for intrastate facilities, if such standards are compatible with the minimum standards prescribed in the Act. On October 14, a federal interagency task force convened to study the issue and released a final report and fact sheet on underground natural gas storage regulation. The task force was co-chaired by the DOE and PHMSA, and included members from numerous federal, state, and local government agencies. The report included 44 recommendations regarding well integrity, public health and environmental effects, and energy reliability. On 19 December 2016, as required by the Act, PHMSA published an interim final rule that revised existing federal pipeline safety regulations related to downhole facilities, including wells, wellbore tubing, and casing at underground natural gas storage facilities. The interim final rule also incorporated certain recommended practices of the American Petroleum Institute into PHMSA’s federal safety standards, including practices applicable to the design and operation of solution-mined salt caverns used for underground storage, and practices applicable to the functional integrity of natural gas storage in depleted hydrocarbon reservoirs and aquifer reservoirs. The interim final rule also requires that operators of underground natural gas storage facilities file annual reports, obtain operator identification numbers, and file incident and safety-related reports. The interim final rule also applies to intrastate storage facilities, and requires states to update their safety regulations to include the specified recommended practices. The interim final rule became effective on 18 January 2017, and owners and operators are expected to implement the new requirements by 18 January 2018.

The state of Texas and two natural gas and pipeline industry trade associations have filed separate petitions for review of PHMSA’s interim final rule, which are pending at the US Court of Appeals for the Fifth Circuit and the DC Circuit. Texas contends that the interim final rule impermissibly overrides the state’s authority to regulate intrastate underground natural gas facilities, while the trade associations challenge the timeframes for implementation and certain technical aspects of the interim final rule. In 2017, the petitions and enforcement of the interim final rule was stayed while PHMSA solicited additional comments. PHMSA plans to issue a final rule in early-to-mid 2018.

VII CONCLUSIONS AND OUTLOOK

Energy regulation in the United States remains complex and multilayered, and will continue to evolve for the foreseeable future. Competing economic and political interests (including effects on ratepayers and taxpayers, and state policy initiatives aimed at increased deployment of clean energy resources and decreased GHG emissions) cause conflict surrounding jurisdictional issues, energy security, transmission system planning, cost allocation, renewable
development and integration and many other issues. The variety of energy industry participants and regulators, as well as the geographical differences across the United States, can provide an opportunity for the development of innovative policies, but such heterogeneity may also lead to disjointed or overlapping regulatory obligations and may ultimately undermine the development of a uniform national energy policy.
ABOUT THE AUTHORS

MASOOD AFRIDI

Afridi & Angell

Masood Afridi is a partner at Afridi & Angell specialising in the areas of infrastructure and project finance, corporate and commercial, and energy law.

After working as an associate at the New York offices of the law firm of Sidley & Austin, he joined the Dubai office of Afridi & Angell in 1993. For several years, he has been a frontrunner in Pakistan's energy sector, and has participated in the development of numerous thermal and hydroelectric power projects in the country. He has also been nominated from time to time to resolve other global issues with the power purchaser on behalf of the industry.

Acting in the capacity of project developer’s lead counsel, Mr Afridi has concluded transactions with a cumulative value of over US$4 billion, spread over several project finance transactions.

Mr Afridi has an LLM in international business and trade law from Fordham University (1990) and an LLB from the University of Bristol. At Fordham University, Mr Afridi received the Edward J Hawke Prize for graduating with the highest grade point average in his class.

PASCAL AGBOYIBOR

Orrick, Herrington & Sutcliffe (Europe) LLP

Pascal Agboyibor is a partner and a member of the Orrick, Herrington & Sutcliffe energy and infrastructure group. He currently advises lenders, governments and investors on major energy, mining and infrastructure projects in Africa.

ADITE ALOKE

Afridi & Angell

Adite Aloe is an associate at Afridi & Angell. Her practice focuses on energy and infrastructure and project finance. She has extensive experience in advising on the development of renewable energy projects in India as well as on public-private partnerships. Ms Aloe was an associate with a leading law firm in India prior to joining Afridi & Angell in 2013. She spent two years at Afridi & Angell then rejoined the firm in 2016 after working with another leading law firm in India. Ms Alok holds an LLB from Amity Law School, Guru Gobind Singh Indraprastha University, in India (2009).
RICHARD ALONSO
Sidley Austin LLP
Richard Alonso focuses his practice on Clean Air Act (CAA) issues, including complex New Source Review (NSR) applicability and permitting, mobile source regulations, Environmental Protection Agency (EPA) rulemaking efforts, legal challenges to EPA actions and CAA enforcement defence and compliance counseling. Prior to building a private practice, Mr Alonso served as the chief of the Stationary Source Enforcement Branch at the EPA’s Office of Enforcement and Compliance Assurance, where he managed and negotiated CAA enforcement cases, including NSR cases with power plants and manufacturing facilities and played a key role in developing CAA policies and regulations. He was also instrumental in cases relating to defeat devices and engine certification requirements under the CAA’s Title II mobile source programme. Mr Alonso received his law degree and a master’s in environmental engineering from Syracuse University.

RICARDO ANDRADE AMARO
Morais Leitão, Galvão Teles, Soares da Silva & Associados, Sociedade de Advogados, SP, RL
Ricardo Andrade Amaro joined Morais Leitão, Galvão Teles, Soares da Silva & Associados in 2002 and became a partner in 2015. He is a member of the corporate and commercial and capital markets team. He has extensive experience in corporate and commercial law and securities law, as well as in energy law.

In the area of corporate and commercial law, he has acted as legal adviser in several mergers, restructurings, acquisitions and sales of companies, on behalf of domestic and foreign clients.

He has also acted as legal adviser in the setting up of several initial public offers, including the largest initial public offer ever made in Portugal and the largest in Europe during 2008, and also in the structuring of several public share takeover bids.

In the area of energy law, he was involved in the reorganisation of the national energy sector in 2003 and 2004. Recently, he acted as a legal adviser in the setting up of securitisations made in Portugal regarding the right to receive amounts arising from tariff adjustments. He regularly acts as legal adviser in regulatory matters related to the energy sector.

AKSHITA AMIT
Trilegal
Akshita Amit is an associate in the Trilegal energy, resources and infrastructure team. Her principal area of practice is renewable energy-based power projects and public–private partnerships in various sectors. She has primarily advised renewable energy power generators on developing projects under various state and central policies, acquisition of developed and under-construction renewable projects and tariff-based competitively bid projects.

FARIZ ABDUL AZIZ
Skrine
Fariz Abdul Aziz is an energy partner in the corporate department of Skrine. Fariz’s main area of focus is on cross-border mergers and acquisitions, energy, oil and gas, takeovers, private equity investments and corporate restructurings. Fariz was also appointed as facilitator
for the Corridors and Cities Lab under the Performance Management and Delivery Unit (PEMANDU) of the Prime Minister’s Department, covering the manufacturing and oil, gas and petrochemical Entry Point Projects in Malaysia’s East Coast Economic Region. This project forms part of the government of Malaysia’s Economic Transformation Programme, which aims to make Malaysia a high-income nation by 2020. Fariz is recognised by the International Financial Law Review as a ‘notable practitioner’ for M&A in Malaysia, and receives positive client feedback in the same publication as having ‘in-depth industry knowledge . . . Good turnaround times.’ Another client respects practice head Fariz Aziz’s ‘extensive contacts and up-to-date knowledge of the oil and gas industry in Malaysia’.

SHERYL F BALOT

Puyat Jacinto Santos Law Office

Sheryl is a senior associate at Puyat Jacinto Santos Law Office. She has extensive experience on project development and M&A transactions. She served as project officer of the Public–Private Partnership Center (PPPC) of the Philippines from 2003 to 2011. Sheryl received her Juris Doctor (JD) degree from the University of the Philippines in 2011 and was admitted to the Philippine Bar in 2012. She obtained her Bachelor of Science in economics from the same university in 2002, where she graduated cum laude.

ANNETTE BÁRCENAS OLIVARDÍA

Alfaro Ferrer & Ramírez

Annette is a partner at Alfaro Ferrer & Ramírez, where she began her career in 1990. She has been advising clients in the electricity sector industry for 20 years. Her work in this field dates back to 1998, when the restructuring of the state-owned, vertically integrated utility that used to provide most services in Panama began. Annette also has extensive experience in advising clients – both public and private sector entities – in matters relating to other public services (telecommunications, energy, water, natural gas and public transportation); and in matters of public procurement in a wide variety of projects and transactions, including many key service and infrastructure projects. Mrs Bárcenas has been a professor at Santa María La Antigua Catholic University (USMA) and the Latin University of Panama where she has taught classes relating to public services. She is a member of the Panama Bar Association and the American Bar Association, and is fluent in Spanish and English.

JULIA BATISTELLA MACHADO

Pinheiro Neto Advogados

Julia is an associate at Pinheiro Neto Advogados and part of the energy team. In 2016–2017, she worked for the Centre for Analysis of Risk and Regulation (CARR), a consultancy branch of the London School of Economics and Political Sciences, where she was part of the team developing studies on public–private partnerships (PPPs) and logistics infrastructure regulation for the Brazilian federal government, in connection with the establishment of the Brazilian Investment Partnership Programme (PPI). The consultancy was developed together with RAND Europe and with the sponsorship of the UK Prosperity Fund, and resulted in the report ‘Regulation of Logistics Infrastructure in Brazil’ (2017). Julia is also the author of several academic and journalistic papers in areas related to public law and regulation. Her practice in energy focuses on assisting clients in generation and transmission auctions and
in the acquisition of project companies, setting up consortiums and joint ventures, drafting EPC and O&M agreements and bank collaterals, and providing support on regulatory matters and risks involved in doing business in Brazil.

**DOUX DIDIER BOUA**

*Orrick, Herrington & Sutcliffe (Europe) LLP*

Doux Didier Boua is a senior associate in the Orrick, Herrington & Sutcliffe energy and infrastructure group. His practice focuses on corporate, finance, commercial and regulatory advice within the energy sector, including mining, oil and gas and power projects in Africa.

**SALEM CHALABI**

*Stephenson Harwood Middle East LLP*

Salem Chalabi, an Iraqi national and a lawyer, has been a corporate and projects partner at Stephenson Harwood LLP since June 2014.

Mr Chalabi is a graduate of Yale University (BA), Columbia University (MA) and the Northwestern University School of Law (JD). He has practised law with international law firms Morgan Lewis (in New York), Clifford Chance (in London) and DLA Piper (in Dubai). He is also a member of the New York Bar.

In 2003, Mr Chalabi was a deputy member of the Interim Governing Council of Iraq, and a member of the finance and legal committees. In these roles, he was responsible for drafting a large number of orders and laws, in conjunction with the Coalition Provisional Authority. In addition, in 2004, he was one of two Iraqis who drafted the Transitional Administrative Law (the Interim Constitution), which was the basis of the permanent constitution adopted in 2005.

Mr Chalabi represents various Iraqi government ministries, including the Ministry of Finance, Electricity and Oil. In this capacity, he has been very closely involved in various developments relating to the government. Mr Chalabi also advises international oil companies in Iraq, as well oil services companies.

In 2018, Mr Chalabi led a team that was given the award for the Best Banking and Finance team in the Middle East at the Middle East Legal Awards.

**ANDREINA DEGLI ESPOSTI**

*Studio Legale Villata, Degli Esposti e Associati*

Born in Bologna in June 1960, Andreina Degli Esposti graduated *magna cum laude* in law from the University of Bologna in February 1984. She also studied at the University of Münster and was admitted to the Bar in 1986. She has been involved in research and lecturing in the department of constitutional law at the University of Bologna and the departments of administrative law at the Universities of Milan and Pavia, thus publishing various essays and contributing to entries in legal encyclopaedias.

Throughout the course of her practice – which covers both judicial (predominantly before the regional administrative courts and the council of state) and extrajudicial (stipulating agreements with public administrations and providing advice in the administrative areas of M&A and joint ventures) work – she has gained expertise in the sectors of energy, public procurement (also concerning the German legal system), environment, telecommunications and town planning, including the drafting of general planning regulations. She also has
extensive experience as member of arbitration panels. She is currently involved in the professional network of the online administrative law review GiustAmm.it.

Chambers Europe and The Legal 500 place her among the most prominent Italian lawyers in the field of public law.

CEDRIC DEGREEF
Stibbe
An associate at Stibbe, Cedric Degreef concentrates on energy and climate law, regulated markets and natural resources. He has relevant expertise with regard to electricity and natural gas; mining law; renewables; offshore energy; nuclear energy; grid construction and operation; grid tariffs; energy commodity trading; market transparency; market supervision; the role of energy regulators; CO2 emission trading; and EU ETS.

OKAN DEMİRKAN
Kolcuoğlu Demirkan Koçaklı Attorneys at Law
Mr Okan Demirkan currently leads Kolcuoğlu Demirkan Koçaklı’s energy and dispute resolution practices.

Between 2004 and 2010, Mr Demirkan was heavily involved in all legal issues surrounding the Baku–Tbilisi–Ceyhan Crude Oil Pipeline Project (BTC), where he played a key role in real estate, corporate, employment, litigation and regulatory issues. In addition to BTC, Mr Demirkan advised clients in connection with the Nabucco gas pipeline and the Samsun–Ceyhan oil pipeline.

In 2011, Mr Demirkan took an active role in the Shah Deniz Stage 2 natural-gas import project, where he led the KDK team advising on the project’s legal structure in Turkey, including intergovernmental agreements, Turkey’s natural gas market legislation, the Transit Law as well as on related commercial and public international law matters. Mr Demirkan’s energy experience includes advice to an American energy company in its proposed bid in the privatisation of Turkey’s electricity distribution entities. He currently leads the KDK team in its legal advisory services to a Japanese company, in relation to the Sinop Nuclear Power Plant.

Between January and June 2012, Mr Demirkan led the KDK team in the firm’s key role in the Trans-Anatolian Natural Gas Pipeline (TANAP) project. In this multibillion-dollar project, the KDK team drafted the Host Government Agreement and negotiated it with the Turkish government, along with the IGA, which was signed in late June 2012. In 2013, 2014 and 2017, Mr Demirkan received the Client Choice Award for his work in energy and natural resources projects. He is also the founding member and board member of the Turkish chapter of the International Nuclear Law Association (INLA).

Mr Demirkan has also been heavily involved in several international arbitration proceedings, concerning disputes arising from major infrastructure projects including build-operate-transfer model investments, share purchase agreements, shareholders’ agreements, EPC contracts, asset transfer agreements and licensing contracts.
MONALISA C DIMALANTA

Puyat Jacinto Santos Law Office

Monalisa leads the energy practice group of PJS Law. Recognised as a ‘market leader’ and leading practitioner in the energy sector and in project development in Asia-Pacific, Monalisa continues to be the top choice as legal counsel of the major players (local and foreign) in the industry, as well as investors seeking to gain entry into this dynamic area of the Philippine economy. She is also a member of the Inter-Pacific Bar Association (IPBA) and is a professor at the Ateneo Law School in Makati City, Philippines.

NIGEL DREW

DLA Piper International

Nigel Drew is a solicitor qualified in England and Wales and heads the firm’s successful energy and infrastructure finance team in London. He has led on some of the largest energy and infrastructure projects in Europe and Africa, and has acted for arrangers (bank and bond), sponsors, contractors and the public sector on international projects across a wide range of sectors. In his extensive experience in the energy sector, he has advised on renewable power projects throughout Europe and Africa, including the largest project financing in Poland.

Nigel has been listed in Expert Guides: Project Finance, Euromoney’s guide to the world’s leading project finance lawyers. His recent experience includes advising the sponsors of the multi-award-winning US$840 million Maamba coal-fired power project in Zambia.

GBOLAHAN ELIAS

G Elias & Co

Professor Gbolahan Elias is the presiding partner of G Elias & Co, one of Nigeria’s leading business law firms. He is also a visiting professor of law at Babcock University, Ilishan where he teaches shipping, petroleum and arbitration law. He has published widely on a range of both historical and topical legal matters and served on numerous law reform committees, university administration boards and law journal editorial boards.

He read law at Magdalen and Merton Colleges, Oxford. He has DPhil, BCL (first-class honours), MA and BA (first-class honours) degrees from the University of Oxford. He was called to the New York Bar in 1990. Professor Elias was an associate at the Cravath firm in New York and has been a senior advocate of Nigeria since 2005. He is a member of the Chartered Institute of Arbitrators.

He has advised on numerous transactions in the Nigerian energy sector, including the largest acquisitions to date of electricity generation and distribution companies. He also advised on the development and negotiation of the precedent-setting power-purchase contracts and vesting contracts for the federal government-backed single buyer of grid electric power. He recently advised on a US$1.2 billion ‘gas-to-power’ project financing and a US$1.5 billion refinancing of NNPC petroleum product import receivables. He is currently advising the Transmission Company of Nigeria on the Eligible Customer Regulation 2017.
EUGENE R ELROD
Latham & Watkins LLP

Latham partner Gene Elrod has more than 35 years of experience representing companies across the oil and gas industry – including producers, pipelines, storage and local distribution companies – and large commercial end-users of natural gas. He is ranked among the nation’s leading energy regulatory and litigation lawyers by Chambers Global, Chambers USA, The Legal 500 United States, The Best Lawyers in America and Who’s Who Legal. He was named Best Lawyers’ ‘Lawyer of the Year’ in Washington, DC for energy regulatory (2018), energy (2015) and oil and gas (2014), and an ‘Energy and Environmental Trailblazer’ by The National Law Journal (2015).

FABRICE FAGES
Latham & Watkins AARPI

Fabrice Fages is a partner with a focus on litigation and arbitration, and he is chair of the Paris litigation department. He has also developed strong experience in regulatory and public policy, notably in regulated sectors such as the energy sector. Prior to joining Latham & Watkins, Mr Fages worked for the French Senate and the French National Assembly on various law drafts. He is a regular speaker at professional conferences on energy matters. Mr Fages is also a lecturer at the Pantheon-Sorbonne University (Paris 1), the CentraleSupélec School of Paris and the Cairo University, Egypt.

DANIEL FAJARDO VILLADA
Holland & Knight

Daniel Fajardo Villada is an associate in Holland & Knight’s Bogota office. He practises in the areas of oil and gas and mining law, as well as litigation and dispute resolution. Mr Fajardo Villada primarily represents oil and gas and mining companies as well as other types of corporations. He advises clients in contracting, due diligence, and mergers and acquisition matters, and also has experience with both litigation and arbitration. He has served as assistant professor of general regime of obligations at Universidad del Rosario, and as an intern at the International Court of Arbitration at the International Chamber of Commerce (Paris, France).

LIDO FONTANA
Covington & Burling (Pty) Ltd

Lido Fontana is of counsel in Covington’s Johannesburg office. He has significant experience in international oil and gas, mining and power, including renewable energy, and large infrastructure development transactions, including public–private partnerships and the United Kingdom’s private finance initiative.

GABIN GABAS
Orrick, Herrington & Sutcliffe (Europe) LLP

Gabin Gabas is an associate in the Orrick, Herrington & Sutcliffe energy and infrastructure group. His practice focuses on projects in the field of energy and extractive industries, mainly within Europe and Africa.
† WOUTER GELDHOF  
*Stibbe*  
Wouter Geldhof joined Stibbe in 2000 and became partner in the firm’s Brussels office in 2010, where he developed the stand-alone energy law practice. His expertise covered contractual and energy regulatory matters including regulatory issues concerning grid operation; exemptions for major new energy infrastructure; renewable energy projects (onshore and offshore wind turbines, solar, biomass and CHP); renewable heating projects; construction and grid connection of power generation plants; electricity and gas market transparency issues; electricity and gas (supply) contracts; CO2 emission trading; and energy performance contracts (EPC/ESCO).

MICHAEL J GERGEN  
*Latham & Watkins LLP*  
Latham partner Michael Gergen has extensive experience developing practical applications of economics, finance and regulatory law to assist clients in the electric, natural gas and other network industries to compete successfully in an environment of market-based, open-access competition. Mr Gergen is recognised as a leading energy lawyer by *Chambers USA* and by *The Best Lawyers in America*. Mr Gergen is an adjunct professor of law at the New York University School of Law.

NATASHA GIANVECCHIO  
*Latham & Watkins LLP*  
Latham partner Natasha Gianvecchio focuses her practice on the regulatory and regional energy market developments that impact clients in the electric and natural gas industries. Her representations involve a broad range of issues under various federal and state energy statutes and regulations and regional energy market rules affecting the domestic energy industry. Ms Gianvecchio is consistently recognised as a leading energy lawyer by *Chambers USA*, is consistently recommended by *The Legal 500 United States* and was highlighted by the publication as a ‘next generation lawyer’ for her energy regulatory work, and, in 2015, was named by *Law360* as a ‘top energy attorney under 40’ and a ‘Rising Star’.

ANDREAS GUNST  
*DLA Piper International*  
Andreas Gunst is an energy, projects and finance practitioner qualified in England and Wales, and is a partner at DLA Piper based out of both the London and Vienna offices. His practice areas cover the entire energy value chain, including upstream oil and gas exploration, production, transportation and trading (both OTC and exchange); electricity generation projects from conventional and renewable energy sources; electricity transmission, distribution, trading (both OTC and exchange) and supply; and emission reduction projects and environmental securities, allowance and certificate trading, as well as related regulatory advice.

Andreas takes an active role in the energy regulatory sector, serving as chairman of several working groups, including the drafting committee for the European Federation of Energy Traders (EFET), the RECS International Legal Task Force, the gas transportation
committee of the Association of International Petroleum Negotiators (AIPN), and the Carbon Markets and Investors Association (CMIA) EU Emissions Trading Scheme working group, and he is member of the Renewable Energy Performance Platform advisory panel. Andreas additionally advised one of the participating governments up to and during the Paris Agreement negotiations in 2015.

Andreas has been named ACC/ILO European Counsel of the Year 2013 (Regulatory) and is listed in The Legal 500 for energy and projects.

MUNIR HASSAN

*CMS Cameron McKenna Nabarro Olswang LLP*

Munir Hassan is head of clean energy at CMS in London, helping to determine the firm’s strategy on renewables and clean generation. Munir has almost 20 years of experience advising the power sector on commercial arrangements, M&A transactions, electricity sector restructurings and reforms, price-regulated energy networks, regional trading arrangements, establishment of regulatory frameworks and wholesale/retail supply arrangements. He has advised on technologies across the power space, including on offshore and onshore wind, solar, tidal, biomass, energy from waste, tidal and tidal lagoon, wave power, CCGT and CHP, coal-fired projects, electricity transmission networks and electricity distribution networks. He has advised extensively on both the sector in the United Kingdom and power projects and market reforms across numerous jurisdictions around the world.

FABRÍCIA DE ALMEIDA HENRIQUES

*Henriques, Rocha & Associados*

Fabrícia de Almeida Henriques is a partner at Henriques, Rocha & Associados, member of MLGTS Legal Circle as Mozambique Legal Circle. At an early stage of her career, which she started at Morais Leitão, Galvão Teles, Soares da Silva, she participated in several privatisations involving Portuguese companies, as well as in transactions in the area of project finance. More recently, her activity has been primarily focused on assisting national and international clients in M&A operations, mainly in the energy sector.

Currently she is a non-equity partner at Morais Leitão, Galvão Teles, Soares da Silva & Associados, coordinating all matters pertaining to Mozambique.

Ms Henriques was a lecturer at the law faculty of the University of Lisbon from 2000 to 2011. Currently, she lectures at the Eduardo Mondlane University and the Higher Institute of Science and Technology of Mozambique, both located in Maputo.

She has participated in several conferences and seminars on securities, banking, e-commerce and internet law.

WATARU HIGUCHI

*Anderson Mōri & Tomotsune*

Wataru Higuchi is a partner at Anderson Mōri & Tomotsune. He studied at Hitotsubashi University (LLB) and Columbia Law School (LLM) and is admitted to the Bar in Japan (Dai-ni Tokyo Bar Association) and New York.
HENRY HODA

Linklaters LLP

Henry Hoda is a managing associate at Linklaters LLP and a dispute resolution and energy lawyer in Berlin. He studied in Berlin, Paris (license en droit, Panthéon-Assas University (Paris II)) and London (LLM in competition law, King’s College) and has been trained as a lawyer in Berlin and Shanghai.

Henry is specialised in complex national and international litigation and arbitration proceedings with a focus on the energy sector, commercial and infrastructure disputes. He has particular expertise regarding long-term supply, storage and gas transport agreements and large infrastructure projects. Henry also advises companies on regulatory matters and contract law in the energy sector. Henry regularly represents gas storage operators and energy suppliers in proceedings for adjustment of storage and supply agreements and recently advised several investors on legal requirements for construction and operation of power storage facilities in Germany.

HACHEM EL HOUSSERI

Abou Jaoude & Associates Law Firm

Hachem El Housseini is a senior associate at Abou Jaoude & Associates Law Firm, practising in the areas of media, energy, corporate law and aviation.

Throughout his career, Hachem has advised key companies with respect to various aspects of their onshore and offshore business. In the energy sector, Hachem has a particular expertise in the oil and gas industry, and has worked on a number of major oil and gas projects in the region.

He also provides legal advice to the UNDP in the context of the preparation of a legislative framework study for the transport and energy sectors in Lebanon, a component of the SODEL project.

Hachem holds a JD in private law from the Francophone sector of the Lebanese University, and an MBA from ESA/ESCP (Ecole Supérieure des Affaires/Ecole Supérieure de Commerce de Paris). He is a lecturer at the American University of Beirut.

He is admitted to the Beirut Bar Association and the International Bar Association, and is an Associate Member of the Chartered Institute of Arbitrators, London. He is fluent in Arabic, French and English.

GÖKÇE İLDİRİ

Kolcuoğlu Demirkan Koçaklı Attorneys at Law

Ms Gökçe İldiri has been an associate at Kolcuoğlu Demirkan Koçaklı since August 2012.

Ms İldiri is experienced in mergers and acquisitions and energy law. She has represented various energy sector international clients in connection with a wide range of transactions. She is also a member of the project team that provides legal advice to a Japanese company, in relation to the Sinop Nuclear Power Plant. She has worked in a number of M&A transactions entailing the transfer of power plants.

She is also a founding member and board member of INLA’s Turkey chapter.
NICOLAS JANS
_HVG Law LLP_
Nicolas Jans is an associate at HVG Law and part of the energy and utilities team. He is admitted to the Bar in Amsterdam. Nicolas advises domestic and international companies in a broad range of energy and competition-related procedures against the Dutch energy regulator and competition authorities, usually in an international context. In this regard, Nicolas litigates in the areas of corporate and commercial law, energy law and national and EU competition law with a focus on the field of anti-corruption/fraud and state aid.

RANA KATEB
_About Jaoude & Associates Law Firm_
Rana Kateb is a senior associate at Abou Jaoude & Associates Law Firm, practising in the areas of energy, pharmaceuticals, corporate law, and mergers and acquisitions.

Throughout her career, Rana has advised key companies with respect to various aspects of their onshore and offshore business. In the energy sector, Rana has particular expertise in the electricity industry, and has worked on a number of major power projects in the region.

Rana holds an LLB in both private and public law from St Joseph University, and a Diploma of Higher Specialised Studies (DESS) in arbitration and ADR from the Francophone sector of the Lebanese University accredited by Panthéon-Assas University, Paris. She is recommended by _The Legal 500_.

She is admitted to the Beirut Bar Association, and is fluent in Arabic, French and English.

KARYN KHOR
_Skrine_
Karyn Khor is a projects and energy lawyer at Skrine whose practice encompasses energy M&A, project development, competition and oil and gas. Karyn Khor began to read law at King’s College London in 2008. In her third year at King’s, she was selected as one of five students to participate in a one-year intensive programme in international, comparative and transnational law at the Center for Transnational Legal Studies, encompassing students and faculty from 23 world-class law schools in a study on the transnationality of law in theory and in practice. She went on to graduate in 2012 with an LLB in law and transnational legal studies. Upon graduation, she carried on to do her master’s in King’s College London, obtaining an LLM in competition law in 2013. Karyn was called to the Bar of England and Wales in 2014, following which she joined Skrine as an associate.

NICOLAJ KLEIST
_Bruun & Hjejle_
Nicolaj Kleist has extensive experience in advising on regulatory matters and public law issues, especially within the energy sectors, where he advises energy and supply utilities in the areas of oil, gas, electricity, heating and renewables. He regularly assists in disputes before public authorities, complaints boards and the courts, and has assisted in a number of landmark cases regarding price issues.
MELİS ÖGET KOÇ
Kolcuoğlu Demirkan Koçaklı Attorneys at Law

Ms Melis Öget Koç is a senior associate at Kolcuoğlu Demirkan Koçaklı. Before joining the firm in 2015, she was a senior associate at another major Istanbul-based law firm for seven years.

Ms Koç has significant experience in energy law and M&A transactions. Her cross-border energy transaction experience includes a variety of deal types, ranging from joint ventures to M&A transactions involving the companies in the energy sector. She advised major companies both on renewable energy and non-renewable energy law matters, including regulatory matters relating to renewable energy generation activities, down-stream and up-stream oil and natural gas matters and licensing procedures. She has also worked in a number of M&A transactions contemplating the transfer of power plants.

She is a member of INLA’s Turkey chapter.

RORY LANG
Duane Morris & Selvam LLP

Rory is an international corporate lawyer and senior associate at Duane Morris & Selvam LLP’s offices in Yangon and Singapore. He practices in all areas of dispute resolution, banking and finance, capital markets, corporate, cross border transactions, commercial, M&A, real estate, employment, and energy and resources law. He has significant experience in all forms of foreign direct investments and cross border transactions. Rory provides ongoing legal assistance in relation to corporate structuring for investment; commercial contracts with local and international corporations and individuals; labour law; local regional compliance requirements; and real estate guidance for developers and hospitality providers.

Rory’s clients regularly refer to ‘his exceptional insight and understanding of the legal framework in Myanmar’ as he provides ‘good legal advice that helps to map our business plan and strategy’. Apart from corporate and project matters, Rory is also actively involved in pro bono services, which a client described as ‘could not have been more attentive, kind and professional’. Rory is listed as a 2018 ‘next generation lawyer’ in the practice areas of corporate and M&A by The Legal 500 Asia Pacific. He is also named as a recommended lawyer in projects (including energy) by The Legal 500 Asia Pacific 2018 for his ‘extensive experience in foreign investment, project finance and commercial contracts’.

Rory has more than nine years of experience in Australia and South East Asia, including over three years on-the-ground experience in Myanmar, Laos, Thailand and Singapore. He speaks regularly on market entry, M&A, employment law, energy, resources, insurance and property matters at conferences throughout the ASEAN region.

Rory is admitted to practise as a lawyer of the Supreme Court of Western Australia and as a solicitor of the Federal and High Courts of Australia. He is also a registered foreign lawyer in Singapore. Rory is a graduate of the University of Notre Dame Australia, where he was a member of the Notre Dame Law Students Society, and a masters of law graduate from the University of Western Australia.
CHANGWOO LEE
Yoon & Yang LLC
Changwoo Lee is a senior associate at Yoon & Yang LLC. Mr Lee’s main practice focuses on patent litigation, particularly in the energy and life sciences sector. He also has extensive experience in trademark and copyright matters.

KWANG-WOOK LEE
Yoon & Yang LLC
Kwang-Wook Lee is a partner at Yoon & Yang LLC. Mr Lee’s main areas of practice include antitrust law, telecommunications and energy, broadcasting and privacy law. Mr Lee represents a broad range of companies in the energy industry. He also has extensive experience providing legal advice concerning issues arising in the environment and clean-tech sector.

PIETER LEOPOLD
HVG Law LLP
Pieter Leopold is an associate at HVG Law and part of the energy and utilities team. He is admitted to the Bar in Amsterdam and is a member of the Dutch Association for Energy Law. Pieter studied International and European law at the University of Amsterdam. He litigates and advises national and international clients on energy regulation and competition issues. Pieter also represents clients in proceedings with the regulator. Prior to joining HVG Law, Pieter worked at the Authority for Consumers and Markets in The Hague.

RUTH LOSCH
Linklaters LLP
Ruth Losch is a managing associate at Linklaters LLP and a corporate and energy lawyer in Berlin. She studied law in Osnabruck, Kingston upon Hull, Berlin, Brussels (LLM) and Heidelberg (Juris Doctor) and has been trained as a lawyer in Berlin and Gdansk.

Ruth is an experienced adviser of clients in the public domain on regulatory matters, specialising in energy and public procurement law. She advised several municipalities in awarding concessions for their gas, electricity or district heating grids.

She also specialises in legal knowledge management and regularly publishes and lectures on questions of energy law.

CONNOR MCCLYMONT
Squire Patton Boggs
Connor McClymont is an associate in the corporate practice group of Squire Patton Boggs in Perth. He has assisted clients on a range of corporate transactions and advisory matters and has experience assisting international and domestic clients on research, drafting and due diligence.
SOURAYA MACHNOUK

*Abou Jaoude & Associates Law Firm*

Souraya Machnouk is a partner at Abou Jaoude & Associates Law Firm, and lends her specialised knowledge and experience to several practice groups, including mergers and acquisitions, banking, finance, corporate law, telecommunications, and energy.

Throughout her career, Souraya has advised key companies with respect to various aspects of their onshore and offshore business. In the energy sector, Souraya has a particular expertise in the oil and gas industry, and has worked on major LNG-to-power projects in the region.

Souraya holds a JD in private and public law from St Joseph University, a master’s degree (DEA) in banking and financial markets law from the University of Paris II-Assas, and a joint Master of Laws degree (LLM) from George Washington and Georgetown Universities. She is recognised as a leading lawyer by *The Legal 500*, *Chambers & Partners* and *IFLR1000*.

She is admitted to the Beirut Bar Association and the International Bar Association, and is fluent in Arabic, French and English.

MARTHE MASELIS

*Stibbe*

An associate at Stibbe, Marthe Maselis specialises in energy law and climate law. Besides concentrating on the contractual and regulatory aspects of energy law, she also focuses on the real estate aspects of energy infrastructure works and renewable energy projects, including energy performance contracting. Marthe also works intensively on (geothermal) district heating projects.

FIONA MEATON

*Squire Patton Boggs*

Fiona Meaton practises principally in commercial and corporate law with a focus on energy and resources transactions and projects. In particular, Fiona advises Australian and international clients in relation to joint venture arrangements, acquisitions, risk management and due diligence associated with exploration and production activities within Australia. She also advises on corporate law and corporate governance issues, in particular in relation to Corporations Act compliance and ASX Listing Rules. Fiona is the Perth head of the Australian Young Energy Network and a member of the Australian Institute of Energy Young Energy Professionals and the Australian Mining and Petroleum Law Association (AMPLA). Fiona was a member of the team working on the Ichthys LNG transaction, which was named Energy and Resources Deal of the Year at the Asian Legal Business Japan Law Awards 2013.

NEERAJ MENON

*Trilegal*

Neeraj Menon is a partner in the Mumbai office of Trilegal and is a member of Trilegal’s Energy, Infrastructure and Natural Resources team of the firm. His primary areas of practice are energy and infrastructure projects.

In the energy sector, Neeraj has advised the Government of India on the policy regime for the conventional power sector and has commented on various government policies in
the renewable energy and resources sectors. He has extensively advised the private sector on bidding and developing energy and infrastructure projects including on compliance with environmental legislations, conducting land title verification and on acquisition of real estate.

Neeraj has advised numerous financial and strategic investors, lenders, multilateral agencies and utilities on all aspects of investing, developing and financing solar, wind and hydro power projects. He led the team that advised IFC and Government of Madhya Pradesh on the development of 750MW of Rewa Ultra Mega Solar PV project on PPP basis. This project was recognised in the prestigious Government of India’s Prime Minister’s Book of Innovation, 2017 and World Bank Group’s President award for Innovation and Excellence for its innovative PPP transaction structure.


Neeraj is an alumnus of Symbiosis Law School, Pune University and a member of Bar Council of Delhi, India. He is a member of CII’s National Committee on Renewable Energy. He has co-authored the India chapters in successive editions of *The Energy Regulation and Markets Review* (since 2012) *Getting the Deal Through: Electricity Regulation* (since 2015) and *Getting the Deal Through: Mining* (2017).

**CİHAN MERCAN**  
*Kolcuoğlu Demirkan Koçaklı Attorneys at Law*

Cihan Mercan has been an associate at Kolcuoğlu Demirkan Koçaklı since 2016. He is experienced in energy law, with a particular focus on oil and gas, dispute resolution and commercial law and has been heavily involved in the public tender matters. He advises local and international companies in their energy related projects and represents clients in commercial disputes.

He is a member of INLA Turkey.

**ANTONIO MORALES**  
*Latham & Watkins LLP*

Antonio Morales is the deputy office managing partner and the responsible partner for the regulatory and litigation practice in the Spanish offices of Latham & Watkins, as well as being part of the environmental, land and resources practice group. Mr Morales’ practice focuses on projects and transactions relating to public and administrative law, including the energy, utility, water and telecommunications sectors.

In 1997, Mr Morales became a state attorney. During his time in the public administration, he worked at the Government Delegation in Madrid from 1998 to 1999 and from 1999 to 2002 at the Superior Court of Justice of Madrid. From 2002 and 2005 he served as Secretary General of the Spanish Nuclear Safety Council. Prior to joining Latham & Watkins, Mr Morales was a partner at Hogan Lovells. In 2008, Mr Morales obtained his PhD at the Autonomous University of Barcelona (UAB).

Mr Morales has been recognised as a leader in administrative and public law by *Chambers Global* for the past eight years and in the energy sector by *Chambers Europe* from 2008 to 2015. Additionally, he was recognised as a leading Iberian energy lawyer by
About the Authors

Iberian Lawyer in June 2006 and, in 2007, he also received Iberian Lawyer’s ‘40 under Forty’ award. Mr Morales was commended by Chambers Europe in 2011 for being ‘a lawyer with tremendous expertise’ and for the ease with which he ‘explains the most complex legal issues to clients with staggering clarity and simplicity’ and ‘total dedication to the client’s needs’.

LUIS HORACIO MORENO IV
Alfaro Ferrer & Ramírez

Luis Horacio Moreno IV is an associate at Alfaro Ferrer & Ramírez. He has been an associate at AFRA since 2010, concentrating his practice on the areas of acquisition and procurement law; government concessions and permits; telecommunications law; public transportation; energy law; administrative law; infrastructure; contracts; and general commercial law.

Luis is also a professor of administrative law at Santa María La Antigua Catholic University (USMA). He obtained his Bachelor of Law and Political Science at USMA in 2009, after which he went to Duke University School of Law and obtained a Master of Laws (LLM) in 2010. He obtained a Master of Law (LLM) in tax law from the Specialized University of Certified Public Accountants (UNESCPA) in 2013, and a Master of Business Administration for Law Firms (MBA) from the Superior Institute of Law and Economics (ISDE) in 2015. In 2017, Luis received his Certificate in Public Procurement Law from the Latin University of Panama, and the Certificate from the Public–Private Partnerships: Implementing Solutions in Latin America and the Caribbean (ES), from the Public–Private Partnerships programme of the Inter-American Development Bank (IDB edX).

Mr Moreno is a member of the Panama Bar Association, the International Bar Association and the Panamanian Association of Business Executives (APEDE). He was chair of the Legislation and Taxation Committee of the American Chamber of Commerce and Industry of Panama (AMCHAM) in 2015 and 2016, Secretary of the Administrative Law Commission of the Panama Bar Association in 2016, Secretary of the Law Commission of APEDE in 2017/2018 and Director and Secretary of AMCHAM in 2017–2018.

CHARLES MORRISON
DLA Piper International

Charles Morrison is a trade and project finance lawyer qualified in England and Wales, and is international group head of the finance and projects practice at DLA Piper. He has a particular focus on energy work, especially oil and gas, and his energy experience extends to upstream, midstream and downstream oil and gas, power projects, and the related financing. His clients include governments, oil companies, trading houses, banks and other financial institutions. Charles is a partner in the energy and infrastructure finance team, and was previously head of the Africa group, as well as head of the energy infrastructure finance and commodities team.

Charles appears regularly in the principal legal directories and awards. He has headed a number of teams in major international energy and infrastructure projects, and has significant experience throughout Africa. He was rated ‘leading individual’ in the 2013 The Legal 500 United Kingdom awards, commended as a ‘respected practitioner’ and for ‘thorough commercial advice’, and was appointed by the British government (DFID) and Uganda’s central bank, the Bank of Uganda, as an inspector to review the sale of Uganda Commercial Bank to Stanbic Bank Uganda.
JOHANA N’DIA
*Orrick RCI*

Johana N’Dia is an associate in the Orrick, Herrington & Sutcliffe energy and infrastructure group. Her practice focuses on energy and infrastructure, mining projects finance and development.

J PATRICK NEVINS
*Latham & Watkins LLP*

Latham partner Patrick Nevins has over 25 years of experience advising leading energy companies in the development of major infrastructure projects, administrative litigation and high-stakes regulatory matters. His clients have included companies in all segments of the natural gas industry including pipeline companies, LNG project developers, local distribution companies, producers, as well as oil and liquids pipelines and shippers. He is consistently recognised as a leading energy regulatory and oil and gas lawyer in *Chambers Global*, *Chambers USA*, *The Legal 500 United States*, *Who’s Who Legal*, *Best Lawyers* and *Euromoney’s ExpertGuides*.

OKECHUKWU J OKORO
*G Elias & Co*

Okechukwu J Okoro is a senior associate in the law firm of G Elias & Co. He holds a Bachelor of Laws degree from Ebonyi State University.

He has been involved in several of the firm’s energy deals. He has been actively involved in the legal review of gas sale documentation and is currently advising on three embedded power projects. He was on the team that recently advised two distribution companies on the Central Bank of Nigeria’s Nigerian Electricity Market Stabilization Facility, and on the team that advised Africa Finance Corporation on its investment in and divestment from the acquirer of a 45 per cent participating interest in an OML. Okechukwu J Okoro was also on the team that advised on a US$1.2 billion ‘gas-to-power’ project financing and a US$1.5 billion refinancing of NNPC petroleum product import receivables. He is currently advising the Transmission Company of Nigeria on the Eligible Customer Regulation 2017.

JOSÉ ROBERTO OLIVA JR
*Pinheiro Neto Advogados*

José Roberto Oliva Jr is a partner at Pinheiro Neto Advogados, in the energy team. He has more than 13 years of experience advising clients on matters related to the energy industry. His practice focuses mainly on energy regulation, project finance and M&A. He has extensive experience in assisting clients in domestic and international mergers and acquisitions, project development, financing, private equity investments, joint ventures, and a variety of other matters related to energy and infrastructure projects. He is consistently ranked among the nation’s top energy lawyers by *Chambers Latin America* and *Chambers Global, The Legal 500* and *IFLR1000*. He holds a Bachelor of Laws (LLB) from the University of Rio de Janeiro and two master’s degrees – a Master of Laws (LLM) from Insper (Institute of Education and Research), São Paulo and an LLM from the University of California, Berkeley. He is deputy general counsel for the Brazilian Association of Independent Power Producers.
(APINE), a member of the Energy Committee of the Brazilian Bar Association (OAB/RJ) and a member of the Brazilian Institute of Energy Law (IBDE).

CATARINA LEVY OSÓRIO

*ALC Advogados*

Catarina Levy Osório is a partner at ALC Advogados. She previously worked at another law firm as a consultant in the tax department and as a senior tax consultant with a major international consulting firm.

Ms Osório is also a partner with Morais Leitão, Galvão Teles, Soares da Silva and is responsible for all matters pertaining to Angola. She is a member of the Angolan and Portuguese Bar Associations and has relevant experience in Angolan law, having advised clients on private investment, tax and labour law in that jurisdiction.

HELENA PRATA

*ALC Advogados*

Helena Prata is a partner at ALC Advogados, with expertise ranging from advisory to complex corporate and asset financing and restructuring transactions, incorporation of SPVs and structured security arrangements and labour law. She is highly experienced in corporate law, environment, oil and gas and has worked extensively with national and international clients in these areas.

She is the author of several articles published in specialised Angolan magazines and also teaches business law at the law faculty of the Agostinho Neto University. Ms Prata was recently elected a member of the Luanda Provincial Council of the Angolan Bar Association.

GEORGES RACINE

*HFW*

Georges Racine is a partner at HFW. He is a dual-qualified civil and common law lawyer with intimate knowledge of Switzerland, developing countries and emerging markets. He has wide-ranging experience in corporate, commercial and international business law, with particular emphasis on projects (energy, infrastructure, telecoms and transport), construction, licensing and concessions, privatisations, mergers and acquisitions, joint ventures, public–private partnerships (PPPs), foreign investment and public procurement. Mr Racine has acted as lead counsel in international projects and transactions in over 25 countries worldwide. He was a member of the expert group that advised the Secretariat of the United Nations Commission on International Trade Law (UNCITRAL) on its draft Legislative Guide on Privately Financed Infrastructure Projects. He has written several articles on energy, infrastructure, telecommunications, PPPs and other subjects for international publications and attended several international conferences as a speaker. He has also acted for several international investment banks, international financial institutions (e.g., World Bank, IFC, EBRD), foreign governments, regulatory authorities, sponsors, developers, independent power producers, utilities, trading firms, contractors, service providers, suppliers, investors and consulting, engineering and accounting firms.
FILIP RADU

CMS Cameron McKenna Nabarro Olswang LLP

Filip Radu is an associate at CMS in London, practising in the firm’s energy projects and construction department, focusing on the power sector. Filip has advised on both conventional and renewable power projects around the world, acting for UK and international utilities, developers, financiers, governments and regulators. He also has experience advising on market reform, helping enshrine international best practice into national energy rules, regulations and legislation. Filip’s experience also spans M&A transactions within the energy sector, advising on corporate, regulatory and commercial matters.

KRISHNA RAMACHANDRA

Duane Morris & Selvam LLP

Krishna is managing director of Duane Morris & Selvam LLP in Singapore and of Duane Morris & Selvam (Myanmar) Limited. He is head of the corporate, FinTech and TMT practice groups. His practice includes M&A and capital markets, investments funds, private equity, financial technology and telecommunications, media and technology. Krishna also has significant experience in Myanmar, having worked in Myanmar for over five years.

Krishna advises issuers, fund managers, investment banks, venture capitalists, start-ups and high-net-worth individuals in Asia, Europe and the United States on a wide range of equity and debt securities issuances, compliance and regulatory matters. His extensive experience in mergers, acquisitions and takeovers, private equity participation and exit strategies has led to his being regularly cited by the reputable directories as a leading lawyer.

He is regarded as one of the most highly recommended lawyers in the practice areas of capital markets (foreign firms), corporate and M&A (local and foreign firms), and TMT (local firms) and capital markets (foreign firms) in Singapore by The Legal 500 Asia Pacific 2018 edition and Chambers Asia-Pacific and Chambers Global, which regularly refer to ‘his creative yet practical and client-focused approach’ and his ‘decisiveness and commerciality.’ In Myanmar, Krishna is recognised as a ‘leading lawyer’ in corporate and M&A and a recommended lawyer in projects (including energy) by The Legal 500 Asia Pacific 2018. IFLR1000 2018 also named Krishna as a ‘highly regarded lawyer’ in Singapore capital markets.

Krishna is a corporate lawyer with a very commercial approach. His practice develops according to the needs of his clients and currently due to Singapore’s emergence as one of the world’s leading FinTech hubs, he has more of a focus on the legal and regulatory advice relating to new financial technology business models, including crowdfunding, peer-to-peer lending platforms, blockchain technology, virtual and digital currencies such as BitCoin and Ethereum, e-wallet and trading platforms. As his clients’ trusted adviser, Krishna has established himself as one of Singapore’s ‘go-to’ lawyers for FinTech, having previously achieved a solid reputation in the TMT space, particularly in relation to telecommunications.

Krishna graduated from Christ’s College, Cambridge with an LLM in corporate finance on a Freshfields Bruckhaus Deringer (‘Freshfields’) scholarship. He articled and qualified with Freshfields in London prior to relocating to Singapore with Clifford Chance. He subsequently joined Selvam LLC and is now managing director of Duane Morris & Selvam LLP.

Krishna is an advocate and solicitor of the Supreme Court of Singapore and a solicitor of England and Wales. He previously sat on the Singapore Law Society’s Corporate Practice

**SIMON REAR**  
*Squire Patton Boggs*  
Simon Rear is a partner in the corporate practice group of Squire Patton Boggs in Perth. He has broad experience in private and public M&A, equity capital markets and general corporate advisory work in both Australia and the United Kingdom. He has advised in connection with takeovers, schemes of arrangement and private M&A transactions. He has also advised on a number of fundraisings including IPOs, rights issues and placements acting for both issuers and underwriters.

Simon’s expertise has been consistently recognised by leading legal directories, including *Doyle’s* and *The Legal 500 Asia Pacific* for Corporate and M&A.

**PAULA DUARTE ROCHA**  
*Henriques, Rocha & Associados*  
Paula Duarte Rocha is a partner at Henriques, Rocha & Associados, member of MLGTS Legal Circle as Mozambique Legal Circle. Engaged as a legal assistant, she had started her career even before completing her law degree. She then became a legal assistant to a partner at Pimenta, Dionísio & Associados. From 2000 to 2002 she provided multidisciplinary legal consultancy at the tax and legal services department of PricewaterhouseCoopers, cooperating with national and foreign investors. She was also an associate lawyer and senior legal adviser at MGA Advogados & Consultores.

More recently, Ms Rocha was a lawyer and managing partner at Ferreira Rocha & Associados, Sociedade de Advogados, involved in all areas of practice, advising national and foreign private companies with respect to public sector laws, public tenders and contracts, as well as advising foreign entities on compliance with all Mozambican tax, labour and commercial obligations.

**MYRIA SAARINEN**  
*Latham & Watkins AARPI*  
Myria Saarinen is a partner in the litigation department of the Paris office of Latham & Watkins.

Ms Saarinen's practice focuses on resolving a broad range of complex disputes through litigation proceedings, mostly in an international context, and in various areas of business, including in the energy sector.

**THOMAS SCHULZ**  
*Linklaters LLP*  
Thomas Schulz is a partner at Linklaters LLP and a corporate and energy lawyer in Berlin. He studied in Würzburg, Liverpool and Hamburg and has been trained as a lawyer in Brussels, Moscow and Beijing.
Thomas advises utilities, financial investors, project developers and banks on M&A, joint ventures, project developments and financings as well as contract law and regulation in the energy sector. He has in particular advised on numerous renewable energy projects and conventional power plants in Germany and abroad as well as electricity and gas grid transactions.

DAVID L SCHWARTZ  
Latham & Watkins LLP  
David Schwartz is a partner in the finance department of Latham & Watkins’ Washington, DC office. He serves as global chair of the energy regulatory and markets practice, is a member of the project finance group, and is co-chair of the firm’s global power industry group. He has extensive experience representing entities involved in electric generation, transmission and distribution, electric and gas marketing and trading, and gas transportation and distribution.

Mr Schwartz has been active in the formation of the developing electricity markets in the United States; led transactional and regulatory teams in mergers and acquisitions and divestitures of energy companies and assets; litigated contract, rate and transmission access disputes; and drafted federal and state energy legislation. He also has extensive experience in negotiating power purchase and sale agreements, electric transmission agreements, natural gas transportation agreements, energy management agreements, and electric and gas interconnection agreements.

Mr Schwartz regularly advises clients on energy matters before the Federal Energy Regulatory Commission, various state public utility commissions, the US Department of Justice, the Federal Trade Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission and the Department of Energy.

Mr Schwartz is regularly named as a leading energy lawyer in Corporate Counsel magazine, The Best Lawyers in America, The Legal 500 United States and both the global and the US Chambers & Partners guides to leading business lawyers. Mr Schwartz is a member of the American Bar Association and has held leadership positions in the Energy Bar Association.

SANDER SIMONETTI  
HVG Law LLP  
Sander Simonetti co-heads the HVG Law energy and utilities team. He graduated from Leiden University and was a fellow (energy and climate law) at the European University Institute in Florence. Sander advises national and international companies and governments on regulation, transactions, disputes and projects in the energy and natural resources industry. He handles complex deals right across the sector and advises on the full range of energy-related issues and projects, including wind, solar, geothermal and biomass, as well as oil and gas, LNG, district heating and co-siting.

Samantha Smart is an experienced corporate and commercial lawyer with a strong background in supporting companies across all industries in commercial transactions and corporate governance, particularly across the resources sector.
Samantha specialises in advising in relation to public and private mergers and acquisitions, the development of independent power projects, joint venture and farm-in arrangement structuring and secondary capital raisings. Samantha also regularly provides advice to clients on a broad variety of corporate law issues and corporate governance risk mitigation, including directors’ duties, continuous disclosure requirements, company secretarial matters and general regulatory compliance issues involving the Corporations Act and the ASX Listing Rules.

SHAGHAYEGH SMOUSAVI
CMS Pars
Since February 2016, Shaghayegh Smousavi has been the managing director of CMS Pars. Her work focuses on cross-border transactions and financing, in the energy sector in particular. She has special, local know-how and experience in advising international companies both on taking up operations in Iran and on re-entering the Iranian market.

Shaghayegh started her legal career with an international accountancy firm in Frankfurt and Paris, and then worked for a tax consultancy in Niamey in Niger, as well as for the European Commission in Brussels. She subsequently joined Clifford Chance, where she worked as a counsel in her final post there. Shaghayegh has been a CMS partner since 2013.

CHADI STEPHAN
Abou Jaoude & Associates Law Firm
Chadi Stephan is a senior associate at Abou Jaoude & Associates Law Firm, practising in the areas of energy, corporate law, and mergers and acquisitions.

Throughout his career, Chadi has advised key companies with respect to various aspects of their onshore and offshore business. In the energy sector, Chadi has a particular expertise in the electricity industry, and has worked on a number of major power projects in the region.

Chadi holds an LLB in both private and public law from the Holy Spirit University of Kaslik (USEK), and a Diploma of Higher Specialised Studies (DESS) in international agreements from USEK accredited by the University of Montpellier.

He is admitted to the Beirut Bar Association, and is fluent in Arabic, French and English.

MONICA SUN
Herbert Smith Freehills LLP
Monica Sun, a partner at Herbert Smith Freehills in the global energy practice in Beijing, has experience of advising on oil and gas (including LNG), power, renewables, mining, infrastructure projects and transactions around the world, in particular advising major Chinese companies on their outbound investment. Her clients include major Chinese state-owned enterprises such as Sinopec, CNOOC, CNPC, State Grid, Huaneng, Huaadian, Shenhua, Minmetals, SRF, Power China, CMC and CMEC. Her practice covers M&A, joint ventures, project development and project finance, private equity investment, corporate law and corporate finance. She also has considerable experience in advising foreign clients on doing business in China. Monica has advised on acquisitions and projects in jurisdictions including China, Australia, Indonesia, Africa, the former Soviet Union, South America, the United Kingdom and other key markets along the routes of the Belt and Road Initiative.
About the Authors

KEI TAKADA
Anderson Mōri & Tomotsune

Kei Takada is an associate at Anderson Mōri & Tomotsune. He studied at the University of Tokyo (BEC) and the University of Tokyo, School of Law (JD) and is admitted to the Bar in Japan (Dai-ichi Tokyo Bar Association).

REJI TAKAHASHI
Anderson Mōri & Tomotsune

Reiji Takahashi is a partner at Anderson Mōri & Tomotsune. He studied at the University of Tokyo (LLB) and the University of Virginia (LLM). He is a lecturer at the University of Tokyo School of Law and is admitted to the Bar in Japan (Dai-ni Tokyo Bar Association) and New York.

NORIFUMI TAKEUCHI
Anderson Mōri & Tomotsune

Norifumi Takeuchi is a partner at Anderson Mōri & Tomotsune. He studied at the University of Tokyo (LLB) and University of London (LLM) and is admitted to the Bar in Japan (Dai-ni Tokyo Bar Association).

NUNO GALVÃO TELES
Morais Leitão, Galvão Teles, Soares da Silva & Associados, Sociedade de Advogados, SP, RL

Nuno Galvão Teles joined Morais Leitão, Galvão Teles, Soares da Silva & Associados in 1987 and became a partner in 1995. He is the managing partner of the firm. He coordinates one of the corporate and commercial and capital markets teams. He also leads the firm's energy team, an area in which he has extensive experience.

His relationship with the Portuguese energy sector dates back to the early 1990s. During the past 15 years, he has been involved with enterprises in the energy sector and given support to the Portuguese government on some of the most important transactions to have occurred in the country's energy sector.

He has advised and assisted several companies and banks with a focus on M&A and capital markets operations. During recent years he has played an active role in key M&A transactions in Portugal or carried out overseas by Portuguese companies.

Mr Teles has led the team of lawyers responsible for some of the major privatisation transactions in Portugal, in the energy, pulp, motorway and cement industries.

JOHN A TRENOR
Wilmer Cutler Pickering Hale and Dorr LLP

John Trenor is a partner in the litigation/controversy department at Wilmer Cutler Pickering Hale and Dorr LLP in Washington, DC and a member of the firm's international arbitration practice group.

Mr Trenor has represented companies, states, state-owned entities, international organisations and individuals in a wide variety of disputes in the aviation, defence, financial services, manufacturing, oil and gas, pharmaceutical, technology, telecommunications and other industries. He has advised clients regarding commercial, investor-state and state-to-
state arbitrations under virtually all of the major institutional as well as ad hoc rules, including ICC, LCIA, AAA, SCC, VIAC, ICSID, UNCITRAL and others, and regarding international litigation in national courts in the United States, Europe and Asia. He has extensive experience in matters regarding public and private international law, including such areas as investment protection, state responsibility, reparations, territorial sovereignty, sovereign immunity, the law of treaties, the law of the sea, conflict of laws, and extraterritoriality and jurisdiction.

WANG BEI

Duane Morris & Selvam LLP

Bei is an international corporate lawyer and associate at Duane Morris & Selvam LLP’s office in Yangon. Bei practises in the areas of banking, corporate, commercial, capital markets, employment, energy and real estate law. Bei advises in relation to foreign direct investment, corporate structuring, M&A, commercial contracts, employment related matters and legal compliance for real estate development.

Bei is a graduate of the National University of Singapore. She is admitted to the Bar of the People’s Republic of China and registered as a foreign lawyer in the Republic of Singapore. Bei speaks fluent English and is also a native Mandarin speaker.

DICK WEIFFENBACH

HVG Law LLP

Dick Weiffenbach is senior partner at HVG Law, and energy and utilities sector leader of the global EY Law network of law firms associated with EY. He graduated from the universities of Leiden and Utrecht and is a Harvard Business School alumnus. Dick is member of the Dutch Association for Energy Law and advises national and international energy companies in the field of contract law, corporate law, energy law and regulatory affairs, including licensing and tariff regulation. He has supervised the unbundling of several Dutch energy companies.

PETER WHITFIELD

Sidley Austin LLP

Peter Whitfield is an environmental attorney with Sidley Austin LLP in Washington, DC, representing corporations and trade associations in regulatory advocacy and litigation regarding environmental, energy and climate change laws and regulations. Prior to joining Sidley, Mr Whitfield served as a trial attorney in the Environment and Natural Resources Division of the US Department of Justice. Mr Whitfield also served as law clerk to the Hon William Osteen in the United States District Court for the Middle District of North Carolina. Mr Whitfield graduated cum laude from the University of Hawaii Law School where he was an executive editor of the Asia and Pacific Law and Policy Journal. Mr Whitfield received his undergraduate degree from Duke University.

SHARON WING

Covington & Burling (Pty) Ltd

Sharon Wing is a corporate and project finance lawyer in Covington’s Johannesburg office. She has experience working on traditional and renewable energy projects, corporate transactions and various renewable energy and mining projects across Africa.
KUNITARO YABUKI
*Anderson Mōri & Tomotsune*

Kunitaro Yabuki is an associate at Anderson Mōri & Tomotsune. He studied at Chuo University (LLB) and is admitted to the Bar in Japan (Dai-ni Tokyo Bar Association).

SOONG-KI YI
*Yoon & Yang LLC*

Soong-Ki Yi is a partner at Yoon & Yang LLC. Mr Yi’s main areas of practice include mergers and acquisitions, corporate finance, foreign investment, and information and data protection. He also has extensive experience in the areas of energy, telecommunications and broadcasting, and regulatory matters.

KUNIHIRO YOKOI
*Anderson Mōri & Tomotsune*

Kunihiro Yokoi is a special counsel at Anderson Mōri & Tomotsune. He studied at the University of Tokyo (LLB) and University of California, Los Angeles, School of Law (LLM) and is admitted to the Bar in Japan (Dai-ni Tokyo Bar Association).

JOSÉ VICENTE ZAPATA
*Holland & Knight*

José Vicente Zapata is a partner in Holland & Knight’s Bogotá office with more than 20 years of experience in the natural resources sector. He focuses his practice on corporate and commercial matters with an emphasis on the environment, energy and natural resources. Mr Zapata primarily represents government organisations as well as electric, oil, gas, mining, agrochemical and industrial companies. In addition, he regularly advises clients in the structuring of foreign investment transactions, corporate reorganisations, and mergers and acquisitions as well as matters of environmental liability and judicial proceedings such as class-action lawsuits. He has represented clients in many of the largest transactions made in Colombia to date in the mining, oil and gas sectors, in addition to assisting a range of companies in obtaining mining and oil and gas concessions. Utilising his extensive experience in contract negotiations, Mr Zapata has assisted numerous government agencies both in defining the terms and conditions of regulations and in sensitive international judicial cases. Mr Zapata has participated in critical environmental liability cases and class action litigation in Colombia. Of particular importance is his participation in complex cases where communities and companies discuss their corresponding rights and in prior public consultations.

JEWELYNN GAY B ZARENO
*Puyat Jacinto Santos Law Office*

Gay Zareno, a senior associate at Puyat Jacinto Santos Law Office, has broad experience on energy and M&A transactions. She has served as counsel to several of the firm’s major transactions. Gay received her Juris Doctor (JD) degree from the University of the Philippines in 2012. She also completed her Bachelor of Science degree in accountancy from De La Salle University in 2005, and was admitted as a certified public accountant the following year.
JAMES ZHANG

_Herbert Smith Freehills LLP_

James Zhang is a member of Herbert Smith Freehills’ global energy practice in Beijing. He has worked across Herbert Smith Freehills’ offices in London, Hong Kong and Beijing and is admitted as a solicitor in England and Wales. James has advised clients on upstream oil and gas (including LNG) projects in Africa, the United Kingdom, North and South America, Southeast Asia, the Middle East, Australia and Greater China, in respect of equity M&A, project development, project operation, tie-in facilities and joint venture arrangements. James also has extensive experience in project development and finance on power, roads and railway projects in multiple jurisdictions.
CONTRIBUTING LAW FIRMS’ CONTACT DETAILS

**ABOU JAOUDE & ASSOCIATES LAW FIRM**
OMT Building
266 Sami El Solh Avenue
PO Box 116-5079
Beirut
Lebanon
Tel: +961 1 395555
Fax: +961 1 384064
s.machnouk@ajalawfirm.com
h.elhousseini@ajalawfirm.com
r.kateb@ajalawfirm.com
c.stephan@ajalawfirm.com
www.ajalawfirm.com

**ALC ADVOGADOS**
Masuika Office Plaza
Edifício MKO A
Piso 5, Escritório A
Talatona, Município de Belas
Luanda
Angola
Tel: +244 926 877 476/8/9
catarinaosorio@alcadvogados.com
helenaprata@alcadvogados.com
www.alcadvogados.com

**AFRIDI & ANGELL**
Jumeirah Emirates Towers
Office Tower, Level 35
Sheikh Zayed Road
Dubai
United Arab Emirates
Tel: +971 4 330 3900
Fax: +971 4 330 3800
mafridi@afridi-angell.com
aaloke@afridi-angell.com
www.afridi-angell.com

**ALFARO FERRER & RAMÍREZ**
AFRA Building
Ave Samuel Lewis and 54 Street
Panama City
Republic of Panama
Tel: +507 263 9355
Fax: +507 263 7214
abarcenas@afra.com
lhmoreno@afra.com
www.afra.com
ANDERSON MÔRI & TOMOTSUNE
Otemachi Park Building
1-1-1 Otemachi, Chiyoda-ku
Tokyo 100-8136
Japan
Tel: +81 3 6775 1000
reiji.takahashi@amt-law.com
norifumi.takeuchi@amt-law.com
kunihiro.yokoi@amt-law.com
wataru.higuchi@amt-law.com
kunitaro.yabuki@amt-law.com
kei.takada@amt-law.com
www.amt-law.com

BRUUN & HJEJLE
Nørregade 21
1165 Copenhagen K
Denmark
Tel: +45 33 34 50 00
Fax: +45 33 34 50 50
nkl@bruunhjejle.dk
www.bruunhjejle.com

CMS
CMS Hasche Sigle
Breite Straße 3
40213 Düsseldorf
Germany
Tel: +49 211 49 34 415
Fax: +49 211 49 34 120
shaghayegh.smousavi@cms-hs.com
www.cms.law

CMS Pars
No. 4 Rahimi Street
Nelson Mandela Boulevard
Tehran 1967916959
Iran
Tel: +98 21 226 51 665
Fax: +98 21 262 90 187

CMS Cameron McKenna Nabarro
Olswang LLP
Cannon Place
78 Cannon Street
London EC4N 6AF
United Kingdom
Tel: +44 20 7367 3000
Fax: +44 20 7367 2000
munir.hassan@cms-cmno.com
filip.radu@cms-cmno.com
www.cms.law
www.cms-lawnow.com

COVINGTON & BURLING (PTY) LTD
Graysand Office Park
2 Sandton Drive
Sandton 2146
Johannesburg
South Africa
Tel: +27 11 282 0860
lfontana@cov.com
swing@cov.com
www.cov.com

DLA PIPER INTERNATIONAL
3 Noble Street
London
EC2V 7EE
United Kingdom
Tel: +44 20 7796 6444 (C Morrison)
Tel: +44 20 7796 6149 (N Drew)
Tel: +44 20 7796 6062 (A Gunst)
Fax: +44 20 7796 6666
charles.morrison@dlapiper.com
nigel.drew@dlapiper.com
andreas.gunst@dlapiper.com
www.dlapiper.com

© 2018 Law Business Research Ltd
Contributing Law Firms’ Contact Details

DUANE MORRIS & SELVAM LLP
No. 14, Kaymarthi Street (1)
Thriyadanar Yeikthar Housing
Quarter 3 Mi Kyaung Kan, Thingangyun Township
Yangon, Myanmar
Tel: +959 6359 3879
kramachandra@duanemorrisselvam.com
rjlang@duanemorrisselvam.com
bwang@selvamandpartners.com
www.duanemorrisselvam.com

HERBERT SMITH FREEHILLS LLP
28th Floor Office Tower
Beijing Yintai Centre
2 Jianguomenwai Avenue
Chaoyang District
Beijing 100022
China
Tel: +86 10 6535 5000
Fax: +86 10 6535 5055
monica.sun@hsf.com
james.zhang@hsf.com
www.herbertsmithfreehills.com

G ELIAS & CO
6 Broad Street
Lagos
Nigeria
Tel: +2341 4607890
Tel: +2341 2806970
Fax: +2341 2806972
gbolahan.elias@gelias.com
okechukwu.okoro@gelias.com
www.gelias.com

HFW
13-15 Cours de Rive
1204 Geneva
Switzerland
Tel: +41 22 322 48 00
Fax: +41 22 322 48 88
georges.racine@hfw.com
www.hfw.com

HENRIQUES, ROCHA & ASSOCIADOS
Edifício JAT V-1
Rua dos Desportistas, 833, 6º
Fração NN5
Maputo
Mozambique
Tel: +258 21 344000
Fax: +258 21 344099
fahenriques@hrlegalcircle.com
pdrocha@hrlegalcircle.com
www.hrlegalcircle.com

HOLLAND & KNIGHT
Carrera 7 # 71-21
Torre A, Piso 8
Bogotá, DC
Colombia
Tel: +57 1 745 5720
Fax: +57 1 541 5417
jose.zapata@hklaw.com
daniel.fajardo@hklaw.com
www.hklaw.com

HVG LAW LLP
Antonio Vivaldistraat 150
1083 HP Amsterdam
Tel: +31 88 407 04 44
Fax: +31 88 407 04 45
dick.weiffenbach@hvglaw.nl
sander.simonetti@hvglaw.nl
nicolas.jans@hvglaw.nl
pieter.leopold@hvglaw.nl
www hvglaw nl nw en home
Contributing Law Firms' Contact Details

PINHEIRO NETO ADVOGADOS
Rua Hungria, 1100
01455-906 São Paulo, SP
Brazil
Tel: +55 11 3247 8400
Fax: +55 11 3247 8600
joliva@pn.com.br
jbmachado@pn.com.br
www.pinheironeto.com.br

PUYAT JACINTO SANTOS LAW OFFICE
10th Floor, 8 Rockwell
Hidalgo Corner Plaza Drive, Rockwell Center
Makati City 1200
Philippines
Tel: +63 2 840 5025
Fax: +63 2 810 0890
mcdimalanta@pjlaw.com
sfbalot@pjlaw.com
jbzareno@pjlaw.com
www.pjlaw.com

SIDLEY AUSTIN LLP
1501 K Street, NW
Washington, DC 20005
United States
Tel: +1 202 736 8000
Fax: +1 202 736 8711
ralonso@sidley.com
pwhitfield@sidley.com
www.sidley.com

SKRINE
50-8-1, 8th Floor
Wisma UOA Damansara
50 Jalan Dungun
Damansara Heights
50490 Kuala Lumpur
Malaysia
Tel: +603 2081 3803
Fax: +603 2094 3211
fariz.aziz@skrine.com
karyn.khor@skrine.com
www.skrine.com

SQUARE PATTON BOGGS
Level 21
300 Murray Street
Perth WA 6000
Australia
Tel: +61 8 9429 7444
Fax: +61 8 9429 7666
simon.rear@squirepb.com
samantha.smart@squirepb.com
fiona.meaton@squirepb.com
connor.mcclymont@squirepb.com
www.squirepattonboggs.com

STEPHENSON HARWOOD MIDDLE EAST LLP
Office 01, 04, Level 12, Tower 2
Al Fattan Currency House
Dubai International Financial Centre
PO Box 482017
Dubai
United Arab Emirates
Tel: +971 4 407 3900
Fax: +971 4 327 6714
salem.chalabi@shlegal.com
www.shlegal.com

© 2018 Law Business Research Ltd
STIBBE
Central Plaza
Loksumstraat 25 rue de Loxum
1000 Brussels
Belgium
Tel: +32 2 533 53 14
Fax: +32 2 533 53 84
cedric.degreef@stibbe.com
marthe.maselis@stibbe.com
www.stibbe.com

STUDIO LEGALE VILLATA, DEGLI
ESPOSTI E ASSOCIATI
Via San Barnaba, 30
20122 Milan
Italy
Tel: +39 02 54 92 951
Fax: +39 02 54 62 107
a.degliesposti@vilde.it
www.vilde.it

TRILEGAL
Peninsula Business Park
17th Floor, Tower B
Ganpat Rao Kadam Marg
Lower Parel (West)
Mumbai 400 013
Tel: +91 22 4079 1000
Fax: +91 22 4079 1098
akshita.amit@trilegal.com
neeraj.menon@trilegal.com
www.trilegal.com

WILMER CUTLER PICKERING
HALE AND DORR LLP
1875 Pennsylvania Avenue, NW
Washington, DC 20006
Tel: +1 202 663 6222
Fax: +1 202 663 6363
john.trenor@wilmerhale.com
www.wilmerhale.com

YOO N & YANG LLC
ASEM Tower
517 Yeongdong-daero
Gangnam-gu
Seoul 06164
Korea
Tel: +82 2 6003 7000
Fax: +82 2 6003 7800
soongki@yoonyang.com
kwlee@yoonyang.com
cwlee@yoonyang.com
www.yoonyang.com