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# CONTENTS

PREFACE.............................................................................................................................................................. vii

*David L Schwartz*

<table>
<thead>
<tr>
<th>Chapter</th>
<th>Country</th>
<th>Authors/Editors</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>AUSTRALIA</td>
<td>Simon Rear, Fiona Ellett and Connor McClymont</td>
<td>1</td>
</tr>
<tr>
<td>2</td>
<td>BELGIUM</td>
<td>Frederik Vandendriessche and Cedric Degreve</td>
<td>14</td>
</tr>
<tr>
<td>3</td>
<td>BRAZIL</td>
<td>José Roberto Oliva Jr and Julia Battistella Machado</td>
<td>23</td>
</tr>
<tr>
<td>4</td>
<td>CHINA</td>
<td>Monica Sun, James Zhang and Qiujiie Tian</td>
<td>37</td>
</tr>
<tr>
<td>5</td>
<td>COLOMBIA</td>
<td>José Vicente Zapata and Daniel Fajardo Villada</td>
<td>55</td>
</tr>
<tr>
<td>6</td>
<td>DENMARK</td>
<td>Nicolaj Kleist</td>
<td>69</td>
</tr>
<tr>
<td>7</td>
<td>EUROPEAN UNION</td>
<td>Andreas Gunst, Natasha Luther-Jones and Michael Cieslarczyk</td>
<td>78</td>
</tr>
<tr>
<td>8</td>
<td>FRANCE</td>
<td>Fabrice Fages and Myria Saarinen</td>
<td>94</td>
</tr>
<tr>
<td>9</td>
<td>GERMANY</td>
<td>Thomas Schulz, Julia Sack and Ruth Losch</td>
<td>108</td>
</tr>
<tr>
<td>10</td>
<td>ITALY</td>
<td>Giorgio Telarico, Mario Cigno and Amalia Serena Scimè</td>
<td>118</td>
</tr>
<tr>
<td>Chapter</td>
<td>Country</td>
<td>Contributors</td>
<td></td>
</tr>
<tr>
<td>----------</td>
<td>---------------</td>
<td>-----------------------------------------------------------------------------</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>JAPAN</td>
<td>Reiji Takahashi, Norifumi Takeuchi, Wataru Higuchi, Kunihiro Yokoi, Keisuke Hayashi and Kei Takada</td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>LEBANON</td>
<td>Carlos Abou Jaoude, Sounaya Machnouk, Hachem El Housseini, Rana Kateb and Chadi Stephan</td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>MALAYSIA</td>
<td>Fariz Abdul Aziz and Karyn Khor</td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>MYANMAR</td>
<td>Krishna Ramachandra, Priyank Srivastava, Wang Bei and Ken Tan</td>
<td></td>
</tr>
<tr>
<td>15</td>
<td>NIGERIA</td>
<td>Gbolahan Elias and Okechukwu J Okoro</td>
<td></td>
</tr>
<tr>
<td>16</td>
<td>PANAMA</td>
<td>Annette Bárcenas Olivardia and Luis Horacio Moreno IV</td>
<td></td>
</tr>
<tr>
<td>17</td>
<td>POLAND</td>
<td>Piotr Ciołkowski and Ada Szon</td>
<td></td>
</tr>
<tr>
<td>18</td>
<td>PORTUGAL</td>
<td>Bruno Azevedo Rodrigues and Ashick Remetula</td>
<td></td>
</tr>
<tr>
<td>19</td>
<td>RUSSIA</td>
<td>Thomas Heidemann and Dmitry Bogdanov</td>
<td></td>
</tr>
<tr>
<td>20</td>
<td>SOUTH AFRICA</td>
<td>Lido Fontana, Mzwandile Khumalo and Yolanda Dladla</td>
<td></td>
</tr>
<tr>
<td>21</td>
<td>SOUTH KOREA</td>
<td>Soongki Yi, Kwang-Wook Lee and Chang Woo Lee</td>
<td></td>
</tr>
<tr>
<td>22</td>
<td>SPAIN</td>
<td>Antonio Morales</td>
<td></td>
</tr>
<tr>
<td>23</td>
<td>TAIWAN</td>
<td>Chung-Han Yang and Chengkai Wang</td>
<td></td>
</tr>
<tr>
<td>Chapter</td>
<td>Country</td>
<td>Authors</td>
<td>Page</td>
</tr>
<tr>
<td>---------</td>
<td>-----------------</td>
<td>-------------------------------------------------------------------------</td>
<td>------</td>
</tr>
<tr>
<td>24</td>
<td>UNITED ARAB EMIRATES</td>
<td>Masood Afridi and Adite Aloke</td>
<td>318</td>
</tr>
<tr>
<td>25</td>
<td>UNITED KINGDOM</td>
<td>Andreas Gunst, Natasha Luther-Jones and Kenneth Wallace-Mueller</td>
<td>333</td>
</tr>
<tr>
<td>26</td>
<td>UNITED STATES</td>
<td>Tyler Brown, Eugene R Elrod, Michael J Gergen, Natasha Gianvecchio and J Patrick Nevins</td>
<td>350</td>
</tr>
<tr>
<td>27</td>
<td>UZBEKISTAN</td>
<td>Maxim Dogonkin and Iroda Tokhirova</td>
<td>387</td>
</tr>
<tr>
<td>Appendix 1</td>
<td>ABOUT THE AUTHORS</td>
<td></td>
<td>397</td>
</tr>
<tr>
<td>Appendix 2</td>
<td>CONTRIBUTORS’ CONTACT DETAILS</td>
<td></td>
<td>419</td>
</tr>
</tbody>
</table>
In our ninth year of writing and publishing *The Energy Regulation and Markets Review*, the most pressing global concerns have revolved around the covid-19 pandemic. Accordingly, many of our contributing authors have emphasised concerns associated with the effects of the crisis on energy demand and consumption, and delays in the development of infrastructure. Beyond this crisis, we have seen many other significant geopolitical changes that have added uncertainties to global energy policies. For example, oil prices have hit record lows, which has slowed exploration and production efforts, and has threatened economic stability for countries that depend upon oil revenues. The United Kingdom is now within its 11-month transition period to exit from the European Union (a process known as Brexit), creating uncertainties regarding the future of the UK’s energy policies and its coordination and cooperation with the European Union, including with respect to commitments to reduce greenhouse gases (GHGs). The Trump administration’s ‘America First’ trade policies have continued to alienate US allies and historical trading partners. Despite its withdrawal from the Paris Agreement and expressions of support from the Trump administration for the coal industry, the United States has continued its extensive investment in renewable generation resources. The 2011 Fukushima nuclear incident continues to affect energy policy in many countries. Finally, there are continued efforts to liberalise the energy sector globally.

I CLIMATE CHANGE DEVELOPMENTS

Despite the US withdrawal from the Paris Agreement, we continue to see significant carbon reduction efforts globally, including increased use of renewable resources, and measures to improve energy efficiency and reduce demand.

In the United States, despite the Trump administration’s support for the US coal industry, coal and other aged fossil fuel plants are retiring at an unprecedented rate. Additionally, many states have pushed for the procurement of thousands of megawatts of renewable resources, including from new offshore wind development projects on the east coast. However, the US Bureau of Ocean Energy Management has delayed granting approvals for offshore wind projects, and the Federal Energy Regulatory Commission has imposed regulatory restrictions on the ability of state-subsidised renewable energy projects to clear in the regional capacity markets through a minimum offer price rule to mitigate buyer market power.

The European Union issued a revised Renewable Energy Directive, which will take effect in 2021, targeting 32 per cent renewable consumption by 2030. Despite continued efforts to follow through on Brexit, the United Kingdom’s renewable energy targets already exceed those of the European Union. France is seeking to double its wind and solar capacity and President Macron has announced a goal to close the remaining coal plants by 2022.
Italy had previously targeted a 28 per cent reliance on renewable energy by 2030 but is now working to reach the 32 per cent target adopted by the European Union. Belgium has continued its significant offshore wind procurement efforts, and is seeking to reduce subsidies in future procurements. In Denmark, renewables already constitute 40 per cent of electricity consumption and the aim is to have all energy demand met by renewables by 2050. Germany will not meet its goal of reducing emissions by 40 per cent by 2020, or its goal to reduce energy consumption by 20 per cent as compared with 2008, but remains focused on the continued development of renewable generation, energy efficiency and conservation, as well as energy storage technologies. Poland has been struggling to meet the European Union renewable energy targets but has plans to develop offshore wind generation.

Japan has continued its efforts to develop solar and wind resources, including opening new sea areas for offshore wind. But the shutdown of most of its nuclear generation has resulted in a significant reliance upon natural gas, including liquefied natural gas, and reductions in renewable energy prices has caused a slowdown in new solar and wind development. China continues to have ambitious renewable energy goals, capping energy from coal generation to an amount equivalent to 5 billion tonnes and aiming to have 15 per cent of generation supplied by non-fossil fuel generation. Korea aims to generate 20 per cent of its power needs from renewable energy and has committed to cut GHGs by 37 per cent by 2030.

This year, Australia has reached almost 20 per cent reliance on renewable energy resources, including significant amounts of energy storage capacity (battery and pumped water) and South Africa increased its renewable independent power procurement efforts, with a goal of producing 17,800MW of renewable energy by 2030.

The United Arab Emirates aims to reduce its carbon footprint by 70 per cent by relying on 50 per cent renewable energy by 2050, and Abu Dhabi is seeking to reduce electricity consumption by 22 per cent by 2030. In Brazil, hydroelectric resources already constitute more than 60 per cent of its installed generation capacity, and efforts continue to increase wind and solar generation as the cost of renewable generation has decreased. Colombia has significant renewable energy resources and recently completed its first auctions for renewable projects, with 1,398MW awarded and installed.

II INFRASTRUCTURE DEVELOPMENT

For many countries, a reliable energy supply remains the primary concern, regardless of fuel source. As only 35 per cent of Myanmar is connected to the grid, there are continued efforts to electrify remote parts of the country. Lebanon is hoping to solicit bids for the development of 890MW on floating barges to increase electricity supply. Panama and Colombia continue to seek foreign investment.

South Africa is utilising its Integrated Resource Planning process with a goal of doubling its generation and transmission capacity by 2030. Australia is developing the Snowy Hydro Project, which, at 2,000MW, will be one of the largest pumped hydroelectric storage projects in the world. Colombia is developing a large hydroelectric project that is expected to produce up to 17 per cent of the country’s energy needs, but that effort is hindered by construction delays.

In its eighth licensing round for oil and gas exploration in the North Sea, Denmark received five new applications, but owing to political pressure relating to GHGs, Denmark has put this licensing round on hold indefinitely.
III NUCLEAR POWER GENERATION

Nine years after the Fukushima disaster, Japan has stopped operations at all but nine of its 48 nuclear power stations, and 11 nuclear power stations are in the process of being reviewed for restart under Japan’s new stringent safety standards. Germany continues efforts to phase out all nuclear generation by 2022, and Belgium’s nuclear plants have often been offline for maintenance for technical issues in the past few years. France was seeking to eliminate nuclear generation by 2025 but has extended that date to 2035. South Korea has continued its efforts to phase out nuclear power (replacing nuclear plants with new renewable facilities over time). South Africa’s nuclear ambitions appear to be on hold at least until 2030.

However, the phasing out of nuclear energy is not universal. The United Arab Emirates’ new 5,600MW Barakh nuclear power station is almost complete and one of its units is already operational. When all units are on-line, Barakh will supply 25 per cent of the emirates’ electrical needs. Poland still intends to explore the development of nuclear power in the future. In the United States, even though the early retirement of certain nuclear plants has been driven by cost and power market considerations (rather than safety concerns), some states have passed legislation to subsidise nuclear energy to allow owners to continue to operate through zero emissions credit programmes, including Illinois, New York, New Jersey and Ohio, with similar legislation being considered in Pennsylvania.

IV LIBERALISATION OF THE ENERGY SECTOR

We have seen significant energy sector regulatory reforms in many countries. The European Union has sought to continue efforts to centralise the regulation of the EU energy sector. France has taken significant steps towards further liberalisation of its energy sector. Japan has fully liberalised its electricity and gas sectors and is encouraging market entry. Australia has opened access to transmission through regulatory reforms to encourage entry into the generation market and is undertaking significant energy market reforms to send more accurate price signals to market participants. Brazil continues its efforts to implement net metering regulations this year. China has reduced subsidies for renewable energy, prices transmission and distribution rates based upon a cost-plus regulatory methodology, and has implemented a market-priced mechanism for pricing coal-based generation. The United Kingdom has implemented a competitive tender process for the development of offshore transmission. In the United States, while states have continued to subsidise nuclear and renewable generation, the Federal Energy Regulatory Commission has permitted regional markets to implement minimum offer price rules to combat buyer-side mitigation in an effort to maintain competitive capacity markets.

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

David L Schwartz
Latham & Watkins LLP
Washington, DC
May 2020
I OVERVIEW

Energy regulation and market control continues to be a highly politicised issue in Australia. Debate surrounding the benefits of renewable energy versus traditional energy sources such as coal continues to create confusion about the future direction of Australia’s energy policy. Despite the growing national and global political pressure on emissions reduction and climate policy, and the ever present demand for reliable and cost-effective energy supply, the fundamentals of energy policy remain unchanged.

A successful and efficient energy policy should aim to deliver:

a. reduced electricity costs for households and industry (which are being crippled by soaring electricity prices);

b. reduced carbon emissions so that Australia can meet its commitment at the Paris climate change conference to reduce emissions by between 26 and 28 per cent, as compared with 2005 levels, by 2030; and

c. stability and reliability of supply so that consumers can be confident of uninterrupted supply, including during peak demand periods.

Since 2007, Australia has seen a parade of different energy policies at the federal level, with not one staying in place for more than a couple of years. This has left the electricity generation, transmission and retail industry in limbo, and no doubt has been the driver behind the lack of investment in new generation facilities, which has in turn driven up electricity prices and provided no coherent or integrated pathway for investment in grid upgrades and carbon reduction schemes.

In many ways, the chaos at the federal level has left state governments and industry to go it alone. Therefore, we have seen state governments each introduce their own energy policies, designed to address the three issues noted above, and industry making investment decisions based predominantly on those market drivers that are divorced from the influence of federal policy.

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


3 Power prices rose by 117 per cent between 2008 and 2018, more than four times the average price increase across other sectors during that time (source: Australian Bureau of Statistics).
Given the differing energy regulation and markets, this chapter summarises the following in each state of Australia and looks at possible policy and market developments:

a regulatory framework;
b transmission and distribution networks;
c retail markets; and
d policies and developments.

II REGULATION

i The regulators

The Australian Energy Market Operator (AEMO) is the industry-funded organisation that oversees the functioning of the National Electricity Market (NEM) in the states of Queensland, New South Wales (NSW), the Australian Capital Territory, Victoria, Tasmania and South Australia and the Wholesale Electricity Market (WEM) in Western Australia (which supplies electricity to the South West Interconnected System (SWIS)).

The NEM is regulated pursuant to the National Electricity Rules and National Electricity Law created by the Council of Australian Governments (COAG). The WEM is regulated pursuant to the WEM Rules and related WEM Market Procedures. In 2016, there was a proposal for Western Australia also to be regulated by the National Electricity Rules and National Electricity Law so that Australia could have national uniform regulations; however, this proposal stalled and, following the Western Australian state election in 2017, neither major party’s platform includes amendments to energy regulation in Western Australia at this time.

In relation to the NEM, the Australian Energy Regulator (AER) oversees economic regulation and compliance with the National Electricity Rules and is accountable to the Commonwealth government as an arm of the Australian Competition and Consumer Commission (ACCC). The Australian Energy Market Commission (AEMC) works alongside the AER and AEMO to determine the policy and governance structures that support Australia’s energy markets. The AEMC is responsible to the COAG. To coordinate the operation of the AEMO, the AER and the AEMC in overseeing energy policy and regulation relating to the NEM, these organisations also come together as members of the Market Bodies Forum, which reports to the COAG in relation to matters requiring action on the part of these organisations.

In relation to the WEM, the Economic Regulation Authority (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

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4 National Electricity (Western Australia) Bill 2016 Explanatory Memorandum.
various codes 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.

The Clean Energy Regulator Act 2011 (Cth) established the Clean Energy Regulator (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 under the National Greenhouse and Energy Reporting Act 2007, the Emissions Reduction Fund under the Carbon Credits (Carbon Farming Initiative) Act 2011, the Renewable Energy Target 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.

The Energy Security Board (ESB), established by the COAG Energy Council, aims to provide oversight regarding the future direction of the NEM, with its focus placed on maintaining reliability and security. The ESB’s main purpose is to implement the outcomes suggested by Australia’s Chief Scientist, Dr Alan Finkel, in his June 2017 paper ‘Independent Review into the Future Security of the National Electricity Market – Blueprint for the Future’. The key outcomes of this blueprint are increased security, future reliability, lower emissions and rewards for consumers. It is expected the new market framework will apply from the mid 2020s.

**Regulated activities**

**NEM**

The National Electricity Law and associated National Electricity Rules regulate market activities, and the National Energy Retail Law and associated National Energy Retail Rules regulate retail activities. A National Energy Customer Framework (NECF) has also been adopted in all states participating in the NEM, other than Victoria. However, Victoria has now completed a process of harmonising the Victorian Energy Retail Code with the NECF and intends to facilitate a smooth transition to the NECF from existing frameworks.

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8 Id.


NECF is effectively a package of reforms to the National Energy Retail Law that implement the framework, with the National Energy Retail Regulations 2012 and the National Energy Retail Rules. The extent to which the NECF has been adopted in each state is slightly different; therefore, it is necessary to consult the relevant state and territory laws to see which provisions have been amended.12

The following key activities are regulated within the NEM by the AER:

- At a wholesale level, participant bidding, dispatch and prices, network constraints and outages and forecasting in relation to demand and capacity are monitored by the AER to ensure there is no misuse of market power.
- In relation to networks, the AER sets a maximum revenue that network service providers can earn based on proposals submitted by those providers that detail their required revenues based on customer demand, their cost base, age depreciation of their infrastructure and maintenance measures required to maintain network safety and stability.
- At a retail level, the AER provides a price comparison guide on its website (applicable to those jurisdictions that have adopted the National Energy Retail Law) to provide customers with visibility of costs and charges by the different providers. Thus, the AER seeks to reduce prices in the market through aiding competitive tension between providers, rather than setting retail energy prices. The AER also authorises new retail providers and enforces compliance with the National Energy Retail Law, Rules and Regulations.13

WEM

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 if 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.14

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, when 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
- when 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.

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14 Electricity Industry Act 2004 (WA), Section 4; Economic Regulation Authority, Licence Application Guidelines (November 2016), 2.
iii  Ownership and market access restrictions

NEM

The NEM is described as an open access transmission system whereby generators apply to the network service provider with an access proposal and the network service provider makes an offer to connect to generators whose load meets network requirements and will enhance the reliability of supply on the network. Network service providers must invest in network upgrades as and when needed to meet their statutory obligations to maintain reliability of supply to end customers. Generators have a right to connection but not to being able to export all their output to the system and therefore pay a fix connection charge. Customers then bear the cost of network use by paying variable charges linked to demand. Network service providers can also invest in network upgrades along their region of the network to reduce network congestion, provided this passes a cost benefit test relating to the benefit to market participants and consumers of the proposed investment. The AER also creates incentive schemes to promote investment by network service providers in targeted areas of the network to meet its network planning objectives.¹⁵

WEM

The Electricity Networks Access Code 2004 (the Access Code) established under the EI Act provides the framework for the independent regulation of certain electricity networks in WA.¹⁶ 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.¹⁷ 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.¹⁸

Currently, the SWIS is the only regulated network in WA and Western Power is the service provider. Unlike the NEM, the WEM is described as having a ‘physical firm access’ system whereby generators are only able to connect to the network if they can show that their generation output will not interfere with other generators on the network who have a firm right to export their capacity onto the network. This means that if the network is already constrained in the region where the generator wants to connect its asset, the generator must pay to upgrade the transmission line to alleviate the congestion. This is beneficial in the sense that generators are incentivised to connect in areas of low congestion to avoid the cost

¹⁶ Economic Regulation Authority, Guidelines for Access Arrangement Information (last updated 27 October 2018), 1.
¹⁷ Electricity Networks Access Code 2004 (WA), Section 2.1.
¹⁸ Electricity Networks Access Code 2004 (WA), Section 4.1, Section 4.48.
of upgrading the network, customers now bear the costs of network upgrades and, once connected, generators can be certain that they will be able to export their output. However, the downside of this regime is that it has resulted in an overinvestment in the transmission line as it has been built to carry the output of all generators at all times; in fact, in practice, not all generators will be exporting at the one time. In turn, generators pass on the cost of network upgrades through higher prices, resulting in higher electricity prices for consumers.\footnote{Government of Western Australia, Department of Treasury, Public Utilities Office, ‘Improving access to the Western Power Network: Proposed approach to implement constrained network access’ (9 August 2018), at https://www.wa.gov.au/sites/default/files/2019-08/Consultation-Paper-Two-Improving-access-to-the-Western-Power-Network_0.pdf.}

This system is threatening to prevent new entrants to the market because although there may be sufficient spare capacity on the network at various times throughout the day, the existing generators have a contractual right to ‘unconstrained network access’, which means that this spare capacity is held aside for the existing generators, thus reducing the available capacity for new generators to provide for.

\section*{iv Transfers of control and assignments}

If a proposed acquisition may have an 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 ACCC. The ACCC may provide either formal or informal clearance, which typically takes up to three months. Alternatively, the Australian Competition Tribunal may grant authorisation based on a ‘net public benefit test’ if it is 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, and the potential for anticompetitive conduct to ensue from vertically integrated structures.\footnote{Australian Competition and Consumer Commission, Informal Merger Review, at https://www.accc.gov.au/business/mergers/informal-merger-review (April 2020).}

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 if 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 of electricity generation or distribution assets 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’. The Australian Taxation Office and the ACCC are among the departments that have been actively assessing foreign investment proposals.\footnote{Angus Grigg and Angela Macdonald-Smith, ‘ATO to “test national interest”’, Australian Financial Review (1 April 2016).}

On the recommendation of FIRB, the Federal Treasury may then issue a notice of no objection or, if the transaction is against the national interest, disallow the proposed transaction, or impose conditions on how it may be conducted.\footnote{Foreign Acquisitions and Takeovers Act 1975 (Cth), Section 17.} The FIRB approval process generally takes up to 40 days from the time the application is made; however, FIRB
may extend this period for a further 90 days for complex applications. During the current worldwide pandemic relating to the new coronavirus, and the covid-19 disease, applications may take up to six months to process.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Although the generation, transmission and retail sections of the electricity market were segregated in the 1990s, there has been a trend towards vertical integration by generators and retailers as a means of managing market risk and reducing reliance on hedging arrangements. Although vertical integration reduces reliance on contract markets, it results in a potential barrier to entry for retailers or generators who are not vertically integrated. This trend is visible within the private businesses that own most of the generation capacity, with the AER stating that a few large vertically integrated participants control the significant majority of generation capacity and output in Victoria, NSW and South Australia, and the government generators and retailers in Queensland and Tasmania.

Similarly, 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 more than half of the state’s consumable load. Western Power, as another state-owned entity, then builds, maintains and operates the SWIS distribution network.

Similarly the North West Interconnected System (NWIS), which is the interconnected electricity generation, transmission and distribution infrastructure in the Pilbara region of Western Australia, 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 NWIS customers. The NWIS is owned by significant users of the electricity network: Horizon Power, Alinta Energy, BHP Billiton, Pilbara Iron (Rio Tinto) and ATCO Australia. The Western Australia government is currently working on implementation of a light-handed access regime and to establish an independent system operator for the Pilbara region. The focus of the reform initiative is to implement a regulatory regime that is a more efficient alternative to facilitate third-party access to electricity networks and at a lower cost than the default arrangements currently in place under the Access Code. New regulatory arrangements are intended to commence in 2020.

ii Transmission/transportation and distribution access

Across the different networks within Australia, the connection process is broadly similar. Generators must approach the network service provider with a connection proposal that details the design and technical connection requirements of the generation facility. The network service provider then considers the enquiry or application against set criteria (such as the technical rules for the SWIS in Western Australia and the reliability standards set by the

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National Electricity Rules on the east coast). 26 The network service providers are responsible for approving the connection of new generation systems to their network. A system can only be connected once all 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 the network in the region where it will be installed. 27

### iii Rates

In the NEM, network service providers set network charges, but they are limited by a cap on allowable revenue set by the AER. The amount of allowable revenue is based on the revenue required for the network service provider to cover its costs of reliably supplying customers and to provide an appropriate return on capital.

In relation to the SWIS in Western Australia, a schedule of network charges is submitted by Western Power to the ERA, which then assesses and approves the proposed schedule of network charges by reference to the price control and pricing methods in Western Power’s access arrangement. 28

### 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 faulty 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 of power transfer capability or level of service to users is minimised. 29

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 towards a shared responsibility for network security, with customers becoming generators who 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;

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funding research and development of advanced technology to create a secure and resilient electricity infrastructure;

c supporting the development of cybersecurity standards to protect against vulnerabilities, including alignment with international standards;

d facilitating timely sharing of actionable and relevant threat information;

e advancing risk management strategies to improve decision-making;

f supporting sector incident management and response; and

g enhancing and augmenting the cybersecurity workforce within the electric sector.30

In 2018, the AEMO, in collaboration with industry and government partners, developed a tailored cybersecurity framework for the Australian energy sector, known as the Australian Energy Sector Cyber Security Framework (AESCSF). This allows participants to undertake assessments of their own cybersecurity capability and use the results to inform and prioritise investment to improve their own cybersecurity.31 In December 2018, the inaugural Summary Report into the Cyber Security Preparedness of the National and WA Wholesale Markets was issued, addressing the following issues:

a the cyber maturity of all energy market participants to understand where there are vulnerabilities;

b an assessment of current regulatory procedures to ensure they are sufficient to deal with any potential cyber incidents in the NEM;

c assessment of the AEMO’s cybersecurity capabilities and third-party testing; and

d an update from all energy market participants on how they undertake routine testing and assessment of cybersecurity awareness and detection, including requirements for training employees before they access key systems.

Although there have been no major changes from the inaugural AESCSF assessment, the 2019 version of the AESCSF includes many important lessons learned from the 2018 assessment process and the feedback received.

With the growth of renewable technologies, the AEMO will continue to undertake studies designed to investigate how the integration of these technologies is likely to affect market operation in the future. The 2019 AEMO Power System Security Guidelines outline how the AEMO seeks to operate the power system, and meet its power system security responsibilities generally, and the information and actions required from participants to assist in maintaining or restoring power system security.32


### Development of energy markets

#### NEM

The NEM is a spot market in which generators offer to supply specified amounts of electricity at a set price for set periods and can revise and resubmit this offer at any time. Based on the bids submitted, the AEMO then decides which generation offers to accept and therefore which generators shall be dispatched to meet demand in the most cost-efficient manner. The spot price for electricity in the NEM is driven by supply and demand and set at half-hour intervals. The National Electricity Rules set a maximum spot price, which is adjusted annually for inflation.\(^{33}\) There is a different spot price in each of the five NEM regions. Customers purchase their electricity from a retailer, which charges a set price based on customers’ contract plan. The retailer then bears the price risk of fluctuations in the spot price and must manage this risk through entering into wholesale hedging contracts.\(^{34}\)

#### WEM

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.\(^{35}\)

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 to 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 (formerly known as RECs and, since 2011, split into small-scale technology certificates and large-scale generation certificates depending on the eligible electricity generated). 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 with electricity as part of a bundled power purchase arrangement so that customers can use them to meet their own obligations to surrender renewable energy certificates or sell to the AEMO through a capacity auction.

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 situation, the market customer makes bids on the market for the volume of electricity required to balance its contract position and pays the market price for that balancing amount of electricity. The WEM’s bilateral net settlement system for uncontracted energy is overseen by the AEMO.

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33 AEMO, ‘Fact Sheet – the National Electricity Market’ (April 2020).
IV RENEWABLE ENERGY AND CONSERVATION

Developments in renewable energy

A 2019 report by the AEMO titled ‘International insights for Australia’ states that parts of Australia are experiencing some of the highest levels of wind and solar generation in the world, with a large focus on high levels of residential solar. As of March 2020, Australia’s renewable power percentage sits at 19.31 per cent; however, the focus is on the variability and uncertainty of higher levels of wind and solar generation.  

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, using Tesla’s domestic lithium-ion batteries. 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 and provide much-needed stability to the South Australian grid, which had been plagued by load shedding events. The Tesla Powerpack has been in operation since December 2017 and is said to be performing in line with, and in some cases exceeding, expectations in terms of its ability to respond to outages and peaks in demand.

Further, in early 2019, the federal government announced that it would assist funding for the Snowy Hydro 2.0 project in Tasmania by investing A$1.4 billion in equity. If completed, Snowy Hydro will be one of the largest pumped hydro projects in the world and add 2,000MW of energy generation and 175 hours of storage to the NEM. This expansion of Tasmania’s famous Snowy Hydro facility will provide critical storage capacity and dispatchable base load power that will help support the network and counter the influx of intermittent renewable generation facilities.

V THE YEAR IN REVIEW

i NEM

Significant change continues to occur in the NEM, with which regulators are grappling at a regulatory level, including changes in:

- the mix of generation facilities connected to the network with a decline in dispatchable generation (with the retirement of ageing traditional coal-fired plant) and increased renewable generation, which is variable by nature;

patterns of demand with higher ramping and more customers exporting to the network with their own rooftop generation facilities; and weather patterns with prolonged heatwaves that are placing more stress on the network.\footnote{41}

The AEMO has considered these issues and how they interact with the spot price electricity market and has determined that a market based on real-time spot market price and bilateral contracts is no longer offering the best outcome. This is because with the increased presence of renewables on the network, generators’ are needing to compete with low-cost renewables in the spot market and in situations where the spot price is below that of the generator’s marginal costs, there is no incentive for the generator to bid on the market during these periods. Unfortunately, this is compromising reliability on the network because the more stable and traditional dispatchable generators are withdrawing from the market during peak demand periods when that reliability is needed.\footnote{42} Therefore, the AEMO considers that a series of reforms will be required to augment the current market design to better suit supply and demand characteristics going forward by appropriately valuing generation resources with flexibility and dispatchability to incentivise investment in these facilities.\footnote{43}

ii WEM

During 2018, a WEM Reform Coordination Committee was established to manage a three-stage reform process within the WEM to implement an open access regime for the connection of new generation facilities (similar to that in the NEM) by October 2022.\footnote{44} The reforms aim to make more efficient use of the existing transmission infrastructure, attract private sector investment by reducing barriers to entry (particularly for renewables) and generally improve the wholesale market to reduce the retail price for consumers.\footnote{45} By moving to an open access regime, it is hoped to make the market more efficient by dispatching to the generator with the lowest-cost power, rather than the generator that has priority access to network capacity (i.e., unconstrained access).\footnote{46} This system ought to make it easier for new renewable generation facilities to connect to the network and also increase their economic viability because with their low operating costs, they ought to provide power at the lowest cost and therefore be dispatched first. As part of the reform process, it is anticipated that those generators with ‘unconstrained access’ will be paid some form of compensation for the loss of that right, which will be negotiated individually with those generators.\footnote{47} To date, this process has been driven by stakeholder consultation under the WA government’s Energy Transformation Strategy.

\footnote{42} id., at page 10.
\footnote{43} id., at page 11.
\footnote{45} ‘Improving access to the Western Power Network: Proposed approach to implement constrained network access’ (footnote 19, above), at page 4.
\footnote{46} id., at page 5.
\footnote{47} id., at page 7.
VI CONCLUSIONS AND OUTLOOK

The continued transformation of Australia’s electricity market in recent years has, with the growth in the renewables sector, brought about considerable policy and regulatory changes. Notwithstanding these changes, the energy market still faces major challenges, the first of which is 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 Australia’s growing metropolitan population and can also service remote off-grid communities through stand-alone facilities. Therefore, it is imperative that Australia continues to invest in the technological research and development, infrastructure upgrades and legislative reforms required to ensure Australia 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.
I OVERVIEW

As an EU Member State, Belgium has implemented EU energy legislation on electricity and natural gas. Electricity and natural gas markets have been unbundled: a single grid operator is appointed for a designated area, within which the grid operator is responsible for the operation, maintenance and development of the grid. The grid operator has to grant non-discriminatory third-party access to producers, suppliers and offtakers against regulated tariffs. The regulatory authority oversees market functioning and compliance by market actors.

Belgium is a federal state, in which legislative powers over energy matters and policy are divided among the federal and regional governments. The federal government is responsible for legislation regarding large energy generation and storage facilities, nuclear energy, offshore energy, transmission of electricity, transport of gas and retail energy prices. The regional governments of Flanders, Brussels and Wallonia enact legislation regarding renewables, energy efficiency, distribution grids and district heating. All governments cooperate on the implementation of Belgium’s long-term energy policy and the shift to a climate-neutral economy. Pursuant to the Governance Regulation, Belgium has also submitted an integrated national energy and climate plan for the period 2021–2030 to the European Commission.

In 2003, Belgium decided to phase out nuclear energy from its energy mix and to decommission all seven nuclear power plants after 40 years of operation. Given that construction took place in the 1970s and 1980s, the last of the plants should be decommissioned by 2025. However, nuclear power plants still account for roughly half of Belgium’s power generation. Furthermore, the politics on the phasing out of nuclear energy have been sending out contradictory signals, resulting in little effort being made by the market or the government to construct alternative (renewable) production units. A draft ‘energy pact’ has been agreed, which will result in a long-term energy policy for Belgium and facilitate the construction of new production units (gas-fired or renewable) to replace the nuclear power plants. As a transitory measure, the extension of the lifetime of the two most recent nuclear power plants – Doel 4 and Tihange 2 – is being heavily debated.

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II REGULATION

i The regulators

Because of its federal structure, regulatory responsibilities are distributed between the federal regulating authority, the Commission for Electricity and Gas Regulation (CREG), and the three regional energy 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, both from market players and from policymakers. Notably, the regulatory authorities may not receive any direct instructions from ministers or policymakers. However, they do 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 the energy legislation (e.g., do not possess the required licences). The energy regulators cooperate closely with other market regulating bodies, such as the antitrust bodies.

ii Regulated activities

Considering that electricity and natural gas markets are unbundled, a distinction has to be made between grid operators on the one hand, and producers and suppliers on the other.

Grid operators are appointed for a fixed duration for a designated area. Before being appointed, they must receive an unbundling certification proving that they are operationally and legally independent from other market players, such as producers and suppliers. Depending on the level and region, grid operators are appointed by the competent minister or by the energy regulator. Grid operators enjoy a legal monopoly to carry out their activities, but are subject to strict regulatory supervision and to regulated revenue (through the grid tariffs). 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.

The construction and operation of new onshore power plants requires three permits: a production permit, an environmental permit and an urban planning permit. In Flanders and Wallonia, the latter two have been merged into a single permit. Smaller plants (of less than 25MW capacity) are exempt from the requirement to obtain a production permit. Very small plants, such as photovoltaic installations with consumers, do not require an environmental or planning permit either.

The production permit is granted by the federal Minister for Energy after he or she has obtained advice from the CREG, while the environmental and planning permits are granted by the regions, the provinces or even the municipalities. These different decision levels add to the complexity of constructing new production units, although it should be noted that a production permit is rarely refused after an environmental or planning permit has been obtained.

Offshore power plants 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. All such permits are granted at the federal level. Until now, only offshore wind farms have been constructed in Belgium.
Finally, 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 duration of a federal supply licence is limited 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 a licence to operate on the Belgian market. However, they must communicate certain information (stocks and volumes) to the CREG and other authorities for the purposes of market monitoring.

iii Ownership and market access restrictions

As mentioned above, 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. For what concerns 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.

Except for Flanders, 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

Pursuant to European directives, grid operators in Belgium are ownership-unbundled, meaning that they may not have any direct or indirect participation in or control over any supplier or producer, or vice versa. This model has been implemented gradually since the 1990s, with full ownership occurring since the beginning of the millennium. The structure of the industry has therefore not changed significantly in 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 are legally obliged to grant non-discriminatory third-party access to producers, suppliers and offtakers who meet the necessary legal and technical requirements. The grid codes set out which technical and legal requirements must be met by grid users to have access to the grid. Requirements include signing of a balance responsible party (BRP) contract and having a safe and certified installation. The grid codes have recently been revised to comply with the EU Network Codes.

iii  Rates

Grid tariffs must be approved by the relevant regulator: transmission grid tariffs are approved by the CREG, and distribution grid tariffs are approved by the regional energy regulators VREG, BRUGEL and CWaPE. Grid operators have to submit a tariff proposal, calculating the expected costs and revenue for the coming years. This proposal has to take into account the general tariff guidelines and principles, as set out in tariff methodology (general framework), which is developed by the energy regulator. The grid tariffs are principally fixed for four to five years (the regulatory period). The tariffs of the transmission system operator are based on a cost-plus model, while the distribution grid tariffs are more incentive-based; for example, in Flanders, there is a specific stimulus to preserve the quality of services by the distribution system operators. Costs that stem from a legal obligation (such as public service obligations) or costs that the grid operator merely passes on, may always be fully integrated into the grid tariffs.

iv  Security and technology restrictions

There used to be no specific regulation concerning the protection of critical energy infrastructure. However, Flanders introduced in 2019 a decree granting the Flemish government the power to annul any legal act (so not only share deals, but also contracts) from Flemish public bodies (including distribution system operators (DSOs)) that would lead to foreign persons or companies gaining control or decision-making power in those bodies, and where there is a risk that (1) the strategic interests of the Flemish government are threatened, (2) certain strategic or sensitive knowledge is likely to fall into foreign hands, or (3) the strategic independence of the Flemish government, including the functioning of the democratic legal order, is compromised. Before annulling a legal act, the Flemish government must first try to reach an amicable settlement with the foreign person or company. Other regions and the Belgian federal level do not yet have similar legislation, but are considering introducing it.

With regard to cybersecurity, 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 BRPs happen by means of the data management system MIG. Access to and imports 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: EPEX Spot Belgium, in short, is the physical power exchange for electricity supply and offtake on the Belgian hub and was established in Brussels in 2006. It facilitates anonymous, cleared trading in two market segments, namely a day-ahead market segment (DAM) and a continuous intraday market segment (CIM). EPEX Spot Belgium’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 CIM 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 Power BE 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, seasonal and annual 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 BRP is responsible for maintaining a quarter-hourly balance between total injections and total withdrawals of the grid users in its portfolio. The BRP can be a producer, a major customer, an energy supplier or a trader. Each BRP can exchange energy 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 these auctions, the BRP 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 EU Member States have created shared rules governing these explicit auctions. The auctions are organised through a jointly created entity called the Joint Allocation Office.

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 a standard transport contract with Fluxys Belgium. Depending on the nature of their activities, electricity traders might have to conclude a BRP 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 Fluxys Belgium standard transport contract.
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 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, which 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 a BRP or similar contract with the grid operator. Each end consumer is also the holder of its grid data.

In the European Clean Energy for All Europeans 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 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, Belgium signed the United Nations 2030 Sustainable Development Goals, which set a target of 18 per cent of renewable energy consumption by 2030. All EU Member States have committed themselves to reaching jointly a renewable energy target of 32 per cent by 2030.
It is feasible for Belgium to reach its individual target despite unfavourable geographical and weather conditions, but given the division of powers, it will require political cooperation between all the 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 carbon dioxide 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, in turn, they can 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 is yet to be determined by the government.

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. 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 Inter-ministerial Conference for Economy and Energy.

EU Member States must report annually on the progress they have achieved towards their national energy efficiency targets.

The Buildings Directive\(^3\) 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 encouraged by the European Union, the Belgian federal government and the regional governments.

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iii Technological developments

The value of 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 also benefit from premiums and investment subsidies under certain circumstances and conditions.

Following the potential from the geothermal energy projects in north-east 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 has been ratified by the Flemish parliament, the 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 rolled out gradually in Flanders in the coming years. No regional initiatives are currently undertaken for Wallonia or the Brussels Capital Region.

VI THE YEAR IN REVIEW

Since the nuclear reactors in Belgium have experienced technical issues (for example, cracks in the concrete walls), they have regularly been offline for maintenance in the past few years. In 2014, Belgium introduced a winter reserve obliging certain production installations that are no longer in the market (i.e., that are shut down and awaiting deconstruction) to be on standby in case of an electricity shortage. This winter reserve shall be replaced by a fully fledged capacity mechanism, subject to a decision by the EU Commission on compatibility with the EU state aid rules.

Within its territorial sea and exclusive economic zone, 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 taxpayers, a deal was struck with the three newest offshore wind farms – Mermaid, Seastar and Northwester 2 (for which an offshore domain concession has been granted but is not yet operational) – to reduce the number of offshore green certificates that would be granted to them. In parallel, the Belgian government is working on a second offshore area for the installation of offshore wind farms. Plots for the new area will be tendered, as in the Netherlands, via calls for tender for zero-subsidy offshore wind bids.

On the gas market, the gradual depletion of the Groningen natural gas field has prompted the Netherlands 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 developed the Synergrid road map as part of its 10-year investment plan and is on track to complete the conversion on schedule in 2029.
Finally, the coronavirus pandemic and related government measures are causing energy prices to drop significantly and even become negative. The lockdown has significantly reduced the demand for electricity. Many companies are at a standstill or running at half power, which has reduced electricity consumption in Belgium by approximately 16 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 latest European Clean Energy for All Europeans Package (draft legislation) is to further foster the 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.

Hydrogen, energy storage, district heating and geothermal energy are expected to be the biggest game changers in the next few years.

From a contractual point of view, corporate power purchase agreements are becoming increasingly frequent on the Belgian energy market.

Finally, Brexit may give rise to a wide range of problems: from new permits and licences to be obtained by UK-based suppliers, over guarantees of origin no longer being valid for submission, to specific trading issues (e.g., on the Nemo electricity interconnector between the United Kingdom and Belgium).
Chapter 3

BRAZIL

José Roberto Oliva Jr and Julia Batistella Machado

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 investment, and was submitted to further regulatory reform in 2004. Security of supply, regulatory stability and competitiveness provide the basis for the regulatory framework.

The main power source used in Brazil is hydropower (63 per cent of the installed capacity, excluding small plants), while thermal power plants have an important role in complementing the mix and assuring security of supply (17 per cent of the installed capacity). 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 during the past few years, as evidenced by the latest power auctions.

The electricity system is connected by transmission facilities that enable electricity produced in the 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 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.

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1 José Roberto Oliva Jr is a partner and Julia Batistella Machado is a senior associate at Pinheiro Neto Advogados. The authors want to thank Lucas José Russo for his assistance with the research required to update this chapter.

2 Information provided by the Brazilian electricity regulatory agency (Agência Nacional de Energia Elétrica (ANEEL)) on its power generation data centre – see Banco de Informações de Geração, at www.aneel.gov.br/aplicacoes/capacidadebrasil/capacidadebrasil.cfm (last accessed on 22 April 2020).
The main government 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 have an important role in this sector, namely:

a. the National Council on Energy Policy, which is the 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, which was created mainly as a response to the rationing in 2001 (by Law 10,848/2004), and is responsible for monitoring security of supply and suggesting correction measures.

Since the market’s liberalisation, the industry’s participants have been regulated by the National Electric Energy Agency (ANEEL),3 which has been granted autonomy by central government but is nevertheless attached to the MME. ANEEL, created by Law 9,427/1996, regulates and supervises power generation, transmission, distribution and trading activities to ensure 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 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 carrying out of power auctions and the granting of certain 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 four other directors, is organised into technical divisions and is charged with performance of administrative functions in various areas, such as economic regulation, market studies, supervision, mediation and the granting of concessions and authorisations.

The restructuring processes undergone by the power sector have 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; its governance system was granted even more independence as part of reforms in 2004. 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 measurement, accounting and financial settlement of electricity trading operations. Within 2004’s reform, another institutional entity was created: the Energy Research Company (EPE), a publicly held company responsible for studies and research on the energy industry with a view to enabling planning within the sector, 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 approval to enter the market. The regulatory licence required for entrepreneurs to operate in the power sector depends mainly on the segment

3 In a way, the companies were already subject to regulation before the creation of the National Electric Energy Agency [ANEEL], but the previous government bodies lacked effectiveness since they did not have autonomy and were part of 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 size of the reservoir (a requirement for hydropower plants). Given that regulation of the power sector is constantly evolving, there are several legal frameworks in existence, each from different points in time. As a result, the rules relevant to one power plant may not apply to others, even though they fall under the same regimen. The specifics of the applicable law must always be assessed individually, alongside the provisions of the specific concession agreements.

In general terms, as for new 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.

However, authorisation is required for 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 of not more 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, for which the process is conducted by ANEEL. All of these, including hydropower plants subject to authorisation, may participate in power auctions (either new project, existing project, or backup energy auctions) to sell their production on the regulated market, or may sell it in the free market.

In respect of 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 on the regulated market. They may also decide to sell their production on the free market, but will first need to undergo an 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.

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

The table below gives a general summary of the regulatory licences required by 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 but 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 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>

There are currently discussions on whether private investors are allowed to participate in nuclear power plants in the country. It has long been understood that private participation is forbidden 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 the two nuclear power plants that are currently active. However, more recent opinions argue that the Constitution establishes the monopoly of limited parts of the supply chain, such as research, extraction, enrichment, reprocessing, manufacturing and trade of nuclear mining and metals, which would be restricted to the federal government, and that private partners could participate, for example as partners of Eletronuclear or even controllers (subject to a public procurement).

Power transmission and distribution activities are considered natural monopolies, given their dependence on the electrical grid. Therefore, most Brazilian power distribution consumers are still legally locked in to purchasing energy from only one intermediary: the local distribution companies to which they are connected. Although there is a special regulation for those that use between 500kW and 3MW, they can choose to buy energy from incentivised sources or SHPPs.

In addition, in light of their importance, their operation requires a public service concession, preceded by a mandatory public bid.

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

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5 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.
iii Ownership and market access restrictions

The 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 law to have the regulatory licence granted; and

b 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.

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 these 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 extended further as part of the 2004 regulatory reform, restricted the activities of distribution companies in the regulated market, limiting their participation in other activities within 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 a regulatory licence or of a controlling interest\(^6\) in an industry participant is subject to ANEEL’s prior consent, mainly to adhere to the bidding process and transparency principles.

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, becomes the holder of ‘a significant share of the power generation market for the safety of the regulated market\(^7\)’ – a concept yet to be established 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 within which to inform ANEEL of the implemented transaction and may be required also to maintain a dossier available for inspection.

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\(^6\) 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.

\(^7\) Art. 5º (IV) of ANEEL Resolution 484/12.
The rules currently in force may be further amended after forthcoming 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 as yet.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Segregation of the different levels of the production chain was implemented mainly to promote efficiency and competitiveness, after it had been proven that the vertically integrated industry was 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 restructuring during the 1990s, separation of the contracting of access to the grid 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).

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;
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 instances provided by law or in the concession contract.

Currently, there is no legislation in respect of unbundling between the generation and transmission segments, nor any that restricts economic groups from having companies in several segments. Furthermore, distribution companies have a monopoly in both electricity transport and electricity trade in respect of those consumers designated as ‘captive consumers’ in their concession area.

A different kind of unbundling has been under discussion recently, in respect of the future expansion of the free power purchase market, namely the unbundling of distribution services, to limit the distribution monopoly to just electricity transport in the respective concession area.

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 electricity grid, upon reimbursement of the cost incurred by transportation.

ANEEL and the National Telecommunications Agency (ANATEL) collaborated to issue regulations on the reference price applicable to infrastructure sharing (Joint Resolution 04/2014), following several disputes on the subject.

iii Rates

Power transmission and distribution companies are subject to price regulation, and thus have their revenues calculated by ANEEL, which aims to set prices to promote economic efficiency as if the segments were competitive rather than characterised as natural monopolies.

Rates are based on a price-cap mechanism (revenue cap for transmission companies) and thus are subject to adjustment by an inflation rate; a productivity factor, known as 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 subject to annual adjustments for inflation, periodic reviews (every four or five years, depending on the concession contract) and possibly to further extraordinary reviews to restore the concession’s balance upon ANEEL’s approval.

Between the periodic reviews, rates are adjusted annually for inflation (from which the X factor is subtracted). 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 essentially aims to set new efficiency standards for operational costs and investment returns, to ensure that private companies receive an adequate remuneration and that consumers pay a fair price for their electricity. The new standards established will be valid for the new period up to the following price review.

IV ENERGY MARKETS

i Development of energy markets

The 2004 restructuring process that established the current regulatory framework for the Brazilian power sector 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, which participate as buyers in public auctions conducted by the government. Generation companies compete against each other according to the rules of each auction by the lowest bid price (BRL/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 serves the captive market. In other words, the power bought by distribution companies in the auctions is purchased by captive consumers (those defined as not having any choice in selecting their power supplier). As a rule, distribution companies are obliged to buy power on the regulated market (apart from a few legal exceptions) and to ensure that 100 per cent of their consumers’ demand is met.
There are three types of auctions within the regulated market:

- **a** new-project auctions, conducted to promote power generation expansion sufficiently in advance to enable plant construction, to meet growth in market consumption;
- **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** backup energy auctions, conducted to increase security of power supply.

Auctions for new projects may include HPPs designated by the government, but companies usually 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. There are also auctions for existing projects, in which generation companies with projects in operation may sell power within the regulated market, and renewable energy auctions, which can be launched for either new or existing projects. Finally, backup energy auctions relate to contracted power originated from SHPPs, wind and biomass plants. The auctions are known as ‘A minus N’, where ‘A’ is the year in which the plant must enter operation and start delivering power to the grid.

Within the free market, power is freely traded between those parties entitled to participate in it: generation and trading companies, and free and special consumers. Free consumers, who may choose their power generation supplier, are those whose demand is currently higher than 2MW. According to an Ordinance issued by the MME in December 2018, as amended in 2019, this requirement has been reduced and will continue be reduced in the coming years. The first reduction occurred in July 2019, when free consumers were required to have demand higher than 2.5MW, and the second was in January 2020, when it dropped to 2MW. The demand requirement will be reduced further: in January 2021 to 1.5MW, in January 2022 to 1MW and in January 2023 to 500kW.

Special consumers, which may constitute a single 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.

### Energy market rules and regulations

Sector participants that carry out power trading transactions are obliged to comply with the sector's 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. Whereas distribution companies need to serve 100 per cent of their market’s demand, sellers need to produce or purchase the same amount as sold under PPAs, and consumers need to consume the same amount as 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, in proportion with the amount not produced or purchased, to cover their original PPAs. Financially exposed participants are:

- obliged 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 (the PLD), which is defined weekly by the CCEE; &
- subject to penalties imposed by the CCEE.

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. This calculation is very important as it sets the limit on the power available for sale (originating from the plants’ own power generation).

The operation of the Brazilian interconnected system may cause a dissociation of the participants’ contractual commitments from the actual physical delivery of the power 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 these participants facing financial exposure for reasons they cannot manage, such as the energy reallocation mechanism that is applicable to hydropower plants.

### iii Contracts for sale of energy

Within the regulated market, as a result of the auction process, long-term PPAs are executed between the generation companies that have won the bid and the distribution companies buying at the auction. Similarly, in backup energy auctions, a backup energy agreement is executed between the sellers and the CCEE, as the 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 one year to 15 years for existing-project auctions, and for up to 35 years for backup energy auctions. The PPAs may be executed under one of two modes: quantity or availability. Under quantity contracts, sellers assume hydrological risks (variations between the amounts contracted and effectively

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8 The Electricity Trading Chamber [CCEE] calculates the PLD based on the Operation’s Marginal Cost and a variety of criteria established by legislation (e.g., hydrologic conditions) for each submarket and 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 Although 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.
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 production that is lower than the amount contracted.\(^\text{12}\)

Within the free market, participants execute PPAs in which they freely establish the 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 made recently. Particularly, 2019 was intended to be the year in which ANEEL would change its regulation on distributed energy and net metering. There were expectations that higher tariffs would apply to consumers connecting a power generation facility to the grid after the issuance of the revised regulation, but these discussions were postponed to 2020. Nevertheless, the expected changes caused a race among consumers such that units with distributed energy jumped from 58,000 at the end of 2018 to 176,000 at the end of 2019 and installed capacity jumped from 0.7GW to 2.2GW, mostly from solar sources.

### V RENEWABLE ENERGY AND CONSERVATION

#### i Development of renewable energy

One of the most significant regulatory policies adopted to encourage the development of renewable power in the past has been 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 20 years. According to the programme regulations, a total of 3,300MW was expected to be contracted under the first phase of Proinfa. The second phase aimed to achieve 10 per cent of the annual energy consumption deriving from renewable sources until 2022, excluding large HPPs. For the current year, the incentive is evaluated in an amount of 4 billion reais. Proinfa costs are shared among all energy consumers, except low income consumers.

Pursuant to recent information made available in the 2020–2029 Energy Plan,\(^\text{13}\) the EPE forecast that in 2029 the installed capacity of distributed generation and net metering would reach 32GW if there is no change in regulation. However, current discussions would suggest that the projection for 2029 is more likely to reach 11GW of installed capacity. This will still represent a significant proportion, amounting to 2.3 per cent of the total installed capacity in Brazil. The segment handled more than 2 billion reais in investments in 2018. Although solar is the most common source, it also expected that wind, hydropower and thermal projects will increase in the coming years.

Wind power is the source that has been most prevalent and has grown the most in regulated auctions. The EPE has stated in the Energy Plan that, although wind power has

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\(^{12}\) 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.

become more competitive in price, the 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 also 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 to some special credit lines from the National Bank for Economic and Social Development. Benefits may change in the future as the sources become more competitive, as anticipated in the discussions about a bill of law to implement certain changes in the regulations.

The Special Incentives Regime for Infrastructure Development, known as REIDI, is a federal tax incentive scheme for the development of infrastructure that lasts for five years and is applicable to the purchase of equipment related to power generation and transmission projects, including those involving renewable energy, 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 increased in efficiency during the 2001 rationing, when the market learned how to reduce the consumption required by the government. As the market has suffered unfavourable hydrological conditions in recent years, broad awareness campaigns about the country’s exposure to water shortages 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. Moreover, a new pricing scheme is available as from January 2019 for certain consumers (namely those who consume more than 250kWh), while others will have the option from 2020. This pricing scheme is also referred to as an hourly tariff or white tariff and allows users to pay different rates according to the time and the day of the week of their consumption. ANEEL believes that this change will improve and rebalance the utilisation factor of the system.

iii Technological developments

The Brazilian market has taken some important steps towards the implementation of smart grid technologies and batteries. 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 on distribution companies to instal electronic metering for Group B consumers. The aim of these measures,

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14 Green, yellow and red flags indicate lower, medium and higher generation costs. As a result of the recent water shortages, the Operador Nacional do Sistema Elétrico [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.

15 Under this policy, the possible excess of a consumer's production is exported into the grid and assigned to the distribution company, and thus may be compensated with credits in the subsequent billing periods, under the conditions set forth by regulations.

16 Residential, rural and other classes, except for low income consumers and streetlight facilities.
taken to allow integration between power supply and communications technology, was to improve the quality of service provision and to reduce operational costs and technical losses in power supply.17

VI THE YEAR IN REVIEW

There was been a cautious resumption of growth in the Brazilian electricity sector. In 2019, ANEEL carried out several successful generation and transmission auctions, delineated operation strategies to modernise the Brazilian electricity grid, issued important regulatory resolutions and incorporated changes to the current regulation.

Regarding the revision of the current net metering regulations, ANEEL launched a series of public consultations and public hearings to discuss concepts, issue a regulatory impact assessment and potential changes in the regulations. The aim of the revision is to rebalance the costs generated by the current system of net metering that are borne by other consumers and distribution companies and may increase tariffs paid by net metering users in the future. ANEEL’s current proposal is to respect the financial expectations of those connecting net metering systems before 2020, which may be subject to lower tariffs than those connecting after 2019. Recently, Jair Bolsonaro, Brazil’s elected president, has spoken out against ANEEL’s proposal to reduce incentives with regard to net metering. The last public hearing took place in December 2019 and the outcome of the proposal is not yet known.

During the period in review, one transmission auction was successfully conducted, marking the entrance and consolidation of foreign investors. The bid occurred in December 2019 and contracted 2,467km of transmission lines and 7,791MVA in substation capacity in 11 states, with an expected investment of 4.18 billion reais.

Generation auctions were also successfully conducted in 2019:

- in December, separate bids contracted:
  - 4,888GWh from existing power ventures (an estimated investment of 838 billion reais); and
  - 5,08GWh from existing power ventures (an estimated investment of 80 billion reais);

- in October, the bid contracted 3GW from new projects of power generation from hydroelectric, wind, solar photovoltaic and biomass power plants (an estimated investment of 11.2 billion reais);

- in June, the auction sold 0.4GW from new project power generation from hydroelectric, wind, small solar plants, thermoelectric and biomass power plants, with supply starting in January 2023 (an investment of 1.9 billion reais); and

- in December, the auction was carried out to serve the isolated state of Roraima (an estimated investment of 1.6 billion reais).

Mergers and acquisitions transactions have also been successfully carried out during the year, including the following:

- the acquisition, by Engie, of a transmission project named Projeto Novo Estado, formerly owned by the transmission company Sterlite, for about 410 million reais;
- the acquisition, by Vinci Partners, of a transmission project named Projeto Arcoverde, formerly owned by the transmission company Sterlite, for about 141 million reais;
- the acquisition, by Energía Bogotá Group and Red Eléctrica Internacional, of the transmission company Argo Energia, for about 3.5 billion reais;
- the acquisition, by Enel Green Power, of wind farms totalling 540MW of installed capacity, formerly owned by Enel Green Power Brasil, for about 4.1 billion reais;
- the acquisition, by Vale, of all the energy produced from the Folha Larga Sul wind farm (151.2MW/BA), with the option to purchase the entire project after it went into operation in 2020;
- Canada Pension Plan Investment Board entered the national holding Equatorial Energia, with the purchase of 5 per cent of the common shares traded on the Brazilian B3 exchange;
- the acquisition, by Mitsui, of 17 per cent of Órigo Energia’s share capital;
- the acquisition, by the transmission company Taesa, of two Âmbar Energia projects located in the states of Piauí and Bahia for about 753 million reais; and
- the acquisition, by Actis, of a wind farm formerly owned by EDP Renováveis, for about 650 million reais.

VII CONCLUSIONS AND OUTLOOK

Activity on the Brazilian electricity market continued to be eventful in 2019. The sector has been trying to adjust to the new economic and political situations, and important transactions can be expected in the near future. Competition and the number of new foreign bidders entering the market is expected to continue to increase.

In addition, the MME defined a long-term schedule, detailed below, for next year’s energy auctions from new projects (LEN) and energy from existing projects (LEE):

<table>
<thead>
<tr>
<th>Year</th>
<th>Auction</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>LEE A-4</td>
<td>30 April 2020</td>
</tr>
<tr>
<td></td>
<td>LEE A-5</td>
<td>30 April 2020</td>
</tr>
<tr>
<td></td>
<td>LEN A-4</td>
<td>28 May 2020</td>
</tr>
<tr>
<td></td>
<td>LEN A-6</td>
<td>24 September 2020</td>
</tr>
<tr>
<td></td>
<td>LEE A-1 e A-2</td>
<td>4 December 2020</td>
</tr>
<tr>
<td>2021</td>
<td>LEN A-4</td>
<td>29 April 2021</td>
</tr>
<tr>
<td></td>
<td>LEN A-6</td>
<td>30 September 2021</td>
</tr>
<tr>
<td></td>
<td>LEE A-1 e A-2</td>
<td>3 December 2021</td>
</tr>
</tbody>
</table>

Certain large companies are likely to be privatised in the coming years, such as Eletrobrás, Cemig, Copasa and CEB.

In addition, net metering is expected to continue growing after reaching the level of 2.2GW of installed capacity in 2019.
Furthermore, the expansion of the free market is already set forth in the regulations, with reduced demand requirements entering into force in January 2021 (to 1.5MW), January 2022 (to 1MW) and January 2023 (to 500kW). There are also expectations for a full opening of the free market from 2024.

The strength of the Brazilian market’s institutions certainly will continue to play an important part in stability. The EPE estimates that investments in centralised power generation in the years 2020–2029 will amount to 303 billion reais, net metering generation to 50 billion reais, and another 104 billion reais in power transmission and substations.18 In summary, the Brazilian power sector should be viewed as a target for long-term investment, to the extent that investors are knowledgeable of the characteristics of each type of investment and are able to assess the risks involved accurately.

I OVERVIEW

Energy regulation in China involves a number of stakeholders, including various government 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 is anchored in China’s ambitious economic restructuring agenda. The main priority in China’s economic reform plan is environmental goals and the deployment of cleaner energy. The ‘energy revolution’ proposed in the 13th Five-Year Plan for National Economic and Social Development (2016 to 2020) is in three main sections, namely upgrading the energy structure, developing the energy transmission network and establishing a smart energy internet.

China, as one of the world’s largest economies, 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 the domestic energy regulation regime and its market structure. This chapter aims to provide an overview of these, with a focus on oil and gas, power and renewable energy from a foreign investment perspective. The authors have endeavoured to state China’s energy regulation and practice on the basis of the materials available as of March 2020.

II REGULATORY REGIME

i The regulators

Oil and gas

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 and implementing the management of the various energy sectors.

In the upstream sector:

a the Ministry of Natural Resources (MNR) is responsible for the supervision and administration of the exploration and exploitation of mineral resources throughout

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1 Monica Sun is a partner, James Zhang is a senior associate and Qiujie Tan is an associate at Herbert Smith Freehills LLP.
China. It has the authority to grant the licences required for the exploration and production of crude oil and natural gas. It also has a role in the examination and approval of blocks open to private and foreign investment;

b the NEA was previously charged with the authority to examine and approve the overall development plans for individual upstream oil and gas projects; however, in February 2019, the approval requirements for overall development plans were officially removed, and replaced with a record filing procedure and continuing, post-event supervision by the NDRC and the NEA; and

c the Ministry of Commerce (MOFCOM) was previously in charge of review and approval of entry into and amendments of all production sharing contracts (PSCs). This approval is no longer applicable and was replaced in 2013 with a requirement to file records at MOFCOM.

In the midstream and downstream sectors, the NDRC is responsible for price regulation and MOFCOM is responsible for licensing in certain categories of trading businesses.

**Power**

The NDRC and the NEA (which took over from the State Electricity Regulatory Commission in 2013) regulate the power industry. They are responsible for the enactment and enforcement of regulations and for granting power business permits to power companies.

**Others**

Other regulators include:

a the Ministry of Ecology and Environment, which is in charge of administering and enforcing environmental protection matters in China;

b the National Nuclear Safety Administration, an authority under the Ministry of Ecology and Environment that acts as the central government agency responsible for regulating nuclear safety and supervising all civilian nuclear infrastructure in China. It also inspects nuclear safety activities and regulates the project approval mechanism; and

c the Ministry of Emergency Management, which is responsible for overseeing and administering safety at work nationwide.

**Laws and regulations**

The principle laws and regulations governing the energy sector include 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.


The Measures for Regulation of Fair and Open Access to Oil and Gas Pipeline Facilities (2019) provide the access regime that allows third parties to use the surplus capacity of pipeline facilities.

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’.

The Regulation on Electricity Regulation was issued in 2005 to strengthen and improve electricity regulation, including a permitting regime for power businesses, focusing on


The Circular on the Power Industry Institutional Reform Plan (2002) initiated reform across the industry with a focus on the unbundling of power generation and power transmission.

maintaining the order of electricity markets and promoting the development of the
electric power industry. The Measures on Electricity Market Regulation (2005) clarified
the types of market players in the electricity sector, which include power generation,
transmission and supply companies, electricity users and government authorities.

The Administrative Regulation on Power Industry Business Permits (2005) sets out the
types of power generation, transmission and supply companies subject to a permitting
regime and the conditions and procedures for acquiring those permits.

The Opinions regarding Further Reform of the Electric Power Regime (2015) set out
the plan for further reform, which mainly aims to open up sales of electricity, develop
the electricity market and establish market-oriented prices for electricity.

The Circular by the NDRC and NEA on Issuing Supporting Documents for Power
Industry Institutional Reforms (2015) provides six implementation measures for the
reform of the power regime, covering the areas of power distribution price, power
market development, power trading centre, power planning, power sales reform and
coal-fired captive power plant.

The Measures on the Supervision and Examination of the Cost of Power Transmission
and Distribution (2015, amended in 2019) sets out rules for determining the costs of
power transmission and distribution.

The Circular by the NDRC and NEA on Issuing Administrative Measures on
Electricity Companies’ Entrance and Exit and the Administrative Measures on
Orderly Derestriction of the Electricity Distribution Network Business (2016) provide
opportunities for social capital to enter into the electricity distribution industry.

The Circular by the NDRC and NEA on Orderly Derestriction of the Power Generation
and Consumption Plans (2017) provides plans for promoting electricity traded through
market-based transactions.

The Circular by the NDRC and NEA on Actively Promoting Market-oriented Power
Transactions and Further Improving the Trading Mechanism (2018) sets out the road
map to remove restrictions on market players in respect of their participation in seeking
market-oriented power transactions.

The Circular by the NDRC on Fully Liberalising Power Generation and Consumption
Plans for Commercial Power Users (2019) deregulates power generation and
consumption plans for commercial users.

The Measures for Transmission and Distribution Prices for the Provincial Network
(2020) and the Measures for Transmission and Distribution Prices for the Regional
Network (2020) provide further detailed rules regarding the calculation of
transmission prices.

Renewables

energy conservation.

The Renewable Energy Law (2005, amended 2010) sets outs general principles on
renewable energy.

The Guiding Opinions on Facilitating the Development and Utilisation of Geothermal
Power (2013) aims at promoting the development and utilisation of geothermal power.

The Administrative Regulation on Guaranteed Purchase of Renewable Energy-generated
Power in Full Amount (2016) sets out detailed rules to guarantee the purchase of power
generated by renewable energy.
The Rules for Issuance and Voluntary Subscription of Green Power Certificate (for Trial Implementation) (2017) provide for the regime of issuing and free trading of green power certificates.


The Circular by the NDRC and NEA on Positively Promoting the Work on Subsidy-free Grid Price Parity for Wind Power and Photovoltaic Power (2019) aims to implement a subsidy-free policy to reduce subsidies in the solar and wind sectors.


The Circular by the NDRC and NEA on Establishing and Improving the Mechanism to Guarantee the Consumption of Electricity from Renewable Energy Sources (2019).

The Opinions on Promoting the Healthy Development of Non-hydro Renewable Energies (2020) set out broad policy guidance, including to develop green power certificate trading under a quota regime, the objective to decrease FITs for renewable energy and the development of distributed photovoltaic solar power generation in residential areas.

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 principle law and regulations.

### iii Regulated activities

#### Oil and gas

Upstream oil and gas exploration and production activities are subject to exploration and exploitation licences issued by the MNR.

In the upstream oil and gas sector, foreign companies typically partner with and enter into PSCs with legally designated national oil companies; however, China is pushing for deregulation in this regard (see also Section II.iv).

Pipeline design and construction activities are subject to government review based on criteria relating 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 Market Regulatory or its local branch, as the case may be.

A specific business permit is required for retail of refined oil products. The storage and domestic trading of crude oil and refined oil products were previously subject to similar specific business permits but have been gradually liberalised since 2019.
**Power**

Power companies are required to obtain electric power business permits issued by the NEA. There are specific permits for different types of businesses: (1) a power generation permit for power generation companies; (2) a power transmission permit for power transmission companies; and (3) 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 permit 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 the environmental regulations issued with the electric power business licence.

Through an NEA notice issued in April 2014 and further amended in December 2016, the following types of generation projects enjoy a general exemption for a power generation licence:

- distributed generation projects registered or approved by the NEA;
- small hydropower stations with single-station generating capacity below 6MW;
- 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 with generating capacity below 6MW; and
- captive power plants without direct combustion of fossil fuel and that are dispatched by dispatching organisations at city level or below.

In addition, companies that undertake the installation, reparation or commissioning of electricity facilities shall obtain a permit for those businesses accordingly.

**iv Ownership and market access restrictions**

**General foreign investment regime**

China’s foreign investment regime is undergoing significant changes introduced by the new Foreign Investment Law in 2019 (the FIL 2019), which entered into force on 1 January 2020 with the Implementing Regulation for Foreign Investment Law. The FIL 2019 formally adopts a ‘pre-establishment national treatment and negative list’ approach nationwide. Foreign investments are given same level of market entry as domestic investors, subject to specified exceptions in consolidated lists.

China periodically publishes Special Administrative Measures for Access of Foreign Investment (the Foreign Investment Negative List). These catalogues are typically the first regulatory guides to look at when making investments in China. The latest version of the Foreign Investment Negative List was jointly published by the NDRC and MOFCOM in 2019, and includes (1) Special Administrative Measures (Negative List) for Access of Foreign Investment (2019 Edition), which applies nationwide to all foreign investments (other than free trade zones) and (2) Special Administrative Measures (Negative List) for Access of Foreign Investment in Pilot Free Trade Zones (2019 Edition), which is less restrictive and applies to foreign investments in free trade zones only. Under the Foreign Investment Negative List, the prohibited items are entirely closed to foreign investment, while the restrictive items typically impose one or more restrictive measures on foreign investments, such as maximum limits for shareholding by foreign investors.

Certain sectors and businesses are specified as those in which foreign investment is encouraged, and additional incentives are provided. Similar to the negative lists, China
periodically publishes catalogues of these ‘encouraged’ sectors, the latest version of which, published by the NDRC and MOFCOM in 2019, is the Catalogue of Industries for Encouraged Foreign Investment (2019 Edition) (the Foreign Investment Encouraged List).

**Oil and gas**

The state has ownership of all mineral resources within the territory of China. Pursuant to the Mineral Resources Law, a licensing regime has been adopted and the MNR has the authority to grant exploration licences and production licences.

For a long time, foreign investment in oil and gas exploration and production activities has been restricted to joint ventures or cooperation with Chinese companies. In practice, the national oil companies (NOCs) (i.e., China National Petroleum Corporation (CNPC), China Petrochemical Corporation (Sinopec) and China National Offshore Oil Corporation (CNOOC)) hold the licences, and foreign companies need to partner with an NOC through a PSC arrangement to invest in onshore and offshore exploration and production in China.

However, the door has gradually been opening wider. The first step was marked by shale gas being recognised as ‘unconventional gas’ in 2011, for which two rounds of exploration licence tenders were held. Private investors (domestic or foreign) were eligible to participate in the tender, however, foreign investors could only participate by incorporating a joint venture with majority interests controlled by Chinese investors. In 2017, the ‘joint venture or cooperation’ requirement was removed in respect of oil shale, oil sands and shale gas. In July 2019, the restriction was removed in respect of conventional oil and gas (including coal-bed gas). In December 2019, the MNR issued a new Opinion on Several Matters Concerning Promoting the Reform of Mineral Resources Administration (for Trial Implementation), which is effective from 1 May 2020. It is provided that all companies incorporated in mainland China (either domestic or foreign invested) with net assets of at least 300 million yuan shall be qualified to apply for oil and gas mining rights. Owing to the continuing efforts of deregulation, future opportunities are expected to be available for foreign investors in the upstream oil and gas sector.

The midstream oil and gas industry is dominated by the NOCs. The CNPC controls nearly all the long-distance pipeline networks in China, including the West-East Pipelines system. In addition, approximately 90 per cent of the liquefied natural gas (LNG) receiving capacity is now controlled by the NOCs. On 9 December 2019, a national oil and gas pipeline network company (PipeChina) was incorporated, after more than two years of preparation driven by the central government. It is planned that PipeChina will take over the midstream assets from the NOCs and operate the infrastructure assets as an independent business, which will open up the energy market, making access to the infrastructure available to more players. However, it remains unclear which assets will be injected into PipeChina, and at what pace. It is anticipated that the company will not be truly ready for operation until the end of a transition period of one to two years.

The downstream oil sector, including refineries, petrochemical production and gasoline retail businesses, is still dominated by the NOCs, although it is generally open to both private and foreign investment, subject to ordinary permitting procedures. The downstream gas sector (including distribution of gas utilities) is much more diversified. The provincial SOEs play an important part in the intra-province pipeline networks, especially in the coastal provinces such as Guangdong and Jiangsu. For city utility businesses, there are many private
investment players (such as ENN and Guanghui), and SOE conglomerates (such as China Resources). In practice, it is less common for foreign invested companies to participate in downstream oil and gas business.

**Power**

The main market players in the power industry include generation 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).

With continuing reforms to open up the power sales businesses and to develop a competitive power market, more and more power sales companies have been registered at the power trading centres. In 2019, the NDRC announced that the control over power generation and consumption plans for commercial users would be lifted. Commercial users are encouraged to freely negotiate power purchase prices with power generation companies. It can be foreseen that this policy will further boost a dynamic power market and strengthen the role of power sales companies and direct purchase users as emerging market players.

It is apparent that there have been attempts by foreign investors to invest in power distribution networks, which is now generally open to private investment. However, the main opportunities for foreign investors in the power industry remain in the construction and operation of power stations with pioneering technologies and in the renewable energy sub-sector. Specifically, the following types of businesses in the power industry are included in the Foreign Investment Encouraged List:

- **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;
- **f** construction and operation of hydropower stations for the primary purpose of power generation;
- **g** construction and operation of nuclear power stations (the Chinese party must hold a controlling interest);
- **h** construction and operation of new-energy power stations (including solar, wind, geothermal, tidal, wave and biomass);
- **i** construction and operation of natural gas peaking power stations and natural gas distributed energy stations in important load centres with secured gas supply;
development and application of hybrid systems of gas-fired power generation and renewable power generation; and

construction and operation of a power grid.

Although not specifically addressed in the Foreign Investment Negative List, some types of projects are typically restricted or prohibited for all (foreign or domestic) investors, pursuant to the Market Access Negative List (2019) issued by the NDRC and MOFCOM and the Guiding Catalogue for Industrial Structure Adjustments (2019) issued by the NDRC:

a. within the coverage of the large power grid, wet-cooled power generator with coal consumption levels higher than 300g standard coal per kWh, and air-cooled power generator with coal consumption levels higher than 305g standard coal per kWh;

b. diversion-type hydroelectric power generation without draining ecological flow;

c. conventional coal-fired power plants whose single generator capacity is 300,000kW or less and is not compliant with standards, and oil-fired boilers and generating units mainly for power generation;

d. coal-fired generator, oil-fired generator or coal-fired thermal generator that is not compliant with national requirements; and

e. captive coal-fired power plant for new construction projects located in the Beijing-Tianjin-Hebei region, Yangtze River delta region and Pearl River delta region.

v. Transfers of control and assignments

The transfer of exploration rights and exploitation rights for mineral resources (including oil and gas) is subject to the approval of the MNR, provided that the following conditions are satisfied:

a. 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,\(^2\) or one full year has passed since the exploitation enterprise began exploitation;

b. the specified minimum input for exploration has been fulfilled;

c. no disputes have arisen regarding the ownership of the exploration rights and exploitation rights;

d. the exploration right usage fees, exploitation fees or any price for the exploration and exploitation rights have been paid; and

e. 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.

\(^2\) The MNR issued a notice in late 2017 that applies only to ‘minerals other than oil and gas’ (note that it is not clear whether oil sands or other types of unconventional oil and gas will fall into this category). For exploration rights acquired by ways of (1) prior application, (2) bidding, (3) auction, or (4) listing (i.e., other than by private agreement), the conditions for transfer of exploration right shall include that two years have passed since the issue of the exploration licence, or one year has passed if a geographical report has been filed for recording after reserve assessment at or above the general survey level. If the exploration right was acquired by private agreement, then 10 years shall have passed, otherwise the requirements and procedures for a new private agreement shall apply to such transfers.
The MNR will determine 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 the transfer of a participating interest under a PSC. Previously, any amendments to a PSC were required to be approved by MOFCOM. This requirement was abolished in 2013 and now only record filing with MOFCOM is required. In terms of operatorship, Chinese PSCs often provide that the consent of a foreign investor is required if the NOCs propose to take over the production operations before the foreign contractor’s full recovery of the development costs. After the full recovery of the development costs incurred in accordance with the overall development plan 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 written notice to the foreign contractor.

The transfer of power generation units in operation requires a change to the power business permit, which needs to be approved by the NEA. The NEA will review whether the requirements for granting the relevant permits 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 FITs and sell power at the regulated power sales prices.

The current 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 Circular by the NDRC and NEA on Issuing Supporting Documents for Power Industry Institutional 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 the basis of ‘cost plus reasonable profits’.

Since 2009, the user-generator direct trading system has been trialled 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 these 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’s midstream oil and gas infrastructure ownership and operations have been dominated by SOEs, which has hindered market liberalisation of the petroleum and energy value chain.

In 2014, China started a five-year trial for a third-party access scheme to provide market participants (non-NOCs) with access to the midstream oil and gas infrastructure. Under this regime, 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. However, there are various issues jeopardising the implementation of the open-access scheme. One of these is the lack of a clear definition of ‘surplus capacity’, and there is no clear mechanism to determine it. As a result, the five-year trial period came to an end in February 2019, with a very limited number of facilities having been opened for third-party access.

On this basis, in May 2019, the new Measures for Regulation of Fair and Open Access to Oil and Gas Pipeline Facilities were published. This regulation emphasises that operators of oil and gas pipeline facilities within China are obliged to grant third-party users ‘fair and open access’ to their facilities, and provides for new principles and policies to support this access. Conditions and the process for access, metering, pricing related requirements are also provided in this new regulation. It is expected to provide a more integrated and detailed legal framework to support further development of a fair and open access regime in China in the next five years.

**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:

- grid structure and line layouts;
- amount and status of transformation facilities;
- total installed capacity;
- power supply and demand and transmission capacity of major lines and outgoing lines; and
- 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 FIT.

Grid companies must ensure non-discriminatory and fair access to their grid to qualified power plants. The NEA issued a draft Measures for Regulation of Fair Access to Power Grids for public comment in 2019, which provides a more detailed regime for securing non-discriminatory and fair access to power grid.

For renewable power generation (RPG) enterprises, the grid operators are required to:

- build and manage the interconnection system for qualified RPG projects;
- enter into grid connection agreements with qualified RPG enterprises; and
- purchase all the on-grid power generated by RPG projects at a higher FIT.

**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 basis of ‘allowed cost plus reasonable profits’. The NDRC completed the costs assessment of 13 interprovincial pipeline systems in August 2017 and published reduced tariffs effective from September 2017.
These tariffs were adjusted in March 2019 to reflect the reduced rates of value added tax. Intra-province pipeline transportation tariffs are regulated by local development and reform commissions and are reported to the NDRC annually.

According to the Circular by the NDRC on Issuing the Guiding Opinions on Strengthening Regulations over the Gas Distribution Price (2017), gas distribution prices 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 the middle while liberalising the front and end’.

**Power**

Power transmission prices are regulated by the government. The Measures for Transmission and Distribution Prices of the Provincial Network and the Measures for Transmission and Distribution Prices of the Regional Network issued in early 2020 improved and clarified pricing mechanisms in power transmission and distribution. Different tranches of transmission prices were established and approved for different types of users (including large industrial users, general industrial and commercial users, other users, residential users and agricultural users) and different voltage levels of power transmission.

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 producers or traders 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 steady 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. Prices of gas (including LNG) used to be heavily regulated by the NDRC, but there has been a steady process of deregulation. According to an NDRC press release, as of October 2017, the price for 50 per cent of all gas consumption in China was completely deregulated, 30 per cent was regulated on a base-price basis, and the remaining 20 per cent was for residential use and the price was set by the government.
In respect of electricity, 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 current power price reforms, the Chinese government is exploring the possibility of opening up electricity markets, including a plan to continue the deregulation of power generation and consumption. The aim at this stage is to establish a medium- to long-term market and a spot market.

ii Energy market rules and regulation

Oil and gas

To engage in refined oil 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 not included on that list may become a non-state trading enterprise if they:

- have a foreign trade business qualification;
- satisfy the requirements published by MOFCOM; and
- 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 2020 is 202 million tonnes for crude oil. In 2015, MOFCOM issued a notice setting out the detailed requirements for refineries to import crude oil, including requirements regarding equipment, product quality, safety management and personnel. In 2018–2019, MOFCOM issued notices regarding the qualifications and process for companies registered in Zhejiang, Fujian and Shanghai free trade zones to import crude oil, which provide for fewer restrictions.

Use of imported crude oil was previously limited to the NOCs. In February 2015, 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. Forty refineries have obtained a permit from the NDRC to use imported crude oil as of November 2018.

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, more participants are expected to come on the market. Apart from the user–generator direct trading system, the Circular by the NDRC and NEA on Issuing Supporting Documents for Power Industry Institutional 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 a ‘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 city gate prices are subject to government regulation:

a the retail and wholesale of gasoline and diesel, and the sale of gasoline and diesel to wholesale businesses, railway customers and transportation customers are subject to the government guidance prices; and

b the supply of gasoline and diesel for state reserves or Xinjiang Production and Construction Corps, and the factory price of aviation gasoline, are subject to government (fixed) pricing.

The price of gasoline and diesel is adjusted every 10 business days based on the international crude oil price, processing cost, taxes, transmission fees and reasonable profits.

For natural gas, the government provides a base city gate price for natural gas, which means gas supplier and city gas utilities may negotiate the city gate price and that price shall not exceed 120 per cent of the base price. The prices of gas produced from unconventional gas (including shale gas, coal-bed gas and coal gas), domestic offshore production and imported LNG are deregulated and can be determined by parties. The prices for direct sale arrangements between upstream gas producers and industrial users under a direct supply arrangement and gas traded at the Shanghai and Chongqing exchanges are also deregulated.

In addition, in the latest Catalogue of Pricing Control by Central Government (2020) issued by the NDRC, the price of gas sold to gas utilities in provinces where a competitive market exists can also be negotiated by parties and is not subject to regulation, meaning that gas prices in those qualified provinces will be completely deregulated. In the earlier edition of the Catalogue, Fujian is the only named province that benefits from this deregulation as a pilot. The change of references in the 2020 Catalogue suggests that the deregulation will be extended to more provinces; the scope of this is not yet clear.
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 (whether residential, agricultural or industrial and commercial).

Customers are allowed to participate in the power market if certain criteria are met, and may choose to enter into power purchase agreements with power supply companies or directly with power generators. The terms and conditions of these agreements can be freely negotiated between the two parties.

The Opinions regarding Further Reform of the Electric Power Regime (2015) and the Circular by the NDRC and NEA on Issuing Supporting Documents for Power Industry Institutional Reforms (2015) sets out future steps to further facilitate the reform, including determining qualified generators based on energy conservation and environmental protection requirements, expanding the direct trading to power supply companies and encouraging long-term agreements between generators and customers.

The NDRC and NEA issued the Circular on Actively Promoting the Market-oriented Power Transactions and Further Improving the Trading Mechanism in 2018, which stipulates a further increase in the scale of market-oriented power trading, the speed of development of power consumption plans, the scope of market entities, and the active promotion of the participation of various market entities in power market transactions.

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 within the term of the 13th Five-Year Plan (2016 to 2020). The NDRC also set medium to long-term for renewable energy development: 10 per cent of total energy consumption should be sourced from renewable sources by 2010 and 15 per cent by 2020. The mid-term target (10 per cent by 2010) was achieved. In July 2017, the NEA issued Guidelines for 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 (2017 to 2020).

For about a decade, China's renewable energy projects benefited from higher FITs to encourage power generation from renewable energy. The difference between renewable energy FITs and the benchmark FITs for desulphurised coal-fired power is paid from the Renewable Energy Development Fund. With developments in technologies and the decline of manufacturing costs during the past few years, the renewable energy FITs set by the government has been in continual decline and the renewables sector is expected to compete with coal-fired utilities on a subsidy-free basis.

The tables below set out the current policy on FITs for wind, biomass and solar power, effective from 1 July 2019.
Wind and biomass

<table>
<thead>
<tr>
<th>Electricity source</th>
<th>FITs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind Onshore projects: guidance prices are set in four tiers ranging from 0.34 yuan/kWh to 0.52 yuan/kWh (for projects approved in 2019) and from 0.29 yuan/kWh to 0.47 yuan/kWh (for new projects approved in 2020), depending on project locations. If, at any location, the guidance prices are lower than the benchmark FITs for coal-fired power plants, then the benchmark FITs for coal-fired power plants shall apply as the guidance prices. Offshore projects: guidance prices are set at 0.8 yuan/kWh (for projects approved in 2019) and 0.75 yuan/kWh (for projects approved in 2020). Newly approved centralised onshore wind power projects and offshore wind power projects: feed-in tariffs shall be determined through competition and not be higher than guidance prices introduced above.</td>
<td></td>
</tr>
<tr>
<td>Wind Offshore projects: guidance prices are set at 0.8 yuan/kWh (for projects approved in 2019) and 0.75 yuan/kWh (for projects approved in 2020).</td>
<td></td>
</tr>
<tr>
<td>Biomass 0.75 yuan/kWh</td>
<td></td>
</tr>
</tbody>
</table>

Solar

<table>
<thead>
<tr>
<th>Resource area</th>
<th>Centralised photovoltaic: feed-in tariff</th>
<th>Distributed photovoltaic: subsidy payments</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>General (guidance price)</td>
<td>Poverty alleviation projects</td>
</tr>
<tr>
<td>Class I regions</td>
<td>0.4 yuan/kWh</td>
<td>0.65 yuan/kWh</td>
</tr>
<tr>
<td>Class II regions</td>
<td>0.45 yuan/kWh</td>
<td>0.75 yuan/kWh</td>
</tr>
<tr>
<td>Class III regions</td>
<td>0.55 yuan/kWh</td>
<td>0.85 yuan/kWh</td>
</tr>
</tbody>
</table>

Notes
1. The photovoltaic power plant feed-in tariff in Tibet is 1.05 yuan/kWh.
2. The FIT and subsidies for photovoltaic projects are decreasing over the years, and the rates above are applicable to new projects connected to grid since 1 July 2019.
3. A new policy was released in early 2020 to update the guidance prices regarding solar power in 2020 but do not enter into force until 1 June 2020.

Other incentives include:

- **a** surcharges collected from all electricity end users are used to subsidise the difference between FITs 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 and land supply priority.

However, the Action Plan (2014–2020) for Energy Development Strategy marks a concerted shift to a more market-driven approach to future build-out in China. To implement this plan, the Circular on Photovoltaic Power Generation (2018) and the Circular on Positively Promoting the Work on Subsidy-free Grid Price Parity for Wind Power and Photovoltaic Power (2019) were issued to gradually reduce subsidies in the solar and wind sectors.

After the Fukushima Daiichi nuclear accident in 2011, 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 represents a shortfall of 39 million kW. The industry was expecting a large wave
of investment in nuclear power in the near future. In January 2019, two units of Zhangzhou Nuclear Project Phase I (a joint investment by China National Nuclear Corporation and China Guodian Corporation) and two units of Huizhou Taipingling Nuclear Project Phase I (investment by China General Nuclear Power Corporation) were finally approved by the State Council, which marked the end of a three-year period during which no new nuclear projects were approved. In early April 2019, the NDRC issued a new circular providing that the first batch of third-generation nuclear power projects shall apply FITs case by case.

To help reduce government subsidies to the renewables sector, the NDRC, 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 in January 2017. According to this Circular, solar and wind power producers would apply for and be issued tradeable certificates for the renewable electricity they generate. End users are encouraged to buy these 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. In July 2017, an official website for trading of the Green Power Certificate was launched. As of March 2020, while more than 27 million certificates have been issued, only around 37,000 certificates have been 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 that it would be rolled out nationally. 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 the end of 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 no more than 58 per cent from coal by the end of 2020.

China continues towards achieving the marketisation of its energy supply from upstream to downstream. Removal of investment restrictions opens up upstream oil and gas industry further to attract more investors, both foreign and domestic. The establishment of PipeChina and publication of new rules on a fair and open-access regime for oil and gas pipeline networks marks one step towards breaking up the monopoly and denomination of the midstream oil and gas sector by the NOCs. In the downstream sector, gas price deregulation also continues.

During 2019, there was further development in electricity industrial reform. Power generation and utilisation plans have been liberalised for commercial users. China has also set up a market-orient pricing regime for coal-fired power plants. Further regulation of transmission and distribution tariffs requires that these tariffs shall be calculated based on ‘permitted costs plus reasonable profits’. In the renewables sector, China continues to reduce the subsidies for the fast-growing wind and solar industry and promote a more competitive energy supply market.
However, it is also acknowledged that there is a long way to go before China has a completely competitive energy market. A draft Energy Law was published by the NEA in early April 2020 for public comments. This new law aims to work as a comprehensive and overall legal regime for the energy sector.

The novel coronavirus pandemic hit China towards the end of 2019 and has caused significant disruption to the economy in the first quarter of 2020. China is facing unique challenges and it is expected the energy demand and consumption in 2020 will be widely affected, which may have a consequential effect on the current reforms.

VII CONCLUSIONS AND OUTLOOK

The regulatory environment is changing quickly 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 continuing, it is vital to keep a close eye on energy regulations in China.
Chapter 5

COLOMBIA

José Vicente Zapata and Daniel Fajardo Villada

At the time of writing, the world is affected by the pandemic generated by the new coronavirus, and Colombia is no exception. Owing to the country being in a state of economic, social and ecological emergency, the Colombia government enacted Decree 457, which ordered mandatory preventive isolation throughout the national territory from 25 March to 13 April. As a result, various government entities have issued several regulations, most of which focus on protecting the continuity of public utilities and generating economic relief for customers. While it is still unclear how long the isolation will continue, it is evident that there will be economic and social consequences for the country in the short term and that further measures will be required in the future.

I OVERVIEW

The electricity sector in Colombia has evolved significantly during the past 20 years and today is an efficient sector with world-class practices. This trend will continue to increase in the coming decades, both because of the growth of foreign direct investment in Colombia and as a result of the positioning and expansion of Colombian companies abroad.

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 the country is a target for international investment, having extensive trade relations and an attractive business environment, there is currently a sense of uncertainty, which has had adverse effects on international investment and on the country’s credit rating. Nevertheless, some elements can be highlighted as providing a positive boost for the economy and investment: the continuing implementation of the peace process with the Armed Revolutionary Forces of Colombia (FARC) ending an armed conflict of more than 50 years, the election in 2018 of the young right-wing former senator Ivan Duque as President of the Republic, who has actively promoted boosting investment as one of the government’s goals, and the sustained growth of companies dedicated to generating energy.

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Under the terms of the Colombian Constitution of 1991, the electricity sector has been transformed from one wholly owned by the government into one in which there is clear separation between the roles of service providers and utility companies, and that of the regulators, policymakers, and control and oversight agencies. The sector now operates on three main levels: (1) the Ministry of Mines and Energy (MME), which governs policy and establishes the long-term plans for the whole sector; (2) 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 (3) the Superintendence of Domiciliary Public Utilities (SSPD), which is an inspection, monitoring and surveillance body that oversees operators and guarantees supply to the end user.

The main power source used in Colombia is hydropower, which represents 68.3 per cent of the installed capacity, followed by thermal power stations operating with coal and gas with a share of 30.7 per cent. The remaining energy is obtained and supported by other sources such as cogeneration, with a share of approximately 1.1 per cent.4

In terms of connectivity, the Colombian electricity sector is divided into (1) the National Interconnected System (SIN), which comprises generation plants, the interconnection network, and regional and interregional transmission and distribution networks, and (2) the non-interconnected zones, in which electricity services are provided by independent small-scale systems.

II REGULATION

i The regulators

The Constitution, issued in 1991, conferred legislative power on Congress and granted regulatory power to the national government, which in turn exercises its 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.

The MME is the government entity responsible for formulating, adopting, directing and coordinating the policies, plans and programmes of the mining and energy sector and the supervision of the electricity sector. The MME regulates generation, interconnection, transmission and distribution activities and is in charge of generation and transmission programmes.

The administration and issuance of regulations in the electricity sector is dealt with by the following technical entities:

a CREG, a special administrative body created in 1994, is responsible for 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;

4 Colombian Association of Electricity Generators, at https://www.acolgen.org.co/.
• 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 Mining and Energy Planning Unit (UPME) is a special administrative unit attached to the MME that is in charge of planning matters for 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 utility companies that operate within the Colombian territory. Among other functions, the SSPD:
• supervises the quality and efficiency of all public service companies;
• takes over public utilities companies when they are financially non-viable or when the service rendered is at risk; and
• imposes sanctions on companies under surveillance, and particularly 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 National Operation Council, which is responsible for determining the technical standards for the efficient operation and integration of the SIN; and

b Commercialisation Advisory Board, created by CREG as an advisory entity to monitor and review 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, and 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 relating 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.

Further, 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 a specific project.\(^5\)

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\(^5\) Decree No. 1076 of 2015, Article 2.2.2.3.2.1.
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.

Pursuant to the International Labour Organization's Convention 169 and Colombian regulations, should ethnic communities be located within the area of influence of the project, a prior consultation process with those 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 by 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 ISA, as a transmission company with system and market operating functions, and ISAGEN, a new company for electricity generation.

Law 142 regulates all aspects relating to energy as a public service, and Law 143 sets out the legal regime applicable to generation, interconnection, transmission, distribution and commercialisation as well as the Wholesale Electricity Market, which came into operation in July 1995. Further, Law 143 of 1994 states that all the activities that involve the supply of electricity, from generation to commercialisation, are intended to satisfy primary collective needs permanently and thus are considered as mandatory public utilities, and essential in nature.

In relation to projects, free private initiative is the general rule and thus, private and public-private partnerships may be involved in the generation, transmission, distribution and commercialisation of electricity without requiring a concession. In other words, Colombia will only be involved in the development of electricity generation projects when no private entity is willing to assume that activity.6

iii **Ownership and market access restrictions**

There are no limitations or prohibitions on foreign participation or investment in Colombia's electricity sector. However, foreign investment is prohibited in national security and defence, and the 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

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6  See Article 56 of Law 143 of 1994.
7  Compiled in Article 2.17.2.2.3.1 of Decree 1068 of 2015.
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 an address in Colombia or to incorporate a Colombian entity. 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, under the supervision of the Superintendence of Public Utilities.

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. Further, Article 74 of Law 143 of 1994 expressly prohibits companies involved in the electricity sector from engaging in more than one activity except for commercialisation, which can be developed with other activities in the electricity sector.

In addition, CREG regulations have set out specific restrictions as follows:

- electricity generators shall not have an equity participation of more than 25 per cent in distribution companies;
- no company shall have more than 25 per cent of market participation in generation activities;
- no company shall own, directly or indirectly, more than 25 per cent of the equity of a company involved in the commercialisation of electricity.

### 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 by or to be notified to the SIC.

Mergers require notice to the SIC when they meet the following conditions:

- 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;
- 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 more than 60,000 minimum monthly Colombian legal wages;
- whenever the companies involved in the transaction are dedicated to the same activity or participate in the same vertical value chain; and
- 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 by the SIC when they meet the conditions in points (a), (b) and (c), above, and the market participation of the companies individually or jointly equals or exceeds 20 per cent of the relevant market under Colombian jurisdiction.

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8 See CREG Resolution 60 of 2007.
Approval must be submitted as a pre-completion requirement of the transaction; clearance by the SIC is therefore a mandatory condition of proceeding with completion of the transaction.

In addition to the foregoing, Article 34 of Law 142 of 1994 mandates that companies involved in public utilities must avoid unjustified privileges and discriminatory acts and must 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 with obligations and imposing sanctions.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

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:

- utility companies incorporated before Laws 142 and 143 of 1994 can develop more than one activity under separate accounts for each business; and
- utility companies constituted after the enactment of Laws 142 and 143 of 1994 can only undertake, at one time, complementary activities such as generation retailing or distribution retailing and are prohibited to perform simultaneously activities relating to generation transmission, generation distribution, transmission distribution and transmission retailing.

With respect to horizontal integrations, as previously stated, pursuant to Resolution 128 of 1996 of the CREG, a single company may not own more than 25 per cent of the country’s generation, commercialisation and distribution activities. Furthermore, Resolution 128 establishes that a generation company cannot hold more than 25 per cent of the shares in an energy distribution company. The same rule shall apply to distribution companies having share participation in generation companies.

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 26,333.49 kilometres comprising:

- the SIN;
- the regional transmission system; and
- 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.

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The grid system supply, provided by the National Transmission System, enables 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 substations that operate at voltages lower than 220kV and do not belong to the National Transmission System.

With respect to third-party participation, the National Transmission System operates an open market, and thus transmission operators must provide open access to customers on a non-discriminatory basis, while receiving regulated revenues using transmission system charges. These charges are regulated by CREG, paid by electricity consumers and further collected by retailers.

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

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(1) of Law 142 of 1994 provides:

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 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.

Although each company negotiates its own rate, rates are capped at the maximum rate established by CREG. For affixing rates to be charged for utilities, CREG establishes the methodology and procedure for calculating the rate, including associated costs. Thus, resolutions that set rates include the costs assumed by the provider of the service and the methodology used for regulating that cost.

Furthermore, Article 87 No. 9 of Law 142 of 1994 provides that the rates and formulas used to calculate the 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, and its modifications as provided by Resolutions 166, 67 and 43 of 2010, 98 and 42 of 2009, and 113, 135, 166 and 178 of 2008, among others.

iv  Security and technology restrictions

While more recent developments regarding peace in the country have led to substantially fewer attacks on 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, named COPEI, for the protection of infrastructure, including pipelines, energy towers, oil platforms and infrastructure in general. The various outcomes of the implementation of COPEI included the creation of a special operation centre and the distribution of a daily report, including possible threats and events.

Nonetheless, currently there is a nationwide debate regarding whether the hydraulic fracturing technique (with horizontal drilling commonly referred to as fracking) should be permitted in the exploration and production of hydrocarbons from unconventional basins. A ban could represent a potential threat to energy security in the country, as it would limit substantially the production of gas from unconventional basins (e.g., coalbed methane). This debate has been presented not only in the legislative sphere but also before the judiciary, as various lawsuits have been filed challenging the legal framework under which this technique is deployed.

IV  ENERGY MARKETS

i  Development of energy markets

The Colombian electricity sector is comprised of a system of interaction between retailers and large consumers, who conduct their transactions in a market of large energy blocks. This market operates freely according to supply and demand conditions. This competitive model is accessible through the MEM, 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 the negotiations. For example, long-term participants opt for bilateral agreements while short-term agreements usually refer to next-day purchases between all the generators on the market, which are subject to explicit regulations. These kinds 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 the generation companies are obliged to participate in the MEM with all 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

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 with hourly availability. The prices at which electricity is offered reflect the variable costs of generation and opportunity costs.

Firm energy obligation auctions

Allocation of firm energy obligations (OEFs) between the different generators and investors is effectuated through dynamic auctions. OEFs are the resulting links from the auctions, according to which generators must create a daily amount of electricity. When the stock market price exceeds the price of shortage, the OEF price is determined by descending clock auctions.11 The purpose of these auctions is to allocate OEFs (between the generators and investors), thus ensuring reliability in long-term firm energy supply at efficient prices. 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 pre-qualifying period; (2) the planning period; and (3) the obligation effectiveness period – the total of which ranges from one to 20 years.

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. These contracts are freely agreed commitments acquired by generators and commercialisation companies to sell and buy electricity. Energy is delivered through 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 these agreements is that the contract specifies the amount of energy that will be used per hour. 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 the agreements. Energy purchases made through these contracts, intended for regulated users, are governed by rules that guarantee competition between generators, while the prices and conditions on contracts intended for non-regulated users are freely negotiated and agreed by the parties.

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 it is finalised by the National Dispatch Centre. It considers real demand and availability, but not the 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

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energy demand every hour, which establishes the price at which all 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.

V RENEWABLE ENERGY AND CONSERVATION

i 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, 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.

Law 1715 defines unconventional sources of energy as environmentally sustainable energy resources that are globally recognised but are not widely used in Colombia or are not widely marketed, such as nuclear or atomic energy, unconventional sources of renewable energy and those determined by UPME. Further, the Law defines unconventional sources of renewable energy as those that meet the aforementioned 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.

This Law classifies activities relating 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, among other things. It also assigns competence to entities such as the National Environmental Licensing Authority and regional autonomous corporations to implement rapid evaluation cycles for projects relating to non-conventional sources of energy, and for matters pertaining to this Law.

Law 1715 is especially relevant as it authorises small-scale 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. These credits may be negotiated with third parties, in accordance with the regulations issued by CREG. A 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.12 This refers 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.

12 See CREG Resolution 30 of 2018.
Law 1715 also 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 income tax for five years after the taxable year in which a company 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 (MESD). In addition, nationally sourced or imported equipment, elements, machinery and services for use in the pre-investment and investment stages of production and use of energy from unconventional sources and for the measurement and evaluation of potential resources will not be subject to value added tax (VAT). For these purposes, a certification from the MESD must be provided, declaring 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 involving 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 using 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 those sources, provided that they have been acquired or constructed exclusively for that purpose, and after the validity of this Law.

For full implementation, Law 1715 needs to be regulated by the different government entities affected by the measures of the Law. Thus, to date, the following aspects have already been regulated, in line with information published on the MME website:

a Decree 0570 of 23 March 2018 of the MME, 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 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
- reducing greenhouse gas emissions by 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 MME, which regulates the FENOGE;

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13 See www.minminas.gov.co.
Resolution 1670 of 15 August 2017 of the MESD, which adopted the terms of reference for the preparation of the environmental impact study in projects for electric power transmission systems;

Resolution 1312 of 11 August 2016 of the MESD, 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;

Resolution 1283 of 8 August 2016 of the MESD, which establishes the procedure and the requirements of the certification of environmental benefit to obtain the tax benefits granted by law;

Resolution UPME 045 of 3 February 2016, which establishes the procedures and requirements for issuing certification and endorsing projects from non-conventional energy sources to obtain the benefit of VAT exclusion and exemption from the tariff levy; and

Decree 2143 of 4 November 2015, issued by the MME in relation to the definition of the guidelines for the application of incentives established in Chapter III of the Law.

ii Energy efficiency and conservation

The energy efficiency section 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, with the MESD 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, and to promote campaigns on the use of renewable energy sources.

In addition to the foregoing, Law 1715 provides that the national government and public administration should establish energy efficiency objectives in public buildings and plans and actions for 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 the country is considered one of the most promising markets for foreign investment in terms of non-conventional renewable energy.14 Therefore, large projects in this area are being planned in Colombia, and there are others at the implementation stage.

VI THE YEAR IN REVIEW

In 2019, the Colombian energy sector was shaped by the milestone of carrying out (and awarding) the first auctions for renewable and clean energy projects, to the extent that it was the first time that in an OEF auction, solar and wind energy were incorporated into the electricity matrix (1398MW installed, representing 6 per cent of installed capacity), the first environmental licence for the generation of photovoltaic energy was granted by the environmental authority\(^\text{15}\) and the first renewable energy auction was carried out by the government. This first auction did not result in any awards, as the proposals presented would have resulted in market concentration in excess of the limits set forth in the applicable regulation.

Therefore, the UPME decided to receive new proposals for the purchase and generation of energy within the framework of a new renewable energy auction to be held in October 2019. In this second auction, the target-determined demand established by the MME was 12,050.5MWh per day, with 10,186MWh per day being allocated. In the auction, eight energy generation projects were awarded to seven companies and 22 energy commercialisation projects were awarded to 22 companies. The allocation for purchase had a weighted average of 95.65 COP kWh.

In view of there being a difference between the target-determined demand and the amount awarded, the UPME decided to hold an additional auction to award the remaining 1,864.5MWh per day, which resulted in 168 contracts for the supply of electricity. Of these, three projects correspond to electricity generation, while the other 165 contracts correspond to commercialisation and were assigned to 28 companies. The average allocation price was 106.66 COP kWh. The results were published by the UPME on 24 October 2019. The UPME indicated that all the awarded projects will be in operation from 1 January 2022, for a period of 15 years.

According to the Office of the President of Colombia,\(^\text{16}\) the awarded contracts are the ‘pay as you go’ variety, implying that the buyer is obliged to pay the seller for the contracted energy, regardless of whether the seller consumes it or not, and that the generator commits to supplying a fixed amount of energy to the buyer during the hourly block.

Additionally, in 2019: (1) energy consumption increased by 4.02 per cent, which is solid evidence of a sustained increase in electricity demand in the country; (2) besides the renewable energy auction that contributes to the expansion and diversification of the electricity supply, obligations in the order of 900MW of thermal power and 160MW of


hydraulic power were allocated; and (3) experts have stated that Colombia continues to consolidate its position as a major player in renewable energy sources, owing to the diversity of energy sources that can contribute towards ensuring greater energy security.

VII CONCLUSIONS AND OUTLOOK

The Colombian electricity sector has come a long way since the power outages during the 1990s. Privatisation, promotion of investment and the implementation of regulations have transformed the sector into an attractive and competitive market in the region.

However, the rapid expansion of the sector and the continuing dependence on resource-driven sources of energy, such as hydroelectric power, still have the capacity to bring the system to a halt, as the El Niño phenomenon showed in early 2016.

In addition to the foregoing, foreign investors have adopted a more cautious attitude towards the country because of the environment of legal uncertainty generated by certain governmental and judicial decisions, especially by the Constitutional Court. Nonetheless, the new government has openly encouraged foreign investment and is creating a positive environment for investors.

The main objectives and challenges faced by the electricity sector to develop and secure the Colombian market include:

a providing greater legal security to investors;
b attracting greater investment in the sector;
c promoting unconventional renewable resources, aiming to achieve self-sustainable and permanent energy sources;
d advancing regional integration;
e increasing the installed capacity and effective generation and reliability; and
f drafting and issuing the necessary regulations for the supply of non-conventional renewable energy and related projects.


I OVERVIEW

The Danish energy demand is primarily met by domestic natural gas resources and oil, and domestic renewable energy sources such as waste, woodchips, sun, 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 both oil and gas have been exploited in Denmark. In 1966, hydrocarbons were discovered in the North Sea and the first oil was produced in 1972. 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 all energy demand covered by renewable energy by 2050. The government and the parties in the Danish parliament entered into an agreement on 29 June 2018 to be followed up by the forthcoming Climate Act, which sets new objectives for 2030 with the aim of achieving net zero emissions by 2050. By 2030, it is expected that 55 per cent of all energy consumption in Denmark will come from renewable energy. Wind power alone is expected to cover between 53 and 59 per cent of electricity consumption in 2020, and the goal for 2030 will partially be reached by establishing three new offshore wind farms, each with a capacity of at least 800MW.

1 Nicolaj Kleist is a partner at Bruun & Hjejle.
2 Act No. 1533 of 16 December 2019 on the Use of Danish Subsoil.
3 Act No. 119 of 6 February 2020 on the Supply of Electricity.
II REGULATION

i The regulators

The overall administrative responsibility for the energy sector lies with the Danish Minister for Climate, Energy and Utilities (the Minister).\(^4\) Part of the Minister’s authority has been delegated to the Danish Energy Agency (DEA).\(^5\) 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 Utility Regulator (DUR)\(^6\) controls prices and conditions in the energy sector. DUR’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 DUR. Decisions made by DUR may be appealed to the Energy Board of Appeal.\(^7\) Decisions made by the Energy Board of Appeal cannot be brought before any other administrative body but may be challenged before the courts.

Energinet,\(^8\) 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. In March 2019, Energinet acquired the entire Danish gas distribution network.

The city councils in the municipalities\(^9\) are responsible for the planning of local heat supply.\(^10\) In each municipality, the city council must carry out planning in cooperation with the supply undertakings and other stakeholders.

The Energy Supplies Complaint Board is a private board established by the energy industry and the Danish Consumer 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.

The main legislation for energy regulation is the Continental Shelf Act,\(^11\) the Act on Raw Materials,\(^12\) the Subsoil Act,\(^13\) the Pipeline Act,\(^14\) the Natural Gas Supply Act,\(^15\) the Heat Supply Act\(^16\) and the Electricity Supply Act.\(^17\)

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4 www.kefm.dk.
5 www.ens.dk.
6 www.forsyningstilsynet.dk.
7 www.ekn.dk.
8 Established by Act No. 1097 of 8 November 2011.
9 There are 98 municipalities (city councils).
10 Act No. 120 of 6 February 2020.
11 Act No. 1189 of 21 September 2018.
13 See footnote 2, above.
14 Act No. 807 of 13 August 2019.
16 See footnote 10, above.
17 See footnote 3, above.
ii  Regulated activities

A licence issued by the DEA is necessary for all exploration, production, transmission, distribution and storage activities. 18

A permit is required for the establishment of plants and for expansion or changes to plants that cause increased pollution. 19 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 environmental impact assessment under the Planning Act. 20 Offshore plants are primarily subject to approval under the Subsoil Act and the 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 or 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 majority 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. The fund is administered by the Danish North Sea Partner, a unit under the Ministry of Climate, Energy and Utilities. The fund, which was established in 2005, is 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 access an upstream pipeline network subject to payment. In March 2019, Energinet’s last acquisition of the gas distribution network was finalised, and Energinet now owns the entire gas distribution network. The physical planning of the system for the 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

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18 See also Section III.iii.
19 Act No. 681 of 2 July 2019.
20 Act No. 287 of 16 April 2018.
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. In 2016, 2018 and 2019, the Danish state purchased the three large gas distribution networks in Denmark. The Danish state now owns the entire gas distribution network.

Since 1998, Danish competition legislation has been strongly influenced by EU competition law, but the Danish rules are generally stricter than those of the European Union 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 of unbundling of the main transmission grids and the gas distribution network.

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, liquefied natural gas business or universal service obligations to conduct only activities allowed under the licence.

As a general rule, the Electricity Supply Act does not allow both 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, however, does not preclude the use in combined waste incineration plants of other types of fuel (e.g., straw, chipped wood or natural gas) 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 participate, directly or indirectly, 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 participate, directly or indirectly, 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 the 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. Both the Danish transmission network and the distribution network are owned by Energinet. 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 DUR.

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 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. These 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.

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21 See footnote 8, above.
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 a store of oil follow from an EU directive and from rules laid down by the International Energy Authority. The Danish Act on Emergency Oil Supplies\(^{22}\) 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 Oil Stockholding Entity, which is an independent organisation set up by the oil companies and appointed by the DEA.

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 2019, the group had a total turnover of 494TWh. 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 affect 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.

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.

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22 Act No. 354 of 24 April 2012 on Emergency Oil Supplies.
iii Contracts for sale of energy
Most power in the Nordic and Baltic regions 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 Pegas. In 2017, for instance, 17,380,709MWh of natural gas from the Nordic and Baltic regions was traded on Pegas; this figure rose in 2018 to 25,097,094MWh. Danish energy legislation generally only regulates end-user contracts.

iv Market developments
There is 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 one of 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 progressed 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. Currently, 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 100 per cent of Danish electricity production in 2030. A new political agreement between the government and all the major opposition parties was reached in June 2018. The agreement sets out the following goals for 2030: approximately 55 per cent renewable energy in final energy consumption, 100 per cent of Danish electricity production to be covered by renewable energy, at least 90 per cent of district heating consumption to be covered by renewable energy and more than 50 per cent of electricity consumption to be supplied by wind power. These are all goals that will enable Denmark to be a net zero emissions society by 2050 at the latest.

Energy taxes on electricity and oil were introduced in 1977, since when taxes have been increased several times and have 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 transport.

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 to 45 per cent of electricity is currently produced by wind turbines (this is expected to exceed 50 per cent in 2020).
In 2009, the Promotion of Renewable Energy Act\textsuperscript{23} was introduced to promote the production of energy through the use of renewable energy sources, in accordance with climate, environmental and macroeconomic considerations, to reduce dependence on fossil fuels, ensure security of supply, and reduce carbon emissions and other greenhouse gases.

In 2018, the Danish government and parliament entered into an agreement that allocates 19 billion kroner to investments in renewable energy, 3.5 billion kroner to easing of taxes on electricity generally and on electricity for heating purposes, and has the purpose of accelerating the phase-out of coal through a modernisation of the heating sector.

\section*{ii Energy efficiency and conservation}

Denmark has long supported energy efficiency and conservation initiatives, which played an important part 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:

\begin{itemize}
  \item \textit{a} heat consumption in buildings;
  \item \textit{b} industrial and process – covering industrial and production-related consumption; and
  \item \textit{c} appliance and components – covering electrical appliances and components not directly related to industrial use.
\end{itemize}

A number of schemes have also been implemented, designed to promote energy savings in buildings and industry. Major current initiatives include:

\begin{itemize}
  \item \textit{a} taxes on domestic and public sector energy consumption of energy and carbon;
  \item \textit{b} taxes on industrial consumption of carbon;
  \item \textit{c} carbon emission allowance trading scheme;
  \item \textit{d} voluntary agreements for industry;
  \item \textit{e} energy labelling for large and small buildings;
  \item \textit{f} energy labelling of appliances and lighting;
  \item \textit{g} norms for energy efficiency and voluntary agreements; and
  \item \textit{h} reduction of standby consumption.
\end{itemize}

\section*{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 effect by public funds used in the field.

\section*{VI THE YEAR IN REVIEW}

\subsection*{i Technology neutral tender scheme for renewable energy}

On 27 September 2019, the DEA opened for bids on Denmark’s technology neutral tender scheme for renewable energy. Seven bids were received and the DEA expects that seven contracts will be signed with four onshore turbines and three solar photovoltaic (PV) installations, corresponding to the electricity consumption of approximately 154,000

\textsuperscript{23} Now Act No. 125 of 7 February 2020 on the Promotion of Renewable Energy.
households. The yearly tender is successful in securing competition between renewable energy sources, with the latest tender securing a record low level of aid to onshore wind turbines and solar PV.

ii Broad agreement on Climate Act
On 6 December 2019, the Danish parliament signed an agreement to adopt a new Climate Act during the first half of 2020. The Act will secure that the government will work to realise a 70 per cent reduction in greenhouse gas emissions by 2030 compared to 1990 levels. The Act will further call for future climate ministers to achieve net zero emissions by 2050. The Act will include assurances to work towards these goals, and secure continuous follow-up through climate action programmes. The final Act is yet to be negotiated and enacted, and the concrete regulation is yet to be determined.

iii Eighth licensing round for exploration and exploitation of oil and gas deferred
The eighth licensing round ended on 1 February 2019. The five applications for exploration and exploitation of oil and gas in the Danish North Sea came from four corporations: Ardent Oil Ltd, Lundin Norway AS, MOL Dania ApS and Total E&P Danmark A/S. Owing to political pressure on the government to increase the use of renewable energy, the eighth licensing round has been put on hold indefinitely.

iv Denmark calls for greater climate ambitions in the European Union
The government in Denmark, with 11 other EU Member States, has called for an increase in targets for the reduction of greenhouse gas emission from 40 per cent to between 50 and 55 per cent by 2030. Even though the Danish goal calls for an even further reduction, by 70 per cent, the Minister stresses that the European Union has the potential to set a good example for the rest of the world.

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 significant focus on cost-effectiveness and ensuring cheap energy for consumers while maintaining incentives for new investments in the sector.
Chapter 7

EUROPEAN UNION

Andreas Gunst, Natasha Luther-Jones and Michael Cieslarczyk

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 the European Union, the Treaty on the Functioning of the European Union, the Treaty establishing the European Atomic Energy Community and the Charter of Fundamental Rights of the European Union. Other treaties include the Energy Charter Treaty, the Energy Community Treaty, the United Nations Framework Convention on Climate Change and the 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. It addresses four areas:

- non-discriminatory conditions for trade and provisions on reliable cross-border energy transit;
- protection of direct foreign investment and protection against key non-commercial risk;
- a dispute resolution system between participating states and between investors and host states; and
- 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. 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.

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The Paris Agreement has been ratified by 189 of the 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 on all EU 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. EU competition law has an essential and complementary role in achieving these objectives, with free market provisions being enforced in coordination with energy regulators.

The Energy Union was introduced by the Juncker Commission (2014–2019) and ‘A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy’ was adopted in February 2015. The European Commission set itself the priority of establishing the Energy Union as a grand strategy for European energy policy, which was to go beyond the concept of the internal energy market. Five key ‘dimensions’ were set out:

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

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 updates the Third Energy Package and other key EU environmental legislation. This was fully enacted in June 2019 and consists of the following legislation:

- recast Renewable Energy Directive;
- amendment to the Energy Efficiency Directive;
- new Regulation on the Governance of the Energy Union;
- recast Electricity Directive;
- recast Electricity Access Regulation;
- recast ACER Regulation; and
- a new Regulation on Electricity Sector Risk-Preparedness.

Following the entry into force of the individual directives, EU Member States have a period of one to two years to transpose them into national law. The ACER Regulation and the Regulation on Electricity Sector Risk-Preparedness entered into force on 4 July 2019 and the Regulation on the Governance of the Energy Union and the Electricity Access Regulation will enter into force on 1 January 2021.

On 11 December 2019, the European Green Deal was introduced by the current von der Leyen Commission (2019–2024). This elaborates on the Energy Union and sets a clear focus on climate, sustainability and biodiversity conservation for all policy areas of the Commission. The main aim of the Green New Deal is to achieve no net emissions of greenhouse gases by 2050.

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It is clear that there is a substantial body of legislation regulating the European energy markets. For the purposes of this chapter, the main provisions of key secondary energy legislation are 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,\(^4\) the Electricity Directive,\(^5\) the Gas Directive,\(^6\) the Electricity Access Regulation\(^7\) and the Gas Access Regulation.\(^8\) The Clean Energy Package has resulted in the revision of the Electricity Access Regulation and the ACER Regulation, whereby the Electricity Directive will remain in force until the end of 2020, on which the last part of the new electricity market rules will apply.\(^9\) The regulatory system for the European energy markets is effectively divided into the national and European Union level.

At 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.

At the European Union level, the ACER Regulation provides for the establishment and legal status of the Agency for the Cooperation of Energy 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 recast ACER Regulation includes provisions on new tasks and restructuring to reflect the enhanced role ACER is to play in the Energy Union, and allowing ACER to establish local offices in Member States. The recast ACER Regulation entered into force on 4 July 2019.

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.

As part of the Clean Energy Package, a new Regulation on the Governance of the Energy Union and Climate Action\(^10\) was introduced, which 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

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7 Regulation (EC) No. 714/2009 on conditions for access to the network for cross-border exchanges in electricity.
the European Union. The Regulation entered into force in December 2018, with provisions on the establishment and operation of registries to account for the nationally determined contributions and minor amendments to related legislation applying from 1 January 2021.

III ELECTRICITY

i 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 also be unbundled. The Directive provides for their designation by Member States, their tasks and confidentiality obligations, and 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.

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 in Section II, the 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 recast Electricity Directive sets out 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, clarification of the roles of TSOs regarding energy storage and regional coordination centres, and clarification of the role of DSOs regarding energy storage and recharging points for electric vehicles. The recast Electricity Directive has been in force since June 2019 and is to be implemented into national law by 1 January 2021.

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), regulates network access charges, the provision of information by TSOs, general principles of congestion management and special provisions on new interconnectors.
The recast Energy Access Regulation sets out 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.

The recast Electricity Access Regulation has been in force since June 2019.

### 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.

The electricity network codes are grouped into three categories:

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

To date, eight – and thereby all 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. The CACM includes detailed provisions on terms, conditions and methodologies on capacity allocation and congestion income distribution.

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11 As established for the electricity market by the Electricity Access Regulation.
12 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.
The network code on forward capacity allocation\textsuperscript{14} sets out methods for allocating capacity in the forward markets and aims to:
\begin{itemize}
  \item[a] promote effective long-term cross-zonal trade with long-term cross-zonal hedging products for market participants;
  \item[b] optimise the calculation and allocation of long-term cross-zonal capacity;
  \item[c] provide non-discriminatory access to long-term cross-zonal capacity;
  \item[d] ensure fair and non-discriminatory treatment of TSOs and market participants; and
  \item[e] enhance the transparency and reliability of information.
\end{itemize}

The network code on electricity balancing\textsuperscript{15} sets out:
\begin{itemize}
  \item[a] provisions on terms and conditions or methodologies of TSOs and their approval;
  \item[b] roles and responsibilities of TSOs in the electricity balancing market;
  \item[c] the establishment of European platforms for the exchange of balancing energy from:
    \begin{itemize}
      \item replacement reserves, frequency restoration reserves with manual activation; and
      \item frequency restoration reserves with automatic activation;
    \end{itemize}
  \item[d] the establishment of a European platform for the imbalance netting process;
  \item[e] the procurement of balancing services;
  \item[f] cross-zonal capacity for balancing services, balancing settlement and balancing algorithms; and
  \item[g] reporting obligations.
\end{itemize}

The network code on emergency and restoration\textsuperscript{16} sets out:
\begin{itemize}
  \item[a] provisions on regional coordination;
  \item[b] the development of a system defence plan and a restoration plan;
  \item[c] the development of rules and procedures for the suspension and restoration of market activities;
  \item[d] information exchange between TSOs; and
  \item[e] compliance testing with obligations under the code.
\end{itemize}

The network code on demand connection\textsuperscript{17} 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\textsuperscript{18} sets out requirements for long-distance direct current connections, links between different synchronous areas and direct current-connected power park modules, such as offshore wind farms.

The network code on requirements for generators\textsuperscript{19} provides requirements for newly constructed generators, notification procedures and compliance provisions.

\textsuperscript{14} Commission Regulation (EU) 2016/1719 establishing a guideline on forward capacity allocation.
\textsuperscript{15} Commission Regulation (EU) 2017/2195 establishing a guideline on electricity balancing.
\textsuperscript{16} Commission Regulation (EU) 2017/2196 establishing a network code on emergency and restoration.
\textsuperscript{17} Commission Regulation (EU) 2016/1388 establishing a network code on demand connection.
\textsuperscript{18} Commission Regulation (EU) 2016/1447 establishing a network code on requirements for grid connection of high-voltage direct current systems and direct current-connected power park modules.
\textsuperscript{19} Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators.
The network code on system operation sets out:

- provisions on operational security requirements;
- data exchanges between different market participants;
- compliance with system operator 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  Proposal for risk preparedness
The Commission published the Regulation on Risk-Preparedness in the Electricity Sector in the Official Journal of the European Union on 14 June 2019. This new Regulation proposes measures for risk assessments and risk preparedness, and 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 at the level of both Member States and their regions. This Regulation has been in force since 4 July 2019.

IV  NATURAL GAS

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. The Directive regulates 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.

20 Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation.
The European Commission proposed an amendment to the Directive in November 2017, to be implemented by Member States by 23 May 2019. This amendment has extended the rules set out under the former Gas Directive to gas transmission infrastructure running between Member States and third countries.

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.

As with the Electricity Access Regulation, the Gas Access Regulation establishes network codes (see Section IV.iii). 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. To date, 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. The 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 timeframes. It further regulates the bundling of cross-border capacity, incremental capacity, interruptible capacity and capacity booking platforms.

The network code on 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 renomination procedures. The balancing procedures include provisions on short-term standardised products and the establishment of a trading platform for their procurement, and incentives for TSOs to undertake efficient balancing actions.

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21 As established for the gas market by the Gas Access Regulation.
22 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.
The network code on interoperability and data exchange\textsuperscript{25} regulates interconnection agreements, providing that adjacent TSOs mutually agree on rules for flow control, measurement 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 and provisions for gas quality and odorisation.

The network code on tariff harmonisation\textsuperscript{26} aims to homogenise gas transmission tariffs within the European Union, promoting fair and objective tariffs, providing methodologies on reference prices, reserve prices, clearing prices and payable prices, provisions on reconciliation of revenues, pricing of bundled capacity and capacity at virtual interconnection points, consultation and publication requirements, and tariff principles for incremental capacity.

Congestion management procedures\textsuperscript{27} are fundamentally guidelines that address 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. They also set out the technical information necessary for network users to gain effective access to the system.

Further 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.

\textbf{iv \hspace{1em} Gas Security of Supply Regulation}

The Gas Security of Supply Regulation\textsuperscript{28} 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:

\begin{itemize}
  \item \textit{a} the establishment of a Gas Coordination Group;
  \item \textit{b} the development of a robust infrastructure network across the European Union;
  \item \textit{c} the development of a gas supply standard to ensure that vulnerable consumers have a supply under certain extreme circumstances;
  \item \textit{d} the performance of a regular risk assessment by ENTSOG and coordinators of regional cooperation Member State groups;
  \item \textit{e} the establishment of preventive action plans and emergency plans, different supply crisis levels, regional and Union emergency responses;
  \item \textit{f} 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;
\end{itemize}

\begin{footnotesize}
\begin{enumerate}
\item Commission Regulation (EU) 2015/703 establishing a network code on interoperability and data exchange rules.
\item Commission Regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures for gas.
\end{enumerate}
\end{footnotesize}
information exchange, and 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 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 economic and technical points 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 for publication 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 Oil Stockholding Directive sets out rules to mitigate an oil supply crisis in the European Union. It also sets out obligations for Member States to maintain emergency stocks, including a methodology for calculating stock levels, and 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 provide support in meeting 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.

29 Directive 94/22/EC on the conditions for granting and using authorisations for the prospection, exploration and production of hydrocarbons.

30 Directive 2009/119/EC imposing an obligation on Member States to maintain minimum stocks of crude oil and/or petroleum products.
VI TRANS-EUROPEAN ENERGY INFRASTRUCTURE REGULATION

The Trans-European Energy Infrastructure Regulation (TEN-E)\textsuperscript{31} 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 EU 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.

A list of PCIs is established by the European Commission every two years; the third PCI list was published in November 2017.\textsuperscript{32} 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. Receiving PCI status increases the attractiveness of a project 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 carbon dioxide emissions.

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 regarding reporting and evaluating PCIs, and information and publicity obligations.

VII RENEWABLE ENERGY DIRECTIVE

The Renewable Energy Directive (RED)\textsuperscript{33} 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, and to adopt national renewable energy action plans. 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, costs and energy efficiency of renewable source energy to consumers, builders, architects and equipment suppliers.

\textsuperscript{31} Regulation (EU) No. 347/2013 on guidelines for trans-European energy infrastructure.


\textsuperscript{33} Directive 2009/28/EC on the promotion of the use of energy from renewable sources.
One important aspect of the Directive is the establishment of guarantees of origin of electricity, heating and cooling produced from renewable energy sources, 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, the sustainability criteria for biofuels and bioliquids and verification of their compliance, and specific provisions relating to energy from renewable sources in transport. The Commission is additionally required to monitor and report the origin and effects 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.

In December 2018, the recast Renewable Energy Directive (REDII) entered into force. It is to be implemented by Member States as of 1 July 2021, on which date the Renewable Energy Directive is to be repealed. REDII includes provisions on a minimum target of 32 per cent for the share of energy from renewable sources in the Union’s gross final consumption of energy in 2030, the opening up of support schemes to projects in other Member States (permitting Member States to support renewable generators in other Member States), new qualifications for accounting for guarantees of origin issued to supported generators, extending the use of guarantees of origin to non-renewable projects, and the right of consumers generating their own electricity (known as renewables self-consumers) to sell any excess while retaining their rights as consumers.

VIII ENERGY EFFICIENCY

i Energy Efficiency Directive

The Energy Efficiency Directive aims to promote energy efficiency across the European Union 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 mobilise investment for improving the energy efficiency of buildings, whereby public bodies are to have 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, to provide final consumers with meters, cost-free access to metering and billing information and information on energy, and to 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

34 Directive (EU) 2018/2001 on the promotion of the use of energy from renewable sources.
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 small and medium-sized enterprises, and are permitted to set up an energy efficiency national fund and other financing and technical support to increase energy efficiency in different sectors.

In December 2018, the amended Energy Efficiency Directive\(^{36}\) entered into force, and the amendments to the current Energy Efficiency Directive are to be made by Member States by 25 June 2020 (with some provisions to be implemented by 25 October 2020). The amendment sets out a binding 32.5 per cent minimum energy efficiency target for 2030, building on that of 20 per cent for 2020, updates the energy savings obligation for Member States and extends consumer rights, in particular regarding billing and energy consumption information through smart metering systems.

**ii Energy Performance in Buildings Directive**

The Energy Performance in Buildings\(^{37}\) Directive aims to promote the improvement of the energy efficiency of buildings within the European Union.

The Directive sets out a common general framework to develop:

- a methodology to calculate the energy performance of buildings and building units;
- minimum requirements on the energy performance of new and existing buildings;
- a national plan for increasing the number of nearly zero-energy buildings;
- rules on energy certification of buildings or building units; and
- rules on independent control systems for energy performance certificates and inspection reports.

The amended Energy Performance in Buildings Directive\(^{38}\) entered into force in December 2018, with an implementation deadline of 10 March 2020. The amended Directive introduces an obligation for Member States to establish a long-term renovation strategy and develops requirements for residential and non-residential buildings, such as installing recharging points for electric vehicles, and details on heating systems and air-conditioning systems.

**IX DECARBONISATION**

**i Emissions Trading Directive**

The European greenhouse gas emissions allowance trading scheme (the Emissions Trading Scheme) was established by the Emissions Trading Directive\(^{39}\) 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;


\(^{39}\) Directive 2003/87/EC establishing a scheme for greenhouse gas emission allowance trading within the Community.
c the development of a national allocation plan;
d allocation methods for allowances;
e the transfer, surrender and cancellation of allowances throughout the European Union;
f the validity of allowances;
g guidelines for monitoring and reporting of emissions; and vh verification of reports submitted by operators.

Allowance allocation decisions are to be made available to the public, and Member States must establish allowance registries; Member States 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 DIRECTIVE

The Carbon Capture and Storage 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:

a the composition of carbon dioxide streams and their acceptance procedure;
b the monitoring of storage facilities;
c reporting obligations of the storage operator;
d inspections of the facilities;
e closure and post-closure obligations;
f the provision of financial security by operators for storage permits; and
g a financial mechanism for the competent authority.

Since its adoption, the Emissions Trading Directive has undergone a series of amendments:

(2) Directive 2008/101/EC amending Directive 2003/87/EC to include aviation activities in the scheme for greenhouse gas emission allowance trading within the Community;
(3) Regulation (EC) No. 219/2009 adapting a number of instruments subject to the procedure referred to in Article 251 of the Treaty to Council Decision 1999/468/EC with regard to the regulatory procedure with scrutiny;
(5) Decision No. 1359/2013/EU amending Directive 2003/87/EC clarifying provisions on the timing of auctions of greenhouse gas allowances; and


The aforementioned competent authority is to be designated by the Member State to fulfil its duties under the Directive, and 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 and regular updates to the Commission on the implementation of the Directive.

XI ENERGY MARKETS

Following the global financial crisis of 2008–2009, the European Union adopted a number of legislative instruments to stabilise the financial markets, to limit price volatility of commodities and to 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.43

With the Third Energy Package (and the respective amendments and additions brought through the Clean Energy Package) and REMIT,44 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 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 (including its implementation through successive conferences of the parties to the United Nations Framework Convention on Climate Change).

The European Green Deal, which was introduced in December 2019 under the current von der Leyen Commission, elaborates on the Energy Union introduced by the Juncker Commission and seeks to transform the European Union into the first climate-neutral continent.

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 reinforced by the European Green Deal makes an increased commitment from the European Union and its Member States to decarbonise the economy.


On 29 March 2017, the United Kingdom triggered Article 50 of the Treaty on the European Union following the result of the Brexit referendum in June 2016. This started a negotiation window for the European Union and the United Kingdom to agree on the terms of UK withdrawal and potentially the EU–UK cooperation mechanism. On 24 January 2020, the European Union, the European Atomic Energy Community and the United Kingdom signed the ‘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 Withdrawal Agreement). The Withdrawal Agreement provides for the formal withdrawal of the United Kingdom from the European Union on 31 January 2020 at 23:00 GMT and a transition period until 31 December 2020 (subject to any agreed extension) during which the United Kingdom remains subject to EU law, the jurisdiction of the Court of Justice of the European Union and remains within the single market. However, the United Kingdom is not involved in the EU legislative procedure during the transition period unless invited by the Member States. If no final agreement is reached by 31 December 2020 and the transition period has not been extended, a no-deal Brexit will be the default outcome.

Of possible relevance to the energy sector, the Withdrawal Agreement provides at a high level for the movement of goods placed on the market prior to the end of the transition period and for continuing customs procedures. Neither the Withdrawal Agreement nor the current status of negotiations, however, provide any clarity as to the effects of Brexit on the energy sector.

Notwithstanding the effects of Brexit on the UK energy sector, the regulatory landscape in the European Union is likely to remain largely unchanged; however, certain issues may arise as part of the proceedings. These may include the adaptation of the Emissions Trading Scheme to account for the withdrawal of the EU’s second-largest emitter, and issues involving connection to the newly established UK energy sector. The exact nature of any possible effects of Brexit on the EU energy sector remains unclear; however, because of the Withdrawal Agreement, any such effects will be delayed until 31 December 2020.
Chapter 8

FRANCE

Fabrice Fages and Myria Saarinen

I OVERVIEW

The energy market in France 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 focuses mainly on electricity and gas markets since they are the markets that have been affected the most by these changes. It should be underlined, however, that the other sources of energy are also subject to specific regulation.

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 customers, by 1 July 2007.

Although significant progress had been made, the European Commission adopted the Third Energy Package to further liberalise the energy market, which included two new

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1 Fabrice Fages and Myria Saarinen are partners at Latham & Watkins AARPI. This chapter was written with the assistance of Floriane Cruchet, an associate at the firm.
3 Law No. 46-628 of 8 April 1946 concerning the nationalisation of electricity and gas, repealed by Law No. 2004-803.
France

Directives\(^5\) replacing the former electricity and gas Directives. These were transposed into French law on 7 December 2010 by a new law commonly referred to as Law NOME,\(^6\) 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, between January 2011 and 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 Dispute Settlement and Sanctions Committee (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 relating 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 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 gas.

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\(^6\) Law No. 2010-1488 of 7 December 2010 establishing a new organisation of the electricity market.

\(^7\) French Energy Code, Articles L131-1 to L135-16.
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.  

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 that policy and on decisions relating to the electricity and gas markets.

ii Regulated activities

The energy market is composed of four main areas of activity: production (generation), transmission, distribution and supply (commercialisation). Under the regime that was in place until 2000, these four activities were carried out by EDF and GDF, which self-regulated the monopoly.

Greater strides have been taken towards liberalisation as production and supply are now open to competition. However, transmission and distribution are still public service activities supervised by the CRE. Where, to guarantee this public service mandate, a legal and financial separation between these activities has taken place, transmission is performed by GRT (gas) and RTE (electricity), and distribution is performed by GRDF (gas) and Enedis (electricity) or local distribution companies.

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 applicable 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. The previous threshold ranged from 12MW to 30MW. The authorisation is issued by the Minister of Energy according to specific considerations such as security, energy efficiency, technical and economic capacities of the applicant. Similarly, gas exploration requires an administrative authorisation or a concession, which is granted subject to a public inquiry and a tender procedure.

iii Ownership and market access restrictions

Although the French Energy Code does not provide for any restriction 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 Engie (to protect the French national interest, the state may benefit from specific shares within the capital of Engie).

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8 id., at Article L134-16.
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 French Energy Code, Article R311-1 et seq.
12 id., at Article L311-5.
13 French Mining Code, Articles L131-1, L132-3 and L132-4.
14 French Energy Code, Articles L111-67 and L111-68.
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:

1. Worldwide aggregate turnover of all the parties to the concentration exceeds €150 million;
2. Turnover in France of each or at least two parties concerned exceeds €50 million; and
3. The transaction does not meet the thresholds set by Council Regulation (EC) No. 139/2004 (the EU Merger Regulation).

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 effects 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. At this stage, the Ministry of the Economy has the ability to intervene and to take a position on the transaction for considerations of general interest, other than fair competition, that would compensate the harm to competition resulting from the transaction.

The FCA’s authorisations for acquisitions may be subject to conditions. 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.

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 monopolies.

The European Commission issued Directives 2003/54/EC and 2003/55/EC principally to ensure efficient and non-discriminatory network access, to ensure free choice of suppliers

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17 See, e.g., 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 competition 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 French Monetary Code, Article L151-3.
by consumers and to 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 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 level of unbundling between network and supply interests deemed to have negative effects on the market and investment. Consequently, under Directives 2009/72/EC and 2009/73/EC, priority was given to achieving effective unbundling of network and supply activities.

As has been explained, 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 fulfill 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. Any discrimination, prevention of new participants from entering the market or restriction to fair competition in favour of the consumer is subject to sanctions issued by the CoRDIs committee.

Among the measures guaranteeing non-discriminatory and fair access, any refusal to enter into an agreement must be justified and notified to the applicant, and to the CRE, specifying that any refusal is justified by objective, transparent and non-discriminatory reasons. 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.

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.

**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. 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

20 French Energy Code, Article L111-91 et seq.
21 id., at Article L134-25 et seq.
22 id., at Article L111-93 (for electricity) and Article L111-102 et seq. (for gas).
23 id., at Article L111-61.
24 id., at Article L134-15.
25 French Mining Code, Articles L211-2 and L231-1.
operators 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.\textsuperscript{26}

\textbf{iv Rates}

The aim of access tariffs to networks is to guarantee transparent and non-discriminatory access to public networks. These fees are calculated in a way that covers 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 in both the short and long term to increase efficiency, to foster market integration and security of supply and to support related research activities.\textsuperscript{27}

\textbf{v Security and technology restrictions}

Security of electricity and gas supply is an essential public service obligation.\textsuperscript{28} The Ministers of Energy and Economy must ensure the fulfilment of this public service mission mainly by EDF, GDF, RTE, GRT, Enedis, GRDF and local distribution companies. In the event of a serious energy shortage, the government may subject energy resources to control and allocation.\textsuperscript{29} These measures mainly concern production, imports, exports, storage, acquisition and transportation. In the event of a serious energy market crisis, or a 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.\textsuperscript{30} In times of war or serious international tension, the government may regulate or even suspend oil imports or exports completely.\textsuperscript{31}

In addition, to ensure energy autonomy, France has put in place a capacity market that entered into force on 1 January 2017. The aim of the capacity mechanism is to encourage demand management, especially during peak hours, via the purchase or sale of certificates depending on whether energy consumption needs are met.

\textbf{IV ENERGY MARKETS}

\textbf{i Development of energy markets}

The sale of energy takes place within either the wholesale market or the retail market. The wholesale market is where 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).\textsuperscript{32}

\textsuperscript{26} French Energy Code, Articles L421-5 and L421-8.
\textsuperscript{27} id., at Articles L341-3 (electricity), L452-2 and L452-3 (gas).
\textsuperscript{28} id., at Articles L121-1 (electricity) and L121-32 (gas).
\textsuperscript{29} id., at Article L143-1.
\textsuperscript{30} id., at Article L143-4.
\textsuperscript{31} id., at Article L143-7.
\textsuperscript{32} id., at Article L331-1.
The participants of the wholesale market are:

- producers who trade and sell their production;
- suppliers who trade and supply gas or electricity before selling gas or electricity to the final client; and
- brokers or traders who purchase gas or electricity for resale and thus favour market liquidity.

As most of the activity in the wholesale gas and electricity markets 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 government approval. Indeed, suppliers willing to purchase electricity or gas to sell it 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 NOME 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. As per a decision dated 19 July 2017, the Council of State declared that the gas-regulated tariffs were not in line with European Union law as they were a restriction on the existence of a competitive common gas market that failed to respect the conditions that would have made this restriction permissible under European Union law.

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33 Commission of Regulation of Energy [CRE], Electricity and gas market report, fourth quarter of 2011.
34 French Energy Code, Articles L333-1 (electricity), L443-1 and L443-2 (gas).
36 id., at Article L337-7.
38 id., at Article L445-4.
Finally, the Contribution to the Public Electricity Service, which has been funded since 2016 by the domestic consumption tax on electricity for end users, was 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.

To prevent this, the Law dated 7 December 2006, completed by the Law NOME, created a new section in the French Consumer Code titled '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 last for at least 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 to change supplier. Professionals are not entitled to ask the consumer for any costs other 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 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 in the future.

### 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, with the aim of promoting environmental objectives such as an increase in 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. In 2017, the share of renewable energy corresponded to 16.3 per cent of the final consumption while 19.5 per cent was targeted by the French government to reach the 2020 goal. These laws were codified in a separate section dedicated to renewable energy in the French Energy Code. 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, 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, which provides that EDF is obliged to enter into a contract for the purchase of electricity – the duration of which 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:

- 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;
- Decree No. 2016-690 of 28 May 2016 setting out the terms and conditions of the assignment of the purchase obligation contract; and
- 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, the European Union adopted Directive 2012/27/EU on energy efficiency on 25 October 2012. 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. These targets were recently revised as per the Law on Energy and Climate adopted in 2019 (see also Section VI.1).

The transposition of this Directive into French law led to the adoption of several measures intended to improve energy efficiency, such as:

- the creation of an obligation for companies to be subject to an energy audit every four years;
- the submission by France of a report on its efficiency energy target to the European Commission on 24 April 2014; and

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44 Law No. 2009-967 of 3 August 2009 relating to the implementation of the Grenelle Environment Forum; Law No. 2010-788 of 12 July 2010 relating to national commitment for the environment.


47 id., at Articles L314-18 to L314-27.

48 id., at Article L233-1.
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.\textsuperscript{49}

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 phasing out of hydrocarbon production in the French territory by 2040, the Law provides that no new research permit for hydrocarbons will be granted by the government.

iii Technological developments

Directive 2012/27/EU also includes several provisions relating to the development of smart grids and smart meters, the aim of which is to reduce bills by paying what has actually been 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.

The development of smart grids has also been decided. 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 government announcement that 35 million smart meters will be provided to electricity customers throughout the country by 2020, the deployment started in December 2015. According to Enedis, this goal should be reached in 2021.

VI THE YEAR IN REVIEW

The year 2019 and the beginning of 2020 have been characterised by several developments in the energy sector.

i New Law on Energy and Climate

Adopted on 8 November 2019, the Law on Energy and Climate revised several objectives set forth in the Law on Energy Transition dated 17 August 2015, in particular to achieve carbon neutrality by 2050 in response to the climate emergency and to comply with the Paris Agreement.\textsuperscript{50}

The law focuses on four main areas:

a the gradual phasing out of fossil fuels and the development of renewable energies through several measures:

• a reduction in fossil fuel consumption by setting a reduction target of 40 per cent by 2030, compared to 30 per cent previously;
• the cessation of coal-fired power generation by 2022;
• mandatory installation of solar panels or any other process for the production of renewable energy or vegetalisation on new warehouses and commercial buildings;
• securing the legal framework for the environmental evaluation of projects;

\textsuperscript{49} id., at Article R234-1.

\textsuperscript{50} Law No. 2019-1147 dated 8 November 2019 relating to Energy and Climate.
• the creation of the notion of a ‘renewable energy community’, which will allow that community to produce, consume, store and sell renewable energy or to share the renewable energy it produces within the community; and
• the implementation of a support and traceability system for virtuous hydrogen;

The fight against thermal sieves (i.e., accommodations whose energy consumption falls under Classes F and G based on the energy efficiency diagnosis (known as DPE) carried out by an accredited professional required by the law for the rent and sale of real-estate properties)\(^{51}\) deemed to cause 20 per cent of the French greenhouse gas emissions with the implementation of a three-phase action plan from 2021 to 2028. The ultimate goal is to achieve the renovation of all thermal sieves within 10 years;

c  the introduction of new tools for the steering, governance and evaluation of climate policy with the creation of the High Council for the Climate in charge of evaluating France’s climate strategy. A five-year programming law will set, from 2023 onwards, the major energy objectives regarding renewable energy sources, energy consumption, fossil fuel output and the minimum and maximum levels of obligation for energy saving certificates. This Council is chaired by French-Canadian climate scientist Corinne Le Quéré and is composed of 13 members selected for their expertise in the fields of climate science, economics, agronomy and energy transition; and

d  the regulation of the electricity and gas sector through the following measures:
• the ability for the government to increase, by decree, the cap to access to historic nuclear electricity from 100 TWh to 150 TWh;
• the reduction of France’s dependency on nuclear power through the shutdown of two reactors of the Fessenheim power plant by summer 2020 and the postponement to 2035 (instead of 2025) of the 50 per cent reduction of electricity production from nuclear sources; and
• the reinforcement of controls to fight against fraud affecting energy efficiency certificates.

The Law on Energy and Climate also changes the rules for gas-regulated tariffs. As of 20 November 2019, it is no longer possible to subscribe for gas-regulated tariffs and all existing contracts will only be valid until 1 December 2020 (for non-domestic consumers) and 30 June 2023 (for domestic consumers).\(^{52}\) This Law takes into account a decision by the Council of State dated 19 July 2017 according to which the gas-regulated tariffs were not in line with European Union law as it was a restriction on the existence of a competitive common gas market that failed to respect the conditions that would have made this restriction permissible under European Union law.\(^{53}\)

\[\text{ii} \quad \text{Road map for energy strategy (2019 to 2028)}\]

In the course of 2018, the draft of a new decree setting forth the multi-annual energy programmes was publicly debated and submitted to several consultative bodies up to the middle of 2019. Taking into account the feedback received on the first draft, a revised version of the draft decree was finally published and submitted to further public consultation between 20 January 2020 and 19 February 2020. The purpose of this road map is to define

\(^{51}\) French Construction and Housing Code, Article L134-1 et seq.

\(^{52}\) id., at Article 23.

the priority actions to be taken by public authorities to reach the goals set forth by the law in the energy sector and, ultimately, puts France on a trajectory that will lead to carbon neutrality by 2050. The revised version of the draft decree includes the following measures:

- **Development of the production of energy from renewable sources**, in particular by launching competitive tendering procedures for onshore wind power, offshore wind power, photovoltaics and hydropower according to a tentative calendar set forth in the Decree;
- **Roll-out of more recharging infrastructure for alternative fuels** (e.g., 100,000 public electric charging points for electric vehicles);
- **Definition of goals for the incorporation of biofuel in fuel**;
- **Impossibility for the administration to deliver new authorisation to operate a thermal power plant**, except for those already selected after a competitive tendering procedure held before the entry into force of the Decree; and
- **Development of peak shaving capacity for electricity** (4.5GW in 2023 and 6.5GW in 2028).

### iii Inclusion of energy storage within foreign direct investment regulation

The Pacte Act has strengthened the regulation of foreign direct investment in France. First, the Decree dated 31 December 2019 lowers the threshold from 33 per cent to 25 per cent of the voting rights of the French target company from which the control may be triggered. Second, the list of strategic sectors in which the government will be able to oppose a foreign takeover has been extended to include energy storage in the critical technologies mentioned in the new Article R151-3 of the French Monetary and Financial Code (which enters into force on 1 April 2020). Initially, the only energy activities covered by the foreign direct investments regulation were those guaranteeing integrity, security or continuity of the energy supply.

### iv New procedure against EDF and Energie by the French data protection authority

Following on-site investigations, the National Commission for Data Protection (CNIL) issued formal notices against EDF and Engie as (1) the consent collected from their users for the processing of their energy consumption was neither specific nor sufficiently informed for the processing of data relating to their energy consumption every 30 minutes and their daily energy consumption and (2) the retention periods of energy consumption data were excessive in relation to the purpose of their processing.

The CNIL gave EDF and Engie three months to take action to remediate these non-compliance matters.

According to the CNIL, the aim of the publication of these formal notices was to increase users’ awareness of their rights under the General Data Protection Regulation, having

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54 Law No. 2019-486 dated 22 May 2019, Articles 152 to 154.
56 Order dated 31 December 2019, Article 6.
57 French Monetary Code, Article L151-3.
noted that these companies have a very high number of users whose energy consumption is recorded through the Linky smart meter (and noting that 35 million smart meters should be installed by 2021).

v Derogation of regulated tariff not possible

To favour the development of renewable energy, public authorities have implemented a purchase obligation requiring EDF to buy electricity produced from renewable sources for a regulated tariff. In recent case law, facing a payment claim from an electricity producer whose installation benefits from the purchase obligation, EDF claimed that the tariff agreed by the parties was unenforceable as it was not in line with the regulated tariff. The Marseilles Administrative Court of Appeal held that the contract was fully enforceable as it considered that the regulated tariff did not prevent EDF granting producers more favourable tariffs and that the error made by EDF on the applicable tariff did not vitiate its consent. As per a decision dated 22 January 2020, the Council of State overruled this decision and held that the parties to such an agreement with a purchase obligation cannot derogate to the regulated tariff, even if the contractual provisions are more favourable to the producer.

vi Special measures for payment of invoices during coronavirus pandemic

On 24 March 2020, an emergency law that enables the declaration of a state of health emergency and further restrictions on the freedom of movement, enterprise and assembly was enacted to tackle the spread of the coronavirus in France. These measures (implemented by ordinance or decree) also affect the energy sector. As per Ordinance No. 2020-316 dated 25 March 2020, certain businesses disrupted because of the pandemic may benefit from delaying payment of their energy invoices payable between 12 March 2020 and the end of the declaration of a state of health emergency with no penalty. Payment of the deferred invoices shall be distributed evenly between subsequent invoices after the last day of the month following the date of the end of the declaration of a state of health emergency, for a period that cannot be less than six months. Similarly, gas and electricity providers will not be allowed to suspend, interrupt or reduce (including through a termination of the agreement) the provision of energy for the above-mentioned businesses until the end of the declaration of a state of health emergency.

vii Uncertainty around renewal methods of hydraulic concessions

In 2023, 150 concessions will expire. Although the regime of hydraulic concessions has been reformed, notably regarding the procedure applicable to the granting of these concessions, the European Commission sent formal notices to France on 7 March 2019 as it considered that both the legislation and the practice by French authorities for the renewal of these

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60 Marseilles Administrative Court of Appeal dated 12 February 2018, No. 17MA01582.
61 Council of State Decision dated 22 January 2020, No. 418737.
63 Ordinance No. 2020-316 dated 25 March 2020, Article 3.
64 id.
65 id., at Article 2.
concessions are contrary to European Union law. The exact parameters of the renewal are yet to be defined and the French government, still in discussions with the European Commission, is considering options to limit the use of competitive procedures.

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 with the end of regulated tariffs and the adoption of the Law on Energy Transition on 17 August 2015, which aims to develop the role of renewable energy.

Furthermore, the implementation of President Emmanuel Macron’s energy programme will have to be followed. Under this programme, Emmanuel Macron intends to close all coal-fired power plants by 2022, 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 and the objective of reducing the use of nuclear energy.

Finally, the amendment and the adoption by the European Parliament and the 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 fewer than four Regulations and four Directives, the Fourth Energy Package may well have an impact on France’s regulation of its energy market.
I  OVERVIEW

The German energy sector continues to evolve dynamically. As Germany is likely to miss its 2020 carbon dioxide emission reduction goals, the government continues its efforts to pursue the reform of the German energy market (i.e., the transition of electricity generation from fossil to renewable sources, a substantial reduction of carbon dioxide emissions and the phasing 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, including climate change, is mainly 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 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 part 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. 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, and is in charge of merger control.

Both the regulatory authorities and BKartA have wide-ranging powers of enforcement, such as refusal of permits, issue of prohibition orders and imposition of fines.
A market transparency unit at BKartA oversees and publishes fuel prices to increase transparency and competition in these markets. A parallel market transparency unit at BNetzA supervises the wholesale trade in electricity and gas markets.

**Sources of law**

The key source of legislation is the Energy Industry Act, which sets out the main regulation of the German energy market including unbundling requirements, grid operation, energy supply, grid concessions, regulators and legal protection. 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 cogeneration power plants is regulated in the Cogeneration Act.

Another important source of law are the administrative decisions of BNetzA, addressed to individual parties or to groups of network operators. BNetzA also issues general guidelines addressed to the general 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.

**ii Regulated activities**

**Network operation**

Operators of distribution and transmission networks for power and gas must obtain a grid operation permit confirming their personal, technical and economic capability and reliability to ensure the long-term operation of the network.

In addition, transmission system operators (TSOs) require certification by BNetzA confirming their compliance with unbundling regulation. Before making a final decision, BNetzA has to submit its draft decision to the European Commission and must take utmost account of the Commission’s statement.

When using public roads, operators of gas and electricity networks must enter into concession agreements with the municipality owning the roads. These 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. As the German government made a decision to phase out nuclear energy by 2022, commercial nuclear power plants will no longer be authorised. In January 2020, the government introduced a coal-exit bill with the aim of gradually phasing out electricity generation from coal by 2038. Also, no new coal-fired power plants are to 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 household customers must notify the regulatory authority of the commencement and of the discontinuance of their supply activities, including proof of sufficient resources and reliability.

### 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 (EU) or of the European Economic Area (EEA), the grid operator will only be certified by BNetzA if, in addition to compliance with the unbundling rules, 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, BMWi may prohibit on the grounds of public policy or national security the acquisition by a non-EU or non-EEA investor of 25 per cent or more of the voting rights in a German company or asset. For certain critical infrastructures, the threshold is 10 per cent. In the energy sector, this relates among other things, to infrastructures that supply 500,000 persons or more with electricity, gas, fuel, heating oil, or district heating or generation assets with more than 420MW installed capacity. The rules will be further tightened during summer 2020, to reflect recent EU legislation.

### 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 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. BKartA decides within one month of notification or, if an in-depth investigation is initiated, within an additional four months. The European Commission has a maximum of 135 working days in which to carry out an in-depth investigation to review a merger (or a maximum of 160 working days if remedies are offered).

### III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

#### i Vertical integration and unbundling

The Energy Industry Act 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 (ISO) or the independent transmission operator model (ITO).
Most of the TSOs have opted for the ITO model and some for ownership unbundling. 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.

Regarding the ITO model, the German definition of a VIU in the view of the European Commission excludes activities outside the EU. Furthermore, the independence of the ITO’s staff and management was not sufficiently guaranteed. The European Commission has therefore filed a complaint with the European Court of Justice (C-718/18).

With respect to the ownership unbundling model, German law allows a person controlling electricity or gas production, generation or supply activities to hold a minority participation in a TSO of up to 25 per cent at the same time, provided that this participation does not confer significant minority rights. Each case is evaluated on its merits.

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 case by case, taking into account in particular the geographical 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.

**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, of which the connection costs are socialised. Operators of LNG terminals shall bear only 10 per cent of their connection costs.

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 gas, and a second contract is concluded between the grid customer and the grid operator for the off-take of 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).
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. However, the European Commission holds the view that BNetzA does not enjoy sufficient discretion in the setting of network tariffs and other terms and conditions for access to networks and balancing services. It has therefore filed a complaint with the European Court of Justice (C-718/18).

The increase in generation of electricity from renewable energy sources and the phasing out of nuclear energy is leading to a shift of generation to northern Germany, resulting in bottlenecks on the north–south transmission lines. Network operators may restrict network access to maintain system security. They must use non-discriminatory and market-based measures to prevent or eliminate bottlenecks. However, generators of electricity from renewable sources may only be curtailed on a subordinate basis.

Costs for redispach 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 planning approval of projects that cross the borders between German states.

### Rates

As of 2009, grid fees are 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. 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. During the regulatory period, the annual revenue cap will be adjusted only in a few cases, such as when the consumer retail price index or the grid operator’s permanently non-controllable costs change. 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.

As of 2016, capital costs for network investments made after the photo year are 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. These 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 effect on at least two EU Member States. BNetzA can declare these assets to be critical European infrastructure. TSOs have to develop specific security plans for these 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 2019 decreased by 2.3 per cent compared to 2018; gross electricity consumption decreased by 1.8 per cent. In 2019, primary energy consumption was composed of oil (35.3 per cent), natural gas (25 per cent), hard coal (8.8 per cent), lignite (9.1 per cent), nuclear (6.4 per cent) and renewable sources (14.7 per cent).

Gross electricity generation in 2019 was composed of lignite (19 per cent), hard coal (9 per cent), nuclear (12 per cent), natural gas (15 per cent), mineral oil (1 per cent), others (4 per cent) and renewable sources (40 per cent), the latter mainly consisting of wind power (21 per cent), hydropower (3 per cent), biomass (7 per cent), photovoltaic (7 per cent) and waste (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.

As of 1 October 2021, the two separate dual-quality (high caloric and low caloric gas) gas market areas NCG and GASPOOL will merge into one gas market area. Already, gas can be traded without capacity restrictions between the gas market areas 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 and carbon dioxide emission allowances. EEX offers trading of electricity futures for delivery in the German market area and trading of gas futures and short-term gas contracts for delivery in the GASPOOL and NCG areas. The electricity spot market 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 (OTC) 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 in wholesale prices and has pushed conventional generation capacity out of the merit order, in particular flexible gas-fired power plants.

To guarantee security of supply, the Electricity Market Act of 2016 implemented several capacity mechanisms, but without 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 be served mainly by lignite-fired power plants that are being transferred to security standby mode before being decommissioned four years later.

ii 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 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. As of 2015, market participants have to register with BNetzA and report details of wholesale energy transactions executed at organised market places to the European Agency for the Cooperation of Energy Regulators.

As of 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 OTC derivatives and the application of risk mitigation techniques for non-centrally cleared OTC derivatives.

iii Contracts for sale of energy

In principle, there are no regulatory limitations on the entering of individual contracts for the sale of energy, either at wholesale or 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.

Although 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) account for more than half of the final energy prices for electricity and for between 25 and 30 per cent for gas. 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 repeatedly 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 in 2013 and 2014, according to which a standard clause for price adjustments that was widely used in supply agreements is invalid, utility companies have to provide information on the scope, reasons and preconditions for the adjustment.
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 began the acquisition process of RWE’s majority stake in innogy, which was completed in September 2019. In return, E.ON transferred its renewables business to RWE and will also transfer innogy’s renewables business back to RWE. As a consequence of this asset swap, RWE will focus on conventional and renewable energy generation while E.ON will concentrate on energy networks and customer solutions.

In line with the government’s climate protection plans, utilities have also started to divest their coal-fired generation units.

RENEWABLE ENERGY AND CONSERVATION

Development of renewable energy

In 2017, a major reform of the EEG, the law governing the development of renewable energy sources, 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, such as geothermal energy, may be introduced at a later stage. The technology-specific auction volumes are limited to:

- 4,100MW in 2020, 4,250MW in 2021 and 2,900MW per year as of 2022 for onshore wind;
- 1,800MW in 2020, 1,950MW in 2021 and 600MW per year as of 2022 for solar;
- 200MW per year as of 2020 for biomass; and
- 15GW until 2030 for offshore wind.

Finally, the EEG foresees so-called innovation tenders that shall take place on 1 September and have a volume of 400MW in 2020 and 500MW in 2021. Each tender volume increases according to volume not having been awarded in the corresponding previous tender year.

Since December 2017, BNetzA also conducts two auctions for electricity from co-generation per year. In addition, BNetzA carried out technology neutral auctions for onshore wind and solar power together in the amount of 400MW per year from 2018 to 2020.

In addition to the EEG 2017, the Offshore Wind Farm Act sets out rules for the planning, tendering and approval of offshore wind farms (OWFs). It applies to OWFs in the German exclusive economic zone that commission as from 1 January 2021. 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 Federal Maritime and Hydrographic Agency, instead of the developers in a central planning model, identifies suitable areas for the construction of OWFs, which then are put to tender.
ii Energy efficiency and conservation

Germany is going miss its goal to reduce its emissions by 40 per cent in 2020 compared to 1990. Germany will also miss its goal to reduce gross energy consumption by 20 per cent in 2020 compared to 2008: in 2019, the decline was only 9.6 per cent as compared to 2008. The German government reacted to that by formulating a cross-sector energy efficiency strategy based on the ‘efficiency first’ principle. The Commission for Growth, Structural Transformation and Employment implemented by the German government in January 2019 proposed a gradual phasing out of lignite-fired and coal-fired power plants by 2038. The government introduced its Coal Exit Bill one year later, in January 2020. Furthermore, the government has introduced the Federal Climate Protection Act setting out a sector-specific trajectory regarding energy and emission savings.

iii Technological developments

Driven by the need to store the surplus electricity from renewable energy sources, the installation of power storage facilities, at both household level and 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. In particular, the deployment of hydrogen (from renewable and other sources) has become a focus for government and economic actors recently. Currently, the federal government is developing its hydrogen strategy, which will outline whether and how hydrogen is to be promoted and integrated in the regulatory system.

Although from a low level, e-mobility is also picking up speed. In 2019, however, new registrations of electric vehicles increased by 75.5 per cent compared to 2018. In January 2020, 136,000 electric vehicles were registered in Germany. The government promotes this development by providing public funding beyond 2020 as it plans to have between 7 million and 10 million electric vehicles on the road and 1 million charging points available by 2030. Also, as from 2020, tenants and co-owners in condominiums have the right to instal charging points at their own expense. New or refurbished buildings are to be equipped with cabling infrastructure and, in some cases, charging points.

In relation to smart meters, the EU has set a non-binding target of rollout to 80 per cent of all consumers by 2020. The Act on the Operation of Measuring Points (MsbG), which entered into force in 2016, provides for the introduction of smart meters, including rules on data protection, data access, rollout and financing of the rollout. The rollout is expected to start in 2020. The MsbG establishes maximum price limits for the installation and servicing of the smart meters depending on individual consumption. Provided the maximum price limits are met, the installation of smart meters will be mandatory for consumers with a consumption above 6,000kWh per year. The installation of smart meters for consumers with an annual consumption below 6,000kWh per year is optional. The goal is to complete the smart meter rollout in 2032.

VI THE YEAR IN REVIEW

Although auctions as the basic mechanism to determine the remuneration level for the support of power from renewable sources proved successful in countering a further cost increase when introduced in 2019, some of the tenders for onshore wind and solar had low to no competition during 2019 as it became harder for renewable projects to find available spaces and obtain permits for their projects.
Still, the increased share of intermittent renewable generation continued to put further pressure on the viability of conventional generation facilities. This induced the large German utilities to continue the restructuring and consolidation of their generation portfolios and business models, including the divestment of coal generation units, and, in view of the government plans, to phase out power generation from coal.

In response to the government’s climate protection programme, published in October 2019, which emphasised, inter alia, a stronger role for e-mobility, energy storage and hydrogen, utilities sought collaborations with the market players that have recently entered the scene. These are start-ups promoting new technologies, such as blockchain or e-mobility, and companies from other sectors, such as IT and telecommunications, driving forward the digitalisation of the energy sector.

VII CONCLUSIONS AND OUTLOOK

To ensure that Germany achieves its 2030 climate goals, the government needs to continue its course of climate protection.

The details of the gradual phasing out of power generation from coal are yet to be determined. In particular, the extent of compensation for the operators of hard coal-fired plants is still under debate.

The details of the planned reduction of energy bills for households and enterprises by lowering the EEG surcharge foreseen in the climate protection programme have not yet been implemented either.

Finally, the government will need to remove barriers hampering the deployment of new renewable energy generation. In this regard, the climate protection programme foresees lifting the limitation of solar installations to 52GW in total, increasing the goal for offshore wind capacity to 20GW and lifting barriers for new onshore wind projects (notwithstanding a new general ban on onshore wind projects being erected within less than 1,000 metres of residential buildings).

In the coming years, more and more renewable projects will reach the end of their 20-year remuneration period. For those projects remaining in the market, the sale of their electricity via corporate power purchase agreements (PPAs) may become more attractive. The German market has also begun to see new renewable projects selling their electricity via PPAs. However, this phenomenon is not yet very common as regulatory hurdles persist and prices on the wholesale market remain low.

As of 2021, Germany will introduce a national emission trading system within the transport and heating sector. This system obliges fuel suppliers to buy and surrender emission allowances for the fuels they sell. The details are to be set out in ordinances that have yet to be issued. For example, there must be a mechanism for enterprises that are already subject to the EU-wide emission trading system to ensure that they do not have to pay twice for their emissions.

Although the direct effects of the covid-19 pandemic on the energy landscape are not as obvious as for other areas of the economy, the sector has been affected by a reduction in energy demand and the need to keep the critical infrastructure running. We also expect delays to outstanding legislative projects. If, and to what extent, the government will adjust its climate protection ambitions as a reaction to the economic effects of the covid-19 crisis remains to be seen.
Chapter 10

ITALY

Giorgio Telarico, Mario Cigno and Amalia Serena Scime

I OVERVIEW

The process of liberalising the European energy market started more than 20 years ago, with one of its main purposes being to provide and organise the supply of electricity and gas more efficiently by implementing competitive principles where possible and providing proper regulation where needed.

Since 1996, the European Commission has vigorously promoted the idea of a European single market in the energy sector.2

This represented the start of a long process of opening national wholesale and retail electricity and gas markets to trade and competition across the European market area. As a result, the requirement of adhering to a single market strategy has deeply changed Member States’ national energy systems and policies, and has considerably altered the institutional, organisational and managerial structure of the sector and its regulations.

Since then, the Italian energy market has undergone an extensive liberalisation trend, which is still under way now.

The first step towards the substantial liberalisation of the electricity market in Italy was taken in 1999 when the national Parliament implemented European Directive 96/92/EC through Legislative Decree No. 793 (also called the Bersani Decree) as the relevant transposing act, which has profoundly revolutionised the entire organisation of the Italian electrical supply chain.4
The next step in this long-term process is likely to be the long-awaited complete deregulation of gas and electricity retail prices, which is expected to come into force, after several postponements, in January 2022.

II REGULATION

i The regulators

The main competent authorities that currently determine regulatory policies with respect to the energy sector are the Italian Regulatory Authority for Energy, Networks and the Environment (ARERA, formerly AEEGSI), the Energy Services Manager (GSE), as the parent company of the relative GSE group, the Fund for Energy and Environmental Services (CSEA), the Ministry of Economic Development (MISE) and the Ministry of the Environment, Land and Sea (MATTM).

ARERA is an independent regulatory body for energy markets and integrated water services. Established in 1995, it was entrusted with the task of protecting the interests of users and consumers, promoting competition principles and ensuring efficient, cost-effective and profitable nationwide services in the electricity and gas sectors with satisfactory quality levels through regulatory and control activities.

ARERA’s core regulatory competences include defining and maintaining a reliable and transparent tariff system, reconciling the economic goals of operators with general social objectives, promoting environmental protection and the efficient use of resources, setting the standards for quality of service and defining a framework aimed at protecting and empowering consumers in competitive markets. It also provides a specialist advisory and reporting service to the government and Parliament on the regulated sectors with the possibility of formulating proposals, observations and recommendations for further policy actions.

The effectiveness of ARERA’s regulatory and supervisory measures is ensured by the power to impose administrative sanctions on market operators that do not comply with energy laws or regulations.

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5 In particular, Law No. 124 of 4 August 2017 provided the end of the protection services (i.e., the supply services of electricity and natural gas) with contractual and economic conditions defined by the Regulatory Authority for Energy, Networks and the Environment (ARERA) for small end customers (such as households and small businesses) who have not yet chosen a seller in the free market. Initially, the date to enforce the gas sector’s full deregularisation was 30 June 2015. Instead, with reference to the electricity sector, the date was 30 June 2016. Subsequently, a series of postponements – the second-to-last postponement established July 2020 as the date for both sectors – have slowed down the process, with the final decision of December 2019 again deferring the date to 1 January 2022, as provided in Law Decree No. 162 of 30 December 2019.

6 Autorità di Regolazione per Energia Reti e Ambiente.

7 The Authority for Electricity, Gas and Water System (AEEGSI) was renamed ARERA by Law No. 205 of 27 December 2017 as a result of the regulatory and control functions in the waste cycle attributed to the latter.

8 Gestore dei Servizi Energetici.

9 Created under Italian Law No. 481 of 14 November 1995.
Initially limited to electricity and natural gas, the authority’s scope of action has been extended by some regulatory interventions, which allocated regulatory and control functions over water services, district heating and cooling, and waste cycle, including sorted, urban and related waste.

At the international level, ARERA plays an active part in creating a standardised system of energy regulation and integrating the national electricity and gas markets into a single European market.

Another fundamental energy authority in Italy is the GSE, founded in 1999 as a state-owned company that promotes and supports the use and the efficient management of renewable energy sources (RES) in Italy by means of economic incentives and information campaigns aimed at spreading a culture of environmental protection through energy field operators. Specifically, the GSE fosters sustainable development by providing support for renewable electricity generation – it manages more than 10 incentive mechanisms – and by taking action to build awareness of environmentally efficient energy use. In particular, it uses a series of market tools and mechanisms, such as white certificates and renewable energy for heating and cooling support schemes. In addition, the GSE carries out sector studies, processes statistics on sustainable development and supports public administrations in their energy paths.

The GSE is the parent company of the respective GSE group and, therefore, it guides and coordinates the organisational and operational activities of the other special purpose subsidiaries competent in specific segments of the energy market, such as the Single Buyer (AU), the Energy Market Manager (GME), the Energy Research Body (RSE) and all public interest companies operating in the energy sector.

In particular, the AU’s main purpose is to guarantee the availability of electricity by purchasing the required electrical capacity and reselling it to distributors on non-discriminatory terms. Furthermore, the AU has been appointed as the central oil stockholding entity.

11 More specifically, it participates in the work of the Agency for the Cooperation of Energy Regulators and it is a founding member of the Council of European Energy Regulators. It is the main promoter of the Association of Mediterranean Energy Regulators, of which it holds the permanent vice presidency, and it has a prominent role in the Energy Community Regulatory Board. It also supports the International Confederation of Energy Regulators and, in April 2014, it promoted the launch of the European Water Regulators, a network for cooperation between water sector regulators, of which it has held the presidency since 2015.
12 The Energy Services Manager [GSE] was founded by Legislative Decree No. 79 of 16 March 1999 and it has a central role in the promotion, support and development of renewable energy sources in Italy. In particular, it has been identified by the state to pursue and achieve environmental sustainability through the two pillars of renewable sources and energy efficiency. The Ministry of Economy and Finance owns 100 per cent of its share capital and the Ministry of Economic Development [MISE] sets down the strategic and operational guidelines. Originally, its main competence was the management of the electricity transmission grid. However, in 2005, this function was transferred to Terna S.p.A.; the GSE now specialises in renewable energy and public incentives.
13 Acquirente Unico S.p.A.
14 Gestore Mercati Energetici.
15 Ricerca sul Sistema energetico.
16 See Legislative Decree No. 249 of 31 December 2012 and EU Directive 2009/119/CE.
The GME, on the other hand, organises and manages the electricity, natural gas and environmental markets, in addition to the market for trading daily products, the day ahead auction and intraday auction markets, in compliance with the principles of neutrality, transparency, objectivity and competition. The GME also establishes the conditions for admission and the proper rules for the organisation and functioning of these markets.

The RSE carries out publicly funded national and international programmes in the fields of electrical power, energy and the environment.

The CSEA operates in the electricity, gas and water sectors by collecting the system surcharges paid by the end users from market operators. It also manages the funds through dedicated accounts and subsequently uses them to grant subsidies to businesses based on the criteria set forth by the ARERA.

Last, fundamental functions have been assigned to the MISE and the MATTM. The MISE oversees Italy’s energy policy by defining the strategy and setting out general principles for the organisation and functioning of the renewable energy market. In addition, it has regulatory powers to implement any relevant legislation passed by Parliament from time to time. The MATTM is responsible for climate policy and it co-signs MISE policy measures promoting renewable energy and energy efficiency.

ii Regulated activities

As stated in Section I, when the Bersani Decree came into force, the electricity sector liberalisation process started, which for the first time provided the network’s legal unbundling and provided that the generation, importation, exportation, purchase and sale of electricity were free market activities and therefore not subject to any licence or permit regime. Electricity transmission and dispatching phases, being of national interest, have remained under state control.

17 The environmental markets consist of the energy efficiency certificates market and the market of the guarantees of origin.
18 The Interministerial Prices Committee established the Equalization Fund in 1961 with the mandate to compensate losses due to the unification of electricity prices. The current structure of the Fund for Energy and Environmental Services is the result of the reform enacted by Law No. 208 of 28 December 2015.
19 See, for example, ARERA Resolution No. 921/2017/R/eel of 28 December 2017, as amended by Resolution No. 644/2018/R/eel of 11 December 2018, concerning contributions in favour of energy-hungry enterprises (c.d. imprese energivore).
20 The MISE’s main areas of competence include the national energy budget and strategy, transport networks, energy infrastructures and security of supply, the single market for electricity, promotion of renewable energy and energy efficiency and savings, technology for the reduction of greenhouse gas emissions, peaceful uses of nuclear energy, demolition of dismantled nuclear facilities, the national gas system and market, the downstream oil system and its market (refining, logistics, stocks and fuel distribution), national mining policy, issuing permits for exploration and cultivation of subsoil resources (in particular, hydrocarbons on mainland and under the sea), storage of natural gas and methanisation of southern Italy.
21 Before the Bersani Decree, the activities were mainly in the hands of Ente Nazionale per l’Energia Elettrica [ENEL], which manages the energy sector as a domestic monopolist. Municipal companies operate in those geographical areas not served by the ENEL. At that time, however, horizontal bundling was the norm, with no competition in any segment of the sector. Practically, this meant that customers could not choose their energy supplier in any case.
The aforementioned activities are managed through a concession scheme by the National Transmission Grid Operator (Terna), which handles the national transmission system in a non-discriminatory way, makes decisions on grid development and maintenance actions, and at the same time guarantees the security and continuity of supply to any and all companies requesting it against the payment of an energy transmission tariff. In addition, Terna is entrusted with the management of power flows, interconnections and other ancillary services.

With reference to the gas market, Legislative Decree No. 164 of 23 May 2000 (also called the Letta Decree) implementing European Directive 98/30/CE, established that the activities of importation, exportation, transportation, dispatching, distribution and the sale of natural gas, in whatever form and for whatever use, are free.

Thereafter, a comprehensive common regulatory framework was provided by Law No. 239 of 23 August 2004, which ultimately clarified that the production, importation, exportation, dispatch, purchase, transformation and sale of energy is free, although these activities should be carried out in accordance with public service obligations. Further, it specified that both the transportation and dispatch of natural gas, in addition to the management of energy supply networks, are activities of public interest and, therefore, are subject to public service obligations. Finally, Law No. 239 stated that the distribution of electricity and natural gas, the exploration and production of hydrocarbons and the transmission and dispatch of electricity are all subject to concessions by the competent authorities.

With regard to the development and construction of new facilities and infrastructure (e.g., transmission lines, power plants and gas storage facilities), it has been provided that prior authorisation under state and regional legislation is required to ensure compliance with, among other things, health and safety standards, environmental protection and existing infrastructure.
iii Ownership and market access restrictions

The Italian energy market is open to foreign investors who are subject to the non-discrimination general principle. In particular, the European Energy Charter provides for the general obligation of all Member States to comply with the most favoured nation clause and the national treatment principle with reference to national foreign investments.

Hence, as a general principle, there are no foreign ownership or market access restrictions in Italy. Nonetheless, it should be underlined that in some specific cases – and in particular with reference to mergers and acquisitions deals – national and European antitrust authorities may impose certain limitations or prescriptions to comply with and enforce competition rules.

iv Transfers of control and assignments

To safeguard the assets of companies operating in areas deemed ‘strategic’ and ‘of national interest’, Law Decree No. 21 of 15 March 2012 (converted into Law No. 56 of 11 May 2012 and now amended by Law Decree No. 23 of 8 April 2020 – known as the Liquidità Decree) regulates the special powers that can be exercised by the Italian government in the context of corporate transactions involving strategic sectors such as energy, transport, communications and critical infrastructures, among others.

Specifically, the exercise by the government of special powers in the energy sector is subject to the existence of a ‘threat of serious harm’ to public interests, related to the security and functioning of networks and installations and to the continuity of energy supply.

In particular, the Liquidità Decree establishes that market operators holding strategic assets in the aforementioned sectors should notify the government within 10 days of any relevant corporate decision, resolution, act or transaction.

27 The 1991 Energy Charter, also known as the European Energy Charter, provides the political foundation for the Energy Charter process. The Charter is a concise expression of the principles that should underpin international energy cooperation, based on a shared interest in a secure energy supply and sustainable economic development.

28 In particular, according to Article 10 of the European Energy Charter, each contracting party should afford the investors of other contracting states treatment no less favourable than that afforded to national or foreign investors already present in the territory.

29 On 6 April 2020, the Italian government approved Law Decree No. 23 (known as the Liquidità Decree) concerning several measures aimed at, among other things, granting liquidity to businesses to face the covid-19 emergency. The Decree was published on 8 April 2020 and new provisions apply from 9 April 2020. More specifically, Articles 15, 16 and 17 of the Decree provide some amendments to the Italian government special powers discipline.

30 The powers of intervention granted to the government, which differ from case to case and have to be exercised on the basis of objective and non-discriminatory criteria, consist of the opposition to the purchase of shareholdings, the veto, the adoption of corporate resolutions and the imposition of specific requirements and conditions.

31 Indeed, the Liquidità Decree has established that the ‘golden powers’ of the Italian government are immediately applicable for transactions concerning companies that are engaged in the following industry sectors: (1) critical infrastructure; (2) critical technologies and dual use items; (3) supply of critical inputs; (4) access to sensitive information, including personal data, or the ability to control such information; (5) the freedom and pluralism of the media; and (6) the banking, finance and insurance sectors.

32 Pursuant to Article 1 of Presidential Decree No. 85 of 25 March 2014, the national electricity and gas network infrastructure is considered to be of strategic importance for the purposes of the ‘golden power’ rules. Note that the Liquidità Decree provides an additional notice obligation in case of: (1) resolutions, acts, deeds or transactions of a company that owns assets or relationships in the new sectors listed therein (or in other sectors as may be determined by a decree of the prime minister), if such resolutions, acts, deeds or transactions imply a change of the ownership, change of control, change in the availability of such assets or change of their purpose; and (2) acquisitions of stakes
Within 15 days of notification, the government has the right to exercise its ‘golden powers’ in the form of vetoes or conditions whenever the notified operation is assessed to represent an exceptional threat to national interests.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

To ensure impartiality, competitiveness, transparency and to avoid a concentration of activities in the management and development of the energy infrastructure network, the European Union adopted – as one of its main regulatory instruments – a new unbundling regime on vertically integrated energy network operators. In particular, new rules were introduced on unbundling for transmission system operators (TSOs) and for distribution service operators (DSOs).

The unbundling regime for TSOs has been implemented in national law by means of Legislative Decree No. 93 of 1 June 2011, which first adopted the independent transmission operator model and imposed the independence of the electricity TSO (Terna) from companies operating in the generation, distribution and sale of energy, and Law Decree No. 1 of 24 January 2012 converted into Law No. 27 of 24 March 2012, in which the ownership unbundling model was adopted to enact the functional separation between ENI S.p.A. and SNAM S.p.A. with reference to the natural gas market.

Since electricity and gas distribution is an activity reserved by the state and regulated as a natural monopoly, it is granted to eligible companies only under concession.

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33 Should no special power be exercised within the said term, the operation is to be deemed tacitly authorised.
35 The regime comprises legal, accounting, information, functional and even ownership unbundling obligations.
36 With reference to TSOs, the Electricity and Gas Directives provide for a new unbundling regime with the following three models: (1) the ownership unbundling model, which requires a full separation of electricity transport activities (including both the ownership and management of electricity transportation infrastructures) from the production and sale of electricity; (2) the independent system operator; and (3) the independent transmission operator. Member States are free to opt for one of the three models, which are on an equal footing in the Directives.
37 The Electricity and Gas Directives provide that where the DSO is part of a vertically integrated undertaking the basic elements of the unbundling regime are as follows: (1) legal unbundling of the DSO from other activities of the vertically integrated undertaking not related to distribution; (2) functional unbundling of the DSO to ensure its independence from other activities of the vertically integrated undertaking; (3) accounting unbundling: requirement to keep separate accounts for DSO activities; and (4) possibility of exemptions from the requirement of legal and functional unbundling for certain DSOs.
38 In addition, in 2015, ARERA set out detailed obligations of vertically integrated companies in terms of unbundling (functional ownership separation) and debranding (brand and communication separation) between distribution and sale or other lines of business: see ARERA Resolution No. 296/2015/R/com of 22 June 2015.
39 In the electricity sector, tenders should start no earlier than 2030 because the concessions issued on 31 March 2001 will remain in force until 31 December 2030. In the gas sector, in most geographical areas, public tenders have not been launched or have been delayed.

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While the first section of the electricity grid (i.e., long-distance transmission at high voltage as stated above) is now managed by a single operator (Terna), a public tender for the concession of the distribution service to a single DSO in each minimum geographical area of the Italian territory is to be held in turn.

ii Transmission/transportation and distribution access

In the sphere of energy, when dealing with energy transmission and distribution access, the third-party access (TPA) concept applies. Indeed, it refers to the right granted to gas and electricity producers, energy suppliers and their customers, allowing them to make use of, and have their energy traded and transported through, electricity grids and gas pipelines that are owned or controlled by other network operators, providing that TPA does not affect the continuity and safety of the transmission and distribution service.

The TPA principle was first implemented in the national electricity system by ARERA, which adopted the Consolidated Text of Active Connections, in which the detailed technical and economic conditions for TPA to transmission and distribution networks were set forth. Second, non-discriminatory TPA rules are to be found in the Italian Grid Code, introduced by Terna with reference to the National Transmission Grid.

With regard to the gas sector, similar regulatory instruments can be found in the Network Type Code and the SNAM Network Code.
iii Rates

The pricing mechanism covering rates relating to the transmission and distribution of electricity and gas is established and updated annually by ARERA.\(^{47}\)

The pricing regulation on electricity transmission, distribution and metering for the period 2016–2023 was adopted by the authority on 23 December 2015\(^{48}\) in compliance with the price cap method.\(^{49}\)

The electricity transport tariff covers the costs for electricity transmission on the National Transmission Grid, while the distribution tariff is related to the costs for electricity transportation over the distribution network; both tariffs are applied to all end customers with the exception of low-voltage households.\(^{50}\)

With regard to the gas market, in March 2019, ARERA outlined the pricing criteria for the rates of transportation and dispatching of natural gas for the period 2020–2023.\(^{51}\) In addition, a separate tariff regulation for gas distribution and metering was issued in 2020 for the period 2020–2025,\(^{52}\) differentiated between six tariff areas.

iv Security and technology restrictions

One of the most important quality factors in the security of the electricity supply is the continuity of service (i.e., the lack of interruptions).\(^{53}\) For this reason, before 31 March each year, companies must provide ARERA with continuity of service data for the previous year (i.e., information on the number of interruptions and their duration).\(^{54}\)

Regulation of the quality of the natural gas transportation service in terms of security, continuity and commercial quality for the period 2020–2023 is governed by Resolution No. 554/2019/R/gas of December 2019.

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\(^{47}\) The mechanism is based on a balance between the interests at stake (network maintenance, promotion of investments, safety and efficiency of the network, environmental protection and accessible costs for customers).


\(^{49}\) Price cap regulations set a cap on the price that the utility provider can charge. The cap is set according to several economic factors, such as the price cap index, expected efficiency savings and inflation.

\(^{50}\) The electricity transport tariff consists of a component expressed in euro cents/kilowatt-hours and a component expressed in euro cents/kilowatts of committed power. The latter applies only to high-voltage or very high-voltage consumers, while the distribution tariff has a trinomial structure and is expressed in euro cents per pickup point per year (fixed fee), euro cents per kilowatt per year (power fee) and euro cents per kilowatt-hour consumed (energy fee).


\(^{52}\) See ARERA Resolution No. 570/2019/R/gas.

\(^{53}\) See ARERA Resolution No. 653/2015/R/eel of 23 December 2015, concerning the quality of electricity transmission in the regulatory period 2016-2023. Distribution companies must ensure the continuous running of the service and/or they must restore it in a reasonable time when there is a problem. To ensure the smooth running of the service, distribution companies must carry out regular maintenance of the relevant network components.

\(^{54}\) See Article 2.20 of Law No. 481 of 14 November 1995 and ARERA Resolution No. 646/2015/R/eel of 22 December 2015.
In addition, other additional security measures will be taken in accordance with provisions set forth in the European Programme for Critical Infrastructure Protection.\textsuperscript{55} To face the new challenges arising from smart grid infrastructure and cyberattacks, in 2018, Italy transposed into national law the Network and Information Security Directive.\textsuperscript{56}

IV ENERGY MARKETS

i Development and regulation of energy markets

The GME operates the power, gas and environmental markets.\textsuperscript{57} It runs the Italian Power Exchange (IPEX), the venue for transactions involving the wholesale sale and purchase of electricity, gas and energy efficiency certificates, in a neutral, transparent, objective, competitive and non-discriminatory way.

Electricity market

The electricity market was set up in Italy in 1999\textsuperscript{58} and it is managed on the basis of a specific discipline\textsuperscript{59} governing market functioning, trading and settlement rules, operator participation and disciplinary procedures in the event of misconduct. This regulatory framework was updated by the Ministerial Decree of 12 December 2019.

The electricity market is structured in a spot electricity market\textsuperscript{60} and a forward physical market.\textsuperscript{61}

\textsuperscript{55} ‘European critical infrastructure’ means critical infrastructure located in EU Member States, the disruption or destruction of which would have a significant impact on at least two EU Member States. To reduce the vulnerabilities of critical infrastructures, the European Commission has launched the European Programme for Critical Infrastructure Protection. This is a package of measures aimed at improving the protection of critical infrastructure in Europe, across all EU Member States and in all relevant sectors of economic activity.

\textsuperscript{56} See Legislative Decree No. 65 of 18 May 2018 and EU Directive No. 1148 of 6 July 2016. In the gas and electricity sectors, all supply, distribution, transmission and storage operators are considered operators of essential services and are therefore subject to the obligations established by the Network and Information Security Directive.

\textsuperscript{57} As part of the liberalisation process of the electricity sector, the Energy Market Manager [GME] was initially vested with the organisation and economic management of the wholesale power market. It was also tasked with a specific role in market monitoring and setting up specific provisions to monitor the power market in Italy, reinforced by the provision included in Regulation (EU) No. 1227/2011 on wholesale energy market integrity and transparency.

\textsuperscript{58} As a result of the aforementioned Bersani Decree.

\textsuperscript{59} On 19 December 2003, the MISE approved the Integrated Text of the Electricity Market Rules. This discipline was drawn up by the GME and approved by the MISE, after consultation with the ARERA.

\textsuperscript{60} The spot electricity market consists of a day-ahead hourly auction market, a daily products market, the venue for trading daily products with delivery obligations, and an intraday auction market based on seven sessions. It also operates on behalf of the Italian TSO Terna a platform for ancillary services, through which it collects the bids and communicates the results, and a platform for the registration of over-the-counter [OTC] transactions (OTC Registration Platform or PCE).

\textsuperscript{61} Where forward electricity contracts with delivery and withdrawal obligations are traded.
**Gas market**

With the enforcement of Law No. 99 of 23 July 2009 on the development and internationalisation of companies and energy matters, the GME was exclusively entrusted with the organisation and economic management of natural gas markets and associated services.\(^62\)

GME gas markets include the gas trading platform (also known as P-GAS),\(^63\) the wholesale gas market (also known as MGAS),\(^64\) where the GME acts as the central counterparty to the transactions concluded by operators, and the platform for the allocation of regasification capacity (also known as PAR).

**Environmental market**

The GME is directly involved in the implementation of environmental policies by organising and managing environmental markets consisting of the energy efficiency certificates (also called white certificates) market and the guarantee-of-origin market.

Moreover, Legislative Decree No. 249 of 31 December 2012 tasked the GME with developing, organising and managing a market platform for the trading of mineral oil logistic services, as well as collecting mineral oil storage capacity data.\(^65\)

### ii Contracts for the sale of energy and market developments

At the wholesale level, energy transactions may be carried out either in the context of organised markets managed by the GME or over the counter.\(^66\)

At the retail level, since 2003 (gas)\(^67\) and 2007 (electricity),\(^68\) consumers are free to choose their own energy provider. Nonetheless, if they do not choose, by 1 January 2022 the free market will be the only available option and they will be subject to the contractual and economic conditions defined by ARERA.

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\(^{62}\) On 6 March 2013, the MISE approved the Integrated Text of the Gas Market Rules. See the Ministerial Decree dated 6 March 2013, as amended by the GME on 8 February 2019, following ARERA Resolution No. 612/2018/R/gas.

\(^{63}\) When gas quotas of parties subject to the obligations of Article 11 of Law Decree No. 7/2007 are bid, and when investors participating in virtual gas storage may fulfil their obligation to bid the gas quantities made available by the virtual storage operators associated with them.

\(^{64}\) When parties authorised to carry out transactions at the virtual trading point may make forward and spot purchases and sales of volumes of natural gas.

\(^{65}\) With a view to fostering the development of competition in the sector, the same Legislative Decree also established that the GME should set up, organise and operate a platform for the wholesale trading of liquid oil products for the transport sector.

\(^{66}\) In this case, the transaction is to be registered on the PCE, where it will be checked for consistency with the transmission constraints on the National Transmission Grid.

\(^{67}\) See Legislative Decree No. 164 of 23 May 2000.

\(^{68}\) See Law No. 239 of 23 August 2004.
V  RENEWABLE ENERGY AND CONSERVATION

i  Development of renewable energy

In line with the global trend of using RES as the basis for power generation, Italy has experienced and is currently experiencing a substantial increasing trend in renewable energy development projects.69

One of the most notable improvements in the renewable energy industry is the development of the National Energy Strategy (NES)70 presented by the MISE and the MATTM in 2017, which sets clear and ambitious goals: reduce energy costs, meet environmental targets, strengthen the security of energy supply and foster sustainable economic growth.71

Moreover, among the main operative documents of the NES is the Integrated National Energy and Climate Plan for 2021–2030 (NECP),72 a comprehensive environmental action plan presented by the Italian government to the European Commission on 31 December 2019, in which Italy sets new ambitious targets to further increase the share of renewable energy.

With regard to RES promotion, the government has strongly supported renewable energy projects with a range of economic incentive schemes that have not only favoured RES plants over traditional thermoelectric plants in many contexts (such as priority dispatch), but also have simplified administrative procedures for the construction and operation of RES plants.73

At the current stage of the market, the incentives are no longer in place and the operators are targeting grid parity. To achieve this, producers and offtakers (and eventually banks financing grid parity initiatives) are evaluating a workable scheme of long-term power purchase agreements (PPAs).

In this regard, the RES Decree (as defined below) has expressly opened a consultation phase to implement PPAs in Italy, as is further explained below (see ‘Economic incentives’).

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69 Italy, which already produces more than 35 per cent of its electricity from renewable sources, is one of the leading countries in the transition toward renewable power systems.

70 The main objective of the National Energy Strategy [NES] is to evolve Italy’s national energy system to make it more competitive, more sustainable and more secure.

71 The targets of the NES’ latest edition (2017) include: (1) reducing final energy consumption by a total of 10 MtoAe by 2030; (2) reaching a 28 per cent share of renewables in total energy consumption by 2030, and a 55 per cent share of renewables in electricity consumption by 2030; (3) strengthening supply security; (4) narrowing the energy price gap; (5) furthering sustainable public mobility and eco-friendly fuels; and (5) phasing out the use of coal in electricity generation by 2025.

72 According to the Governance of the Energy Union and Climate Action Rules, which entered into force on 24 December 2018, Italy, alongside all EU Member States, was required to develop integrated national energy and climate plans that cover the five dimensions of the energy union for the period 2021–2030 (and every subsequent 10-year period) and submit it by 31 December 2019 to the European Commission. The Integrated National Energy and Climate Plan [NECP] was created by a team of policymakers and technicians drawn from the Ministry of the Environment, Land and Sea [MATTM], the GSE, the MISE, ENEA (National Agency for New Technologies, Energy and Sustainable Economic Development), the Ministry of Infrastructure and Transport, the Energy Research Body, the ARERA, ISPRA (Higher Institute for Environmental Protection and Research) and Polytechnic University of Milan.

73 Indeed, the authorisation, certification and licensing procedures applicable to plants and associated transmission and distribution network infrastructures are simplified and proportionate.
**Simplified administrative procedures**

**Unique regional authorisation procedure**

To pursue the aim of speeding up renewable energy development projects, Legislative Decree No. 104 of 16 June 2017\(^{74}\) has provided the unique regional authorisation procedure (PAUR), which should be initiated when projects are subject to an environmental impact assessment (EIA) under regional competence.

The PAUR allows an applicant to obtain in the context of a comprehensive single procedure all the authorisations, concessions, licences, opinions, clearances and assents needed to implement and execute the project (including the EIA and the single authorisation, as described below – see ‘Single authorisation’), that are therefore ‘absorbed’ and encompassed therein.

Thus, the applicant will submit the PAUR request by attaching the relevant project description and documentation with a list of all authorisations needed\(^ {75}\) to proceed with the project’s execution.

A significant issue related to the PAUR concerns the identification of the competent authority, with some conflict of competence involving regions and provinces.\(^ {76}\)

**Single authorisation**

As stated above, PAUR encompasses the single authorisation.\(^ {77}\)

Nonetheless, these authorisations are generally issued by the region concerned (or by the MISE for power plants with capacity equal to or greater than 300MW), pursuant to a unified proceeding of all the authorities involved in the project.\(^ {78}\)

If the project has nominal power greater than 1MW, it is subject to an EIA or a pre-screening procedure, in which case single authorisation cannot be issued until this procedure has been completed.

**Simplified authorisation procedure**

Another simplified administrative procedure provided to accomplish the easier and faster development of RES project objectives is the simplified authorisation procedure.

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74 See Legislative Decree No. 104 of 16 June 2017, which introduced Article 27-bis into Legislative Decree No. 152 of 3 April 2006 concerning the unique regional authorisation procedure [provvedimento autorizzatorio unico regionale – PAUR].

75 Within 15 days of submission of the application, the competent authority will notify the administrations and bodies concerned that the documentation has been published on the website. Within 30 days of publication of the documentation, the competent authority, as well as the administrations and bodies concerned, will verify the adequacy and completeness of the documentation. Following this verification, the notice to the public is published on the website. The 60-day period for public consultation begins once the notice is published.

76 For example, in certain Italian regions, such as Puglia, a regional law implementing PAUR national discipline has not yet been adopted, causing uncertainty with regard to the identification of the authority (i.e., the region or the province) competent to deal with the PAUR.

77 Provided by Legislative Decree No. 28/2011.

78 The period to complete the single authorisation procedure will not exceed 90 days. In any case, the latter 90-day period is extended if an environmental impact assessment is needed. Essentially, the single authorisation procedure brings together all stakeholders, enabling the economic operator to obtain all necessary authorisations, permits and clearances through a single procedure, thus saving time and, consequently, speeding up investments. See Legislative Decree No. 387/2003.
This latter applies to the construction of small plants with low generation capacity (such as photovoltaic plants on building roofs). The procedure is managed by the competent municipality, which should be notified by the building owner with a declaration and a detailed technical description of the project at issue.  

_Free construction – simple communication regime_

The construction of certain small-scale installations generating energy from RES is exempt from building permit obligations and is thus subject to a simple notification to the municipality, which should contain the works commencement notification and a detailed project report.

_Economic incentives_

Another significant development in the promotion of renewable energy is represented by a series of legislative acts providing economic incentives for developers of RES projects.

The Ministerial Decree dated 4 July 2019 concerning the ‘Incentives for the electricity produced by onshore wind, solar photovoltaic, hydroelectric and gas plants’, which became effective on 10 August 2019 and intended to cover the following three-year period (the RES Decree), is an important contribution.

The RES Decree provides for the promotion of electricity production from plants powered by renewable sources through the promotion of effectiveness, efficiency and sustainability.

The RES Decree divides the plants that can access the incentives into four groups based on their type, their renewable energy source and the size of the projects – Groups A, A-2, B and C – and provides two operative ways to access the incentives depending on the power of the plant and the group to which it belongs: application to the registers or to the auction procedures.

The RES Decree established that the incentives are to be paid on the net electricity produced and fed into the grid by the plant.

An important aspect to be underlined when dealing with the RES Decree is its contribution to the development of PPAs. Indeed, the RES Decree provides that the GME

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79 The declaration should be submitted at least 30 days before starting construction activities. The application is authorised via tacit acceptance. Work can commence 30 days after submission if the municipality has issued no replies or notices.

80 There is no requirement to wait 30 days before starting work. Construction activities can start immediately after the communication has been submitted.

81 Auctions are typically held on the last day of March, June and October each year.

82 There are two different incentive mechanisms, depending on the power of the plant: the all-inclusive tariff, consisting of a single tariff corresponding to the due tariff, which also remunerates the electricity drawn by the GSE; and an incentive, calculated as the difference between the due tariff and the regional hourly price of the energy, as the generated energy remains at the operator’s disposal.

83 A power purchase agreement [PPA] is a long-term electricity supply agreement between two parties. Usually, the PPA is executed between an electricity producer (seller) and an electricity consumer or distributor (buyer). PPAs set out in detail all the terms and conditions for the sale and purchase of electricity, including the volume of electricity to be supplied, the prices negotiated, the balance between production, consumption and penalties for breach of contract. As a bilateral agreement, the PPA may take various forms and may be adapted to the parties.
must enact a regulatory framework for the creation of a market platform for long-term trading to be set up within 180 days of its entry into force; the GME will begin a public consultation aimed at collecting input for the implementation of the platform. 84

The aim is to promote the trading of production by newly constructed renewable energy plants that are entirely reconstructed or reactivated, upgraded or refurbished, which started operating after 1 January 2017 and have not benefited from energy production incentives. Non-economic forms of support are provided for, such as the classification of the plants (by the GSE), the removal (by ARERA) of any regulatory barriers and an update of the guarantee of origin regulations, to enable its direct cancellation by end users.

The operators will be able to use the platform (and any sample agreement eventually adopted by Italian regulators) on a voluntary basis.

ii Energy efficiency and conservation
Within the framework provided by the European Union, 85 Italy has established its own energy efficiency strategy, which is based, among other things, on the following.

Energy efficiency certificates
Projects with the aim of increasing energy efficiency may be eligible to obtain energy efficiency certificates (also known as white certificates).

White certificates are tradable instruments that give proof-of-end-use energy savings that electricity and gas distributors with more than 50,000 customers are required to achieve. The scheme aims to support the production of thermal energy from renewables and high-performance cogeneration units, as well as small-scale interventions of energy efficiency for private persons and public administrations. They are issued by the GME under an authorisation granted by the GSE and they may be sold or bought in the energy efficiency certificates market or bilaterally.

A white certificate scheme has been provided in Italy by the Ministerial Decree dated 20 July 2004, subsequently amended by the Ministerial Decrees of 21 December 2007, 28 December 2012 and 11 January 2017, with the latter determining the national quantitative targets for increasing energy efficiency for the period 2017–2020.

Notably, a new incentive scheme covering the forthcoming three-year period has not yet been adopted. We expect to see further legislative development in the following months clarifying how white certificate mechanisms will be dealt with from 2021.

Thermal energy account
The thermal energy account 86 encourages projects with the aim of increasing energy efficiency and related to the production of thermal energy from renewable sources for small plants. The beneficiaries are mainly public administrations, but also include companies and individuals, who have access to funds of €900 million per year.

84 Preliminarily, PPAs are expected to contribute at least an additional 0.5 terawatt-hours of renewable energy per year.
At the national level, the main rules on energy efficiency can be found in Legislative Decrees No. 102 of 4 July 2014 and No. 115 of 30 May 2008.
86 See the Decree issued on 16 February 2016 by the MISE in agreement with the MATTM and the Ministry of Agriculture.
The National Fund for Energy Efficiency
The National Fund for Energy Efficiency87 supports energy efficiency measures carried out by companies, including energy service companies, and the public administration on buildings, plants and production processes. It also promotes the involvement of national and EU financial institutions and private investors on the basis of adequate risk sharing.

iii Technological developments
One of the main objectives pursued by environmental bodies and authorities is to create a resilient energy system that remains reliable through short-term and mid-term climate situations and that is able to continually evolve, even in long-term situations.

To accomplish this aim of smarter energy infrastructure, it is vital to promote the development of micro grids and smart grids88 to encourage high-efficiency self-generation in urban communities and industrial districts, with due regard to the security of the system.

Following this path, the MISE has established a state aid programme dedicated to investments for the construction of intelligent electricity distribution networks,89 which is valid until 31 December 2020.

Nonetheless, other technological developments, which are still under way in Italy and are related to the evolution of smarter energy networks, are connected to the electric vehicles charging infrastructure system.

To ensure the security of energy supply, promote smarter and renewed energy infrastructures and foster the use of a wide variety of primary energy sources, the Italian government, implementing the Alternative Fuels Infrastructure Directive (AFID)90 by means of Law Decree No. 257 of 16 December 2016, has set forth minimum requirements for the construction of a charging infrastructure for the development of alternative fuels and the establishment of charging stations for electric vehicles and for vehicles that use natural gas, hydrogen and liquefied petroleum gas.

In particular, the decree mandates the establishment of a National Strategic Framework for the development of an alternative fuels market in the transportation sector and the creation of related infrastructures.

With regard to the supply of electricity for transportation, in particular, the Law Decree establishes that, before 31 December 2020, an adequate number of charging stations accessible to the public will be created throughout the country to facilitate urban and suburban transportation services in highly populated areas. Furthermore, specific incentives are established for the installation of charging stations for electric vehicles for the supply of hydrogen used for road transportation and the supply of natural gas and liquefied petroleum gas.

87 See Article 15 of Legislative Decree No. 102/2014 and Ministerial Decree dated 22 December 2017.
88 Essentially, smart grids are energy networks that can automatically monitor energy flows and adjust to changes in supply and demand accordingly.
89 See the Ministerial Decree dated 19 October 2016.
90 Directive 2014/94/EU of the European Parliament and of the Council of 22 October 2014 on the deployment of alternative fuels infrastructure [AFID]. The AFID recommends introducing a minimum level of infrastructure for charging electric vehicles across the European Union (approximately one public recharging point for every 10 vehicles) and giving consideration to wireless charging and battery swapping. Furthermore, the AFID aims to make information about the location of recharging points more easily available and to help standardise their technical specifications. It also recommends that recharging points use intelligent metering systems that recharge batteries from the electrical network at times of low general electricity demand and that, in the long term, recharging points also allow vehicles to feed power from the batteries back into the network.
gas. These incentives allow individuals, companies and condominiums to access a new tax deduction of 50 per cent on a maximum of €3,000, in 10 equal annual instalments, for the purchase and installation costs of electric vehicle chargers from 1 March 2019 to 31 December 2021.

VI CONCLUSIONS AND OUTLOOK
During the past decade, Italy has experienced an impressive increase in renewable energy projects and has proven itself to be one of the leading EU Member States in integrating large volumes of variable renewable generation, even overcoming the target set by the European Union and the Italian legislature for 2020.

As has been stated, with the submission of the NECP to the European Commission, more challenging and ambitious goals have been set, by increasing the 2030 target figures for renewable energy and energy efficiency. However, the adoption of the NES and the NECP is only a first step towards achieving the ambitions of the national government, which must carefully monitor future implementation and maintain momentum.

Nonetheless, in the following months, further and new developments are expected to be seen following the final transposition of the 2018 Energy Efficiency Directive, providing measures that will accelerate the rate of building renovation towards more energy-efficient systems and strengthen the energy performance of new buildings, making them smarter.

92 See EU Directive No. 2018/844/EU of 30 May 2018. Note that the transposition deadline was set for 10 March 2020 but, because of the covid-19 emergency, the transposition process has been slowed down.
I OVERVIEW

Japan is a country with limited natural energy resources and, as such, energy legislation can essentially be divided into that concerning electricity and gas, respectively.

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, both in 2011, government energy policy has been undergoing vast and rapid structural change. As of 23 March 2020, all but six nuclear power plants are currently under suspension in Japan and 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. First, 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. Second, the legal unbundling of the electric power transmission function and sector from the existing dominant power suppliers was implemented on 1 April 2020. In addition to these two changes, feed-in tariffs (FITs) were introduced in 2012 and the renewable energy market has expanded rapidly since then. In response, the FIT system has been continuously revised to address several problems.

The gas industry in Japan can be divided into 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.
II REGULATION

i The regulators

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 METI 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 Electricity and Gas Market Surveillance Commission.

The Organization for Cross-regional Coordination of Transmission Operators (OCCTO) is an independent organisation constituted by all the electricity business entities pursuant to the Electricity Business Act (EBA). 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. 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 government 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, 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 regards 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, 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, 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 in 2011, the Japanese government decided to undertake significant reform of the energy regulation system. 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 just three 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 OCCTO. Then an application document must be filed with 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 comply with 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 24 March 2020, 646 entities are registered as retail companies.

Following the liberalisation of electric power generation and of retail sectors, there are new plans for electricity fees. The liberalisation has also led to promotion of further competition among electricity suppliers, fairness between consumers, and development of the electric power market.

Electricity generation business

Companies that generate and supply electricity in excess of 10,000kW to retail companies are required to register with the METI to commence their generation business. They are also required to apply for membership of OCCTO before filing their registration. 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 and distribution 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 and distribution, transmission and specific transmission and distribution 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.

The most prominent of the companies in these three categories are general transmission and distribution companies. These are business entities providing electricity wheeling services through their own transmission lines throughout their service area. Those intending to engage in the general transmission and distribution 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 meeting demand. To gain approval, the company must submit a 10-year plan, as do companies in the other two above-mentioned categories.

A transmission company supplies the electricity to general transmission and distribution 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 and distribution companies, which transmit electricity to a specific point, are only required to notify the METI.

OCCTO

The three types of electricity business entities are all required to be a member of OCCTO to allow the organisation to monitor and coordinate the whole electricity market. Members of OCCTO have to provide information about the amount of electricity produced by their facilities continuously. OCCTO can instruct its members to maintain a balance of electricity supply and demand in the market to ensure a 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 (called the Gas System Reform). This amendment implements full liberalisation of entry into the gas retail business, which accounts 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 comply with certain
negative requirements, including the lack of ability to procure gas to meet 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 1 April 2020, the number of town gas retail business operators was 1,334. 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 Toho 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, as of 1 April 2017, companies that generate town gas are required to register with the METI.

**Town gas transportation business**

Under the new regulation, a town gas transportation business is categorised in one of two subcategories under the new GBA: general gas transportation business or specific gas transportation business. A general gas transportation business is one that transports gas through its gas pipeline throughout its service areas. 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. A specific gas transportation business is one that transports gas through its gas pipeline to a specific point. Only notification to the METI is required 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 in line with 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 the necessary registration for the sale of LPG must be obtained from the METI when intending to establish sales offices serving 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 2019, the number of business operators that had obtained the necessary registrations and were currently engaged in the sale of LPG was 17,805. 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 approximately one-third 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 (or, if the shares are listed in a financial instruments exchange, 1 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 to carry out an electric power or a 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 any such activities. Furthermore, in the event of the performance of any such activities requiring advance notification to the relevant authorities, a follow-up report after the performance must also be submitted. 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 for, or an order to suspend, a foreign investment, if it hinders national security, public policy 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 and distribution company, or of a merger or demerger whereby the surviving entity completely absorbs any such business. The criteria for granting this approval are the same as those for the original grant of approval to operate this type of business. 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 this type of business. Only post facto notification is required for transfer of the business or merger or demerger of a town gas-related business (i.e., town gas retail business, town gas generation business or 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 required to notify only the METI or the prefectural governor, whichever is relevant.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Electric power

Integrated system for the production and transmission of electric power

Between the end of World War II and until 1995, the production and transmission of electric power in Japan, and its assorted related retail operations, were run as a single integrated utility by 10 electric power companies, each with a regional monopoly over one of the country's 10 main regions.

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, antitrust 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 was passed in 2015, the aim being 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 from 1 April 2020, unless otherwise permitted by the METI. That means that the 10 former general electricity utilities, except for Okinawa Electric Power Company, are required to split those departments to an affiliate or others by that date.

The main obligations and areas of concern for general transmission and distribution companies regarding separation and unbundling are:

a development of a system for information management;
b rules concerning company names, trademarks and advertising;
c entrustment and undertaking by these companies;
d rules concerning transactions among group companies; and
e restrictions on directors and employees holding concurrent positions.

Regarding the development of a system for information management, general transmission and distribution companies are required to be physically separated from generation and retail group companies (i.e., being located on different floors with restricted entry) when they share the same building, as well as identifying and limiting access to information systems if the systems are shared. In addition, they are required to develop their own business status monitoring and surveillance systems.
Companies are generally restricted from using company names and trademarks that are likely to be associated with those of generation and retail group companies. They are also prohibited from advertising to take advantage of the generation and retail business of other group companies.

Regarding entrustment and undertaking by general transmission and distribution companies, these companies are in principle prohibited from entrusting their services to their own subsidiary companies. In exceptional cases, they may do so if the subsidiary companies are not under the control of generation or transmission companies. In addition, general transmission and distribution companies are in principle prohibited from undertaking the services of generation and retail group companies. However, in exceptional cases where the undertaking of these services does not impair the competitive relationships among electricity suppliers, the services may be undertaken.

Transactions among group companies are allowed to the extent that the transactions do not impair the competitive relationships thereof.

Directors of generation and retail business group companies are generally prohibited from acting as directors of general transmission and distribution group companies concurrently. In exceptional cases, a concurrent position may be held provided the holding of such a position does not impair the competitive relationships between the businesses. Further, this restriction also applies to any employee who has an important role in either of the group companies.

Obligations undertaken by general transmission and distribution 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 and distribution 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 and distribution companies must also provide final assurances to deliver electricity to any consumers who do not have a contract with any of the retail companies. General transmission and distribution relationship 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 crucial 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 criteria for CII operators will be clarified. It is clear that electricity business entities, especially general transmission and distribution 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. Under the EBA, an entity that installs electric facilities for business use must maintain those electric facilities to ensure that they conform to certain
technical standards. According to the guidelines for security of electric power control systems and smart meter systems, that entity is required, among other things, to install a security operations organisation, develop management systems and implement training.

**Independent electric power grid**

Two approaches are under consideration as methods to secure a stable supply of electric power in the event of a disaster. First, the introduction of a remote distributed grid that is independent from the main electric power grid, rather than maintenance of the current grids of electricity transmission and distribution, will enable the cost-effective provision of electric power and will reinforce disaster resistance in some rural areas. Second, outside rural areas, a micro electric power grid could connect with the main electric power grid at ordinary times, but then work independently from the main electric power grid in the event of a disaster. In addition, permitting new business operators to engage in the electricity distribution business will be required in some specific areas. The requirements of the electricity distribution business and the associated cost burdens are under discussion.

**Aggregator licence**

The introduction of a licence for aggregators under the EBA is under discussion as a way to aggregate the electric power resources and make it possible to connect more electric resources in the event of a disaster. Also under discussion are the cybersecurity of aggregators, the protection of consumers relating to electricity measurement, the scope of the regulation and the content of the obligation.

**ii Gas**

**Terminating, processing and treatment**

After importation, liquefied natural gas (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, transporting and storing 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 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 with 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 Toho 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 gas transportation companies
Since gas pipelines are dominantly owned and operated by a few operators, including the above-mentioned three major players, 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. Further, the terms and conditions of these contracts and amendments are required to be approved in advance by the METI.

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 established 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, green power selling transactions, non-fossil value transactions, indirect power transmission right transactions and base load 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 and, as of 1 April 2020, 184 companies were trade affiliates. The spot market is open every day of the year. The JEPX has also 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 has been explained, 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 (those allowed to retail electricity at low voltage market before the liberalisation) to continue to provide the existing terms and conditions for the time being to ensure that the price of electricity price does rise 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 under 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

In addition to the market for trading electric power commodity on the JEPX, OCCTO is preparing to set up an auction system to trade the capacity to generate electricity in the future, to be called the capacity market. The first auction is expected to be held by the end of March 2021. It is expected that, at the auction, electricity generation business operators will submit bids for the capacity to generate electricity four years after the auction and OCCTO will pick the operators and fix the price of electricity to secure the capacity to generate electricity four years after the auction and then pay the consideration to the operator. The amount of the consideration to be paid by OCCTO to the operator will be borne by electricity retail business operators, who will be required to contribute to OCCTO to fund that amount. In addition, OCCTO is preparing to set up a new market by the end of March 2022, to be called the supply–demand adjustment market. The trading in this market will be of adjustment power, namely the supply capacity used to match supply and demand for 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 launched an electricity future market on 17 September 2019.

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 on 30 April 2015 and has developed during the past five years. Following the first listing of an infrastructure fund on 2 June 2016, six additional infrastructure funds have been listed on the market. These all 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 been subject to huge developments in the area of renewable energy. The Act on Special Measures concerning the Procurement of Renewable Energy Sources by Electric Utilities (the Renewable 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 for a fixed term). The Renewable Energy Act became effective on 1 July 2012 and the FIT scheme has been amended several times since then to address certain issues (see ‘Increase in renewable electric energy generation and associated problems’ below). 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.
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 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.

Execute a power purchase agreement with one of the general transmission companies or the specific transmission companies for a renewable energy generation facility with the above-mentioned certification. These transmission companies are obliged to accept an offer by a generator to execute a power purchase agreement, unless certain exceptions are applicable.

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 the price of solar panels, the sales price is falling (as discussed further below). In comparison, measures have been taken to establish favourable pricing and to support investment in respect of offshore wind power and existing head race tunnel-type medium and small-scale hydroelectric power generators. A bid system, which was newly adopted in 2017, is applicable to facilities with (1) solar power of 250kW 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 2020.

<table>
<thead>
<tr>
<th>Power source</th>
<th>Installed capacity</th>
<th>Sales price (excluding tax)</th>
<th>Contract term</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biomass*</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>&lt;200kWh</td>
<td>¥13 to ¥39 depending on the material used</td>
<td>¥13 to ¥40 depending on the material used</td>
<td>¥13 to ¥40 depending on the material used</td>
</tr>
<tr>
<td>≥200kWh</td>
<td>¥21</td>
<td>¥21</td>
<td>¥21</td>
</tr>
<tr>
<td>&lt;1000kWh</td>
<td>¥14</td>
<td>¥14</td>
<td>¥14</td>
</tr>
<tr>
<td>≥1,000kWh</td>
<td>¥14</td>
<td>¥14</td>
<td>¥14</td>
</tr>
<tr>
<td>&lt;5,000kWh</td>
<td>¥14</td>
<td>¥14</td>
<td>¥14</td>
</tr>
<tr>
<td>≥5,000kWh</td>
<td>¥14</td>
<td>¥14</td>
<td>¥14</td>
</tr>
<tr>
<td>Existing head race† tunnel-type medium and small-scale hydroelectric</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>&lt;200kWh</td>
<td>¥25</td>
<td>¥25</td>
<td>¥25</td>
</tr>
<tr>
<td>≥200kWh</td>
<td>¥21</td>
<td>¥21</td>
<td>¥21</td>
</tr>
<tr>
<td>&lt;1000kWh</td>
<td>¥14</td>
<td>¥14</td>
<td>¥14</td>
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<tr>
<td>≥1,000kWh</td>
<td>¥14</td>
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<tr>
<td>&lt;5,000kWh</td>
<td>¥14</td>
<td>¥14</td>
<td>¥14</td>
</tr>
<tr>
<td>≥5,000kWh</td>
<td>¥14</td>
<td>¥14</td>
<td>¥14</td>
</tr>
<tr>
<td>Geothermal</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>&lt;15,000kWh</td>
<td>¥40</td>
<td>¥40</td>
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<tr>
<td>≥15,000kWh</td>
<td>¥26</td>
<td>¥26</td>
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<tr>
<td>Hydroelectric</td>
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<td></td>
</tr>
<tr>
<td>&lt;200kWh</td>
<td>¥34</td>
<td>¥34</td>
<td>¥34</td>
</tr>
<tr>
<td>≥200kWh</td>
<td>¥29</td>
<td>¥29</td>
<td>¥29</td>
</tr>
<tr>
<td>&lt;1,000kWh</td>
<td>¥24</td>
<td>¥24</td>
<td>¥24</td>
</tr>
<tr>
<td>≥1,000kWh</td>
<td>¥24</td>
<td>¥24</td>
<td>¥24</td>
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<tr>
<td>&lt;5,000kWh</td>
<td>¥24</td>
<td>¥24</td>
<td>¥24</td>
</tr>
<tr>
<td>≥5,000kWh</td>
<td>¥24</td>
<td>¥24</td>
<td>¥24</td>
</tr>
<tr>
<td>Power source</td>
<td>Installed capacity</td>
<td>Sales price (excluding tax)</td>
<td>Contract term</td>
</tr>
<tr>
<td>------------------------------------</td>
<td>--------------------</td>
<td>-----------------------------</td>
<td>---------------</td>
</tr>
<tr>
<td>Solar</td>
<td>&lt;10kWh</td>
<td>¥37</td>
<td>¥37</td>
</tr>
<tr>
<td></td>
<td>≥10kWh &lt;50kWh</td>
<td>¥32</td>
<td>¥29</td>
</tr>
<tr>
<td></td>
<td>≥50kWh &lt;250kWh</td>
<td>¥32</td>
<td>¥29</td>
</tr>
<tr>
<td></td>
<td>≥250kWh &lt;500kWh</td>
<td>¥32</td>
<td>¥29</td>
</tr>
<tr>
<td></td>
<td>≥500kWh &lt;2,000kWh</td>
<td>¥32</td>
<td>¥29</td>
</tr>
<tr>
<td></td>
<td>≥2,000kWh</td>
<td>¥32</td>
<td>¥29</td>
</tr>
<tr>
<td>Wind</td>
<td>&lt;20kWh</td>
<td>¥55</td>
<td>¥55</td>
</tr>
<tr>
<td></td>
<td>≥20kWh</td>
<td>¥22</td>
<td>¥22</td>
</tr>
<tr>
<td>Offshore wind power** (floating type)</td>
<td>¥36</td>
<td>¥36</td>
<td>¥36</td>
</tr>
<tr>
<td>Offshore wind power (bottom-mounted type)</td>
<td>¥36</td>
<td>¥36</td>
<td>¥36</td>
</tr>
</tbody>
</table>

* Excluding biomass power generated by certain wood or agricultural products with a capacity of 10MW or more and biomass power by biomass liquid fuel, which are subject to a bid system.
† Existing head race tunnel-type medium and small-scale hydroelectric power: generators that utilise existing headrace tunnels with renewable electric power equipment and hydraulic steel pipes.
** Offshore wind power: generators that require a vessel for access for construction and operational maintenance.
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 (in million kWh).

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar (&lt;10kWh)</td>
<td>485,686.0</td>
<td>578,017.8</td>
<td>648,628.4</td>
<td>711,688.7</td>
<td>782,689.5</td>
<td>674,397.8</td>
<td>523,661.8</td>
</tr>
<tr>
<td>Solar (≥10kWh)</td>
<td>425,466.9</td>
<td>1,317,731.0</td>
<td>2,459,108.0</td>
<td>3,454,952.2</td>
<td>4,261,477.4</td>
<td>3,892,502.2</td>
<td>3,192,577.0</td>
</tr>
<tr>
<td>Wind</td>
<td>489,638.3</td>
<td>492,082.3</td>
<td>523,259.9</td>
<td>586,179.9</td>
<td>616,665.7</td>
<td>476,081.2</td>
<td>268,898.7</td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>93,552.6</td>
<td>107,277.2</td>
<td>147,632.9</td>
<td>200,787.3</td>
<td>245,829.7</td>
<td>224,511.5</td>
<td>185,774.1</td>
</tr>
<tr>
<td>Geothermal</td>
<td>570.9</td>
<td>608.1</td>
<td>5,881.1</td>
<td>7,620.2</td>
<td>10,126.9</td>
<td>9,132.5</td>
<td>21,574.6</td>
</tr>
<tr>
<td>Biomass</td>
<td>316,940.0</td>
<td>364,438.0</td>
<td>539,014.4</td>
<td>736,506.5</td>
<td>1,024,778.2</td>
<td>890,802.2</td>
<td>714,917.8</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>1,811,854.7</td>
<td>2,860,154.4</td>
<td>4,323,524.7</td>
<td>5,697,734.8</td>
<td>6,941,565.4</td>
<td>6,167,427.4</td>
<td>4,907,404.0</td>
</tr>
</tbody>
</table>

However, problematic businesses, such as those that used favourable pricing to obtain facility certification from the METI but delayed commencement of work and attempted to obtain fraudulent profits, have been frequently reported. In response, the Renewable Energy Act was amended to introduce a deadline for renewable energy projects to reach the commercial operational stage (the COD deadline).

Under the amendment, if an operator fails to meet the COD deadline, the commencement of the FIT period starts from the day following the COD deadline and the project will not be able to use the full FIT period (for example, one month’s delay triggers a one-month deduction from the FIT period). The project will thus directly incur a loss as a result of the delay in commencement. To be specific, the COD deadline shall be:

- with the exception of projects described in point (c), three years for solar power projects with an output capacity of 10kW or more;
- with the exception of projects described in point (e), four years for wind power, biomass power and geothermal heat projects;
- five years for solar power projects requiring an environmental impact assessment;
- seven years for hydroelectric power projects; and
- eight years for wind power projects and geothermal heat projects requiring an environmental impact assessment.

The COD deadline applies to solar power projects that execute a grid connection agreement or receive certification from the METI on or after 1 August 2016, and other renewable energy projects that receive certification by the METI on or after 1 April 2018.

On 5 December 2018, a new regulation was enforced on pre-operation of solar power projects, for which the certification from the METI is issued during the period from April 2012 to March 2015 and to which the COD deadline does not apply because a grid connection agreement was executed before 31 July 2016. Under the new regulation, (1) an application for the start of grid connection construction (GCCA) to a utility should be received by the utility by 31 March 2019 and (2) operation shall commence by 31 March 2020 (or, if the GCCA is received after 31 March 2019, one year after the GCCA is received by the utility).

On 25 February 2020, an amendment to the Renewable Energy Act was submitted to, and is being discussed by, the Diet. The proposed amendment includes more a straightforward
measure against problematic projects, that is to say revocation of certification from the METI when operation does not commence for a certain period to be decided by the METI after the certification is issued.

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 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 yet to be fully resolved.

**Environmental impact assessment**

The Environmental Impact Assessment Act (EIAA) applies to projects of 7.5MW or more for wind power projects, of 112.5MW or more for biomass power projects, and of 7.5MW or more for geothermal power projects. Furthermore, the EIAA was amended to cover solar power projects of 40MW or more (and solar power projects of 30MW or more, depending on the case) and came into force on 1 April 2020. After the amendment, a survey, forecast and evaluation of the possible environmental changes caused by implementation of a project must be prepared. It takes a considerable time to complete this process and the assessment process could be a considerable burden on solar power projects that are subject to environmental impact assessment.

In addition, some local governments maintain their own environmental impact assessment rules and often require the securing of various permits and licences, depending on the applicable circumstances.

**Enactment of the Re-Energy Area Usage Act**

As Japan is an island nation, marine renewable energy businesses such as offshore wind power generation have been regarded as key businesses from the perspective of energy policy. However, there was no law providing for unified rules for long-term occupancy of general sea areas that are Japanese territories and inland waters. This had been an obstacle to commencing such businesses in these sea areas. To address this issue, on 30 November 2018, the Act on Promotion of Utilisation of Sea Areas for the Development of Marine Renewable Energy Generation Facilities (the Re-Energy Area Usage Act) was passed by the Diet and came into force on 1 April 2019. The Re-Energy Area Usage Act allows for the long-term use of certain designated general sea areas for the purpose of offshore wind renewable energy projects upon approval by the government agency, and is expected to promote these types of projects.

**Gas**

In terms of gas-related renewable energy, biogas has been generating a lot of interest 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 and promoted the purchase of biogas. Additionally, several local governments have begun to produce biogas in a sewage facility or refuse disposal facility.
VI  THE YEAR IN REVIEW

The electric power industry regulations have witnessed great reforms since the events at Fukushima in 2011. 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, has been 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 and for biomass power generation of a certain type and certain size.

As has been explained, 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 Toho Gas) will be unbundled.

No remarkable trends in renewable energy have been seen. The number of new solar projects is decreasing as the sales price has fallen. Wind power projects, and offshore wind power projects in particular, are receiving increased attention, although it remains to be seen whether wind power projects will be popular.

VII  CONCLUSIONS AND OUTLOOK

The events at Fukushima in 2011 served as the main catalyst for the recent reforms within the electric power industry. The full extent of these reforms and their effects, however, remains to be seen. As of 31 March 2020, all but six of the 48 nuclear power stations in Japan are stopping operations. The Nuclear Regulation Authority issued new nuclear power station safety standards in July 2013 and, as of 23 March 2020, 11 nuclear power stations are in the process of review for restart under the new safety standards (14 stations have already passed this review). 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, namely 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. Ultimately, Japan’s energy requirements may push it in the direction of renewable energy sources such as those discussed. However, the output from these energy sources is substantially smaller than that of 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.
Chapter 12

LEBANON

Carlos Abou Jaoude, Souraya Machnouk, Hachem El Housseini, Rana Kateb and Chadi Stephan

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 of the country’s 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 ageing 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 in recent years has exacerbated this crisis.

The energy sector 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 the 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 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 Center for Energy Conservation (LCEC), the MOEW launched a number of tenders for solar and wind energy projects.

1 Carlos Abou Jaoude is managing partner, Souraya Machnouk is a partner and Hachem El Housseini, Rana Kateb and Chadi Stephan are senior associates at Abou Jaoude & Associates Law Firm.

2 The Lebanese Center for Energy Conservation is an independent government organisation operating under the supervision of the Ministry of Energy and Water.
Although 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 reform in the long term.

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, 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 launch 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.

To identify the environmentally and archaeologically sensitive areas offshore from Lebanon and the existing marine conditions, an environmental baseline survey was conducted between March and April 2019 by a specialist scientific vessel by taking samples and video recordings from Lebanese deep waters covering bloc No. 4 and bloc No. 9. The environmental impact assessment study for petroleum activities was conducted by Total on bloc No. 4, in line with Lebanese regulations, and was approved by the Ministry of Environment in February 2020.

As per an international tender, the drillship Tungsten Explorer, owned by the company Vantage Drilling, was contracted to start drilling activities in bloc No. 4. The drillship reached Lebanese waters on 25 February 2020. Drilling activities have started in the Lebanese exclusive economic zone (EEZ), for the drilling operations of the first exploration well within bloc No. 4. Scheduled to last approximately 60 days, the aim of this drilling phase is to evaluate the possible presence of hydrocarbons.

On 4 April 2019, the Council of Ministers approved the launch of the second offshore licensing round for hydrocarbon exploration. The deadline for submission of applications for the second offshore licensing round for hydrocarbon exploration was initially set for 31 January 2020. The deadline was later postponed until 30 April 2020. Given the implications of the spread of the coronavirus worldwide, the deadline to submit applications for the second offshore licensing round has been extended to 1 June 2020.

Regarding onshore hydrocarbon resources, a draft law is still being discussed at the level of parliamentary commissions.

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3 An exploration well does not allow the production of hydrocarbons. However, it verifies their presence and allows the collection of essential information, such as pressure, temperature, permeability, composition of the geological layers and nature of the fluid within the rocks. The data collected during this stage will validate, or not, the presence of hydrocarbons.

4 Minister of Energy and Water’s Decision No. 1/M dated 10 June 2019.

5 Minister of Energy and Water’s Decision No. 10 D/M dated 10 January 2020.

6 id.
A draft hydrocarbon policy is currently being developed by the LPA, and will ultimately be subject to the approval of the Council of Ministers.

At the time of writing, Lebanon is facing the worst economic and financial crisis in its history, coupled with severe political instability since the nationwide civil protests of October 2019. In March 2020, Lebanon defaulted for the first time on its sovereign debt (Eurobonds). The national currency, the Lebanese pound, is officially pegged to the dollar but has witnessed a massive devaluation owing to an acute US dollar shortage in the country. Banks are applying intensive unofficial capital controls and rationing deposit withdrawals and external transfers. The covid-19 outbreak has only exacerbated the situation.

These exceptional circumstances have halted and stalled most of the MOEW’s plans and projects. There is no visibility at this stage of the current status and fate of the targets and deadlines falling in 2020 that feature in this chapter.

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:

a 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;

b proposing the comprehensive rules for the organisation of services relating to the production, transmission and distribution of electrical energy and the supervision of execution activities;

c proposing draft laws and decrees relating to the electricity sector;

d proposing general safety conditions, environmental conditions and technical specifications applicable to electrical installations and equipment, provided that the same are issued by virtue of a decree issued by the Council of Ministers upon the competent minister’s proposal after consulting the competent authorities;

e entering into the necessary contacts with other countries aimed at establishing electrical interconnections and exchanging electrical energy, and ratification of the necessary contracts following parliamentary approval; and

f 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 rights and interests of consumers.

The OPRL vested various prerogatives relating 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 are backed by the LPA’s technical advice and recommendations.

The Council of Ministers approves the state’s petroleum policy and all decrees relating 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 by 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 future hydrocarbon wealth. The LPA’s goal is to ensure a successful, transparent and sustainable development process for all petroleum activities, in concert with various government bodies, international organisations and civil society.

The main laws and regulations governing hydrocarbons in Lebanon are:

1. the OPRL dated 24 August 2010;
2. Decree No. 9438 dated 4 December 2012, appointing the LPA;
3. Law No. 163 dated 18 August 2011, identifying and delineating the marine zones of Lebanon;
4. Decree No. 6433 dated 1 October 2011, governing and delineating the Lebanese EEZ;
5. Council of Ministers Decision No. 41 dated 27 December 2012, opening the first offshore licensing round for hydrocarbon exploitation;
6. Decree No. 9882 dated 16 February 2013, on the pre-qualification of companies;
7. 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;
8. Decree No. 42 dated 19 January 2017, on the delineation of maritime blocs;
9. 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;
10. Petroleum Tax Law No. 57 of 12 October 2017; and
11. Council of Ministers Resolution No. 32 dated 14 December 2017, granting two petroleum licences over bloc No. 4 and bloc No. 9 and mandating the MOEW to sign the corresponding exploration and production agreements, in accordance with the OPRL provisions.

### ii 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 more than 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. EDLs

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⁸ Decree No. 16878 of 1964, Article 1.
capacity to generate electricity stands at approximately 1,800MW, leaving a gap in 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.

To ensure equality and competition, Law 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 462.

Although Law 462 entered into force in 2002, the privatisation process and the formation of the NRESO have not yet been implemented for various reasons, mostly political. The long-awaited Law No. 48 regulating public-private partnerships (the PPP Law), which was enacted on 7 September 2017, applies to government and municipality projects such as infrastructure projects, and 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. Since the NRESO has not yet been established, 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 requires the performance of petroleum activities to be licensed. The term ‘petroleum activities’ encompasses planning, preparation, installation and implementation of 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.

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10 id., at Article 1.
The OPRL also provides that the Council of Ministers awards exclusive authorisation 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.11

iii Ownership and market access restrictions

There are no major ownership and market access restrictions in the energy sector. However, EDL has a monopoly on the market, controlling approximately 90 per cent of the electricity generating capacity in Lebanon, save for the few above-mentioned concessions.

There have been instances in which 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 to compensate for the shortage in the electric supply resulting from the lack of proper maintenance of existing plants. The two power ships 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 each day.

The transmission of electrical energy remains exclusive to EDL, but it is possible, through a decree issued 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.

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 (currently the Council of Ministers) and provided that the transfer or assignment conforms with Law 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:

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;

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11 As per the specific provisions of the draft exploration and production agreement enacted by virtue of Decree No. 43 dated 19 January 2017.
12 Law No. 462 of 2002, Article 23.
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 the company; and

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.\footnote{Offshore Petroleum Resources Law, Article 70, entitled Transfer or Assignment of a Petroleum Right.}

Finally, the OPRL\footnote{id., at Article 40, entitled Sale of Petroleum.} provides that the conditions for the sale or transfer of any interest in petroleum shall be set out in a Decree issued by the Council of Ministers.

### III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

#### i Vertical integration and unbundling

As has been stated above, the Lebanese electricity sector is monopolised by EDL, which currently controls more than 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 with the aim of a partial liberalisation of the electricity sector. 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 relating to the design, implementation, operation and maintenance of a distribution network with the customer and metering services. This is encouraging for private entities to invest increasingly in the Lebanese electricity sector.

In relation to natural gas, there is no market regulation yet; the only relevant instrument issued to date 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 liquefied natural gas (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 the sale or distribution of LNG.

#### 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.\footnote{Law No. 462 of 2002, Article 5.}

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.\(^{16}\)

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 all distribution is executed according to the laws and contracts ratified by the government, to remedy any defects in the electricity sector’s activities that may negatively affect the sector’s interests or the rights and interests of consumers. 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 issued by the Council of Ministers upon the competent minister’s proposal after consulting the competent authorities.\(^{17}\)

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, 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 interests of bodies or persons residing in Israel.

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), record the name of any company breaching the provisions of the Israel Boycott Act on a blacklist and prohibit any dealings with that company.

IV ENERGY MARKETS

i Development of energy markets

Law 462 was expected to liberalise the sale and distribution of electricity in Lebanon and create a competitive free market for electricity. The NRESO, which 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 462 is fully implemented, the supply and sale of energy remains primarily controlled by EDL. Some

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\(^{16}\) Decree No. 16878 of 1964, Article 8.

\(^{17}\) Law No. 462 of 2002, Article 6.
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 have 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, until 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 electricity produced in this way remains the sole right of EDL.

In relation to natural gas, no markets have been developed or regulated yet.

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 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. This Law introduces a new legal regime, replacing the traditional procurement processes, which suffered from weak transparency, competitiveness and accountability standards. It renames and grants the High Council for Privatisation and PPP the authority to evaluate potential PPP projects. The PPP Law stipulates the main mandatory provisions that must be included in any PPP agreement.

On 30 April 2019, the Lebanese Parliament enacted Law No. 129 which allows the contracting by the government of agreements with respect to the design, financing, construction, production, operation and transfer to the government of power plants, according to conditions to be set by the MOEW. Consequently, the MOEW issued an invitation for conventional power plants to be classified as IPPs, whereby applicants can be classified as lead developers or consortium members for the design, engineering, construction, financing, testing, commissioning, operation and maintenance of conventional power plant projects, and the sale of the capacity and electrical energy to the MOEW under a long-term power purchase 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 EEZ.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

There is an obvious trend to increase the level of 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 use 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 (the CEDRO Project) in 2007, with an initial budget funded by the government of Spain to enhance the national energy strategy by contributing to achieving renewable energy projects.

Further, the LCEC works closely with the MOEW by putting in place 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 instigated two consecutive four-year action plans, known jointly as the National Energy Efficiency Action Plan (NEEAP).18 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 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.

The following projects have already been implemented using renewable sources that are connected to the grid via EDL:

a Wind energy: Lebanon is 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 between 50MW and 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

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18 The National Energy Efficiency Action Plan is based on the requirements of the League of the Arab States and in line with a format used by the European Union.
bid round to build additional wind farms for a total capacity of between 200MW and 400MW. The electricity generated by the wind farm will be sold to EDL by means of offtake agreements.

b 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, was part of the NEEAP to instal 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 declared its plan to instal around 30MW of solar farms for the public sector by 2020. In 2017 and 2018, the MOEW launched two consecutive bids for 12 and 24 PV farms, respectively (of between 10MW and 15MW each). A further bid was launched for three PV farms (of between 70MW and 100MW each) to include for the first time electricity storage of 70MW/70MWh. The development of PV farms is becoming more appealing, especially with the decrease in prices of related solar installations, the decentralisation of PV farms and the growing involvement of the private sector.

c Water energy: although 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,19 which will include a 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. The expected generation from hydroelectric sources by 2020 was approximately 300MW.

d 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 with the UNDP as part of the CEDRO Project were reinstated in the NREAP 2016–2020, as the Ministry recognised 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 regards 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 energy conservation legislation, the Renewable Energy and Energy Conservation Law, which sets the legal framework for implementation of the NREAP and addresses production by the private sector of electricity from renewable energy, the management of energy supply and demand, and the computation of renewable energy.

19 The construction of the 300ft high Janna Dam was suspended in May 2016, but was later resumed despite local ecological and environmental warnings and concerns.
tariffs. The proposed Law also covers topics relating 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 foregoing, a series of initiatives are being carried out with respect to the development of smart technologies in respect of energy demand management. The launching by EDL of the advanced metering infrastructure, comprising the installation by three private distribution service providers of smart meters across the Lebanese territory, is expected to provide energy efficiency in terms of monitoring and synchronisation of wide area networks. A wider pilot project is now being carried out in some Lebanese regions to test the responsiveness of the Lebanese network, whereas the smart metering system is fully applicable to some key institutions and establishments, such as shopping malls and schools, in some regions.

VI THE YEAR IN REVIEW

There is an urgent national momentum to implement the action plans for the electricity sector, particularly in the context of the contemplated bailout by the International Monetary Fund (IMF) to help ease Lebanon’s unprecedented financial crisis. The preliminary IMF recommendations include eliminating electricity subsidies, which is an area flagged as the most significant potential expenditure saving. This would involve raising tariffs to close EDL’s financial deficit as soon as possible to generate fiscal savings, possibly targeting the largest consumers first.

A 10-year reform plan proposed by the 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 involved 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 target has been reached for Beirut, while the electricity supply in other regions varies between 16 and 20 hours a day depending on the supply capacity of the grid. 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 constant 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 was met with scepticism and controversy, with challengers alleging its high cost factor, lack of transparency and the expectancy that it would result in a significant increase in electricity tariffs.
I OVERVIEW

Power generation in Malaysia has historically been reliant on fossil fuel such as cheap regulated natural gas and coal. Up to 2010, the country’s reliance on natural gas as an energy source steadily increased, and at the end of that year, natural gas accounted for 71,543 ktoe of the 106,794 ktoe of all 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 (LSS) projects, which were awarded in 2017 and 2019. As of 2018, the country’s energy grid generation mix has comprised 29.4 per cent natural gas, 45.9 per cent coal, 7.8 per cent fuel oil and diesel, and 16.9 per cent renewable resources, of which 15.7 per cent was comprised of hydropower, the remainder being sourced from biodiesel, geothermal, solar energy, biomass and biogas. In 2018, Malaysia announced that it had set a target of 20 per cent renewable energy in its generation mix by 2025.

The national electricity 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 case by case.

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1 Fariz Abdul Aziz is a partner and Karyn Khor is a senior associate at Skrine.
2 ktoe = thousand tonnes of oil equivalent.
3 PricewaterhouseCoopers, ‘The Malaysian Oil & Gas Industry: Challenging times, but fundamentals intact’ (May 2016).
5 Wood Mackenzie, ‘Malaysia power and renewable markets long-term outlook 2019’ (June 2019).
II REGULATION

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 are as follows:

a Electricity Supply Act (ESA) 1990;
b Environmental Quality Act 1974;
c Factories and Machinery Act 1967;
d Gas Supply Act 1993;
e Occupational Safety and Health Act 1994;
f Petroleum and Electricity Control of Supplies Act 1974;
g Petroleum Development Act 1974;
h Petroleum (Safety Measures) Act 1984; and

The legislation listed above also requires compliance with the regulations, orders, rules and other sub-legislation made thereunder. The most relevant of these are as follows:

a Efficient Management of Electrical Energy Regulations 2008;
b Electricity Regulations 1994;
c Gas Supply Regulations 1997;
d Licensee Supply Regulations 1990;
e Petroleum Regulations 1974;
f Renewable Energy (Feed-In Approval and Feed-in Tariff Rate) Rules 2011;
g Renewable Energy (Renewable Energy Power Purchase Agreement) Rules 2011; and

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 rules, guidelines or directives in respect of their regulatory sphere.

There are multiple regulatory authorities in Malaysia overseeing the various segments of the energy sector. The Commission is the primary regulator of the energy and gas supply in Peninsular Malaysia and Sabah. The Commission is empowered with the following functions, inter alia:

a to advise the Minister of Energy, Science, Technology, Environment and Climate Change (the Minister) on all matters concerning national policy objectives for energy supply activities;

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6 On 1 September 1990, legislative powers in respect of energy laws in the state of Sarawak were delegated to the local state authority.

7 The regulation of energy and electricity in the state of Sarawak is under the purview of Sarawak Energy Berhad, known as the Sarawak Electricity Supply Corporation prior to privatisation. Additionally, Sarawak has its own state laws for environmental protection and occupational health and safety.
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;

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;

to promote the use of renewable energy and the conservation of non-renewable energy; and

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.\(^8\)

The Commission reports to the Malaysian Ministry of Energy, Science, Technology, Environment and Climate Change (MESTECC) 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 Section V). 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 Bhd (PETRONAS),\(^9\) and a PETRONAS licence is required to operate a business to process or refine petroleum, or to market or distribute petroleum or petrochemical products.\(^10\)

In April 2018, the Commission implemented a single buyer regime by establishing an entity known as the Single Buyer, which would be responsible for managing the procurement of electricity and related services in Peninsular Malaysia, which includes scheduling, procurement and settlement, and registration under the Commission’s Single Buyer rules.

More recently, Sarawak, a state in east Malaysia, has developed a regulatory role in gas distribution within the state via Petroleum Sarawak Bhd (PETROS).

### ii Regulated activities

#### The 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.\(^11\) There are two main types of licences issued under the ESA (ESA licences):

a licenses 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

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9 Petroleum Development Act 1974, Section 2.
10 id., at Section 6.
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 any 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-transferable 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 (for example, the Guidelines for Single Buyer Market (Peninsular Malaysia)) and those of the Grid Code Operator. The Commission may attach other terms and conditions to the licence as it sees 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 impose any ownership or equity limitations on the applicant, typically, limitations are set out in the terms and conditions of licences and other regulatory approvals, or may be contained in the provisions of the power purchase agreements (PPAs) signed between the independent power producers (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 Section V.i) 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 a renewable energy project and to enable the operator 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 into the renewable energy market. The Commission has stated that any company that requires a bank 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.

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12 id., at Section 9(4).
13 However, the Energy Commission’s Guidelines on Large Scale Solar Photovoltaic Plant For Connection to Electricity Networks do prescribe a 49 per cent foreign equity limit for large-scale solar plant projects.
14 Commission Guidelines on Application for a Provisional Licence.
Generation and supply of gas via pipelines (for private utilities and supply 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. Prior to 2016, there were only two types of licences for the supply of piped gas in Peninsular Malaysia:

a. private gas licence – allowing its holder to supply and use piped gas on its own premises (e.g., restaurants); and

b. gas utility licence – allowing licence holders to supply gas via pipelines to third parties for their use.

Historically, industrial consumers of gas were only able to source gas from PETRONAS and for power producers, this requirement was embedded under the terms of the relevant PPAs. However, as part of the Tenth Malaysia Plan and the country’s New Energy Policy, the government has opened up the gas supply market 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 to liberalise the downstream gas markets. Following these amendments, the Third Party Access System (the TPA System) has been implemented during the past two years in all states in Malaysia except Sarawak, whereby new suppliers can bring liquefied natural gas into Malaysia via the regasification terminals for later distribution to Malaysian buyers. The TPA System was implemented with the aim of permitting third parties to have access to and manage gas distribution networks and promoting competition in Malaysian gas markets. Recently, TNB Fuel Services Sdn Bhd took delivery of the very first gas shipment under the TPA System from Shell Malaysia Trading Sdn Bhd at a price that is below the regulated gas price. The gas will be used as fuel for TNB’s Tuanku Jaafar Power Station in Port Dickson and Connaught Bridge Power Station in Klang.

To participate in the TPA System, interested parties must obtain the relevant licence, or licences, from the following list, depending on the activity to be carried out:

a. distribution licence;
b. import into regasification terminal licence;
c. private gas licence;
d. regasification licence;
e. retail licence;
f. shipping licence; or
g. transportation licence.

Save and except for private gas licences and any other circumstances as may be determined by the Commission, an entity may only hold one licence at any particular time. The tariff for utilisation of gas facilities will be determined by the Commission, but TPA System licensees will be able to negotiate gas prices with buyers on a willing-buyer willing-seller basis, albeit the government retains the right to regulate the price of gas to retail customers as necessary to protect consumer interest.

To obtain a licence under the GSA, the applicant must:

a. be a Malaysian-incorporated company or, if incorporated outside Malaysia, must be approved by the Commission;

15 Section 1(3), Gas Supply Act 1993.
meet the minimum paid-up capital stipulated by the Commission (this ranges from 1 million to 5 million ringgit and depends on the type of licence being applied for);

c not already hold any other GSA licences, and the applicant’s directors must not hold any directorships of other GSA licence holders or applicants;

d have sufficient financial capability;

e have sufficient relevant technical capability; and

f comply with such other additional requirements or licence-specific requirements as may be set by the Commission from time to time.17

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 importing gas into a regasification terminal).18 Licences granted under the GSA are not transferable or assignable without the written consent of the Commission or the Minister.19

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 to enable it to organise and supervise the national gas distribution network.20

Other licences, certifications and approvals

The above-mentioned licences relate to the construction of power plants and power installations, and to the 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 Safety and Health 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 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 Bumiputera21 equity in an applicant company).

Certain 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 matters that are ancillary, but nonetheless essential, to any party interested in entering the Malaysian energy market.

19 id., at Section 11B(4).
20 id., at Section 11A.
21 The term ‘Bumiputera’ or ‘Bumiputra’ is used to describe Malays and the indigenous peoples of Malaysia.
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 electricity grid that supplies power in Sabah is operated by Sabah Electricity Sdn Bhd (SESB), a company owned partly by TNB and partly by the Sabah state government, whereas the grid in Sarawak is owned by SESB, which is fully owned by the Sarawak state government. 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 mixture of local and foreign power producers and a competitive bidding system for power plant projects.

Regarding gas, several licences have already been issued by the Commission under the GSA since the implementation of the TPA System. A full list of licensees is available at the Commission’s official website. The notable new licence holders who have come into play since the TPA System was established include the gas distribution company Gas Malaysia Bhd, which was established by PETRONAS to supply and distribute gas throughout Malaysia. Gas Malaysia operates and maintains the Peninsular Gas Utilisation pipeline system and its subsidiaries, Gas Malaysia Distribution Sdn Bhd and Gas Malaysia Energy and Services Sdn Bhd, have successfully obtained gas distribution and shipping licences, respectively, from the Commission. Sabah Energy Corporation Sdn Bhd (SEC) operates and maintains the gas distribution pipelines in Sabah, in east Malaysia.

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 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 a notice of request from the licensee.

iii Rates

The Commission is empowered to determine the tariffs for both electricity and gas under the ESA and the GSA, and to issue guidelines for tariffs and charges, including the methodology, principles or categories of tariffs and charges, and the duration for the imposition and review of tariffs and charges.

Electricity prices are regulated by the Malaysian government, via the Commission. Similarly, the tariffs for gas supply are vetted and approved by the Commission.

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22 Mohamed Ridza and Co, Malaysia chapter in The International Comparative Legal Guide to Oil & Gas Regulation 2017 (ICLG, 4 January 2017).
23 Electricity Supply Act 1990, Sections 24 and 25.
24 Gas Supply Act 1993, Section 14, subject also to Section 15.
iv Security and technology restrictions
In the case of a lockout, strike or other emergency, or if the constitutional monarch of Malaysia (the Yang di-Pertuan Agong) decides that public interest so requires, he may authorise the Commission to suspend an ESA licence or take temporary possession of any power installation or gas pipeline, and operate it in a manner that the Commission sees fit. Alternatively, 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 the GSA have similar information security provisions, requiring the holder of either an ESA or a GSA licence to be 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 that 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 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, which is sold to the Single Buyer unit of TNB (in Peninsular Malaysia), Sarawak Energy (in Sarawak) and the SESB (in Sabah). The single-buyer units 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 Kertih is the largest by capacity. Captive power is nonetheless a marginal contributor to Malaysia’s total energy generation capacity. The Commission also introduced a New Enhanced Dispatch Arrangement (NEDA) system in 2015, 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 introduced a system by which energy generators bid against each other daily on variable operating rates, according to the rules set by the Commission, with the aim of the increased competition driving down energy prices. NEDA was fully launched in June 2017 and in May 2019, the guidelines were updated to include ‘solar power producer’ as a new category of NEDA participant. The government announced in December 2017 that notwithstanding the implementation of NEDA, 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

25 Electricity Supply Act 1990, Section 52A and Gas Supply Act 1993, Section 37G.
recorded instances in which 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.  

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 in which 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. 

There have also been developments in renewables projects. In February 2019, the government announced its third 500MW LSS power project tender (LSS3). There were more than 100 bids in the tender for the project, with offer prices ranging from 0.17 to 0.58 ringgit per kilowatt hour. Five companies were shortlisted by the Commission. They are expected to commence operations online by 2021.

ii  Energy market rules and regulations

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 earlier in this chapter) also authorise the generator to sell energy. Energy is sold to consumers at fixed tariff rates, which are approved by the government. Notwithstanding Malaysia’s policy of privatisation, which was announced in 1988 by the then Prime Minister of Malaysia, Mahathir Mohamad, 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, historically, 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 end consumers. IPPs do not enter into contracts with individual consumers, save in highly exceptional circumstances (for instance, if the power is generated by a captive plant, to provide power to users who do not have access to the national power grid).


Historically, all gas 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 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) 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 government also maintains that it has the power to determine gas prices and will do so when it deems it necessary to protect the consumer’s interests.30

However, as of late 2019, the Commission has announced that for the purpose of implementing the government’s energy policy, Malaysia Electricity Supply Industry 2.0 (MESI 2.0) and the liberalisation of Malaysia’s power industry, the Commission will no longer approve IPP projects that are tied to PPAs. (See Section VI for more information about MESI 2.0.)

iv Market developments

Net Energy Metering

Under the Net Energy Metering (NEM) scheme, energy produced from the solar photovoltaic (PV) system will be consumed first, and any excess is to be exported and sold to the appropriate distribution licensee (such as TNB for Peninsular Malaysia or the SEC for Sabah and Labuan). The NEM programme was introduced with the intention of replacing the feed-in tariff (FiT) mechanism for solar PV installations, which was closed at the end of 2017.

The scheme is executed by MESTECC, regulated by the Commission, with SEDA as the implementing agency. To participate in NEM, applicants must register as customers of distribution licensees in Peninsular Malaysia, Sabah and Labuan. Foreign entities also are eligible to apply as long as they are customers of the distribution licensees. The resources for producing electricity shall be from solar PV only; however, other renewable energy resources, such as biogas, biomass or micro hydro, may be allowed case by case, at the sole discretion of the Commission.31

The scheme is applicable to all domestic, residential, commercial (including government buildings) and industrial sectors, subject to the capacity limits set out in the Commission’s Guidelines for Solar Photovoltaic Installation on NEM Scheme.

Applications for NEM shall be processed on a first-come first-served basis up to the allocated quota, which is provided by SEDA on its website. The application may be made by the applicant’s appointed registered PV service provider or registered electrical contractor, and it should be submitted either manually to SEDA or via SEDA’s online application portal.

If NEM approval is granted, the NEM consumer will need to apply to the Commission for a public generation licence. Once successful, an NEM contract can be signed between the NEM consumer and the distribution licensee. Energy produced by the NEM consumer’s system will first be used for the NEM consumer’s own energy needs and the excess sold back, or offset on a one-to-one basis by the energy consumed from the national grid.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

Since the implementation of the Tenth Malaysia Plan, the government – via the Commission, MESTECC and SEDA – has implemented a range of programmes and projects to educate the Malaysian public and encourage electricity efficiency and energy conservation. Energy laws and regulations reflect this; for example, the Efficient Management of Electrical Energy Regulations 2008 authorises the Commission to require operators and owners of installations that consume 3 million kWh or more during 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. 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 with the aim of expanding and developing the country’s green energy industry while creating jobs and improving the quality of life of Malaysians generally.

There are a number of fiscal incentives in place that are specifically targeted at potential entrants to the renewable energy market in Malaysia. For example, MESTECC has approved a budget of 5 billion ringgit under the Green Technology Financing Scheme (GTFS) to help fund new energy efficiency projects in Malaysia for the period 2018–2022. Additionally, on 6 March 2019, the Ministry of Finance approved an upgraded scheme, GTFS 2.0, for companies that are majority Malaysian-owned, allocating 2 billion ringgit for the period between January 2019 and the end of 2020. GTFS 2.0, which will last for two years, offers successful applicants an interest/profit rate subsidy of 2 per cent per year on loans and financing for the first seven years of the financing term, and a government-issued financial guarantee of 60 per cent of the green component cost. At the time of writing, the official GTFS website lists 655 projects that have been approved and certified for the GTFS scheme.

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34 Mohd Khalemi, ‘Green Tech Financing Scheme to Continue With RM5bil Funding | Green Technology Financing Scheme (GTFS)’, MESTECC (2 March 2017).
36 See https://www.gfts.my/certified.
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.\footnote{More information available on SEDA's website, at https://www.seda.gov.my/energy-demand-management-edm/energy-audit-conditional-grant-commercial-building/}

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, or a company that purchases green technology assets as listed in MIDA's MyHijau Directory, may be eligible for an investment tax allowance of 100 per cent of the qualifying capital expenditure incurred in a green technology project or asset from the year of assessment 2013 until the year of assessment 2020. Similarly, a Malaysian company that provides green technology services is eligible for an income tax exemption of 100 per cent of its statutory income from the year of assessment 2013 until the year of assessment 2020.\footnote{Malaysia Investment Development Authority, application for Incentive and/or Expatriate Posts for Green Technology.}

**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 the 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:

- \(a\) 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 the renewable energy.

To be eligible to participate in the feed-in tariff system, an applicant must propose to generate renewable energy from a renewable energy installation with an installed capacity of not more than 30MW, or a 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 if the producer is a corporate body, it is subject to the following requirements and provisos:

- \(a\) the company must be incorporated in Malaysia;
- \(b\) the foreign equity participation in the company must not exceed 49 per cent during the application and for the entire period of approval;\footnote{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'.}
if the company is already holds an 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.40

The application may be made by the company or its authorised representative, and it should be submitted either manually to SEDA, or 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 prerequisites 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 72kW. If the installation’s net export capacity exceeds 72kWp, then the minimum paid-up capital is increased to 50,000 ringgit or its equivalent.41 Additionally, SEDA may require the applicant to conduct tests and checks, including a connection confirmation check or a power system study conducted in accordance with the Renewable Energy (Technical and Operational Requirements) Rules 2011.

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.42 SEDA will not approve an assignment or transfer unless it is satisfied that the proposed assignment or transfer (1) was not reasonably foreseeable at the time of application for the initial feed-in tariff approval, (2) is just and reasonable, and (3) 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

41 Guidelines and Determinations of the Sustainable Energy Development Authority of Malaysia dated 5 February 2016.
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 will 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 or 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 quotas that are announced by SEDA on its official website. Successful applications will be placed in a queue and be subject to a ballot process until the quota is exhausted. In January 2020, SEDA announced a feed-in tariff quota of 20MW for biomass installations, 20MW for biogas and 116MW for small hydro installations. An e-bidding process for the latter two was carried out in the first quarter of 2020.

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 LSS PV 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 or to SESB (as the case may be) under a power purchase agreement, and the LSS capacity to be tendered will be between 1 MWac and 100 MWac.

Only Malaysian companies that pass the prescribed minimum Malaysian equity interest thresholds may participate in the LSS programme. These thresholds 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 in which the Malaysian equity interest in the consortium is at least 51 per cent.

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. Under the terms of the latest request for tender in respect of the LSS programme, all contractors engaged for the development of the project must be registered as a ‘local contractor’ with the Construction Industry Development Board of Malaysia, which significantly reduces the ability of foreign contractors to participate in these projects.

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, and chillers for industries. The total energy saved as a result of this initiative was 306.9GWh.44

The government has also taken the approach to lead by example in respect of renewable energy. There is strong encouragement that government procurement activities should comply with Government Green Procurement (GGP) Guidelines, which require that the acquisition of products and services abides by certain environmentally friendly criteria, thereby allowing the government to leverage its purchasing power to encourage industries and private enterprises to do likewise.\(^{45}\) The degree to which each ministry enforces the GGP Guidelines varies, and progress is overseen and facilitated by a steering committee and a working committee.\(^{46}\)

In October 2018, MESTECC, in conjunction with TNB, launched the GSPARX programme, which permits consumers to install solar panels on their property (with the capital cost funded fully by GSPARX). At the time of launch, it was announced that GSPARX has a target of offering 1,500MW of self-generation for solar PV investment by 2025. The scheme is intended to encourage consumers to rely more on renewable energy, and push the country towards achieving its goal of 20 per cent of the country’s generation capacity being fulfilled by renewable energy by 2025.

At the time of writing, the focus on developments in energy technology is strongly renewables-centric, and one of the key objectives is to solve or at least mitigate the issue of intermittent supply of renewables in Malaysia. Anti-theft and anti-tampering technology – including smart grids and advanced theft detection systems – is another of the main items on MESTECC’s table to push Malaysia closer towards its goal of an increasingly sustainable energy sector.

VI THE YEAR IN REVIEW

In October 2018, Malaysia hosted the ninth International Greentech and Eco Products Exhibition and Conference Malaysia, at which 30 countries engaged in round-table discussions and memoranda of understanding signed between various participants, with the aim of facilitating Malaysia’s shift towards renewables.\(^{47}\)

In April 2019, PETRONAS took its first step into renewables with the acquisition of Amplus Energy Solutions Pte Ltd. Amplus’ portfolio includes a six-year history of supplying and distributing renewable energy in Asia.\(^{48}\)

In September 2019, the government introduced MESI 2.0, which is intended to reform and liberalise the power industry in Malaysia by attaining three key objectives: to boost efficiency in the industry, to future-proof key processes, regulations and structure in

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the industry, and to empower consumers by democratizing and decentralizing the electricity supply industry. It remains to be seen how this will be implemented during the initiative’s 10-year life cycle.

In late 2019, Shell Malaysia Trading Sdn Bhd successfully negotiated and delivered a shipment of liquefied natural gas to TNB via the TPA System, marking the first occurrence of sale and delivery of gas via the TPA System.

MESTECC, the Commission and SEDA (in consultation with key industry players) began to develop a Renewable Energy Transition Road Map for 2035 in late 2019, focusing on the growth of renewable energy in Malaysia, in particular its affordability, accessibility and stability, increasing the suitability of renewables as a viable alternative to existing energy sources. It was announced that the outcome of the Road Map would form part of the Twelfth Malaysia Plan (2021–2025).

Pursuant to the Sarawak Distribution of Gas Ordinance 2016 (the Ordinance), any person who intends to undertake activities in the Malaysian state of Sarawak is required to obtain the relevant licence from the Ministry of Utilities of Sarawak. Although the Ordinance officially came into force on 1 July 2018, an informal grace period up to 31 December 2019 was provided for existing industry participants to comply with the provisions of the Ordinance.

In March 2020, a high court held that the state of Sarawak had the power to impose its state sales tax (5 per cent) on PETRONAS for the export of petroleum products from the state.50

VII CONCLUSIONS AND OUTLOOK

There is a strong push in Malaysia towards the development of renewable energy, which is reflected in recent policy developments by MESTECC and in the introduction of strong, key market players at various levels of the renewables fields, including state-owned enterprise PETRONAS, whose energy portfolio prior to this has been solely in petroleum and gas markets. Policy and infrastructure changes in renewables regulations in recent years have been aimed at facilitating a swift and smooth growth curve in Malaysia’s renewables markets. It remains to be seen to what extent these efforts will be hindered by low oil prices and the state of the economy as a result of the coronavirus pandemic.

These strong statements and policy developments come at a time when Malaysia’s political environment remains relatively volatile, and the liberalisation of the power sector will develop alongside continuing discussions between state and federal governments – particularly the state of Sarawak – in respect of regulatory authority over upstream and downstream oil and gas industries. It appears likely that we can expect key regulatory changes during the next decade to reflect the changing power landscape in Malaysia.

Chapter 14

MYANMAR

Krishna Ramachandra, Priyank Srivastava, Wang Bei and Ken Tan

I OVERVIEW

The Myanmar energy market started legal reform in 2011, at a time when the country opened up to foreign investment after decades of isolation. An increase in 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.

In terms of the National Electrification Plan for Myanmar, the Ministry of Electricity and Energy (MOEE), intends to extend electricity access to the entire population by 2030. In the meantime, benchmarks are set for 2021, with the aim of providing electricity to 55 per cent of Myanmar’s population, rising to 75 per cent in 2026. We understand that the MOEE has been working towards arranging for international funding, and allocating a national budget for implementation of the objectives for electrification.

The national grid currently produces 3,448MW, 2,400MW of which is produced by hydropower plants and 1,038MW by thermal power industries. According to the Asian Development Bank, Myanmar has an abundance of hydropower – in access of 100,000MW – so the government’s focus is naturally on upgrading and developing those plants.

The MOEE’s announcement involving the National Electrification Plan is a highly positive development for Myanmar citizens and both local and foreign sponsors, as poor infrastructure is impeding the country’s economic development. Currently, only 35 per cent of the population of Myanmar is connected to the electricity grid compared to a world average of almost 88 per cent; and the average annual per capita electricity consumption is 217kWh (8 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 depends on electrification, without which health, education and other key services will continue to suffer.

Other initiatives to bolster electricity efforts include bilateral cooperation with neighbouring countries. In January 2018, Myanmar and Laos signed a memorandum of understanding on power cooperation. Similarly, in March 2018, Myanmar, China and Bangladesh signed an agreement on trilateral power trade. Further, under the Myanmar Sustainable Development Plan (MSDP) 2018–2030, containing a long-term vision for Myanmar, the Myanmar Energy Statistics 2019 have been issued, which will help the government to estimate the volume of electricity required demographically.

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A new government came into power on 1 April 2016, led by the National League for Democracy (NLD). The NLD is headed by Daw Aung San Suu Kyi, who holds the newly created position of State Counsellor. The Presidency is currently held by U Win Myint.

Prior to the end of the reign of the Union Solidarity and Development Party (USDP) in Myanmar (between December 2015 and January 2016), more than 35 new laws were passed by the USDP. These laws include the new Arbitration Law enacted on 5 January 2016 (the 2016 Arbitration Act), which provides a domestic legal framework to fully implement and comply with the Convention on the Recognition and Enforcement of Foreign Arbitral Awards of 1958 (the New York Convention), which Myanmar signed and ratified in 2013.

**Sanctions and key considerations**

There are at present no sanctions in force against Myanmar (save for arms embargoes and penalties against certain military units and officials based on human rights abuses resulting from the Rohingya crisis) 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:

a. lifts the import ban on rubies and jadeites of Myanmar origin into the United States;

b. 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. 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

d. removes the requirement to comply with the State Department Responsible Investing Reporting Requirements. This is now voluntary.

**II GOVERNMENT FRAMEWORK AND REGULATIONS**

i. **Government 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:

a. the Electric Power Generation Enterprise (EPGE) (formerly the Myanmar Electric Power Enterprise (MEPE) alongside the Department of Electric Power (DEP)), which operates and plans the Myanmar National Grid System, buys electricity from both public and private producers and then sells the electricity on to the Electric Supply...
Enterprise and Yangon City Electricity Supply Board. The Yangon City Electricity Supply Board and other regional and state electricity supply boards assist the EPGE in the purchase and distribution of power; and

b) the Hydropower Generation Enterprise (HPGE), alongside the Department of Hydropower Planning and the Department of Hydropower Implementation, which 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) the Electricity Supply Board (ESB) was formed in 1951 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 to 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 (MOE). The EPC was under the umbrella of the MOE;

e) on 1 April 1989, the EPC was renamed the MEPE;

f) in 1997, the MEPE was extended and reorganised into the MOE and the Ministry of Electric Power. The MEPE was under the control of the Ministry of Electric Power;

g) in 2006, the Ministry of Electric Power (MOEP) was reorganised as 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;

h) 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;

i) in March 2016, the MOE and the MOEP were consolidated into the new MOEE; and

j) in March 2016, following the reorganisation of the Union government’s ministries and departments, the MEPE was reformed as the EPGE.

In addition to the role of the MOEE on power projects, there are a number of other government institutions that are important from the perspective of a foreign investor intending to proceed with a power project in Myanmar. We have categorised the related government authorities in terms of their relevance at the various phases of a power project.

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 some laws have become outdated while new laws 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;
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 so as to instil confidence both domestically and internationally in the business community and, of equal importance, to attract local and foreign investment in support of the government’s rapid energy reform initiatives.

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 only a directive, not actual law. Generally speaking, at present the Tender Directive is local and does not follow international standards.

The Tender Directive, while lacking substance, sets out the procedure to be followed by government departments, ministries and state-owned enterprises (SOEs), including the...
establishment of procurement or tendering committees, open invitations to tender and public announcements of tenders. On 10 April 2017, the Union government issued Notification No. 1/2017 introducing a new tender procedure (the Tender Procedure) 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 a threshold of 10 million kyat for launching a tender for construction or procurement of goods and services. Importantly, irrespective of the fact that the participation eligibility for foreigners is not clear, foreign companies without any presence in Myanmar may participate in a 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 executing the contract with the relevant government department.

Currently, Myanmar has no specific public-private partnership (PPP) laws, guidelines 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 in any details with issues relating to tendering or procurement.

Any investor seeking to develop a self-proposed project will face difficulty, as this is not common in Myanmar.

V FOREIGN INVESTMENT IN THE ENERGY SECTOR

i Myanmar investment commission permit

A foreign sponsor must obtain a permit from the Myanmar Investment Commission (MIC), or investment licence, to develop a power plant (i.e., to carry out business activity) 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, which 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 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 the zone in which the project is located. Zone 1 includes the least developed areas of Myanmar, excluding Yangon and Nay Pyi Taw; Zone 2 (moderate) includes more developed zones, and Nay Pyi Taw, but still excludes Yangon; and Zone 3 (developed zones) includes Yangon and Mandalay. The income tax holidays are inclusive of the year in which the project company begins operations.

An 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 of the reserve being made;
the right to deduct accelerated depreciation from the profit concerning machinery, equipment, building or other capital assets used in the business at rates set by Myanmar;

relief from tax on up to 50 per cent of the profits accrued from exports of goods produced in Myanmar;

the right to pay foreign employees’ income tax at the rates applicable to citizens residing within the country;

the right to deduct from assessable income the expenses incurred with respect to necessary research and development carried out within Myanmar;

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

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 following types of foreign currencies:

- the amount of foreign currency brought into Myanmar as foreign capital; and
- 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 when a business is wound up, subject to approval by the MIC.

A foreign employee can transfer his or her salary and lawful income after deducting taxes and other living expenses incurred within Myanmar.

**ii MIC endorsement**

A foreign sponsor intending to make a small-scale power investment (with investment capital of less than US$5 million) who desires a long-term lease right for a period exceeding one year must apply for an endorsement at an MIC regional office. If the investor’s investment capital exceeds US$5 million, he or she must apply for an endorsement at the MIC’s head office.

It is not industry practice in Myanmar, nor is it recommended, for a foreign sponsor to obtain an endorsement only to develop a power plant. Rather, the tried and tested approach is that a foreign investor will obtain both an endorsement to secure long-term lease rights and an MIC permit to carry out the desired business activity. The authors would recommend that any sponsor intending to develop a power plant in Myanmar obtain an MIC permit.

**Right to enter into a long-term lease**

A foreign-owned company (i.e., sponsor) without an endorsement (as specified below) or MIC permit is only allowed to enter into a lease agreement for up to 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.

**iii Processing time**

MIC permits are granted case by case, 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 the same, although this was not the intent of the legislature.
Tenders are issued through the MOEE, and investors and sponsors can find up-to-date information about independent power producer (IPP) tenders on the MOEE website.²

VI INDIAN INVESTMENT IN THE ENERGY SECTOR

Aside from the Indian downstream entities (mostly publicly owned) that are dominant players in India’s downstream petroleum sector, recent legislative developments 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. The government has been formulating programmes for the use of renewable energy resources such as wind, solar, hydro, geothermal and bioenergy for sustainable energy development in Myanmar. With various alternative fuel sources available in Myanmar, Indian private entities that have sophisticated technical skill sets in the energy and power sectors can look forward to Myanmar as a potentially rewarding market. India also benefits from its geographical location, as it can easily cater for Myanmar’s energy requirements in the energy and power sectors.

VII CHINESE INVESTMENT IN THE 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. 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 SOEs and private Chinese investors developing Myanmar’s energy sector; however, the majority of inbound Chinese investment into Myanmar’s energy sector is largely led by the former.

According to official statistics released by the Directorate of Investment and Company Administration (DICA), China is ranked as the leading foreign investor in Myanmar, boasting a volume of almost 26 per cent of Myanmar’s foreign investment value.

One of the key landmark projects 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 China’s Yunnan province. This project was completed in 2014.

Three Chinese SOEs (China Electric Power Equipment and Technology Company Ltd, China Southern Power Grid Company Ltd (CSG) and 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 an Chinese President Xi Jinping met in May 2017 to discuss, among other things, Myanmar’s energy sector and developing closer ties. The authors’ understanding, based on information released by the MOEE, is that there have not been any further developments since those initial talks. The Chinese and Myanmar diplomatic meetings are the most encouraging cooperation to date since the suspension of the Chinese-backed Myitsone dam in 2011.

The authors expect China to be the leaders in the development of Myanmar’s energy sector.

² www.moee.gov.mm.
VIII BANKABLE PROJECT DOCUMENTS

Arguably, the project documents (e.g., memoranda of agreement, power purchase agreements, build-operate-transfer agreements, engineering, procurement and construction contracts, land lease agreements, security documents, fuel supply agreements) 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, a power deal of this magnitude had not been seen before.

If an 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 the requirements for having in place bankable collateral for meeting the lenders’ requirements for the project. It has also been the authors’ experience that foreign lenders usually push hard to enhance the recourse options by establishing liens on the interests or assets of the sponsors and shareholders of any project company. If the financing involves syndicated contributions from multilateral development financial institutions (multilaterals), this will create another hurdle. Sponsors need to be aware that multilaterals may show little inclination to negotiate any deviation from their standard project documentation.

IX 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 authors understand that 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).

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.

Under the standard MIGA contract of guarantee for shareholder loans, a 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, as mentioned in Section V, above, under the MIL the government guarantees that a business that acquires an MIC permit shall not be nationalised during the term of the contract or during the extended term of the contract. Further, 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. The guarantee provided under the MIL is yet to be properly tested in any Myanmar court or arbitral tribunal, and thus there is no guiding jurisprudence or commentary.

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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 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 that guarantee. If the guarantee is required to be issued in a foreign currency, the Ministry will consult the Central Bank of Myanmar (CBM). However, thus far, the authors are yet to witness guarantees issued by the state referring to the provisions of the PDML.

X PROJECT FINANCING

The difficulties involved in financing power projects to date mainly revolve around the CBM and MIC approvals (for companies with an MIC permit), and concern loan facilities and challenges in perfecting security interests, including:

a charges over shares (normally referred to as pledges of shares);

b fixed and floating charges (these typically include project accounts, movable plant and equipment, buildings and fixtures, and book debts);

c mortgages on immovable property. Typically, a separate land mortgage will be executed and this must be registered at the relevant Myanmar Office of Registration of Deeds;

and

d assignments of contracts.

To comply with Myanmar property laws, foreign lenders often engage a local bank to act as an onshore security agent (OSA) (or collateral agent) to enable holding of charge over immovable property.

All 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 the lack of a modern legal mechanism allowing the government to facilitate registration of security. The first inroads were made under the Registration of Deeds Law 2018, which prescribes a more transparent two-way mechanism involving online registration with the DICA followed by registration with the Deed and Registration Office to properly record a security interest. However, there is no official land titles register or electronic database, making it difficult for investors to accurately determine the ownership of privately held plots of land. 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 conduct a careful due diligence process on landowners.

Use of an OSA is highly recommended to streamline the perfection of security processes, as there are few restrictions 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 that the OSA is not aware of other interests that would affect the security remaining perfected.

Section 229(a) of the MIL 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 common law jurisdictions and can cover the following assets:

1. a mortgage or charge for the purpose of securing any issue of debentures;
2. a mortgage or charge on uncalled share capital of the company;
3. a mortgage or charge on any immovable property wherever situated, or any interest therein;
4. a mortgage or charge on any book debts of the company;
5. a mortgage or charge, not being a pledge on any movable property of the company except stock in trade; or
6. a floating charge on the undertaking or property of the company.

The FFC and any individual mortgage or charge over a company’s assets must be registered with the DICA within 28 days of its creation, otherwise it is void against a liquidator and other creditors should a company be wound 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).

CBM approval is required for all offshore financings. Once CBM approval is obtained with the loan payment and repayment schedule attached, no further approvals are required for each payment made under the loan. For projects approved by the MIC, the creation of any charge or mortgage requires notification to the MIC.

Given the uncertainties regarding onshore security, lenders will also require sponsors based overseas to provide ‘offshore’ security over their interests in the Myanmar-based project company in the usual manner.

XI INVESTOR TIPS

i Myanmar and expatriate counsel

We recommend that an 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 in Myanmar. The process is long and requires the expertise of both skilled Myanmar and expatriate counsel to persist with the constant follow-up on 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 in the country; however, this does not mean that developing a large-scale power project and doing business in Myanmar is not without its challenges. According to a 2013 report published by McKinsey:

1. the average productivity of a worker in Myanmar is US$1,500 per year – about 70 per cent below that of benchmark Asian countries;
b average schooling in Myanmar is for four years;
c there will be an additional 10 million people to be absorbed into Myanmar’s large cities by 2030; and
d 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 the supply of utilities. Improvements to the country’s infrastructure will take time. As Myanmar’s reform process gains speed, many draft laws and amendments are awaiting consideration by Myanmar’s parliament.

XII 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 1899 Myanmar Stamp Act, dated 1 August 2017, stamp duty of 0.5 per cent of the total loan facility is applicable.

Furthermore, certain tax reliefs may potentially be available under applicable tax treaties. Myanmar has double taxation avoidance agreements (DTAs) in force with eight countries including India, Korea, Malaysia, Singapore, the United Kingdom and Vietnam, with a number of other DTAs in the draft phase.

The Income Tax Law provides that a DTA must be ‘notified’ before it is to override provisions of the Law. The details concerning whether a DTA has been notified are contained in the official government gazette. Accordingly, the terms of any DTA will be followed despite anything to the contrary contained in any other provisions of the Income Tax Law.3 The sponsor must follow an administrative procedure for claiming a tax exemption based on the DTA with the Internal Revenue Department (IRD). Under Myanmar law, application of the DTA is not automatic and is at the discretion of the governor of the IRD.

In terms of the tax concessions available for an MIC company, a five-year income tax holiday for an MIC company starts from the first day of commercial production. Typically, a project company would only incur expenditure without having any taxable income during its construction period. A project company’s corporate income tax would be nil if it has negative taxable income. However, if a project company has taxable income during its construction period, it would be liable to pay corporate income tax at 25 per cent on its net profits.

XIII INSOLVENCY

The new Insolvency Law and Insolvency Rules (insolvency legislation) aim to protect both creditors and financially distressed companies, in particular, micro, small or medium enterprises. The insolvency legislation has adopted the United Nations Commission on International Trade Law Model Law in relation to cross-border insolvency. The new legislation

3 The Income Tax Law provides that if the government 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 agreement will be followed despite anything to the contrary contained in any other provisions of the Income Tax Law.
provides a model framework for solving financial distress for companies that have creditors or assets in more than one jurisdiction. In the case of financial distress, companies may choose to solve it by liquidation or rehabilitation.

**XIV 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 (the EIA Procedure), which 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.

**XV 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 the DICA, which have offices in Yangon, all 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.

In the authors’ experience, meetings should be arranged at least seven business days in advance and the meeting request letters should state a preferred date and time and be accompanied by an agenda to allow the relevant authority to coordinate representatives from the MOEE, DEP and others.

It is preferable to have a short agenda, 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 first day of the meeting.

Given these limitations, it is strongly suggested to have more frequent, shorter meetings as opposed to attempting a one-day marathon session with the government.

Despite most meetings being conducted in English, having a translator in attendance can ensure the meeting will run more efficiently.
XVI POTENTIAL DOWNSTREAM AND POWER PROJECTS

The downstream sector, *inter alia*, involves refining petroleum crude oil, treating and purifying natural gas, and marketing and distributing petroleum products.

Recently, foreign investment has been liberalised by the Myanmar government for imports, storage and distribution of petroleum products in Myanmar under the Petroleum and Petroleum Products Law 2017 (PPPL). It has been a welcome move for potential downstream investors, and will create an opening in the downstream petroleum market for foreign investors in Myanmar.

The PPPL replaces the Petroleum Act 1934 and provides clarity on aspects on imports and exports, transportation, storage, refining, distribution, inspection and testing of petroleum and petroleum products. The PPPL also earmarks the authority concerned with issuance of relevant licences. However, the implementation of the provisions of the 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, there are three major refineries: Thanlyin, Chauk and Mann Thanpayarkan. With the promulgation of the recent regulations in the sector, foreign investment is possible in connection with loading, offloading, and operating and maintaining jetty facilities.

XVII CONCLUSIONS AND OUTLOOK

Myanmar has abundant energy resources – hydropower and natural gas in particular. Owing to underdeveloped legislation and a lack of financial and technical capacity, the energy sector 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 policy changes in foreign investment are indicative of the fact that the government is making greater efforts to create a more transparent atmosphere to attract foreign capital and technology. It is to be hoped that there will be significant growth in the energy sector in the near future.
Chapter 15

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 dominated by major joint venture arrangements, production sharing contracts and service contracts between the Nigerian National Petroleum Corporation (NNPC), which is wholly owned by the federal government of Nigeria (FGN), and international oil companies with global operations (IOCs) and recently established indigenous oil and gas companies. A number of statutes and policies encourage indigenous companies to participate actively in the industry.

Activities in the petroleum industry are regulated by several laws in respect of the the ownership, control and enjoyment of rights, construction and maintenance of installations, and environmental protection. 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 sets out the legal framework for the industry. Through EPSRA, the FGN unbundled and privatised the then state-owned monopoly, the National Electric Power Authority (NEPA) as the Power Holding Company of Nigeria, generation companies (Gencos), distribution companies (Discos) and the Transmission Company of Nigeria (TCN). 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 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 the 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 regulate the environmental aspects of the production, transmission, distribution and supply of petroleum and petroleum products in Nigeria. Further, the National Environmental Standards and Regulations Enforcement Agency (Establishment) Act 2007, the Environmental Impact Assessment Act 1992 and the Environmental Guidelines and Standards for the Petroleum Industry in Nigeria 2018 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 effect on the industry include:

- the Nigeria–São Tomé and Príncipe Joint Development Authority, which promotes and supervises petroleum activities in the Nigeria–São Tomé and Príncipe joint development zone;
- the Nigerian Investment Promotion Commission, which registers foreign investments in Nigeria;
- the Central Bank of Nigeria, which, under the Foreign Exchange (Monitoring and Miscellaneous Provisions) Act 1995, supervises foreign exchange dealings in Nigeria (including imports of foreign capital and repatriation of export proceeds from oil and non-oil exports);
- 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;
- the National Oil Spill Detection and Response Agency, which deals with waste emanating from petroleum production and exploration; and
- 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, with 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, respectively, import and market refined petroleum products.
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 and transportation of petroleum, fuelling of aircraft, among other things. 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 reinjection of associated gas into oil wells. The Petroleum Profit Tax Act 1958 (as amended by the Finance Act 2019) taxes profits from upstream petroleum operations in Nigeria.

**Electricity**

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 to ensure standards of quality in the electricity industry. EPSRA further established the Rural Electrification Agency to promote, support and provide rural electrification programmes in Nigeria.

The Federal Ministry of Power, guided by EPSRA and the FGN’s National Electric Power Policy 2001, formulates electricity policy in Nigeria. The Federal Ministry of Power is empowered under EPSRA to issue general policy directions to NERC on the electricity industry, and NERC is bound to comply except where a policy is in conflict with EPSRA or the Constitution. The Energy Commission of Nigeria (ECN) also has 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 Nigerian Electricity Management Services Agency, established under the Nigerian Electricity Management Services Agency Act 2015, is responsible for the enforcement of technical standards, regulations, technical inspection, testing and certification of all categories of electrical installations, electricity meters and instruments to ensure efficient production, delivery and measurement of safe, reliable and sustainable electricity power supply in Nigeria, and to guarantee the safety of lives and property in the Nigerian electricity industry.

The TCN manages the electricity transmission network in Nigeria. The TCN has two key operating officers. One, the market operator, administers the wholesale electricity market, and promotes efficiency and competition. The other, 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 use.
ii Regulated activities

Petroleum

The petroleum industry comprises 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 one year, and is renewable 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. An 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, and 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 or 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. There are three categories of permits: (1) the general category covers minor supply, works and maintenance services; (2) the major category covers rehabilitation, upgrade and fabrication works, onshore pipeline and storage facility maintenance, equipment supply, consultancy, survey and calibration; and (3) 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 all are overseen by the DPR. In addition, the Environmental Impact Assessment Act 1992 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 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 a transmission system in Nigeria, or to 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 operations 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 the 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 is also required to undertake any hydroelectricity project. This must be obtained from the Ministry of Water Resources, which 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 more than 51 per cent Nigerian equity participation. Under the NCA, these 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, during 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. The National Domestic Gas Supply and Pricing Policy (the Domestic Gas Policy) and the National Gas Supply and Pricing Regulations 2008 (the Gas Pricing Regulations) require OPL and OML holders to supply up to a specific volume of gas for domestic consumption. An OML holder is further required to relinquish 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 or royalties, to furnish reports on its operations or to comply with the PA,
regulations or the terms of the licence or lease. The Minister may also revoke these rights if the licence holder comes under the control, directly or indirectly, of 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 these 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 that details 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; however, the DPR is 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 if the Minister is satisfied that the proposed assignee is of good reputation, has sufficient technical knowledge, experience and financial resources to carry out the operations effectively 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, it 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 a licence or transfer an 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 Federal Competition and Consumer Protection Commission is now required for mergers, acquisitions, takeovers and business combinations in which the acquirer and the target combined are worth 500 million naira or more in terms of either turnover or assets. Until early 2019, this approval was given by the Securities and Exchange Commission. 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 and indigenous oil and gas companies also have control over exploration, production and transportation facilities in the petroleum industry. The downstream operations of IOCs in Nigeria are usually not integrated with the upstream operations of the group. In the 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 NEPA (the old, state-owned monopoly). NEPA controlled generation, distribution, transmission and trading of electricity. Through EPSRA, 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 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

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, 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 this 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. If the licence holder and the applicant fail to reach an agreement, the Minister may determine the 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, the FGN in 2008 approved a Gas Master Plan Infrastructure Blueprint, which provides for the development of central gas processing facilities and gas transmission systems.

**Electricity**

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. The captive generator holder must apply for a generating licence before it can supply power exceeding 1MW to an offtaker. Further, embedded power generators (generation of off-grid power to be evacuated through a distribution network to end users) with a capacity of more than 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 obliged to provide third-party access. There are also no restrictions on the provision of 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.

**iii Rates**

**Petroleum**

Under the PA, the Minister shall fix prices at which petroleum products may be sold in Nigeria. However, the Petroleum Products Pricing Regulatory Agency Act 2003 created the Petroleum Products Pricing Regulatory Agency 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. Notwithstanding, the NNPC, as the major importer of petroleum products, had until recently borne the loss for the high landing cost of these products. However, as a result of the global crash in the price of crude oil in the international market, the Ministry of Petroleum and the NNPC announced plans by the FGN to stop subsidising petroleum products, to allow market forces determine prices.

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, shall 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 a reasonable return on investment, promotion of technology and market efficiency through incentives, fairness and openness to consumers, and the 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. MYTO 2.1 was valid for the period 1 January 2015 to 31 December 2018. Effective 1 February 2016, NERC approved an amendment to the MYTO 2.1. MYTO 2015 is to remain in force until 31 December 2024.

The MYTO does not apply to embedded power. Embedded power is priced on a discrete basis to cover the 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 foreign exchange market regulated by the Central Bank of Nigeria to make payments under an unregistered contract.

**IV ENERGY MARKETS**

**i Development of energy markets**

The first national utility company, the Nigerian Electricity Supply Company, was established in 1929, about 33 years after the first power generating station. From mainly hydroelectric and coal-sourced energy, Nigeria has developed to a multi-source generation market (though gas is now the dominant source). 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 and 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 the market is fully competitive and the Discos achieve self-sufficiency. This arrangement is backed by financial assistance in diverse forms from both Nigerian and international governments. 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, which is responsible for rule-making and the licensing of market operators. The rules in force govern the different stages the industry is expected 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 offtake 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 and other off-grid power sources. 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 are still working to fix shortcomings in their facilities while others are working to instal additional capacity. NERC issued the Mini-grid Regulation 2017 to regulate the generation and distribution of electricity with installed capacity of 1MW or less in unserved and underserved areas independent of the national grid. NERC also issued the Meter Asset Provider Regulation 2018 (the MAP Regulation) to provide for the supply, installation and maintenance of end-user meters by other parties (approved by NERC) other than the Discos. The MAP Regulation is expected to close the metering gap through accelerated meter rollout and to encourage the development of independent and competitive meter services in the Nigeria electricity market.

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 February 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 2015 is also in place to govern electricity pricing for both individual and industrial users. The next stage of the electricity market, the medium stage, will involve the cessation of the Bulk Trader, and the Bulk Trader novating to the Discos the power procurement contracts it entered into with the Gencos. At this stage, the Discos will purchase power directly from the Gencos and other independent power generation companies for onward sale to end 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 effects 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. Through its Renewable Energy, Research and Development Division, NERC 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 this electricity. NERC also grants licences for renewable power generation, such as 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 exemptions from withholding tax, capital gains tax, value added tax and custom duties. There are several renewable energy projects at various stages of implementation in Nigeria. In fact, roads in numerous urban areas are lit or powered by solar sourced energy. There also have been several intervention funding programmes for renewable energy projects in Nigeria. There are several ongoing small-scale off-grid renewable energy projects sponsored by the World Bank, the Association of Bilateral European Development Finance Institutions and other development finance institutions in Nigeria. Further, some IOCs in Nigeria have undertaken programmes to support access to clean energy in Nigeria.

ii Energy efficiency and conservation

Efficiency and conservation are still poorly advanced despite the inclusion of basic policies and strategies in the national energy policy and the energy master plan. However, there are no definitive codes and regulations for energy efficiency and conservation. The Federal Ministry of Environment’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. Further, the ECN, in partnership with the Cuban government and with support from the Economic Community of West African States, has advanced the use of compact fluorescent lamps.

In addition, NERC has expressed its intention to develop energy efficiency labelling standards for domestic appliances and energy efficiency standards for luminaires, air-conditioning units and other household appliances. Currently, energy-saving equipment, such as high-efficiency voltage controllers and energy-saving home appliances, is now more readily obtainable on the Nigerian market.

iii Technological developments

Technological development in Nigeria is significantly slower than it should be. There are indications, however, that some Discos have signed memoranda of understanding to formalise agreements with the United States Trade and Development Agency (USTDA) to promote smart-grid solutions for Nigeria’s transmission and distribution challenges. So far, the USTDA has funded at least three power projects in Nigeria. The USTDA has also assisted in training some Disco staff in the use of technology to better manage their operations.
VI THE YEAR IN REVIEW

i Petroleum

Recently, there has been an unprecedented fall in the international price of crude oil. This coupled with the global coronavirus pandemic, has resulted in a drop in crude oil production. Some operators of oil acreage in Nigeria are still struggling to settle outstanding debt service obligations. To stay afloat, some of these companies have resorted to debt refinancing and, in some cases, limited equity injection.

With the global crash in the price of crude oil on the international market, the FGN (through the NNPC) has stopped subsidising petroleum products. The Ministry of Petroleum and the NNPC announced plans by the FGN to stop subsidies on petroleum products to allow market forces to determine prices.

In the past, the NNPC, as the largest importer and supplier of petroleum products in the market (more than 90 per cent), bore the costs of under-recoveries of petroleum products caused by the high landing costs. With the drop in oil price, oil marketers are to resume importation and sale of petroleum products to end users.

In a move towards revamping the Nigerian petroleum industry, the FGN approved two major policies for the sector in 2017: the National Gas Policy 2017 and the National Petroleum Policy 2017. As a follow-up to these policies, the President of Nigeria, in his capacity as the Minister of Petroleum Resources, issued the Flare Gas (prevention of Waste and Pollution) Regulations 2018 (the Flare Gas Regulation). The aim of this Regulation is to implement the Nigerian Gas Flare Commercialisation Programme launched in 2016. The Flare Gas Regulation, among other things, creates the framework for preventing the waste of gas, creation of social and economic benefits from gas production and disincentivising of gas flaring. To strengthen the FGN commitment to focus on gas, the NNPC signed agreements on the Seven Critical Gas Development Projects. These landmark projects are expected to bring on line 3.5 billion standard cubic feet of gas (3.5 bcf) per day, and generate at least 15,000MW of electricity by 2021.

Finally, the Petroleum Industry Governance Bill is currently pending before the National Assembly.

ii Electricity

Within the year in review, the FGN signed an implementation agreement for the Nigeria Electrification Road Map with Siemens (the Road Map). The Road Map, which comprises three phases, is aimed at resolving the existing challenges in the power sector. The Road Map covers the upgrading and expansion of the infrastructure across the various value chains in the power sector – generation, transmission and distribution.

During the past year, despite the call for a review, NERC has 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 reflecting costs. On 19 August 2019, NERC issued its 2016–2018 Minor Review of MYTO 2015 and the Minimum Remittance Order for the year 2019 (the First Review) effective from 1 July 2019. This is the first minor review of the MYTO 2015 by NERC since it took effect in February 2016. The First Review was replaced on 31 December 2019 by the Minor Review of MYTO 2015 and the Minimum Remittance Order for the year 2020 (the Second Review). The Second Review took effect from 1 January 2020. The two Reviews were based on the following variables: inflation, exchange rate, the US rate of inflation and gas price. The
available generation capacity between 1 January 2016 and 31 December 2018 was also taken into consideration in the First Review while the available generation capacity as at 31 October 2019 was considered in the Second Review. The Reviews made projections for the year 2019 and beyond. They also provided minimum remittance thresholds by the Discos to the Bulk Trader and the market operator under the vesting contracts.

There has been greater awareness of the MAP Regulation during 2019, with improvement in the deployment of pre-paid meters under the Regulation. The MAP Regulation is designed to bridge the widening end-user metering gap in Nigeria’s electricity supply industry, with the goal of eliminating estimated billing. Through the Regulation, the Discos ceased to have the exclusive right to the metering of end users. Under the Regulation, a new class of operators, meter asset providers, shall be responsible for the provision, installation, maintenance and 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 metering services.

VII CONCLUSIONS AND OUTLOOK

With the crash 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 FGN is expected to continue with 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 in the electricity industry and enhance competition in the electricity market. There is, as yet, no express communication from the FGN that any fundamental changes will be made to the electricity sector.

On 17 April 2019, NERC published a consultation paper calling for comments, options, objections and representations on the regulatory framework for electricity distribution franchising. The proposed franchising regulation seeks to allow Discos to grant franchises to third parties to undertake specific Disco roles within the coverage areas. When finalised, the regulation is expected to bridge power supply deficit, improve customer satisfaction, provide better service and improve investments in Disco networks. With multiple intervention funding programmes for renewable energy available, it is expected that there will be many more renewable energy projects in Nigeria. Pursuant to (1) NERC’s Order on the Transition to Cost Reflective Tariffs in the Nigerian Electricity Supply Industry, which took effect on 1 April 2020 and (2) the FGN’s updated Power Sector Recovery Programme, there are ongoing plans to implement an increase in electricity tariffs by 30 June 2020. The plan is to transition to a fully cost-reflective tariff by the end of 2021. Ahead of this, Discos are expected to submit performance improvement plans and to put in place procedures for improved and better service delivery to end users.
I OVERVIEW

Since the mid-1960s, energy related services in Panama 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 increase in demand for electricity (approximately 5 to 6 per cent per year) has become a challenge for Panama. As of the first semester of 2019, the energy generated was 39.24 per cent hydroelectric, 48.37 per cent thermal (fossil fuel), 9.55 per cent wind and 2.84 per cent solar.

The installed capacity as of the first semester of 2019 was 3,741.26MW, of which 46.68 per cent was hydroelectric, 41.32 per cent thermal (fossil fuel), 7.12 per cent wind and 4.88 per cent solar.

In 2017, the total energy sales by the distribution companies was 8,474.12GWh. As of the first semester of 2019, the total was 4,217.57 GWh.

The three main sub-sectors 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 with the distribution activity, except that generators may commercialise their capacity or energy with large customers only.

Electricity generation is rendered in competition. Distribution and commercialisation, on the other hand, are 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 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) 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 for 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 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), which defines Panama’s road map regarding energy policy up to 2050. The PEN is driven by four main pillars that will guide the energy policy in Panama:

- 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 to assure the proper functionality of the system. These entities are as follows.

**National Authority of Public Services**

ASEP is an autonomous government 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 at any moment in time.

**The Authority for Consumer and Competition Protection**

The Authority for Consumer and Competition Protection is an autonomous government entity legally empowered to investigate, verify and sanction monopolistic, anticompetitive and discriminatory behaviours and activities by agents of the market generally, including the electricity market, among other powers granted by law.

**Empresa de Transmisión Eléctrica, SA**

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 affect other agents on the market.

**National Energy Secretariat**

The SNE is a government entity ascribed to the Ministry of the Presidency, whose primary task is to establish and conduct the country’s energy policy, within the legal framework, to guarantee supply, access, efficient use of energy, and 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 as a public service. This Law is regulated by Executive Decree No. 22 of 1998.

b Law No. 45 of 2004 (as amended) 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 promotion of the construction and exploitation of natural gas-based power generation plants.

e Law No. 37 of 2013 (as amended) dictates incentives for promotion of the construction, operation and maintenance of solar power generation plants.

f Law No. 42 of 2011 (as amended) 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 and commercialisation, and generation. However, other forms of participation in the sector 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 through use of the interconnection network; and

c auto-generators and cogenerators who can generate energy for their own consumption, sell excess energy through 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 and 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 issued by ASEP.

These concessions shall be issued through processes that guarantee public concurrence, in the following situations:

a. when ASEP deems it 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 those 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 for the project.

The term of these concession contracts may be as long as 50 years, with the possibility of an extension 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.

**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 or 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, for which the licensee should file an application.

Licences shall be granted for 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.

A licence applicant must complete a special form approved by ASEP for those purposes. 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 thereof.

The application form requires the applicant to include certain general information about itself, a technical description of the project and to attach a number of documents that are listed on 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 definitive licence. (Note that definitive licences are valid for a specified term and the validity is dependent on the completion of certain milestones.)

The most important documents required for a licence under the regulation include:

\( a\) a sworn statement by 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 for 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 for issue of 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 by 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 for the power project.

**Transmission concessions**

Resolution JD-1244 of 10 February 1999 (as amended) governs the award of transmission concessions. These concessions shall be awarded through a concurrence process, unless there are no interested competitors (other than 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 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 the 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 above, the distribution activity may be carried out by third parties (other than the three main distribution companies) external to 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 285 of the Constitution, Article 34 of Law No. 6 of 1997 (unified text) 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 in 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 aforementioned land. This rule does not encompass the use of land for an electricity sector project through means other than ownership rights.

Other restrictions

Further restrictions that are specific for the electricity sector are as follows:

a energy generation, transmission, distribution and commercialisation companies located in Panama shall have, as a 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 relating 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 in or control, directly or indirectly, generation plants in their concession area; and
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

There are no special requirements to seek approval before transferring direct or indirect ownership of capital stock of a concessionaire or licensee. However, it is recommended to notify any changes at an appropriate time after the change of ownership occurs because one of the requirements to obtain a concession or licence is to provide a 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 by 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.

As regards assets of concessionaires or licensees used in the provision of electricity services, Law No. 6 of 1997 sets forth the duties and obligations of electricity sector players, which include administering and maintaining 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 prior notice to ASEP.

As indicated above, provisional generation licences are not transferable. Other licences or concessions typically would be transferable subject to prior approval by ASEP.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

In the 1990s, prior to its restructuring, the IRHE performed all three of the main electricity sector activities discussed herein (transmission, distribution and generation). The IRHE also acted as regulator of the sector in many – if not most – respects. At that time, a few private power plants had been authorised by the IRHE to operate.

Law No. 6 of 1997 disaggregated these services by:

a restructuring the IRHE into seven different service providers in which the private sector would have stakes, as described above;

b creating restrictions in the law leading to avoidance of 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 on their own merit and regulating other alternatives for players on the market to participate (i.e., autogenerators and cogenerators).

Further, special rules have been dictated for electricity sector players to share infrastructure with other agents on 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 that render public services, or 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 now constitute part of the electricity forum of Panama. To date, three definitive licences have been granted for natural gas projects, but only one has started operations.

ii  Transmission/transportation and distribution access
As indicated above, 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. This 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, judging by the large number of projects (in all technologies) that have been or are being constructed since the 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.

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 the 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 regulate 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 the collective needs of the general public. As a general rule, the state must intervene in services of public interest to guarantee an efficient, continuous and uninterrupted service provision.

The Criminal Code of Panama includes penalties ranging from three to five years’ imprisonment for those who seize movable property destined for public electricity services.

Similarly, the Criminal Code includes penalties ranging from five to 10 years’ imprisonment for those who damage or render useless any networks, channels or works destined for the transmission of energy, gas or energy substances.

In general, providers of public electricity services are subject to certain obligations, including the following:

a to assure that the service is provided continuously and efficiently, without abuse of dominant position;
b to avoid monopolistic or competition restrictive practices;
c to provide for the end customers who are entitled to receive the subsidies granted by the authorities;
d to divulge the efficient and safe way to use the public service;
e to protect the environment in the execution of their daily functions;
f to facilitate interconnection access to other companies or entities providing public services and to their large customers;
g to collaborate with the authorities in cases of public calamity to avoid harm or injury to the end users;
h to register with the regulatory authority and provide notification of the commencement of services;
i to respond to damage caused to end customers; and
j to provide clear information to end customers regarding services and costs.

The obligations of transmission companies include the following:

a to provide for the transmission service as established in Law No. 6 of 1997;
b to prepare the generation expansion plan of the interconnected national system;
c to prepare the transmission expansion plan for the interconnected national system;
d to undertake basic studies required to identify possible hydroelectric and geothermic developments; and
e to expand, operate, maintain and provide services relating to the national network of meteorology and hydrology.

The obligations of distribution companies include the following:

a to provide the energy distribution service within the corresponding concession area;
b to extend their services to rural areas within the corresponding concession area;
c to comply with the terms of the concession agreement, and provide the services in a regular and continuous manner within the concession area;
d to expand the distribution networks when required to serve any increase in demand within the concession area; and
e to 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 obliges distribution companies to enter into power purchase agreements to meet the demand in their respective 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 these processes.

Following the restructuring of the IRHE, 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 be able 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.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

Law No. 45 of 2004 (as amended) establishes a number of general incentives for the promotion of energy generation systems fuelled by new, renewable and clean sources.

There are a number of tax incentives, including exoneration of import tax, tariffs, rates and other contributions caused by importats 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 carbon dioxide 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:

a  Law No. 44 of 2011 (as amended), establishing incentives for the construction and operation of wind generation plants;
b  Law No. 37 of 2013 (as amended), establishing incentives for the construction and operation of solar generation plants; and
c  Law No. 41 of 2012, establishing incentives for the construction and operation of natural gas generation plants.

The PEN, prepared by the SNE as per Law No. 43 of 2011 (as amended), 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 government affairs and in relation to citizens. Perhaps the entity that is the most advanced in taking 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 a common goal to incorporate technology to empower citizens.

VI  THE YEAR IN REVIEW

The following are among the most relevant occurrences:

a  The Third Transmission Line is mostly in operation.
b  The bidding process for construction of the Fourth Transmission Line did not result in any award. The government might redesign the contracting process and a new bid will be called.
c  The current trend in large power plant investment is natural gas. Currently, three concessions have been awarded, one of which is in operation.
d  Certain public auctions relating to the electricity sector have been suspended as a result of the coronavirus pandemic.

VII  CONCLUSIONS AND OUTLOOK

The Panamanian electricity sector is expected to continue to attract investment, perhaps with some degree of delay in the development of new infrastructure owing to sanitary measures dictated to control the spread of covid-19. A relatively clear-cut regulation to obtain the relevant concessions and licences is one of the strengths of the system.

If 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 of buying and selling power and energy.
Chapter 17

POLAND

Piotr Ciołkowski and Ada Szon

I  OVERVIEW

The Polish energy mix is based mainly on hard coal and lignite, which cover more than 80 per cent of the generation. Gas fuels, onshore wind farms, and photovoltaic, hydropower and biomass installations are used for the remainder of energy generation. There are no offshore wind farms and nuclear power units in Poland as yet, but there are plans to construct them. In the Energy Policy for Poland until 2040, published by the government, it is highlighted that the energy mix should change in the coming years; in particular, the government assumes that, by 2030, hard coal and lignite should not exceed 60 per cent of energy generation. Indeed, in the past couple of years, the development of energy from renewable sources has been significant, particularly with respect to wind farms and photovoltaics. The renewable energy is supported through various subsidy schemes (i.e., auction systems, feed-in-tariffs and feed-in-premiums). The government has also decided to support the development of offshore wind projects and dedicated regulation is being prepared. The list of the projects under development grows longer each year. However, the most advanced projects are those developed by PGE SA (the largest energy group in Poland) and PKN Orlen SA (the leading Polish oil company), jointly by Equinor and Polenergia (a private Polish company), by EDPR and Innogy.

With respect to natural gas, domestic sources cover around 25 per cent of market demand and the majority of natural gas is imported. As of 2016, Poland no longer imports gas solely from Russia, as a new liquefied natural gas (LNG) terminal in Świnoujście covers a significant part of the gas demand. To diversify the sources of natural gas, two independent projects are currently being undertaken – an extension of the LNG terminal and a new gas connection with Norway (the Baltic Pipe).

II  REGULATION

i  The regulators

The regulatory authority

The administrative authorities that are responsible for determining regulatory policy are the Minister of Climate and the President of the Energy Regulatory Authority (ERA). The Ministry of Climate is currently in charge of energy and climate departments that were previously under control of the Ministry of Energy, which was liquidated at the end of 2019. The Minister of Climate is responsible for the legislative process (i.e., preparation of

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legislative acts that are later adopted by Parliament and signed by the President) and creating policy with respect to the energy market. The role of the President of the ERA is regulator of the activities of participants in the energy market.

The President of the ERA is appointed for five years by the Prime Minister in an open and competitive recruitment process. He or she may be reappointed only once. The regulator shall be impartial and independent of any public or private entities.

The scope of the powers and obligations of the President of the ERA is very broad. His or her general obligation is to monitor the functioning of the whole energy market, that is, all segments of the energy industry, including electricity and gas markets. He or she is entitled to grant licences to conduct business activity in Poland, and approve the tariffs for electricity, gas and heat. The President of the ERA is also responsible for managing auction systems (in the area of renewable energy, cogeneration and capacity mechanism), the purpose of which is to grant state aid for selected projects. Moreover, the President has the power to control the fulfilment of the obligations set forth in the relevant legislation and to impose financial penalties for any violations of those obligations.

Main sources of law

The main legislation setting forth the general framework for the energy sector in Poland is the Energy Law. This statute defines the basic terms regarding the energy sector and provides the rights and obligations of the main market participants, defines the powers and obligations of the administrative authorities (such as the President of the ERA), and sets forth the conditions for conducting business activities in the energy market in Poland.

However, there are many other laws regulating specific sub-sectors of the energy industry. With respect to electricity, the key legislative acts that promote clean energy in Poland are the Act on Renewable Energy Sources, the Act on the Promotion of Electricity from High-Efficiency Cogeneration, and the Act on Electromobility and Alternative Fuels. Also key is the Act on the Capacity Mechanism, which provides a support scheme for electricity generation. The framework for the gas industry is set out mainly in the Energy Law, but also in the Act on Mandatory Stocks of Crude Oil, Crude Oil Products and Natural Gas and on the Principles of Proceeding in Case of a Threat to National Fuel Security and Disruptions on the Crude Oil Market.

Acts of Parliament are not the only source of law regulating the energy market. When it comes to technical information or information pertaining to very specific issues, such as rules for the preparation of the tariffs for electricity, gas and heat, they are usually set out in secondary legislation. These are regulations issued by one of the government bodies; in this case, it is usually the Ministry of Climate (previously the Ministry of Energy).

Although not legally binding, one of the key pieces of legislation that presents Polish strategy with respect to the energy sector is the Energy Policy for Poland until 2040. A draft of the Energy Policy sets out the government’s plans for the development of the energy market and the changes that will affect the industry.

As the energy market in Poland is regulated, one of the most important acts that create the legal basis for conducting business activities in the field are administrative decisions issued by the President of the ERA. The regulator is authorised to grant licences for energy companies that trade, inter alia, in electricity or natural gas, and to issue decisions through which he or she can impose financial penalties for violations of the Energy Law or other relevant acts.
### ii Regulated activities

Conducting business activities in the energy market is subject to approval by the President of the ERA. Approval is given by means of an administrative decision – in most cases in the form of a licence for conducting the business activity (this obligation does not apply to micro and small installations as, for example, the latter need only to be entered into the dedicated register).

The list of activities that are subject to a licence is set forth in the Energy Law. The obligation to obtain a licence encompasses such activities as the generation of energy and fuels, storage of gaseous fuels, transmission and distribution of energy and fuels, and trading in energy and fuels. However, there are some exceptions; for instance, a licence is not required for trading in electricity on the Polish power exchange, which is run by Towarowa Giełda Energii SA (TGE SA).

If an energy company wishes to commence one of the above-mentioned activities, it has to apply to the President of the ERA for a licence. Unfortunately, in the past couple of years, the requirements set forth for these entities have been substantially expanded and obtaining a licence in Poland requires a lot more time and effort than in most other EU Member States.

### iii Ownership and market access restrictions

There are not many restrictions imposed on energy companies willing to do business in the field of energy. However, as a licence is the key requirement for these activities, some specific limitations for licence holders and for entities applying for a licence should be mentioned.

First, a licence shall not be granted to an entity that does not have its registered office in the European Union, Swiss Confederation, a European Free Trade Association Member State or Turkey. Likewise, the President of the ERA will not grant a licence if:

- **a** an energy company:
  - is declared bankrupt;
  - has been convicted of any offence or tax offence relating to the economic activity conducted by the company;
  - is not registered for paying value added tax; and

- **b** an entity that has significant influence or has control or joint control over the applicant within the meaning of the relevant provisions of the Polish Act on Accounting was convicted in the past three years of any offence or tax offence relating to economic activity under the Energy Law.

Moreover, the President will only issue a licence to an applicant that has the financial resources and technical capacity to guarantee proper performance of the licensed activity and ensures the employment of individuals with appropriate professional competence.

Second, if an entity is granted a licence, it must observe the rules set therein and the statutory obligations provided mainly in the Energy Law. If an energy company violates any of these provisions, the President of the ERA will revoke the licence.

Energy companies may face further specific limitations, which vary according to the types of activities they are performing. For instance, electricity traders willing to become members of the Power Exchange must follow its internal regulations.
iv  Transfers of control and assignments
Mergers or acquisitions in Poland are subject to notification to the President of the Office of Competition and Consumer Protection, which is the administrative authority responsible for supervising competition on the Polish market and assessing the concentrations.

The relevant entity is obliged to submit a complete merger notification and pay the relevant fee. The President of the Office of Competition and Consumer Protection shall issue a decision within one month of the start of the merger control proceedings. However, if the President raises any competition concerns or requires a market inquiry, the deadline can be extended by an additional four months.

The European Commission may also review mergers and acquisitions. This is the case when the merger or acquisition has a community aspect (for instance, a significant presence in the European Union).

With regard to assignments, the Renewable Energy Sources Act, in particular, provides for the possibility to transfer the right to the granted subsidy in the event of the sale of a renewable energy installation. However, the transfer will require approval from the President of the ERA. Irrespective of the foregoing, any division or merger of an entity holding a licence is subject to prior notification to the President of the ERA.

III  TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES
i  Vertical integration and unbundling
As required by both EU and Polish regulations, the operation of the national transmission grids for electricity and natural gas is carried out in accordance with the unbundling rules. In both the electricity and gas sectors, the transmission system operators are state-owned companies: Polskie Sieci Energetyczne SA is responsible for the electricity grid and OGP GAZ-System SA is responsible for the natural gas grid.

The provisions on unbundling in Poland comply with the rules set forth by the European Union in the Third Energy Package. Grid activities (transmission and distribution) are separated from activities in the area of production and trade in gaseous fuels and electricity.

There are some exceptions, however. According to the Energy Law, provisions regarding legal and organisational separation do not apply to (1) a vertically integrated company with fewer than 100,000 customers connected to its distribution system or (2) a gas system if the sale of gaseous fuels during the year does not exceed 150 million cubic metres.

ii  Transmission/transportation and distribution access
The transmission system operator is required to give equal treatment in its delivery of transmission services to all final customers and electricity traders or generators. The same applies to distribution system operators. To obtain these services, the applying party must enter into a transmission or distribution service agreement. By law, they must provide access to third parties on the objective and competitive rules. The obligation concerning third-party access results from the Third Energy Package that was implemented by the Polish legislator. Polish regulations are compliant in this respect with EU rules.
iii Rates
Operators prepare the tariffs for gaseous fuels and energy in accordance with the rules set forth by the Energy Law and the relevant secondary legislation, and present them to the President of the ERA for approval. These provisions set the legal limits within which the President of the ERA may approve or reject the tariffs. Tariffs should in particular ensure the legitimate business operation costs of the operator are covered, with a reasonable return on capital and the protection of customers against unjustified rates.

iv Security and technology restrictions
The Polish regulations regarding critical infrastructure meet the requirements of Directive 2008/114/EC. Critical infrastructure is defined as systems and their functionally related objects, including construction objects, devices, installations, services that are key to the security of the state and its citizens, and to ensure the efficient functioning of public administration bodies, and of institutions and entrepreneurs. Certainly, critical infrastructure covers the energy and fuel systems. The designation of a given facility, device or installation as critical infrastructure imposes several obligations on its operators. These include preparation and implementation, in accordance with anticipated threats, of plans for critical infrastructure protection and maintenance of their own reserve systems to ensure security and maintenance of the functioning of the infrastructure until it is fully restored.

Additionally, as a part of the implementation of the NIS Directive, the Act on the National Cybersecurity System was adopted in 2018. One of the strategic sectors covered by this Act is the energy sector. The energy companies affected by the obligations arising from the Act had to obtain a decision regarding their classification as an operator of key services by November 2018. If a company has been classified as an operator of key services, it is obliged to fulfil the statutory requirements pertaining to cybersecurity.

IV ENERGY MARKETS
i Development of energy markets

Electrical energy
With respect to the wholesale power market, participants have broad access to various forms of electricity sales and to information on volumes and prices at which electricity is contracted.

There is an obligation to sell 100 per cent of the generated electric energy on the commodities exchange but there are many exceptions to this rule. For instance, it does not apply to renewable energy sources or energy generated in cogeneration plants.

Various types of companies become participants on TGE SA – electricity producers, traders and large final customers. They can act independently after joining TGE SA as a member or through brokerage houses. At the end of 2018, 77 companies had the status of a member of the power exchange, of which 42 actively participated in trading on electricity markets operated by TGE SA.

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Market participants may also conclude bilateral agreements, creating an over-the-counter (OTC) market. The prices and conditions of these contracts are known solely to the parties to the agreement.

The two sides of the retail market comprise (1) the final customers – both households and enterprises – purchasing the energy for their own use and (2) are suppliers, usually electricity traders or distribution system operators responsible for physical transportation of the electrical energy.

There is also a balancing market in Poland. This is a technical market that is essential for the functioning of the whole energy market.

**Gaseous fuels**

The sale of gaseous fuels on the Polish wholesale market takes place primarily on TGE SA. Similarly to electrical energy, there is a power exchange obligation. According to the Energy Law, any company trading in gaseous fuels is obliged to sell on the power exchange not less than 55 per cent of high-methane natural gas introduced into the transmission network in a given year. OTC, retail and balancing markets exist similarly to the energy markets. Owing to the mandatory stocks regime, the majority of the market is dominated by Polskie Górnictwo Naftowe i Gazownictwo SA and its capital group.

**ii Energy market rules and regulation**

The process of liberalisation of the energy market, set forth in the first, second and third EU energy packages, has been gradually implemented in Poland. On a power market, traders have been gradually exempted from the obligation to submit their tariffs to the President of the ERA for approval. Currently, the tariff obligation is not applicable to electrical energy traders and, hence, they are allowed freely to determine the price at which they sell energy to their customers. However, there is an exception to this rule. The President of the ERA still requires the companies that hold the status of ex officio (last resort) suppliers to submit their tariffs for approval with regard to electricity delivered to households.

As regards wholesale trading in electrical energy, as indicated above, traders are exempted from tariff obligations. Prices are established according to the market. However, when trading on organised markets such as the balancing market or TGE SA, there might be some regulations limiting this rule.

On the gas market, the approval of tariffs for sales of gas to any entities other than households was abandoned with effect from 1 October 2017. The obligation to apply to the President of the ERA for approval of the tariff for households will remain in force until 2023, after which (from 1 January 2024) the gas tariffs will be entirely eliminated.

**iii Contracts for sale of energy**

Apart from trading on an organised market such as that run by TGE SA, market participants are allowed to enter into bilateral contracts that create an OTC market. The price and other contractual terms of these bilateral contracts are the result of negotiations between the parties based on the freedom of contract rule.

The tariff obligation is still in force in certain circumstances, which affects the concluded contracts. As mentioned above, in respect of the power market, the ex officio suppliers who deliver electricity to households are subject to tariff obligation. In respect of the gas market, tariffs for households remain in force until the end of 2023.
Market developments

Corporate power purchase agreements are a new form of regulation of the sale of electrical energy in Poland. There are no legal provisions specifically regulating this issue apart from the general rules concerning the agreement on the sale of energy in the Energy Law. However, in the past few years, there has been a growing interest in direct purchase of renewable energy from generators. This trend will become increasingly popular as it is seen as a way to ensure the stability of energy prices, among other things.


V RENEWABLE ENERGY AND CONSERVATION

Development of renewable energy

The government's goal is to achieve the renewable energy target for 2020 set by the European Union at the level of 15 per cent in its gross final consumption of energy. To be able to reach this level, the government has provided strong support for renewable energy projects in 2018 and 2019.

The main form of support for these projects is state aid (approved by the European Commission). Poland has been supporting renewable energy sources through a system of tradeable certificates of origin. However, it was decided to introduce a new support scheme in the form of auctions. The winners of the auctions obtain the right to cover the negative balance between the respective auction price and the power exchange price. In the auctions held to date, the majority of the support was granted to onshore wind farm projects generating more than 1MW and photovoltaic projects generating up to 1 MW.

Small capacity hydro and biogas installations are supported by two other schemes, namely feed-in tariff and feed-in premium systems.

The government has been putting an increasing emphasis on supporting offshore wind farm projects. During 2019, the government was working on legislation setting forth the state aid rules for these installations, and other issues such as investment process aspects, tax issues and local content.

Energy efficiency and conservation

The Council of Ministers adopted the National Energy Efficiency Action Plan for Poland on 23 January 2018. This document includes a summary of the measures intended to contribute to the overall energy efficiency target of 20 per cent primary energy consumption savings in the European Union by 2020. The plan provides a description of measures to improve energy efficiency by end-use sectors. These measures include a white certificates system, a national advisory support system and information campaigns.

In the area of energy efficiency, there are also programmes prepared by the National Fund for Environmental Protection and Water Management or within the Operational Programme on Infrastructure and the Environment 2014–2020. The aim is to enhance energy efficiency in buildings, in the industry and in transport.
iii  Technological developments

In 2018, the Minister of Energy published a draft amendment to the Energy Law pertaining to the development of energy storage and smart metering. The draft amendment was still being worked on during 2019 and, therefore, the final form and rules on storage activities are yet to be determined.

Not only does the government undertake legislative actions, it also supports technological developments financially. In 2018, some energy companies received financial grants from the Operational Programme on Infrastructure and the Environment 2014–2020. One of the supported companies received a subsidy for a demonstration project of a stationary energy storage system as a smart grid element.

Projects developing smart cities are also being supported. New funds for investments are provided, for instance, to adapt the electricity distribution network in the municipalities to the requirements of the smart grid.

At the end of 2019, Polskie Sieci Elektroenergetyczne SA (Poland’s transmission system operator (TSO), implemented a system for a smart grid project (Special Protection Scheme). The aim of the project is to eliminate grid overload. The TSO is carrying out tests on the system during 2020. There are also companies looking into the possibility of using energy storage on a larger scale.

VI  THE YEAR IN REVIEW

i  The Energy Policy for Poland until 2040

In 2018, the Minister of Energy published a draft of the Energy Policy for Poland until 2040. This document, which was highly anticipated by market participants, presents the long-term strategy in the Polish energy sector. The strategy takes into account the present situation in the energy market, and the current trends and goals that the government is aiming to achieve in the next few decades. The Energy Policy has been designed to mirror the EU strategy presented in the Clean Energy for All Europeans legislative package, known as the Winter Package.

One of the key elements of the Energy Policy is a plan to construct a nuclear power plant. Although it will be quite some time yet before this comes to fruition, the government’s representatives seem determined to develop this project to gradually replace the coal-fired plants.

The government is still working on the Energy Policy and no final paper has been published yet. However, it is expected that the final decisions on the text will be made this year and that the official document will be published in 2020.

ii  Capacity mechanism

One of the milestones in the Polish energy sector in 2018 was the decision issued by the European Commission on 7 February 2018 (State Aid No. SA.46100 (2017/N) – Poland – Planned Polish capacity mechanism) in which the Polish electricity capacity market was approved. In its decision, the Commission has found the Polish capacity mechanism to be compatible with the internal market in accordance with Article 107(3)(c) of the Treaty on the Functioning of the European Union.

However, in 2019, Tempus Energy appealed against this decision to the Court of Justice of the European Union (CJEU). Previously, the same company challenged the British capacity market and the CJEU upheld the company’s complaint.
iii Renewable energy

To strengthen the auction system and make it more efficient and investment-friendly, important amendments to the Renewable Energy Sources Act were introduced in 2019, among others:

a an extension of the deadline for selling the electricity generated by a renewable energy source installation for the first time within the auction system;

b removal of the requirement to submit an environmental decision and excerpts from local zoning plan during the pre-qualification procedure; and

c an extension of the end date of the auction support scheme – from 31 December 2035 to 30 June 2039.

iv Promotion of offshore wind farm projects

As offshore wind farm projects have been attracting more attention from market participants, including major strategic international investors, the government published a draft Act on the Promotion of Generation of Electricity in Offshore Wind Farms. The main aim of this Act is to set the rules for a subsidy scheme to support the generation of electricity from offshore wind farms. According to the draft Act, offshore wind farms will be entitled to obtain the right to settle the negative balance resulting from the difference between a fixed price and the average market price (quasi CfD). The right to settle the negative balance may be awarded by way of an individual decision of the President of the ERA, in which case the fixed price will be set either in a regulation of the minister (specifically for the most advanced offshore projects) or through competitive auction in which the fixed price will be indicated in the auction bid. The subsidy will be paid out for 25 years from the first electricity being generated.

The draft Act also regulates other important issues for offshore projects. First, when applying for support, a project needs to submit a plan regarding the involvement of local equipment, devices and services (i.e., a local content plan). With respect to grid connection, the draft Act stipulates that the project owner and the TSO may conclude an agreement on the sale of the grid connection; however, the TSO would be under no obligation to enter into such an agreement.

v High-efficiency cogeneration

On 15 April 2019, the European Commission approved the support scheme regulated in the Act on the Promotion of Electricity from High-Efficiency Cogeneration. The Act sets forth the rules for providing support for electrical energy generated in high-efficiency cogeneration in cogeneration units. These new support measures replaced the old support mechanism in the form of tradeable certificates of origin.

This Act provides four support measures in the form of:

a auctions conducted by the President of the ERA;

b guaranteed premiums in an amount set by the Minister of Energy;

c individual guaranteed premiums as individually set in a decision issued by the President of the ERA; and

d a selection system – in the form of individual cogeneration premiums – for units that win the selection process conducted by the President of the ERA.
Each of the aforementioned support measures is designed for different types of cogeneration units (new, existing, modernised, materially modernised). Before obtaining support, all cogeneration units must obtain a decision from the President of the ERA allowing the unit to participate in the relevant support scheme.

The first auctions for cogeneration were conducted in the fourth quarter of 2019.

vi  Act on Energy Prices

The Act on Energy Prices was adopted on 28 December 2018. The aim of the Act was to prevent the increase in electricity prices that was expected in 2019 following rising prices of emissions allowances and coal. Its purpose in particular was to freeze electricity prices by setting price caps based on 2018 levels and to decrease the excise tax. Specific compensations for price increases are planned for 2020.

VII  CONCLUSIONS AND OUTLOOK

During 2019, the Polish government continued its work to balance the need for energy security and the need to prevent climate change, to incentivise new investments and to support existing projects, in particular based on coal. One of the major issues was an attempt to fulfil the obligations imposed by the European Union regarding climate change, particularly the target of a 15 per cent share of renewables in gross final consumption of energy in 2020. To achieve this goal, the Renewable Energy Sources Act was amended, the auctions for onshore wind farms and photovoltaics were held and appeared to be a big success. Moreover, the government decided to support new types of installations (namely, offshore wind farms), which shall significantly increase the share of green energy in the energy mix in the coming years. The construction of a nuclear power plant is still being considered as an option for shifting the energy mix from coal-fired power plants.

In light of the EU obligations, the government will most probably continue to promote renewable energy during 2020. In particular, next renewable energy auctions shall be organised. It is expected that photovoltaic projects above 1MW will be as successful as onshore wind farms in these auctions. Further, the government shall finalise its work on the act pertaining to offshore wind farm projects.

Finally, 2020 shall also be the year in which final decisions are made regarding nuclear energy in Poland, and for key decisions on how the energy mix should look by 2030.
Chapter 18

PORTUGAL

Bruno Azevedo Rodrigues and Ashick Remetula

I OVERVIEW

The Portuguese electricity mix is split into conventional generation (coal and natural gas), which contributed approximately 48 per cent of electricity generation in 2019 (enabling the base load of the system), and renewables (wind, solar, hydro and biomass), which contributed the remaining 52 per cent.

All activities in the electricity and natural gas markets, from production to supply (except in a very few specific cases), are subject to mandatory unbundling and must be developed by legally separate entities. The full liberalisation of these sectors in Portugal is due to happen in late 2020 with the extinction of regulated end-user energy supply tariffs, shifting all consumers to the liberalised markets.

Only generation supply and trading of electricity and natural gas are subject to licensing procedures, although these are mostly deregulated activities as compared with the operation, maintenance and exploration of infrastructure such as transmission and distribution grids, liquefied natural gas (LNG) terminals and storage facilities. The use of infrastructure is subject to access rates set administratively by the national regulatory authority, the Energy Services Regulatory Authority (ERSE).

In the past couple of years, in response to European Union policy and directives, legislation and regulation of the energy sector and the energy market in Portugal has undergone remarkable changes with the aim of achieving a carbon neutral society by 2050.

The government’s current policy for the energy sector is set out in the National Plan for Energy and Climate 2020–2030 (the PNEC 2030). The aim of the approach set out in the Plan is to establish the means required to achieve the European Union goals and commitments assumed by Portugal to increase the amount of energy generated by renewable sources, improve energy efficiency and reduce energy prices for consumers, without losing sight of the economic rationale. The main objectives of the PNEC 2030 are to:

a contribute to decarbonising the Portuguese economy;
b prioritise energy efficiency;
c strengthen the commitment to renewable sources of energy and reduce the country’s energy dependence;
d ensure security of supply;
e foster sustainable mobility;
f develop an innovative and competitive industry; and
g ensure a fair, democratic and cohesive transition.

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Following a significant period of standstill, mostly due to the economic crisis of 2012 resulting from interventions by the International Monetary Fund, the European Central Bank and the European Union, there have been relevant changes within the energy sector during the past year (both legislative and commercial) with the country’s strategy focusing once again on renewables (without feed-in tariffs), new investment in research and development, massive electrification of consumption and market liberalisation, all of which has allowed new players to come onto the scene.

II REGULATION

i The regulators

Several entities operate in the Portuguese energy sector, with different natures and responsibilities regarding the various aspects of the industry, but all sharing a common obligation to ensure sustainability of the sector.

The Portuguese regulatory authority of electricity, natural gas, liquefied petroleum gas in all categories and fuel sectors is ERSE, a public entity with administrative and financial autonomy, which is also responsible for regulating the national electric mobility plan. ERSE’s by-laws were enacted by Decree-Law No. 97/2002 and recently amended by Decree-Law No. 76/2019 and the entity is governed by the Framework-Law of Regulatory Bodies (Law No. 67/2013 as amended by Law No. 71/2018).

ERSE, being the economic regulator of the energy sector, has the mission to adequately protect customer interests, promote competition between market agents, contribute to the progressive improvement of environmental and economic conditions concerning the sector, and arbitrate some disputes.

ERSE has also the power to issue regulations, which are required for the performance of its tasks, and are intended to implement legislation governing the organisation, operation and compensation of the energy sector, from generation to supply and trading. Some of the most relevant of these are the Regulation on Trade Relations, the Tariffs Regulation, the Regulation on Smart Grids and the Regulation on the management of the electric mobility network operations.

Besides ERSE, the General Directorate for Energy and Geology (DGEG) is a state-administered entity whose mission is to contribute to the planning, promotion and development of the state’s policies regarding energy matters and the exploitation of natural resources. The DGEG’s nature and missions are set out in Decree-Law No. 130/2014, amended by Decree-Law No. 69/2018.

In almost all cases, when applicable, the DGEG is the competent entity for granting licences and other administrative authorisations concerning energy-related activities, such as production, establishment or exploration.

In summary, whereas ERSE is the independent regulatory authority, the DGEG is the body that represents the state in respect of energy issues, granting licences and receiving the corresponding submissions.

Lastly, the Competition Authority (AdC) ensures compliance with the rules regarding the promotion and protection of competition in coordination with ERSE, and the promotion of competition in a liberalised and free market.
Regulated activities

As mentioned above, the most heavily regulated activities are production, transmission, distribution and trading, and operation and management of the national transmission and distribution grids. Both transmission and distribution are awarded by means of utility concession agreements entered with the Portuguese state, granting the concessionaires the exclusive right to explore the grids for periods of 50 and 35 years, respectively.

There are also municipal distribution grids, mainly composed of low-voltage power lines and substations. The right to explore these grids is also granted through concession agreements, but these are awarded by the respective municipalities and are valid for 20 years.

The import, exploration, transmission, distribution and operation of LNG terminals and of LNG storage facilities are also regulated and subject to administrative authorisations. Although Portugal does not produce LNG owing to a lack of commercial findings, prospection concessions are still on the country's agenda so as to determine the extension and possible economic viability of existing resources on the coast of Algarve.

The operation of the national transmission and distribution grids, 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 grids with no physical connection to the national transmission or distribution grid, which may be operated by obtaining a licence, valid for 20 years. The request for its attribution should be delivered to the DGEG office.

Ownership and market access restrictions

Electricity generation is a free activity subject to licensing, that is to say, any company may be a relevant player regarding production or generation if it has the means and prior conditions to obtain a production or establishment licence. A licence may be requested after the company holds a title that confers the right to generate a certain amount of electricity in the determined region. The main licensing entity is the DGEG, although other entities are also involved in the procedure, such as the Portuguese Environment Agency. Moreover, after the issuance of a production or establishment licence and prior to admission into industrial exploration, the production clusters of the facility must also obtain an exploration licence, granted after an inspection to ensure that all the required technical and safety conditions to start operating have been met.

Production licences do not have a set term, unless the power is generated using public domain water resources (i.e., hydro) or the power plant is installed in maritime space that is under sovereign or national jurisdiction (i.e., offshore wind farms), in which case the term of the production licence will be that stated on the licence or concession agreement that confers the right to use public domain resources.

The transmission grid/system operators (TSOs) of the electricity and natural gas sectors are subject to full ownership under the unbundling regime that Portugal adopted. Currently, Rede Elétrica Nacional, SA (REN) is the Portuguese TSO, until 2057.

Within this framework, no entity may hold an equity participation greater than 25 per cent of the share capital of the TSO. Also, the TSO or the companies that control it may not, directly or indirectly, exercise control or any rights over companies dedicated to generation or supply of electricity or natural gas. Equally, according to Decree-Law No. 112/2012, companies dedicated to generation or supply of electricity or natural gas or the entities that control them, directly or indirectly, cannot exercise control or any rights over the TSO.
The TSO 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 oil or oil products must be legally independent from entities that conduct refining, distribution by pipeline or supply of oil or oil products.

ERSE exercises its powers to supervise the obligations of the TSO relating to the full unbundling regime, in accordance with Portuguese and European Union law.

Distribution activity, carried out by distribution grid operators, is also a regulated activity along similar lines to transmission activity.

iv Transfers of control and assignments
The transfer of any resources related to activities approved through concession agreements must obtain prior authorisation from the competent ministry.

Concentration operations that meet some predetermined requisites must be notified to the AdC and are subject to its prior approval.

After being notified, the decision should be issued within 30 to 90 days, depending on whether a thorough examination of the concentration operation is required and if any additional information or opinion was required by AdC from the company or any other competent entity, respectively.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling
Until 1995, the electricity industry was verticalised under Energias de Portugal, SA (EDP), which owned that monopoly. Then in 1995, a whole new paradigm started with the unbundling of the different energy-related activities.

Nowadays, the operation and exploration of the national transmission grids both of electricity and natural gas are carried out in accordance with that regime. In other words, the company that operates the national transmission grid (i.e., REN) may not participate in any cluster of companies dedicated to the production, distribution or supply of electricity or the distribution or supply of natural gas (albeit there is currently natural gas production in Portugal).

In this context, the EDP was required to spin off any assets relating to the transmission grid into a separate company, which is why REN was established. Concerning natural gas, GALP Energia, SA (GALP), the company in a similar position to the EDP, was also required to dispose of its natural gas transmission assets, which are now owned and operated by REN Gasodutos SA.

The distribution of electricity and natural gas is subject to a legal unbundling regime. This means that operators of distribution grids must be independent from a legal, organisational and decision-making process standpoint from other activities that are 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.

Trading activities are also subject to the unbundling regime, implying that they must be legally separate from other activities. The last-resort trader is also bound by this unbundling regime, even in relation to common suppliers.
ERSE exercises its powers to supervise the obligations of companies relating to the full ownership unbundling framework.

### ii Transmission/transportation and distribution access

To ensure equal market conditions for all market players, the concessionaires of transmission and distribution activities in the electricity and natural gas sectors must comply with specific public obligations to guarantee equal access conditions to all markets participants and to refrain from adopting any discriminatory behaviour or practices.

The safeguarding of equal conditions to all market players for access to and use of infrastructure is envisioned to create efficient and effective market conditions, promoting healthy competition and thus enhancing consumers’ experience in these markets.

### iii Rates

Remuneration for the services of transmission and distribution of electricity and natural gas are determined by ERSE and regulated in accordance with its Tariffs Regulation.

ERSE also determines the issues that must essentially be included in the grid usage agreement. These are better defined in the Grid and Interconnections Access Regulation and include duration, interruption of service conditions, payment methods and terms of resolution, which vary depending on the contracting parties (generators, suppliers, grid operators or consumers). The general terms of the grid usage agreement are submitted to ERSE for prior approval.

The Portuguese tariff system is set up in such a way that for each regulated activity there is an associated regulated tariff, and the tariff applicable to each consumer is made up of the sum of the various activity tariffs.

Tariffs for the use of regulated infrastructure are based on the provider’s cost plus a rate of return, which will determine the operator’s permitted revenue. The 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 TSO’s permitted revenue includes the application of efficiency factors to the provider’s costs, to reward efficient spending and investment, 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 formula applied to determine the permitted revenue of the service provider is set out in the Natural Gas Tariffs Regulation. Although not specifically determined in this Regulation, it is established therein that the cost of the TSO’s activity will be subject to efficiency incentives to be determined by ERSE.

### iv Security and technology restrictions

The concessionaires of electricity and natural gas transmission activities (i.e., TSOs) are also in charge of managing and monitoring the National Electric System (SEN) and the National Natural Gas System under the watchful eye of ERSE and the DGEQ.

Companies responsible for transmission have the following responsibilities:

1. to assure the capacity of both systems;
2. to operate the transmission grid;
to provide information to other operators in order to (1) maintain safety in operation, (2) estimate the level of reserves needed for safety of supply, and (3) in general, form a vital part in both systems; and
d
to coordinate with all other players to maintain the safety of the systems.

Furthermore, to safeguard the systems in the national interest, it is provided by law (i.e., Decree-Law No. 76/2019) that, in some cases, the costs incurred by market players to enter the market revert to guarantee the sustainability of the systems.

The DGEG published a Report for Monitoring the Safety of Supply of the SEN for 2017–2030 (which is expected to be amended given the latest developments in the sector). This Report described the SEN, provided future situations for the grid, planned and installed capacity and levels of energy generation.

### IV ENERGY MARKETS

#### i Development of energy markets

The Iberian Electricity Market (MIBEL) resulted from cooperation between the Portuguese and Spanish governments with the aim of promoting the integration of both countries' electric systems. The results thereof were a significant part of establishing an electricity market at the Iberian level but also at the European level, and contributing to the development of the internal energy market.

The operation of the wholesale market at any given time is determined by the mix of production structure, import capacity, the imperfect meshing of the grid, the inelasticity of demand and the system reserve margin.

One important aspect of MIBEL is the principle of reciprocal recognition of agents: if an agent is granted the status of producer or supplier by one country, it is automatically recognised by the other, and therefore has equal rights and obligations.

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 areas 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.

OMIP is the operator of the Portuguese division of MIBEL and is responsible for the management of the derivatives trading market. On the OMIP trading platform, all features of the futures agreements are standardised. Therefore, when an agent opens a position, it only needs to choose the agreement it will trade, the relevant quantity and the price (except if it is a market offer). These contracts are marked to market each day.

The operations carried out by OMIP are registered in trading accounts and simultaneously registered in clearing accounts through which the financial settlement of the agreements is assured.

The Iberian natural gas market, MIBGAS, offers its users the possibility of trading within-day, day-ahead, balance of month and month-ahead products at the Iberian level.
ii Energy market rules and regulation

The legal framework applicable to the organisation of MIBEL is based on the MIBEL Agreement, entered into between Portugal and Spain, regarding the establishment of an Iberian electric energy market. It establishes the general terms and conditions for the organisation and management of MIBEL, namely the regime for the spot and derivatives markets.

The MIBEL derivatives market, because of its financial nature, is directly subject to Portuguese law and jurisdiction and, hence, to the legislation applicable to this type of market, namely:

a the Portuguese Securities Code;

b the Portuguese Securities Market Commission (CMVM) Regulations; and

c the CMVM instructions.

This market is under the jurisdiction of the CMVM, with a direct connection to ERSE.

Moreover, 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 rules.

MIBGAS and trading, on the other hand, are governed by Spanish law.

iii Contracts for sale of energy

Any entity (producer, supplier, consumer or other player) registered as a market agent (as required by Portuguese law) may enter into a bilateral power purchase agreement.

As regards the applicable legal and regulatory provisions, the terms of a power purchase agreement are defined between the contractors. The market agents must notify the TSO (since it is the global system manager) of the completion of an agreement and indicate the term for which it is executed.

iv Market developments

The full transition to a liberalised market is still a work in progress and the process of phasing out end-user regulated tariffs is still under way. Decree-Law No. 75/2012 approved the timetable for the gradual phasing out of these tariffs for normal low-voltage electricity consumers. Having been delayed several times, the termination of all regulated tariffs is set for the end of 2025.

During the intervening period, transitory tariffs with a gradually increasing component will be applied by ERSE.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

With the purpose of reducing energy imports and dependence and following the enactment of several European Union directives regarding a carbon neutral society by 2050, Portugal has been developing and investing significantly in renewable sources of energy.

The renewables sector finally woke up in 2019 and carbon emissions dropped by almost 5 million tonnes. Portugal has become known worldwide for its leading role in the promotion of renewable energy, thanks to significant developments and investments in wind and solar projects.
Decree-Law No. 76/2019 was an important step towards the generation of electricity from renewable sources owing to the new public tenders instituted to attribute grid capacity to energy from renewable sources. Moreover, the new and more simplified regime for self-consumption and prosumers is also likely to boost this sector in the years to come.

The year 2019 was also marked by the public tender of solar photovoltaic capacity, the approval of the Carbon Neutral Road Map 2050, the announcement of the end of coal-fired power plants by 2023 and the European climate ambition, embodied by the European Green Deal.

As regards the tender that took place in summer 2019, 1,292MW were allocated, with record tariffs worldwide. Nowadays, the procedure for attributing grid capacity and licensing projects includes a competitive electronic auction procedure, in which the interested promoters may bid on lots for granting of capacity. In this public procedure, two types of remuneration schemes were defined, based on a strategy of contribution to the sustainability of the SEN for the next 15 years: the guaranteed remuneration and the system contribution schemes. The success of this new way of attributing grid capacity means that the government is likely to launch more tenders in the next couple of years for solar, wind, hybrid, with storage, among others. In fact, a new auction for 2020 was recently announced, to take place in August and to be held on similar terms to those used in the past. The total auction capacity to be awarded, in relation to the August auction, will be 700MW and it will introduce a major innovation: the possibility of submitting projects providing storage, in conjunction with a new remuneration scheme. By means of this new specific remuneration scheme, the promoter (1) receives the capacity payment at a set price, (2) pays the insurance activation payments against MIBEL price rises, (3) pays the penalties for any contracted availability breaches, and (4) sells the production in the wholesale markets at the market price. Overall, the promoter will enter into an availability agreement (a draft of which will be provided beforehand) with the TSO, abiding by the market rules and ensuring the fulfilment of certain technical parameters to be defined by the TSO.

Further to the above-mentioned procedure, for situations where grid capacity is not available, Decree-Law No. 76/2019 has made it possible to enter into an agreement with the grid operator by bearing the costs incurred by reinforcement of the grid to connect the desired project.

Moreover, in an attempt to stop the licence trading market and to overcome the scarcity of grid capacity, this new legal framework introduced a prohibition on transferring the grid capacity title and the production licence until the issuance of the operation licence.

As regards the performance of renewable electricity in 2019, all the power plants in mainland Portugal produced 56 per cent of the country’s energy, most of which was from wind (28 per cent). There has also been a significant improvement in electricity production through solar photovoltaics.

Towards the end of 2019, Portugal broke the record for 100 per cent renewable consumption: on the 18 December, it began an uninterrupted period of 131 hours, during which renewable generation was sufficient to cover consumption.

Overall, the main incentives behind government policy relate to renewables and new technologies and systems capable of contributing to accomplishing the goals set by Portugal itself and the European Union.
ii Energy efficiency and conservation


One of the primary goals of the PNEC 2030 is to prioritise and boost the development of energy efficiency projects. The government has introduced the following measures, among others, to set that up in the next couple of years:

a to ensure the improvement of efficiency in energy consumption in the various economic fields;
b to review the legal framework for energy management and efficiency and to strengthen the monitoring systems;
c to promote the rational use of energy by end users;
d to capacitate the energy sector with professionals qualified in energy efficiency;
e to simplify procedures and reorient and strengthen funds and funding programmes;
f to encourage research and development in the field of energy efficiency; and
g to promote increased penetration of more efficient equipment and products through the renewal of existing ones.

The promotion of energy efficiency measures is achieved by various instruments.

Since 2006, ERSE has been implementing the Consumption Efficiency Promotion Plan (PPEC), which is a competitive mechanism to support measures that make a real contribution to reducing consumption in the electricity sector.

Under the PPEC, incentives are awarded for the promotion of measures aimed at improving efficiency in electricity consumption. These measures are carried out by suppliers, operators and organisations that promote and protect the interests of electricity consumers in Portugal. The actions result from specific measures, 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 implemented by the promoters, considering the amount available in the PPEC annual budget, which is approved at the beginning of each regulation period for each year of its term.

The implementation of the measures approved by the PPEC for 2017–2018 was carried out until the end of 2019. The 75 measures supported by that edition were selected through a competitive procedure from the 224 measures submitted.

iii Technological developments

In the past couple of years, Portugal has been investing in new energy models for mobility that aim to improve quality of life and reduce pollution.

The Electric Mobility Network, an integrated network linking more than 1,000 charging stations, managed by MOBI.E, enables electric cars to recharge, using just a simple card.

The Portuguese government has been covering some of the costs associated with the use of electricity grids for electric mobility.

Furthermore, the emergence of the legal framework applicable to small production units made possible the emergence of prosumers (i.e., small producers that generate electricity for self-consumption and sell the remainder, even to the public grid in some cases). This is currently possible since the emergence of smart metering systems, and the increased development of these systems around the country.
There have also been amendments to Portuguese law with the aim of enabling a new market niche in this sector: storage of electricity. Even though further legislation is still required, it sets a new paradigm, opening the market to the energy storage options that have been almost impossible until recently. Moreover, the experience gained from Graciólica project (located in the Azores archipelago and using a combination of solar, wind and a storage facility) will bring a new focus and investment in storage options, allowing more efficient facilities in the foreseeable future.

Another significant development relates to the generation of offshore wind energy. The Windfloat project was the first to be developed in Portugal using floating technology. The success of it will result in the implementation of more of these kinds of projects since the technological difficulties regarding the installation of these facilities in Portugal have now been overcome.

Hybridisation is another of the significant developments in the recent past. Facilities may now produce electricity from different primary sources in the same infrastructure and connection point of the grid. This allows an increase in generation and a greater energy mix (albeit different technologies remain subject to different licensing requirements). Combining wind and solar has already caught the eye of major players in the industry. This would allow projects to maximise output and efficiency given the different availability of the sources, without incurring more costs for the grid operator in respect of investment in infrastructure.

VI THE YEAR IN REVIEW

The core and most important legal framework regarding the Portuguese market, namely the electricity market, is Decree-Law No. 76/2019, which brought about remarkable change. Moreover, the success of the public tender for solar photovoltaics envisioned therein, which took place in summer 2019 with record-breaking low tariffs, has made it possible to anticipate that this kind of tender will become the norm for attributing grid capacity. In fact, a second auction is scheduled to take place in August 2020.

With that same legislative paper, the process of licensing has been reduced, allowing more and new players to enter the Portuguese energy sector.

Moreover, the Portuguese tariff deficit decreased substantially to almost half (€2 billion). The measures taken by the government have finally started to be reflected, largely as a result of the Energy Sector Extraordinary Contribution and energy efficiency.

The phasing out of coal-fired power plants is also something to monitor as the projects due to replace them are likely to be innovative and ambitious, and in which the production of ‘green’ hydrogen will have a significant role. The government has announced its firm commitment to maximise the renewable capacity installed by developing large-scale projects for the production of hydrogen, which also benefit from some of the existing infrastructure, notably pipelines. A cluster of companies is being formed to explore a fully dedicated large-scale solar photovoltaic plant and a large hydrogen electrolysis plant, both located to the south of Lisbon. These are the first of several projects which will allow future use of idle renewable capacity through an alternative process of storing energy and reintroducing that energy in the market as a green fuel.
VII CONCLUSIONS AND OUTLOOK

The Portuguese energy market is mature, with a mix in which green energies have been gaining a significant and exponential presence.

The main challenges in the energy market relate to the completion of the liberalisation of the electricity and natural gas industries, extended until late 2025. 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 the next months and years, there is support for a rapid increase in renewable energy communities, set up by groups of companies or natural persons, that jointly will be able to generate energy mainly for self-consumption.

Public tenders will become more frequent and will be the main procedure to attribute grid capacity for electricity generation. Storage will also be an important part of these tenders in the foreseeable future.

Electric vehicles are also taking a significant share of the market, in part due to technological advances already discussed, and advances in battery energy storage.

The Portuguese Parliament approved the President’s proposal to declare a state of emergency in March 2020, owing to the covid-19 pandemic. It is not yet possible to determine the scale of the disruption that this pandemic will have on the energy market, even though, at the time of writing, Portugal is undergoing a period of gradual return to normality. The second solar auction that was scheduled to happen during the second quarter of 2020 is now due to happen in August. Yet the government has acknowledged that the outcome of the first solar auction that took place during the summer of 2019 – which set a new world record in terms of the price per MWh (one of the lowest to date) – may be significantly affected. Furthermore, projects that are still undergoing licence procedures may have to be extended because of the detrimental effects of the pandemic on the availability of engineering, procurement and construction services and the supply of equipment. It is yet to be determined how the government will deal with material adverse changes. The deadlines set for the permission and construction stages of development have been put on hold for the time being.
I OVERVIEW

Russia’s vast geography is an important determinant of its economic activity. It has the world’s largest proven natural gas reserves and acts as the largest exporter of natural gas. It is also the second-largest exporter of petroleum. Enormous energy resources enable producers to generate electricity in thermal, hydro and nuclear power plants and by using gas, oil and coal.

Revenues from the oil and gas industry make up the bulk of Russia’s budget, therefore government regulation in these areas has an important role in the life of the country. However, as a result of global market fluctuations and sanctions imposed by the United States, the European Union and most European countries, Russia is now seeking new markets for the export of petroleum.

Since oil, gas and coal are all non-renewable natural resources, there is a continuing process of development of renewable energy sources and their implementation in the Russian energy system. This is also part of the efforts to reduce the economy’s dependence on the energy sector, particularly oil and gas, as declared repeatedly by the Russian government.

The aforementioned trends have also led to the creation and development of the relevant legal framework.

Government regulation in this sphere is generally aimed at creating favourable economic and organisational conditions for the activities of legal entities.

II REGULATION

i The regulators

In accordance with its Constitution, Russia is a federated state, comprising 85 constituent subjects (i.e., regions within the federation). Some powers are vested exclusively with federal authorities, some are jointly exercisable by the federal and regional authorities, and some are used only by the regional authorities. The Constitution also grants some powers to local (municipal) governments at the lowest level, which are formally separated from the system of the state (federal and regional) government bodies.

In general, the Russian legal system emulates the continental European legal family. The Constitution, federal laws and regional laws form the foundation. At the next level are presidential decrees, resolutions of the Russian government and the decisions of various...
ministries, which are used as by-laws to support and develop the provisions of primary legislation. Local (municipal) governments are also authorised to enact their own legislative acts, although they have less importance in respect of energy regulation.

The main sources of legal regulation of the energy industry in Russia are the following.

**General**

- **a** The Law on Natural Monopolies No. 147-FZ dated 17 August 1995;
- **b** The Law on Procedures for Foreign Investment in Companies of Strategic Significance for National Defence and Security of the Russian Federation No. 57-FZ dated 29 April 2008 (the Law on Strategic Companies); and

**Electricity sector**

- **a** The Law on Use of Nuclear Power No. 170-FZ dated 21 November 1995;
- **b** The Law on Electricity No. 35-FZ dated 26 March 2003 (the Law on Electricity); and

**Oil and gas sector**

- **a** The Law on Subsoil No. 2395-1 dated 21 February 1992 (the Subsoil Law);
- **b** The Law on Gas Supply in the Russian Federation No. 69-FZ dated 31 March 1999; and
- **c** The Law on Gas Exports No. 117-FZ dated 18 July 2006.

**Renewable energy and energy efficiency**

- **a** The Law on Energy Saving and Energy Efficiency Increase No. 261-FZ dated 23 November 2009 (the Energy Efficiency Law);
- **b** The State Policy on Energy Efficiency Improvement by Use of Renewable Energy Sources, adopted by the Decree of the Russian Government No. 1-r dated 8 January 2009; and

The regulation powers in the energy industry are mainly concentrated at the federal level.

The Russian government is vested with the competence to determine and pursue state policies and to regulate economic activities in the whole energy sector, including use of natural resources.

The Federal Ministry of Energy is responsible for implementation of state policies and regulation in the fuel and energy complex, including electric power, oil extraction and refining, gas, coal, shale and peat industries, major oil, gas and petroleum product pipelines and renewable energy sources. It has the general competence in energy efficiency and heat supply.
The Federal Ministry of Industry and Trade also implements state policies in the spheres of energy efficiency and use of renewable energy sources but it is mainly responsible for technical regulation in these areas: namely, adoption of energy efficiency and local content requirements, among other things.

The Federal Ministry of Natural Resources and Ecology exercises state administration in the field of environmental management, protection and safety.

The Federal State Agency on Subsoil Use is in charge of the issuance of licences for subsoil use. It is also responsible for maintaining federal and territorial geological data on subsoil and the state cadastre of deposits.

The Federal Anti-monopoly Service regulates compliance by natural monopoly entities with anti-monopoly requirements. These areas of natural monopoly include:

- electric power transmission services;
- services in operational dispatch management in the electric power sector;
- transportation of oil and petroleum products by major pipeline;
- transportation of gas by pipeline; and
- thermal energy transmission services.

The Federal Anti-monopoly Service also exercises control over foreign investments in companies having strategic significance for national defence and security. According to the Law on Strategic Companies, the relevant strategic activities include geological surveys on subsoil or exploration and extraction of minerals on subsoil plots of federal significance as well as the activities in the natural monopoly areas as listed above.

Furthermore, the Federal Anti-monopoly Service regulates the setting of state prices (tariffs) for goods or services supplied by natural monopolies and other entities, including heating supply, regulated tariffs for electric power (capacity) supply and transmission services, and regulated tariffs for gas supply and transportation.

The Federal Service for Environmental, Technological and Nuclear Supervision is generally responsible for carrying out federal state supervision of the safe and secure use of nuclear, electric, gas and thermal power grids and facilities and other hazardous facilities.

Finally, the Federal Service for Supervision of Natural Resources Use supervises the proper use of subsoil.

Depending on the particular segment of the energy industry and the regions in which the relevant activities are carried out, many of the aforementioned federal authorities have respective structural or regional subdivisions that deal with the dedicated area.

### ii Regulated activities

#### Electricity

From both the technological and legal standpoints, the electric power industry includes:

- production of electric power by generating facilities;
- transmission of electric power via grids;
- providing services on operational dispatch management; and
- sale of electric power to customers, including end consumers.
Except for generation of nuclear power and, subject to certain exceptions, the sale and resale of electric power to customers (including end consumers) on a retail market, no activities relating to production, transmission or sale of electric power require a licence or any other special permit. However, if the relevant power-generating facility uses flammable substances (gas or oil) in volumes exceeding the established limits, then their operation may be subject to licensing. The same requirement also applies to gas transportation via gas distribution or gas consumption networks with pressure exceeding 0.005 megapascal.

The relevant licences are issued by the Federal Service for Environmental, Technological and Nuclear Supervision.

Since there are united (national) electricity grids in Russia, electric power transmission services for all major grids are provided by the state-owned joint-stock company Federal Grid Company and its interregional and regional subsidiaries. These entities are responsible for operation and development of the united (national) electricity grid.

Other owners of electricity grid facilities can also apply for grid company status provided that their grids are duly connected to the united (national) grid.

Operational dispatch management services are provided by another 100 per cent state-owned entity – joint-stock company System Operator of the United Energy System. No other companies are permitted to provide the services for operational dispatch management in the electric power sector.

**Oil and gas**

Under the Subsoil Law, all natural resources in situ, including oil and gas, are state property. Russian law does not provide for any rights of an owner or tenant of a plot of land to the subsoil under that plot of land unless it holds the relevant licence.

According to the Subsoil Law, subsoil plots can be licensed for geological surveys, exploration and extraction of minerals for a fixed term or without any time limit. Depending on their significance, subsoil plots can be either federal or regional. As a general rule, the licences are granted following the tender process.

There are several types of licences:

- for geological exploration and assessment of a subsoil plot;
- for appraisal and production of minerals; or
- a combined licence allowing geological survey, exploration and production.

Among other things, the terms and conditions of the licence stipulate the production volume and the payments for subsoil use.

A subsoil user who has been awarded an exploration and production licence has the exclusive right to use the relevant subsoil plot, provided that it duly follows the requirements set out in the licence. Breach of the terms and conditions may result in the licence being suspended or terminated.

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2 However, from 1 July 2020, it will be mandatory for those who sell or resell electric power to hold such a licence.
iii Ownership and market access restrictions

Electricity

Except for generation of nuclear power, there are no special restrictions as to ownership of new or existing power generating facilities. Therefore, their owners may freely transfer their rights to third parties. However, to access the electric power (capacity) wholesale market, new owners will have to follow the established procedure (see Section IV).

All civil nuclear power-generating facilities in Russia are owned and operated by the state corporation Rosatom, acting through its subsidiary. It is generally prohibited to transfer ownership to third parties.

The owners of electricity grid facilities connected to the united (national) grid may sell those facilities to third parties. However, the joint-stock company Federal Grid Company, as the entity responsible for the operation and development of the Russian united (national) electricity grid, has a pre-emptive right to purchase them.

Oil and gas

The ownership of assets relating to oil and gas exploration and production is subject to specific restrictions.

The Subsoil Law provides for several requirements to the legal entities that intend to apply for a licence for subsoil use, namely technical, technological, human resource and financial capabilities.

Some natural resource deposits are subject to special national security restrictions. In terms of oil and gas, these are deposits with reserves of 70 million tonnes of oil or more or reserves of 50 billion cubic metres of gas or more (deposits of federal significance). Acquisitions of shares or indirect control over the companies that hold the licences to subsoil plots of federal significance are subject to significant restrictions (see Section II.iv).

The transportation of oil and petroleum products within Russia is operated by joint-stock company Transneft, the Russian transport natural monopoly, which owns and operates trunk pipelines.

As for natural gas, joint-stock company Gazprom has a monopoly to export natural gas by pipeline. Historically, this monopoly has also extended to the export of liquefied natural gas (LNG).

Gazprom, as owner of the United Gas Supply System, must provide independent gas producers with access to this system, subject only to availability of the required capacity, compliance of the transported gas with established quality and technical parameters, and availability of pipelines to consumers.

iv Transfers of control and assignments

Pursuant to the Law on Strategic Companies, the following activities are classified as having strategic significance for national defence and security:

a geological surveys on subsoil or exploration and production of minerals on subsoil plots of federal significance;
b electric power transmission services;
c services on operational dispatch management in the electric power sector;
d transportation of oil and petroleum products by major pipeline;
e transportation of gas by pipeline; and
f thermal energy transmission services.
Transactions that result in foreign investors or Russian corporate groups with a foreign element gaining control over a company involved in the aforementioned activities (the strategic company) must be cleared by the specifically appointed government commission.

The procedure for obtaining the relevant approval is lengthy and cumbersome. However, if it is not obtained for a transaction that requires approval, the respective transaction is deemed void.

Foreign investors are considered to gain control over the strategic company if they acquire more than 50 per cent, directly or indirectly, of the voting shares in the strategic company (or 25 per cent or more if the strategic company operates a subsoil plot of federal significance) or otherwise gain effective control over the strategic company.

Certain transactions require post-transaction notification, which must be made within 45 days of the change of control taking effect. One example of this is when foreign investors acquire at least 5 per cent of the shares in the strategic company.

The Law on Strategic Companies further prohibits foreign states, international organisations and organisations controlled by them from gaining control over the strategic company.

It also provides that foreign states, international organisations and organisations controlled by them must obtain prior approval from the Federal Anti-monopoly Service when acquiring more than 25 per cent, directly or indirectly, of the voting shares in the strategic company (or more than 5 per cent if the strategic company operates a subsoil plot of federal significance).

Further, foreign investments in the Russian energy sector are also covered by the general restrictions of the anti-monopoly legislation with respect to economic concentration.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Electricity

As part of the Russian electric power industry’s complex shift towards decentralised public regulation, the Law on Electricity, as a general concept, determined that economic relations in this sector are based on market mechanisms and competition. At the same time, the Law on Electricity provides for such concepts as energy security and uninterrupted and secure operation of the electric power sector.

As a result, the Russian electricity and capacity market today includes both typical market elements and public regulation mechanisms.

On the one hand, production of electric power in hydropower and nuclear power industries is currently highly concentrated. As mentioned above, there are also natural monopolies in the areas of electric power transmission services and services of operational dispatch management.

On the other hand, many relatively small generating companies, including foreign ones, are admitted to the wholesale market in thermal power generation or renewable energy sectors; and their share of the market is increasing.

Oil and gas

There are several vertically integrated joint-stock companies in the oil and gas sector – both privately owned companies (in some cases, with a substantial foreign stake) and state-owned companies. The major ones are Rosneft, Lukoil, Gazprom neft, Surgutneftegas and Tatneft.
The concept of vertical integration was used from the beginning of economic reforms in the late 1990s. Now the general structure of the market players is stable. Active foreign investments in the sector are restricted as a result of sanctions imposed by the United States, the European Union and most European countries.

ii  Transmission/transportation and distribution access

*Electricity*

In Russia, it is declared that any third party is granted non-discriminating access to such services as electric power transmission and operational dispatch management.

Since these services belong to natural monopolies, the rules of access are generally regulated by the Wholesale Market Rules and have to be followed by both producers and consumers of electric power and operators (owners) of transmission and distribution facilities.

*Oil and gas*

Similarly to the electricity sector, it is declared that any third party may access oil and petroleum product transportation services via major pipelines to consume these products on the Russian domestic market and for their export.

The same also applies to non-restricted access to the gas market and particularly gas transportation and distribution networks.

Since these transportation and distribution services belong to natural monopolies, the rules of access are generally regulated by the officially established rules that have to be followed by both producers and consumers of oil and petroleum products and gas and operators (owners) of transportation and distribution facilities (namely, Gazprom for gas networks and Transneft for trunk oil pipelines).

iii  Rates

*Electricity*

As stated in the Law on Electricity, the prices (tariffs) applied by entities providing the electric power transmission services are publicly regulated. The Russian government has established guidelines for pricing and the rules for state regulation of prices (tariffs) in the energy sector.

According to the established rules, the primary goal of pricing is to balance the economic interests of producers and consumers of electric power and to ensure a return in capital investments. Pricing should also consider the requirements and incentives provided by applicable laws on energy efficiency and renewable energy.

The prices (tariffs) may be set either numerically or as a formula or principles of calculation of such prices (tariffs).

To ensure predictability and stability, it is expressly provided that the prices (tariffs), specifically for electric power transmission services, are set on a long-term basis (i.e., for a minimum of 12 months, unless otherwise provided by law or government decision).

*Oil and gas*

Oil prices are not regulated in Russia. They are mainly based on current market fluctuations and depend on the rates of applicable taxes and duties.
The Russian government establishes the principles for setting gas prices and tariffs for gas and oil transportation. These principles take into account reasonable expenditure and profits as well as investments in transportation networks. Tariffs may be also differ between the Russian territories.

iv Security and technology restrictions
Fuel and energy facilities in Russia are subject to both physical protection (against technological accidents, acts of terrorism and other unauthorised intervention) and cybersecurity.

According to the Law on Security of Critical Information Infrastructure of the Russian Federation No. 187-FZ dated 26 July 2017, information and automated management systems, which are used in the energy sector, in the sphere of nuclear energy and in other sectors of the fuel and energy industry, are attributed to critical information infrastructure facilities. Depending on their importance, these facilities must be officially categorised. The owners of these facilities have to develop and adopt internal regulations on the provision of security of their critical information infrastructure.

Additional requirements are provided in respect of critical facilities of critical information infrastructure. In particular, the following activities are prohibited in these critical facilities:

a to grant remote access to software and hardware to persons who are not employees of the owner;
b for persons who are not employees of the owner to have local non-controlled access to software and hardware; and
c to transfer any information to the developer or manufacturer of software or hardware without control by the owner.

IV ENERGY MARKETS
i Development of energy markets
There is no common market for electric power (capacity) and oil and gas in Russia.

Russia’s electricity and capacity sector includes a wholesale market and a retail market for electric power and capacity.

The participants in the wholesale market are large producers and customers of electricity and capacity.

Unlike the wholesale market, the retail market resells electricity to end consumers, generally at publicly regulated tariffs.

The Wholesale Market Rules, among other things, set out the procedure for accessing the wholesale market and the wholesale market operation concepts.

The main concepts of the wholesale market operation include:

a free non-discriminatory access to the wholesale market for all electricity sellers and customers;
b free choice by the wholesale market’s participants in respect of the method of sale and purchase of electricity;
c accounting specifics for certain wholesale market participants; and
d obligatory purchase of capacity by the wholesale market participants when required by the Russian government.

The oil and gas markets can be subdivided into the domestic market and the export market.
ii Energy market rules and regulation

Electricity

As already mentioned, the wholesale market is regulated by the Wholesale Market Rules. The government further determines the zones (territories of Russia) in which market prices or regulated tariffs must apply, including technologically isolated zones that are not connected to the Russian united electricity grid.

Oil and gas

The gas market is generally regulated by the Rules of Gas Supply adopted by the Decree of the Russian Government No. 162 dated 5 February 1998. These Rules govern relations between suppliers and purchasers of gas, including gas transportation and distribution companies.

In the gas supply sphere, the state pricing policy is designed to:

a create favourable conditions for seeking, exploring and developing gas deposits, and for extracting, transporting, storing and supplying gas;
b expand the sphere of application of market prices to gas;
c exercise control over the application of state regulated prices (tariffs) in the gas supply sphere;
d reimburse the organisation owning the gas supply network for gas payment debts incurred by non-disconnectable consumers;
e encourage the use of gas as a motor fuel; and
f ensure the competitiveness of Russian gas on the world energy market.

iii Contracts for sale of energy

Electricity

According to the Wholesale Market Rules, the large suppliers and customers of electricity and capacity, as a condition to accessing the wholesale market, must enter into a contract for connection to the trade system of the wholesale market, and thus become members of a self-regulating organisation of wholesale market participants (the Market Council).

The main goals of the Market Council are to maintain a balance of interests among the wholesale market participants, and ensure the integral operation of its commercial infrastructure. In pursuing these goals, the Market Council, among other things, keeps a register of the wholesale market participants, sets out the wholesale market regulations and standard forms of contracts used by its participants, and monitors compliance with these regulations and contracts.

In addition, an important role in the wholesale market is undertaken by organisations that provide its technological and commercial infrastructure. One of these infrastructure organisations is a commercial operator (Administrator of the Trade System of the Wholesale Market for Electric Power, joint-stock company that is a subsidiary of the Market Council), which is noted specifically for its activities in arranging trading on the wholesale market. In particular, it holds tenders, and registers electricity and capacity sale and purchase contracts made on the wholesale market.

The existing wholesale market consists of a number of segments, each of which has its own terms and conditions of entry into electricity sale and purchase contracts. For instance, in the regulated contracts segment, electricity is sold at set tariffs and the commercial operator selects, at its discretion, suppliers and customers that are required to enter into a relevant electricity supply contract.
This method largely applies when electricity is sold to the general public. This segment also covers the sale of electricity generated from renewable energy sources, in which case tariff rates are based on the localisation level of the relevant generating facilities.

On the day-ahead spot market, electricity sale and purchase contracts are based on the equilibrium price determined by the commercial operator, which compares and selects the competitive price bids submitted by suppliers and customers.

Finally, in the non-regulated electricity segment, contracts are made between suppliers and customers by terms negotiated between them (including the price and scope of supply).

A separate part of the wholesale market is the capacity market, where suppliers provide their customers with a fee-based right (and often an obligation) to enter into future contracts for the purchase and sale of certain volumes of electricity.

The created capacity market facilitates issues such as the financing of new generating facilities, compensation for electricity producers’ fixed costs, and ensuring electricity supply reliability and security.

As in the case of the electricity sale and purchase market, contracts made on the capacity market may be either regulated or non-regulated.

**Oil and gas**

Gas is supplied on the basis of agreements between suppliers and consumers in accordance with the general civil laws and the rules approved by the government for gas supply and use of gas in Russia.

The pre-emptive right to conclude gas supply agreements is enjoyed by the purchasers of gas for state and municipal needs, utility, domestic and social needs of the people.

iv  Market developments

**Electricity**

The Russian electricity and capacity market today is a complex structure that consists of both typical market elements and public regulation mechanisms. The main problem with the existing system is low competition, owing to, on the one hand, the need for the smooth and reliable operation of the electric power sector and, on the other, the relatively small number of electricity and capacity sellers on the wholesale market.

New incentives are currently being sought to increase competition within the market, particularly by increasing the sales of electricity (capacity) that is produced using renewable energy sources.

**Oil and gas**

According to the Energy Strategy of Russia for the period up to 2030 adopted by the Decree of the Russian Government No. 1715-r dated 13 November 2009, the main goal in the oil and gas sector is to diversify the export markets away from the core European market to prospective eastern markets, and to develop oil and gas production and energy infrastructure in the northern Arctic, east Siberia and the far east of Russia. Another objective is to develop and deliver LNG.
V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

After years of being considered an oil and gas country, the Russian government decided to develop a renewable energy sector and promote renewable energy projects in the country.

The legal framework for this progress was set up in 2009. The government approved the State Policy on Energy Efficiency (the Policy), and subsequently adopted the National Strategy for the Development of Renewable Energy. Both documents became the basis for adopting more specific regulation establishing this new legal regime.

This new legal regime replaced the ‘premium scheme’, whereby the government had proposed to motivate market players through premiums payable to them, with the ‘capacity supply scheme’.

The capacity supply scheme implies a predetermined price paid to the capacity supplier which is based on the beneficial tariff. A supplier who meets the Russian localisation requirements can use this beneficial for 15 years and thus receive a guaranteed return on the investment used for building and operating a renewable energy generating facility with a 12 per cent margin.

The existing legal regime applies to solar, wind, moderate-sized hydro and waste treatment power sources generating more than 5MW of renewable power.

The capacity volumes are offered to potential suppliers at annual tenders, which are conducted by the Market Council for each type of power-generating facility: photovoltaic, wind and water energy. In 2017, the procedure was extended to waste-burning energy sources.

The winners of each tender conclude long-term energy supply agreements (CSAs), under which a capacity supplier must build its renewable energy generating facility and put this facility into operation by a certain date defined in the CSA. The capacity should then be supplied to the Russian power system, where large industrial consumers are obliged to buy it. A mandatory CSA form is approved by the government and cannot be renegotiated by the potential supplier.

Failure to meet the deadline for implementation of a renewable energy project indicated in the respective CSA may lead to a significant contractual penalty.

The Policy covers the period until 2024 with the goal of ensuring that the share of renewable energy reaches 4.5 per cent of the entire energy sector. During 2018 and 2019, tenders of 95 per cent of the targeted power generation capacity in the solar and wind sectors were awarded to the potential suppliers. So far in 2020, no new tenders have been announced. New regulations that will govern the activities of the renewable energy market are expected to be implemented by 2024.

The current framework has raised many controversies. Large industrial consumers have objected to the extension of the Policy, instead calling for the adoption of alternative measures to support the renewable energy sector. The main reasons for their dissatisfaction are the price of the power capacity and the increase in the costs of implementing the renewable energy projects. However, the key investors in the Russian renewable energy sector (such as Rusnano and Renova) have requested an extension of the Policy until 2035. These companies believe Russia’s renewable energy sector is still too young to function under the general competitive rules of the Russian energy market applicable to other sectors. In fact, it has been already announced that, subject to certain modifications, the existing capacity supply scheme implemented under the Policy will be applicable until 2035.

In parallel, the Market Council initiated development of the concept of Russian green certificates, which may be used to supplement the existing structure. Work is being done by
the Market Council in this respect; thus, for the first time in Russian history, the concept of Russian green certificates is starting to seem a workable option. By selling these green certificates, consumers could reduce their total amount of payments for capacity under the current support mechanism of CSAs, while for the power suppliers, the green certificates could act as a source of return on their investments.

Consequently, the renewable energy market is awaiting changes to the legal regime, which will certainly provide a new impulse to further development in the industry.

ii Energy efficiency and conservation

The Energy Efficiency Law created a legislative, economic and organisational stimulus for energy saving and increasing energy efficiency.

To facilitate the efficient use of energy resources and to support and encourage energy saving, the Energy Efficiency Law provides for several groups of energy efficiency requirements applicable to various sectors, notably including the construction sector and the public sector. For instance, energy consumption reduction targets are set for publicly financed institutions. Moreover, companies with state participation and those carrying out regulated types of activities are also obliged to adopt and implement programmes aimed at increasing energy efficiency.

According to the Energy Efficiency Law, commercial companies may carry out a voluntary energy audit, which has the aim of:

\begin{itemize}
  \item [a] collecting objective data on the volume of energy used;
  \item [b] defining energy efficiency indicators;
  \item [c] defining the energy saving potential and increasing energy efficiency; and
  \item [d] developing and evaluating a list of possible programmes that target an increase in energy efficiency.
\end{itemize}

The results of an energy audit must be reflected in an energy passport comprising information about the presence of energy meters, the volume of energy used and the variations in those such volumes, among other things.

Instead of energy audits, state and local authorities, and state-owned and municipal institutions, have to submit annual declarations of electric power consumption.

To encourage private investors to participate in the energy efficiency programme, the Energy Efficiency Law proposes a range of financial and tax incentives. The incentives for commercial companies include, in particular:

\begin{itemize}
  \item [a] investment tax credits of up to 100 per cent for companies investing in energy efficiency and energy saving technology;
  \item [b] accelerated depreciation of assets categorised as having high energy efficiency or assets classified in the top energy efficiency class (the qualifying assets);
  \item [c] a three-year corporate property tax exemption on newly accounted for qualifying assets; and
  \item [d] partial compensation of interest on loans granted by Russian banks for the purpose of investing in energy saving and more energy-efficient technology.
\end{itemize}

iii Technological developments

Setting up a new legislative basis and further efforts taken to implement the Policy have introduced complex technologies to the Russian renewable energy sector.
Russian localisation rules, aimed at the development of local production in the renewable energy sector, significantly affect the economics of the projects. These rules stipulate that a certain percentage of the elements and spare parts of the energy-generating facility are to be produced in Russia so as to apply a beneficial capacity price. The potential supplier must commit to a certain degree of localisation when bidding and, if this level has not been reached, the beneficial tariff shall not apply and the capacity price will be significantly lower.

To meet the above requirements, global Russian corporations involved in renewable energy projects usually create joint ventures with large foreign technology owners and local companies. The local partner is usually responsible for handling local issues relating to the renewable energy projects that may arise during the construction and operation of the generating facility. The use of these types of joint venture structures enables the creation of a strong team that can effectively support the implementation of the renewable energy project.

VI  THE YEAR IN REVIEW

Similarly to previous years, the energy market in Russia, especially the export side, has been developing in 2019 under the pressure of US and EU sanctions that restrict access by Russian oil and gas companies to foreign investment and technology. It has encouraged these companies to seek cooperation with investors from the Middle East and China.

After a tremendous boost in 2016–2017, the renewable energy market (mainly, wind and solar photovoltaic) has continued to increase its share in the energy sector with the aim of reaching 4.5 per cent by 2024. However, this still does not seem to be achievable.

New LNG treatment and distribution facilities have been commissioned in the northern regions of Russia.

VII  CONCLUSIONS AND OUTLOOK

It is difficult to overestimate the importance of the energy sector in the Russian economy. Traditional industries such as oil and gas, as well as power generation by thermal (coal), hydro and nuclear power plants, continue to be the basis of both economic development and national security.

On the other hand, these industries are highly affected by the current political tensions caused by international relations between Russia and other countries.

In response to US and EU sanctions, Russia’s local content requirements have become one of its main economic policy drivers supporting inbound investments and technology transfers to develop local innovative technologies, including in the renewable energy sector.

We expect further development of the Russian energy sector. However, the relatively high level of uncertainty may lead to a search for new alternatives and opportunities.
Chapter 20

SOUTH AFRICA

Lido Fontana, Mzwandile Khumalo and Yolanda Dladla

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OVERVIEW

The year 2019 brought with it immediate change and a positive turnaround in the South African energy sector. One of the major stand-out developments was the updated Integrated Resource Plan (IRP) (as discussed in Section IV.iv), which was released in October 2019. This plan provides for a dynamic energy mix that outlines South Africa’s national energy road map and is a great improvement on the former IRP, which was approved by Parliament in December 2017 and sent back for processing for reasons not disclosed. During 2018, announcements were made by the Minister of Energy to the effect that South Africa would launch a fifth Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) that would include a further 1800MW to the grid during November 2018. However, this has yet to come to fruition as many believe the stagnation of the launch of the Bid Window 5 is a result of the instability and financial woes of state-owned utility Eskom, and the updated IRP not yet being signed into law.

In April 2018, South Africa signed 27 independent renewable energy agreements with a combined investment value of 56 billion rand and a combined capacity of 2,300MW from Bid Windows 3.5 and 4 of the REIPPPP. This brought renewed hope to independent power producers and boosted investor confidence. Further, Eskom announced during 2018 that it is preparing to roll out 360MW battery energy storage systems financed by the African Development Bank and the World Bank that will consist of supplying, installing and operating distributed battery storage infrastructure at Eskom sub-stations, including those located at existing variable renewable energy plants operated by Eskom Renewables (including the Bank-funded 100MW Sere wind farm), forthcoming distributed solar photovoltaics to be implemented by Eskom Distribution, and the new REIPPPP sites.

South Africa supplies 40 per cent of Africa’s electricity through the Southern African Power Pool and other arrangements. Although South Africa owns the fifth largest recoverable coal reserves in the world (estimated at 66.7 billion tons), the Minister of Energy confirmed that a total of 91 renewable projects had been connected to the grid with a capacity of 63,000MW. This has brought the total investments in renewable energy to approximately 201.8 billion rand under the REIPPPP. South Africa’s five largest renewable energy projects are multibillion-rand wind farms that contribute a collective 645.71MW to the grid with 6,360MW of wind power being determined for procurement by independent power producers (IPPs).

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However, in 2019, South Africans were also hit by rolling blackouts implemented to protect the grid from total collapse or blackout with Stage 6 load shedding being rolled out since December 2019. The reasons for the lack of energy capacity is Eskom’s poor management, the lack of funding or misappropriation of funds, and maintenance and labour issues. In response to the challenges faced by Eskom, the Department of Mineral Resources and Energy issued a Request for Information in December 2019 with respect to the design of a Risk Mitigation Power Purchase Procurement for power generation (referred to as the RFI). Under the RFI, the Department of Mineral Resources and Energy called for 3,000MW of emergency power capable of connecting to the national grid within two years from the date the RFI was issued. Further, the expensive and overdue operation of Medupi and Kusile coal-fired plants have resulted in severe pressure on the national grid without a sufficient reserve margin from generating assets to meet peak demand, and the government of South Africa being forced to consider the unbundling of Eskom. This will result in Eskom being unbundled in three divisions – generation, transmission and distribution – which will positively end Eskom’s monopoly but will cost millions in taxpayer money to implement.

The Minister of Mineral Resources and Energy also confirmed that the Khanyisa and Thabametsi coal-fired power stations – projects that will add approximately 863MW to the national grid once operational and are South Africa’s first privately owned coal-fired power plants – must implement the latest technology to reduce harmful emissions as a reaction to continued court actions regarding the projects’ impact on the climate. However, following the decision by major financial institutions such as Standard Bank and Nedbank not to fund new coal IPPs, there has been little progress with respect to the development of the Khanyisa and Thabametsi coal-fired power stations.

Unfortunately, there have been no noteworthy developments following the expressions of interest 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, the South African government is still at work to draft regulations that ensure the exploration of shale gas does not harm the environment (shale gas makes up only 3 per cent of the total primary energy supply). This is due to increased interest in shale gas and the US Energy Information Administration confirming that South Africa is ranked eighth in terms of technically recoverable shale gas resources in the world. South Africa’s plans in respect of further nuclear power stations also appear to be on hold, given the amendments to the updated IRP whereby nuclear may not be expected to be introduced until 2030.

II REGULATION

i The regulators

In South Africa, energy regulation is overseen by three regulators:

a the National Energy Regulator (NERSA), established under the National Energy Regulator Act 2004, which regulates electricity, piped gas and petroleum pipeline 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 of 2002 (MPRDA), which regulates petroleum exploration and production.
Each of these Acts, with other key legislation regulating the respective industries (the Electricity Regulation Act, 2006 (the Electricity Regulation Act), the Petroleum Pipelines Act 2003, the Gas Act 2001 (the Gas Act), the Nuclear Energy Act 1999 and the MPRDA) establish the framework for energy regulation in South Africa. That legislation, with the regulations, notices, rules and guidelines issued thereunder, grant expansive regulatory power to the regulators, including issuing, amending and revoking licences, and approving 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 importing, exporting and trading of electricity (collectively, the Licensed Activities). The 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 those 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 the application includes, among other things:

a a description of the applicant, including the vertical and horizontal relationships with other persons engaged in the operation of the relevant Licensed Activity;
b the administrative, financial and technical abilities of the applicant;
c a description of the proposed generation, transmission or distribution facility to be constructed or operated;
d a detailed specification of the services that will be rendered under the licence;
e a general description of the type of customer to be served;
f the tariff and price policies proposed to be applied; and
g evidence of compliance with the IRP.2

The process entails publication of notices of the application in appropriate newspapers or other media, and 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, or 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 the licences is similar to that outlined above, albeit that the timelines are shorter and an applicant may further be directed to serve a copy of its application upon every municipality affected by the application and any 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. Licences for the storage, transportation and

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2 Electricity Regulation Act, 2006, Section 10(2), Paragraphs (a) to (g).
reticulation of petroleum through pipelines are issued by NERSA. Although the procedure for applying for the licences is similar to that for the Licensed Activities, only owners of storage, transportation and reticulation facilities, respectively, may apply.

Licences for exploration or production rights in petroleum resources are generally issued pursuant to bidding processes initiated by the Minister of Mineral Resources and Energy. The Minister invites applications for exploration and production rights in respect of designated blocks on predefined terms and conditions. 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, and 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.

iii 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, produced close to 95 per cent of the country’s electricity, with the balance sourced mainly from municipalities. As with electricity generation, transmission and distribution capacity was restricted to the state and state-owned entities. In his 2020 State of the Nation Address, President Cyril Ramaphosa stated that the South African government will start the procurement of energy power from projects capable of delivering electricity into the national grid within three to 12 months of approval, thus allowing municipalities the opportunity to procure their own power from IPPs.

In 2011, the South Africa government launched the Integrated Resources Plan, which called for the country’s electricity capacity to be doubled 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 southern African.

The REIPPPP has served as the primary vehicle through which the South African government has procured renewable energy from private sector power producers. Bid Window 4 under the REIPPPP programme provided that projects developed thereunder must be 40 per cent owned by South African citizens, with people of colour holding a minimum of 12 per cent (with a target of 30 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 IRP objectives of promoting job growth, domestic industrialisation, community development and black economic empowerment (a programme designed to counter the adverse economic effects 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 HDSAs), as well as skills transfer and enterprise development of legal entities owned by HDSAs).

4 id., at Section 5(1).
The Coal Baseload IPP Procurement Programme provides that 51 per cent of each project must be owned by South Africans and 30 per cent must be black ownership. Ownership criteria for 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 then Department of Energy (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, will only be released once the DOE has finalised the contentious updated IRP, which was released for public comment in December 2016 (extended to 31 March 2017) (discussed in Section IV.iv). Although not linked to the LNG-to-Power IPP Procurement Programme, Transnet (SOC) Limited, a state-owned freight and logistics company, signed a cost-sharing agreement with the International Finance Corporation on 23 July 2019 to conclude a feasibility study and facilitate investment in natural gas infrastructure in Kwa-Zulu Natal. The feasibility study is for the development of an LNG storage and regasification terminal at the Port of Richards Bay and the repurposing of Transnet pipelines for natural gas transmission to inland markets.

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 the Licensed Activities, including generation licences issued to IPPs, are restricted by conditions imposed on the licensee by NERSA. Accordingly, each licence must be reviewed case by case to determine the specific approvals 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 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 cooperation permit is not...

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5 Electricity Regulation Act, 2006, Section 15(1)(k).
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 Resources and Energy 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 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 purpose of the Bill was 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 offtakers. 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. However, the ISMO Bill was suddenly withdrawn in the final stages of it being adopted by its sponsor, the DOE, in June 2015.

On 20 February 2019, an explanatory summary of the ISMO Bill was published for public comment in accordance with Rule 276(1)(c) of the National Assembly Rules. The ISMO Bill now seeks to (1) create the ISMO as the entity responsible for system operation and the purchase of electricity from electricity generators, (2) split Eskom into two parts, in terms of which Eskom will continue to function as an electricity generator and ISMO, with a view that the ISMO will take ownership and control over the national electricity grid and serve as the central buyer and distributor of electricity from all electricity generators; and (3) allow metropolitan municipalities to purchase electricity directly from IPPs in certain defined circumstances. The Bill seeks to bring an end to the Eskom monopoly, by unbundling Eskom into different divisions.

Gas

The gas pipeline network comprises the Rompco Pipeline (used to transport gas from Mozambique into South Africa), which is the main pipeline network in South Africa, and several short-range pipelines, which are privately owned. Owners of these

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7 This is a joint venture between South African Gas Development Company Limited (also known as iGas), Companhia Limitada de Gasoduto (CMG) and Sasol Gas Holding Proprietary Limited.
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, Energy Markets).

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,8 it still remains a complicated process. NERSA has said that it is 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 pipeline 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.

A suite of supply policy guidelines for the integrated national electrification programme was last updated on 26 November 2018 by the DOE (the programme provides that the DOE (which merged with the Department of Mineral Resources in May 2019) is responsible for assisting municipalities with the funding of implementation of electrification projects to achieve universal access to electricity by 2025 and is one of the pillars of the 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 on Energy 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.

8 See www.eskom.co.za/Whatweredoing/Pages/Wheeling_Of_Energy.aspx.
Oil and gas

In relation to gas and piped petroleum product, tariffs are negotiated on a commercial basis and then approved by NERSA.

The Department of Mineral Resources and Energy 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,9 which is based on several international conventions to which South Africa is a party,10 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 developed regulatory requirements 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 latter is the International Atomic Energy Agency’s 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.11

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.

IV  ENERGY MARKETS

i  Electricity

NERSA is mandated, inter alia, to 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 Constitution12 list 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

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9 Nuclear Energy Act 46 of 1999.
10 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/.
11 See www.nnr.co.za/nuclear-security/.
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 sold on 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.\textsuperscript{13} 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 obliged to supply its customers with information on tariffs and tariff structures.

The Minister of Mineral Resources and Energy has indicated possible amendments to the licensing requirements in terms of the ERA which will, \textit{inter alia}, exempt certain activities from requiring a licence under the ERA. Exempted activities may include (among others) the operation of generation facilities (1) for the sole purpose of providing standby or backup electricity in the event of an interruption in supply and (2) which do not have a point of connection. These amendments are also likely to extend to the operation of generation facilities with a capacity of no more than 1MW that supply electricity to customers regardless of whether that electricity is wheeled, and those generation facilities earmarked for demonstration purposes only.

South Africa is part of the Southern African Power Pool (SAPP), which includes several southern African utilities and supplies to neighbouring countries, being Zimbabwe, Lesotho, e Swantini, Namibia, Botswana, Mozambique and Zambia. 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 more than 9,977GWh a year since 2003.\textsuperscript{14}

\textbf{ii Natural gas}

The use of natural gas as an energy source has stagnated; however, the government of South Africa is optimistic that natural gas will form the backbone of regional economic integration among South African Development Community member countries.

\textbf{Shale gas}

The Minister of Mineral Resources and Energy announced that it was the intention of the Department of Mineral Resources and Energy to fast-track the finalisation of exploration rights applications. However, these applications are yet to be finalised.

\textsuperscript{13} Electricity Pricing Policy, GN 1398 of 19 December 2008.

\textsuperscript{14} See www.energy.gov.za/files/esources/electricity/electricity_powerpool.html.
600MW gas
There have been no new developments in relation to the expression of interest, which closed on 20 June 2016, for the Gas 600MW IPP Procurement Programme. However, a feasibility study by NOVA Energy, a South African integrated natural gas company, has been initiated to assess the conversion of the Kelvin power station from a 450MW coal-fired power plant to a 600MW gas-fired power station.

iii Gas pipeline
A cooperation agreement has been signed with investors in respect of a 2,600km gas pipeline from the Rovuma Basin in northern Mozambique to Gauteng province in South Africa with an estimated value of US$6 billion.

iv Nuclear
The updated IRP of 2019 states that South Africa is planning smaller, modular nuclear plants and provides only for the procurement of an additional 1,860MW of nuclear power to be commissioned by 2024, which represents the 20-year extension of the life of the Koeberg nuclear power plant in Cape Town. The Koeberg Power Station reaches its 40-year end of design life in 2024 and plans are already in place to extend its design life and nuclear safety licence for an additional 20 years.

Nuclear power will therefore be procured at a pace, scale and cost affordable to South Africa, taking into account the rate of decommissioning of coal-fired power. One of the nine policy positions listed in the IRP 2019 is for the immediate commencement of a nuclear build programme.

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 DOE launched the REIPPPP, an unprecedented, world-class procurement programme with the audacious goal that the country produce 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 its 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 (REFITs) to facilitate the introduction of renewable energy to 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 IRP**

The initial IRP sets out the 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 southern Africa. 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 government advised that it should be viewed as a ‘living plan’ that would be revised every two years to ensure its relevance with regard to (among other things) technological and environmental developments in the global arena.

The national Integrated Energy Plan (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 investment in electrical power, greater employer benefits and more favourable environmental impact. The IRP, on the other hand, being subordinate legislation to the IEP, focuses specifically on electricity.

It became a necessity to revise the initial IRP owing to capacity additions through Ministerial Determinations\(^{15}\) under Section 34 of the Electricity Regulation Act\(^{16}\) and to update key assumptions that have changed significantly since the promulgation of the initial IRP. Accordingly, the updated IRP was issued in October 2019 and it provides for the following new additional capacity by 2030: 1,500MW of generation from coal, 2,500MW from hydropower, 6,000MW from photovoltaic, 14,400MW from wind, 1,860MW from nuclear, 2,088MW for storage, 3,000MW from gas or diesel and 4,000MW from other distributed generation, cogeneration, biomass and landfill technologies.

**What is the Independent Power Producer Procurement Programme?**

The Independent Power Producer Procurement Programme 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 have 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.

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15 A complete list of Ministerial Determinations can be found under Appendix B of the Updated IRP, hereinafter referred to as the ‘Ministerial Determinations’.

16 No. 4 of 2006.
VI  THE YEAR IN REVIEW

Amendment to the MPRDA

The Mineral Petroleum Resources Amendment Bill [B15D-2013] (the MPRDA Bill) was submitted to Parliament; eight of the nine provinces supported the Bill, subject to amendments. The main concerns raised by the provinces centred on some policy aspects relating to the Bill regarding some of the definitions in the Bill, inadequate procedures, systems and processes, the need for more clarity on concepts raised in the Bill, and conflicts with other legislation and government policies. The MPRDA Bill provides for state participation in any successful mineral 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 Bill proposes that the South African government be provided with a 20 per cent ‘free carry’ in all new exploration and production rights.

On 28 November 2019, the Minister of Mineral Resources and Energy gazetted draft amendments for public comment to the MPRDA, and the guidelines for mine community resettlements. The Minister had withdrawn a previous version of the MPRDA in October 2018 as the legislative process had stalled after the National Council of Provinces had been unable to reach an agreement on the Bill. As a result, the Bill had become irrelevant to the industry’s needs. The draft amendments reflected in the MPRDA 2019 introduce regulations to social and labour plans in the industry. These include requirements that holders of mining rights contribute towards the socio-economic development of the areas in which they are operating, and in labour sending areas. Applicants for mining rights are also required to consult communities to ensure their social and labour plans address the relevant needs of the communities. Further, a mining right holder must widely publish an approved social and labour plan in English and one other dominant in the official language commonly used within a mining community. Social and labour plans must also be reviewed every five years from the date of its approval by the Minister of Mineral Resources and Energy. The document emphasises that collaboration on social and labour plan projects must be transparent, inclusive and based on consultation with all stakeholders.

VII  CONCLUSIONS AND OUTLOOK

The year 2019 brought further positive developments in the energy sector as a result of the updated IRP, which will allow South Africa to focus on building a diverse energy sector that will also encourage the economy. The future looks very positive for renewable energy, and the much-anticipated revised draft of the IRP will help interested parties to understand which parts of the energy sector the South African governments will be supporting in the coming years.
I  OVERVIEW

Korea relies on overseas acquisition for more than 97 per cent of its primary energy sources, and fossil fuels (such as petroleum, gas and coal) account for 85 per cent of these sources. Therefore, there are policy needs to take measures both in the short term against fluctuations in the supply and demand for energy based on global factors, and in the long term against the depletion of fossil fuels. The 2011 Fukushima nuclear power plant accident in Japan has served as a warning that careful consideration should be given to the use of nuclear energy and the new energy environment, and the effects of climate change, and has increased the use and interest in new and renewable energy.

Under the current environment and policy needs, the Korean government aims to convert to safe and clean energy through system innovations in all areas of the energy industry encompassing energy consumption, supply and transmission. The government will also switch to a low-consumption and high-efficiency energy structure by gradually reducing the share of coal and nuclear energy and increasing the share of renewable energy. The government will change the centralised energy distribution system centred on large-scale power plants to a small-scale system by fostering hydrogen and renewable energy industries, while encouraging the new service industries utilising energy big data.

II  REGULATION

i  The 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. The Electricity Regulatory Commission is an affiliated organisation within the MOTIE that was formed, inter alia, to 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 (1) establishing or managing the electricity market, and (2) transactions involving electricity, among others.

Further, the Prime Minister’s Office is in charge of matters relating 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 that was formed, inter alia, to deliberate

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1 Soongki Yi, Kwang-Wook Lee and Chang Woo Lee are partners at Yoon & Yang LLC.
on 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, and joining international treaties.

**Main sources of law and regulation**

The Framework Act 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 in January 2010, 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: 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.


e. Hydrogen: The Hydrogen Economy Promotion and Hydrogen Safety Management Act, enacted on 4 February 2020 and coming into effect on 5 February 2021, regulates matters relating to hydrogen safety and hydrogen industry development.

**ii Regulated activities**

**Electricity**

Under the EUA, electric utility businesses are categorised into five types, 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

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2 Electric Utility Act [EUA], Article 2(iii).
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

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

Electric sales business: a business, the main purpose of which is to deliver electricity to consumers.5

District electric business: a business, the main purpose of which is to generate electricity with 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. KEPCO is still responsible for transmission, distribution and sales of electricity, and 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 relevant business type, from the Minister of the MOTIE (the Minister);7 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 location of electricity installations, equipment capacity and the type of motive power.8 To obtain a licence, the following documents must be submitted to the Minister:9

- an application for a licence;
- a business plan;
- 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
- 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).

The Minister will grant an 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:

- to have the financial and technological capability necessary to operate the electric utility business in the optimal manner;
- to be able to carry out the electric utility business as planned;

3 EUA, Article 2(v).
4 id., at Article 2(vii).
5 id., at Article 2(ix).
6 id., at Article 2(xi); Enforcement Decree of the EUA, Article 1-2.
7 Under the amended EUA, which comes into effect on 5 August 2020, a licence will be issued by the MOTIE or the relevant local government based on the type and scale of the business.
8 EUA, Article 7(1); Enforcement Rule of the EUA, Article 5(1).
9 EUA, Article 7(1); Enforcement Rule of the EUA, Article 4(1).
The EUA requires the Minister to take into consideration the economic efficiency of the electricity installations and their effects on the environment and public safety when establishing a basic plan for electricity supply.\footnote{PBA, Article 5(1); Enforcement Rule of the PBA, Article 4(1).}

\section*{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)’\footnote{PBA, Article 2(iv).} and categorises petroleum businesses into three types: petroleum refinery businesses,\footnote{PBA, Article 2(v).} petroleum export and import businesses\footnote{PBA, Article 2(vi).} and petroleum sales businesses.\footnote{PBA, Article 9(1); Enforcement Rule of the PBA, Article 8(1).}

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.\footnote{id., at Article 25-2 of the PBA.} In connection with petroleum refinery businesses, anyone who intends to operate a business for manufacturing asphalt, or lubricating or base oil must report the business to the Minister.\footnote{id., at Article 5(1); Enforcement Rule of the PBA, Article 4(1).}

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.\footnote{PBA, Article 5(2); Enforcement Decree of the PBA, Article 8(1).} Registration is not required, however, for a person who is already registered as an operator of a petroleum refinery business, or for the import and export of certain petroleum products, such as asphalt,
South Korea

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. The previous storage capacity requirement (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.

The different classifications of petroleum sales businesses are (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 businesses classified under points (1) to (5) need to be registered with the head of the local government, petroleum sales businesses that fall under point (6) need to be reported to the head of the local government.

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. 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. 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 the manufacturing of fake petroleum products.

Urban gas

The UGBA defines the term ‘urban gas’ as natural gas (including liquefied gas), petroleum gas, by-products from naphtha cracking and biogas, and synthetic natural gas (SNG). Under the UGBA, there are five categories of urban gas businesses: gas wholesale, general urban gas, urban gas recharging, by-products from naphtha cracking and biogas manufacturing, and SNG manufacturing.

Besides the above, 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.

19 PBA, Article 9(1); Enforcement Decree of the PBA, Article 10(2).
20 Enforcement Decree of the PBA, Article 12(1).
21 PBA, Article 10(1) of the; Enforcement Rule of the PBA, Article 12, Paragraphs (1) to (6).
22 PBA, Article 10(2); Enforcement Rule of the PBA, Article 12(7).
23 PBA, Article 9(1).
24 id., at Article 39(1)(iii).
25 id., at Article 41-3.
26 Urban Gas Business Act [UGBA], Article 2(i); Enforcement Decree of the UGBA, Articles 1 and 2.
27 UGBA, Article 2(i).
28 id., at Article 2(i-2).
29 id., at Article 2, Paragraphs (ix-2) and (ix-3) and Article 10-2(3).
30 id., at Article 10-6.
According to the UGBA, the definition of each category of 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.\(^{31}\)

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.\(^{32}\)

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.\(^{33}\)

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 a 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 facilities as designated under the MOTIE Ordinance).\(^{34}\)

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.\(^{35}\)

f. Natural gas export and import business: a business exporting or importing natural gas.\(^{36}\)

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.\(^{37}\)

h. Natural gas business for ships: a business that supplies natural gas for ship fuel.\(^{38}\)

Under the UGBA, a person who intends to operate a gas wholesale business must obtain a licence from the Minister of the MOTIE\(^{39}\) and a person who intends to operate general urban gas business must obtain a licence from the head of the local government.\(^{40}\) A licence for a gas wholesale business or general urban gas business will only be granted if the application meets

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\(^{31}\) id., at Article 2(iii).
\(^{32}\) id., at Article 2(iv).
\(^{33}\) id., at Article 2(iv-2).
\(^{34}\) id., at Article 2(iv-3) and Article 8-3.
\(^{35}\) id., at Article 2(iv-4).
\(^{36}\) id., at Article 2(vii).
\(^{37}\) id., at Article 2(ix-2).
\(^{38}\) id., at Article 2(ix-5). This definition is introduced by the amendment to the UGBA made on 4 February 2020 and taking effect on 5 August 2020.
\(^{39}\) id., at Article 3(1).
\(^{40}\) id., at Article 3(2).
the following requirements: 41 (1) the urban gas business is of an economic scale appropriate for the public interest and general demand; (2) the applicant has the financial resources and technical capability necessary to properly conduct such an urban gas business; and (3) the 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 or a business manufacturing by-products from naphtha cracking and biogas must obtain a licence from the head of the local government for each place of business. 42 A person who intends to operate an SNG manufacturing business must obtain a licence from the Minister for each place of business. 43

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 a 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 first import of natural gas). 44 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. 45 Anyone who intends to operate a business that carries natural gas in and out must report the business to the Minister. 46

Nevertheless, the UGBA includes provisions to improve regulations on natural gas import and export business operators, and to strengthen safety requirements. In addition, to respond flexibly 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 approval in advance 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. 47 The UGBA strengthens safety requirements by stipulating that, if 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. 48 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 where urban gas pipelines are installed. 49 The UGBA also sets forth penalty provisions against those parties that cause damage, or inflict harm on the functionality of, urban gas pipelines. 50

41 id., at Article 3(7).
42 id., at Article 3, Paragraphs (3) and (4).
43 id., at Article 3(5).
44 id., at Article 10-2(1); Enforcement Rule of the UGBA, Article 10-6.
45 UGBA, Article 10-5(1).
46 id., at Article 10-2(3).
47 id., at Article 10-5(2).
48 id., at Articles 28-2 and 54(6).
49 id., at Article 28-3.
50 id., at Article 48, Paragraphs (4) and (8).
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.\(^5^1\) 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.\(^5^2\)

The New and Renewable Energy Act provides that tradable renewable energy certificates (RECs) will be issued to new and renewable energy suppliers. However, if 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 on the market to maintain the balance of demand and supply and to stabilise prices.\(^5^3\) 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.\(^5^4\)

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.\(^5^5\) 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 fuel from new and renewable sources in fuel for transport. Violations of these requirements may be punished by civil fines.\(^5^6\) Moreover, the New and Renewable Energy Act requires a new and renewable energy facility certification holder to take out an insurance policy against damage that may be suffered by a third party.\(^5^7\) Under the 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.\(^5^8\)

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51 New and Renewable Energy Act, Article 5, Paragraphs (1) and (2).
52 id., at Article 6(1).
53 id., at Article 12-7.
54 id., at Article 13.
55 id., at Articles 12-11, 12-12.
57 id., at Article 13-2.
58 id., at Article 30-2.
**Hydrogen energy**

As of 5 February 2022, in principle, anyone who intends to manufacture hydrogen products is required to obtain permission from the local government, and those who intend to manufacture hydrogen products in foreign countries to export to Korea should register with the MOTIE.  

**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 the UGBA do not contain any provisions limiting foreign-capital invested companies’ operation of the relevant businesses.

**iv Transfers of control and assignments**

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 of less than 20,000kW) to ensure management control, it must obtain approval from the Minister of the MOTIE. 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**

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 government enacted the Act on the Promotion of the Reorganisation of the Electric Power Industry in 2000 and privatised the electricity generation business by dividing KEPCO’s electricity generation business into six subsidiaries. As of December 2019, the number of private companies participating in the electricity market is 3,574.

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59 Hydrogen Economy Promotion and Hydrogen Safety Management Act, Article 36(1).
60 id., at Article 38(1).
61 EUA, Article 10(1).
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 or a gas wholesale business operator must prepare a gas supply plan for five years and submit it to the head of the local government.

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 on 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 electricity transmission, distribution and sales businesses. The EUA further provides that neither any operator of an electricity generation business or electricity sales business nor any electric vehicle charging network operator 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 electricity transmission businesses, electricity distribution businesses and district electricity 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 management of the quality of petroleum products and prevent the distribution of pseudo-petroleum products. If a petroleum refinery business operator, petroleum import and export 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.

62 id., at Article 44.
63 id., at Article 32; Enforcement Decree of the EUA, Article 20.
64 EUA, Article 14.
65 id., at Article 18(1).
66 id., at Article 27.
67 Products manufactured by a method of mixing petroleum products with other petroleum products or petrochemicals; PBA, Article 2(x).
68 PBA, Article 25(1); Enforcement Rule of the PBA, Article 28(1).
69 PBA, Article 27.
Further, to promote the expansion of exports 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, and the storing or transporting such mixtures, will not be viewed as the manufacturing of fake petroleum products.70

**Urban gas**

In principle, 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.71 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 meets the required quality standards.72

**iii Rates**

**Electric power**

An operator of an electricity 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.73 Further, an operator of an electricity sales business must specify the details of the utility charges based on items in utility bills charged to consumers of electricity.74 An operator of an electricity transmission business or electricity distribution business must set charges for the use of electricity installations and other matters concerning the conditions of their use.75

**Petroleum**

Petroleum refinery business operators, petroleum import and export business operators and petroleum sales business operators must report their sale prices of petroleum products to the Minister.76

**Urban gas**

A general urban gas business can require that a party who is requesting a change in its 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 (UGBA, Article 19-2). Further, when it is difficult to supply urban gas for any of the reasons stipulated under Article 19 of the UGBA, 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 (UGBA, Article 20(1)).

70 id., at Article 29(2)(v-2).
71 UGBA, Article 19.
72 id., at Article 25-2(1).
73 EUA, Article 16(1); Enforcement Rule of the EUA, Article 16(1).
74 EUA, Article 17.
75 id., at Article 15(1).
76 PBA, Article 38-2(1).
iv Security and technology restrictions

Electric power

If an operator of an electric utility business intends to carry out the necessary work for setting up or altering electricity installations for the electric utility, he or she must obtain approval for the plan for the work from the Minister of the MOTIE and undergo periodic inspections conducted by the Minister.78

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 new and renewable energy business, it may be a mandatory requirement for a party that holds more than 500,000kW 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 amount of power production for supply energy.79 If the Minister deems that such a 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.80

IV ENERGY MARKETS

i Development of energy markets

Electricity

As has been 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, as of December 2019, transactions occur between the electricity generation business operators (of which there are more than 3,500) and a sales business operator all day, every day, based on prices that change every hour.

Gas

The gas industry is divided into a wholesale sector and a 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 Korea Gas Corporation, gas is supplied to the regional 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, 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.

77 EUA, Article 61(1).
78 id., at Article 65.
79 New and Renewable Energy Act, Article 12-5, Paragraphs (1) and (2); Enforcement Decree of the New and Renewable Energy Act, Article 18-3.
80 New and Renewable Energy Act, Article 12-6(1).
ii  Energy market rules and regulation

Electricity

Electricity is regulated by the EUA. Electricity transactions must be made 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 Article 53 of the EUA authorises the Electricity Regulatory Commission to adjudicate on disputes concerning the Regulations.

KEPCO has been monopolising the electricity power brokerage business. However, pursuant to the amended EUA (Article 43-2) and the Enforcement Decree of the EUA (Article 1-3), small-scale electricity power brokers may sell renewable energy (under 1,000kW) or electricity generated and stored in energy storage systems (ESS), and electric vehicles. Small-scale electricity power brokers may enter into the market more easily now as they can commence their business after registration. They are not required to obtain approval as existing electricity businesses are. This deregulation of market entry is expected to lead to the effective management of small-scale power resources and to improve the stability of the power sector.

Gas

Gas is regulated pursuant to the UGBA. Prior to the 2014 amendment of the UGBA, direct imports of natural gas by private companies were allowed solely for private consumption. Aside from direct imports by private companies for a limited purpose, the importing and wholesale of natural gas was exclusively conducted by the Korea Gas Corporation (KOGAS). However, the 2014 amendment of the UGBA enabled private companies to resell natural gas they had directly imported. As of August 2019, direct imports of natural gas were 8.01 million tons, which is expected to increase to 11.21 million tons in 2022. This amount is expected to more than double by 2031.

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 it is a public business. After a large-scale power outage in Korea on 15 September 2011, electricity costs were increased four times by November 2013. The main reason for the increase was the need to align costs with actual use. 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 resolved to amend its Implementation Rules of General Terms and Conditions of Supply to expand new and renewable energy and ESS by modifying renewable energy discount standards, introducing new incentives 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 based on the contracts executed between the KOGAS and urban gas companies. Since the KOGAS imports all 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 gas imports, 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.

iv Market developments
As the government takes policy initiatives focusing on the renewable energy market rather than the traditional energy market, investments in solar and wind power are increasing.

The solar market is undergoing not only quantitative expansion but also qualitative improvement. In 2017, the market share for solar modules with energy efficiency of 18 per cent or higher was only about 35 per cent, but in 2019, the share was expanded to more than 80 per cent.

The wind power industry has high scalability for expansion and development potential for manufacture and development of power components, towers and forgings, blades and materials for generators, maintenance, transportation, construction and training. The export share of the wind power industry is increasing.

In particular, the government is planning to build a large-scale renewable energy complex in the Saemangeum reclaimed area, constructing 3GW of power generation facilities in 2020 (comprising 0.7GW of land solar power, 2.1GW of floating solar power, 0.1GW of wind power and 0.1GW of fuel cell power) in stages.

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 efficiency in its 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, a comprehensive technology development plan for energy and the environment, the Energy Technology Development 10-Year Plan (1997–2006), was drawn up to establish a system to promote technological development of not only new and renewable energy but also to help with conserving energy and developing 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 renamed 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 general new and renewable energy output, an obligation for public institutions to use new and renewable energy, and new and renewable energy equipment certification procedures, among other things, 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 the development and dissemination of new and renewable energy, 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), under which certain operators of energy businesses are obliged to supply a certain amount of new and renewable energy.

As of 2017, renewable energy accounted for 5.45 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. To achieve this goal, the government plans to promote:

a  city-type private solar power for one in 15 households by 2030;
b  small-scale projects under 100kW through introducing the Korean FIT, which combines the advantages of the existing RPS and FITs;
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 2017, are waste (57 per cent), bio (22 per cent) and solar (9 per cent). To reduce the proportion of non-renewable wastes, the government is to improve the licensing 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 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 a research and development (R&D) road map 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, to foster new energy industries based on small-scale distributed power such as solar and wind power, the government also plans to establish an intelligent power grid and internet of things (IoT) infrastructure and to 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 IoT technology, and to foster the new services industries through smart-city business models.

In April 2019, the government announced ways to strengthen the competitiveness of the renewable energy industry, focusing on (1) converting a price-oriented market structure into a quality-oriented structure through high-quality solar modules, (2) fostering renewable energy
products and related service markets in which information and communication technology (ICT) and related industries are converged, (3) maintaining momentum to expand investments in renewable energy through stable expansion of the domestic market, and (4) promoting the establishment of a privately led R&D road map. The government has also included the foregoing goals in its Third Basic Energy Plan and will pursue policy actions to establish a minimum energy performance system for solar modules, the renewable energy R&D road map and strategies to promote renewable energy overseas expansion. The government’s aim is to generate 20 per cent of the total amount of power from renewable energy sources.

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). These plans have been in use since 1996 by companies such as KEPCO, the KOGAS 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 stability in the supply and demand of electricity and efficient electricity use, the representative businesses are divided into load-management businesses, which reduce the maximum electricity demand, and energy-efficiency businesses, which reduce electricity consumption through high-efficiency devices. In terms of gas and heating, to maintain stability in supply and demand, there is an emphasis on the dissemination of gas-cooling and cogeneration facilities, and efforts are being made to achieve greater energy efficiency compared with individual heating systems through regional heating and cooling businesses.

In accordance with 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 (whereby 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. 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 the Eighth Electricity Supply and Demand Basic Plan at the plenary session of the National Assembly in July 2016. In this Plan, which was released in December 2017, the government stated that it 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 a stable power supply and environmental improvements. With the proposal of the advisory committee for the Ninth Electricity Supply and Demand Basic Plan, which is due to be released in 2020, the following agenda topics are being discussed:

- a medium to long-term coal reduction road map to implement energy conversion plans and to improve the eco-friendly power mix;
- specific measures to further reduce greenhouse gas emissions;
- a response to output volatility to secure stable diffusion of renewable energy and location-system linkag;
- improvements in the power market system; and
- forecasts for future industry trends and electricity demand.

iii Technological developments

The fourth industrial revolution is revolutionising the energy sector, among others, and an 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. The Second Smart Grid Basic Plan announced in July 2018 aims to foster the new Smart Grid industry by pursuing new projects to promote new services, establishing service experience facilities and expanding infrastructure and facilities. The government has decided to invest 400 billion won in the new projects.

In January 2019, the government announced its Road Map for Promoting the Hydrogen Economy to assess the domestic and overseas hydrogen industry; to increase or expand the production capacity of hydrogen cars, hydrogen fuelling stations and fuel cells; and to build up an economical and stable hydrogen production and supply system, aiming to become a global hydrogen economy leader. Further, the government announced:

- a road map for the standardisation of the hydrogen economy in April 2019;
- a supplementary budget for the supply of hydrogen fuelling stations and hydrogen cars in August 2019;
- a plan for the construction of hydrogen infrastructure and fuelling stations, a road map for the development of hydrogen technology, and development strategies for the future automobile industry in October 2019; and
- comprehensive measures for hydrogen safety management in December 2019.

In 2019, Korea had the leading share in the world’s fuel cell market, at 40 per cent. The government is also planning to expand the number of hydrogen fuelling stations, which are the core infrastructure necessary for the spread of hydrogen cars, from the current 14 to 310 in 2022 and 1,200 in 2040. To achieve this goal, the government is considering subsidies to support the installation and operation of hydrogen fuelling stations until they are economically viable. On 11 March 2019, the Hydrogen Energy Network (Hnet), a special purpose corporation in which 13 hydrogen-related companies participate (including KOGAS and Hyundai Motor Company), was established with the aim of setting up and operating 100 hydrogen fuelling stations by 2022.

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. The domestic smart grid market is expected to grow at an annual average of 28 per cent, from 0.4 trillion won in 2012 to 2.5 trillion won in 2020.

In addition, the 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

The key concepts in 2019 were hydrogen economy, climate change, renewable energy and stable energy supply.

In January 2019, the MOTIE released the Road Map for Promoting Hydrogen Economy, disclosing policy targets relating to hydrogen mobility, hydrogen energy (fuel cells) and hydrogen production, storage and transportation. The Hydrogen Economy Promotion and Hydrogen Safety Management Act (the world’s first act relating specifically to the hydrogen economy) was enacted on 4 February 2020 and will take effect on 5 February 2021, except for the provisions regarding safety management and insurance obligations, which will come into effect on 5 February 2022.

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 obliged to cut greenhouse gas emissions by 37 per cent compared to its emissions forecast by 2030. In addition, to meet another goal of the Paris Agreement to limit the global average temperature increase 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 Road Map for 2030 National Greenhouse Gas Reduction, a detailed plan to achieve the aforementioned 2030 greenhouse gas reduction target proposed by Korea in the Paris Agreement. In July 2018, the government announced a revised Road Map that reflected its energy conversion policy. The target of the revised Road Map is to reduce greenhouse gas emissions by 277 million tons by 2030, which constitutes a reduction of 58 million more tons compared to the previous Road Map, by enhancing energy efficiency, strengthening the management of energy demand and fostering low-carbon industries.

In October 2019, the government established the Second Basic Plan to Respond to Climate Change to strengthen the response system for overall climate change and implement the 2030 National Greenhouse Gas Reduction Road Map. The aim of the Plan is to enhance the climate change response by means of the reduction of coal power plants and a transition to a low-carbon society, the establishment of an adaptation system for climate change, and the creation of a future market by fostering new technologies and new markets to respond to climate change.

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 shift in traditional energy systems.
On 27 February 2020, the MOTIE released the 2020 Action Plan to Develop, Utilise and Supply New and Renewable Energy Technologies, focusing on large-scale projects relating to renewable energy, such as offshore wind power and solar power, expansion of competitive bidding in the renewable energy certificate trading market, and mandatory prior notice to residents for the approval of power generation projects.

The Ninth Electricity Supply and Demand Basic Plan was originally planned to be released in 2019, but postponed until 2020. The government is planning to reduce coal power generation and build new LNG power plants. It is also expected to release the Fourteenth Long-Term Natural Gas Supply and Demand Plan in 2020.

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, it is highly likely that nuclear energy, which accounted for about 12 per cent of the country’s energy mix, will be reduced in the future and 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 is a signatory to 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.

In addition, as the supply of renewable energy is rapidly expanding as a result of technological progress and cost reduction, renewable energy is expected to reach 17 per cent of the primary energy demand by 2040. The use of renewable energy is further expanding as global companies have joined the RE100 initiative. It is expected that the government will continue to pursue policies for the expansion of renewable energy, improvement of energy efficiency, and reduction of power generated by coal and nuclear energy.
OVERVIEW

The energy sector in Spain 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 that 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 and for the internal natural gas market in 1998 and 2009. 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 within 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 aim of the main changes introduced by this regulation was to provide the industry with a uniform, transparent and stable regulatory framework, to give economic and financial sustainability to the electricity system, and to 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 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 completed with a number of royal decrees, including the following in late 2013 and further regulations approved during 2014:

- Royal Decree 1047/2013 (RD 1047/2013) of 27 December, which established the methodology for calculating the remuneration for electricity transmission; and
- Royal Decree 1048/2013 (RD 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

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was passed by means of Royal Decree 413/2014 (RD 413/2014), which regulates electricity generation activity using renewable energy sources, cogeneration and waste. Ministerial Order IET/1045/2014 (MO IET/1045/2014), passed on 16 June 2014, approved the remuneration parameters for standard facilities applicable to certain electricity production facilities based on renewable energy sources, cogeneration and waste. These regulations established a new remuneration system for facilities producing electricity from renewable energy sources, cogeneration and waste, and replaced the former remuneration regime.

The gas market has also undergone several changes, specifically with regard to the remuneration framework for regulated gas activities (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. This regulation was incorporated definitively into the Spanish legal system through the enactment of Act 18/2014 of 15 October (Act 18/2014), which included commercial deregulation measures and established an energy efficiency system in line with EU directives.

Several new regulations were passed by the government during 2015. On 16 January, a draft bill was approved, which modifies the 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.

Royal Decree 738/2015, passed on 31 July 2015 (RD 738/2015), 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 Decree 900/2015 of 9 October (RD 900/2015), 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 (RD 1073/2015) and RD 1074/2015, both of 27 November. The first of these modifies certain provisions in the royal decrees on the remuneration of electricity networks, specifically RD 1047/2013 for transmission and RD 1048/2013 for distribution, referred to above. Among other aspects, RD 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. RD 1074/2015, modifies certain regulations in the electricity industry to ensure they are in line with the Spanish government’s most recent electricity reforms.

During 2016, the reform of electricity distribution remuneration was concluded. Ministerial Order IET/980/2016 (MO IET/980/2016) of 10 June established the remuneration of the different distribution companies in accordance with the new legal framework created by the Electricity Act 24/2013. MO IET/980/2016 was partially repealed by several judgments of the Spanish Supreme Court (among others, those of 30 October 2018, 21 December 2018 and 8 January 2019).

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 for vulnerable
electricity consumers (RDL 7/2016), which amended the Electricity 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 creates the possibility for highly vulnerable consumers to avoid the interruption of their electricity supply.


During 2017, the most relevant regulations were Ministerial Order ETU/120/2017 of 1 February, which determines how information is communicated by the autonomous communities and local entities regarding their saving and energy efficiency programmes; Ministerial Order ETU/130/2017 of 17 February (MO ETU/130/2017), which updated the remuneration parameters of the renewable energy installations for the regulatory period between 1 January 2017 and 31 December 2019; and Royal Decree 897/2017 of 6 October, which regulates discounts for vulnerable consumers, social tariffs and other protective measures for domestic consumers.

In addition, at the end of 2016 and in 2017, three competitive procedures were carried out for the allocation of a specific remuneration regime to electricity producers from renewable energy sources.

Furthermore, Royal Decree-Law 13/2014 of 3 October (RDL 13/2014), through which urgent measures in relation to the gas system were adopted, was partially repealed by judgment 54/2017 of 21 December of the Constitutional Court, in particular with regard to the Castor underground natural gas storage facility.

During 2018, the most relevant regulations were:

a Royal Decree 335/2018 of 25 May, amending various royal decrees regulating the natural gas sector;

b Ministerial Order TEC/1172/2018 of 5 November, which redefines electrical systems isolated from the non-peninsular territory of the Balearic islands and modifies the methodology for calculating the weekly purchase and selling prices of energy in the production office of the non-peninsular territories;

c Ministerial Order TEC/1174/2018 of 8 November, establishing the remuneration parameters for standard installations applicable to slurry treatment and reduction installations approved by MO IET/1045/2014 of 16 June, and updated for the period 2017–2019;

d Ministerial Order ETU/360/2018 of 6 April, establishing the values of remuneration for operations corresponding to the first half of 2018, approving a standard installation and establishing its corresponding remuneration parameters, applicable to certain installations producing electrical energy from renewable energy sources, cogeneration and waste; and

e Ministerial Order ETU/361/2018 of 6 April, amending the application forms for the electricity social bonus.

During 2019, multiple regulations were passed by the Spanish government, including:

b Royal Decree 17/2019 of 22 November, adopting urgent measures for the necessary adaptation of remuneration parameters affecting the electricity system and responding to the process of cessation of activity of power plants.

c Royal Decree-Law 244/2019 of 5 April, regulating the administrative, technical and economic conditions for the self-consumption of energy.

d Ministerial Order TEC/1260/2019 of 26 December, establishing the technical and economic parameters to be used in calculating the remuneration of electricity production activity in non-peninsular territories with an additional remuneration system during the 2020–2025 regulatory period, and reviewing other technical issues.

e Ministerial Order TEC/1366/2018 of 20 December, establishing electricity access tolls for 2019.

f Ministerial Order TEC/1258/2019 of 20 December, establishing various regulated costs of the electricity system for the year 2020 and extending the tolls for access to electricity from 1 January 2020.

g Ministerial Order TED/171/2020 of 24 February, updating the remuneration parameters of standard installations applicable to certain installations producing electricity from renewable energy sources, cogeneration and waste, for the purposes of their application to the regulatory period starting on 1 January 2020.

h Circular 2/2019 of the CNMC, which establishes the methodology for calculating the financial remuneration rates for electricity transmission and distribution activities, and the regasification, transmission and distribution of natural gas.

i Circular 3/2019 of the CNMC, which establishes the methodology for the operation of the wholesale electricity production market and the management of systems operations.

j Circular 4/2019 of the CNMC, establishing the methodology for the remuneration of the electricity system operator.

k Circular 5/2019 of the CNMC, establishing the methodology for calculating the remuneration of electricity transmission activities.

l Circular 6/2019 of the CNMC, establishing the methodology for calculating the remuneration of electricity distribution activities.

RDL 1/2019 grants the CNMC new powers in the energy and gas sector. In this context, the following circulars have been published to date in 2020:

a Circular 1/2020 of the CNMC, establishing the methodology for the remuneration of the technical gas system manager.

b Circular 2/2020 of the CNMC, establishing the rules for balancing natural gas.

c Circular 3/2020 of the CNMC, establishing the methodology for the calculation of electricity transmission and distribution tolls.

II REGULATION

i The regulators

The framework for power distribution between the state and the autonomous regions is directly established in Section 149(1), Paragraphs 22 and 25 of the Spanish Constitution. Paragraph 22 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. Paragraph 25 provides that the state has jurisdiction over establishing the basis of the energy regime. The legal bases of the energy sector have developed within this framework, and facilities within each region are also authorised.

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 principles of economic and financial sustainability of the electricity system.

b. Article 14 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. This Article has been modified by Royal Decree 1/2019, which provides that the rates of financial remuneration for transport and distribution activities will be fixed, for each regulatory period, by the CNMC.

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 the CNMC, a regulatory body that encompasses different supervisory authorities in different sectors, including the former National Energy Commission and the National Competition 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 of their rights and dispute resolution methods, among other things.

Furthermore, RDL 1/2019 modifies the Electricity Act 24/2013 and grants the CNMC powers to approve the remuneration and the corresponding methodology of the electricity systems operator and the technical manager of the gas system.

ii Regulated activities

The main activities involved in the supply of energy are 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.
Spain

Royal Decree 1955/2000 of 1 December (RD 1955/2000), 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, RD 1955/2000 states that the construction, expansion, modification and operation of production facilities, as well as transportation and distribution, require certain permissions. That Royal Decree has been modified by the following later royal decrees:

a Royal Decree 1074/2015 (RD 1074/2015) in relation to the guarantees that must be provided in the authorisation process for production facilities;
b RD 56/2016, which establishes new authorisation criteria for thermal power stations whose thermal power to generate electricity is greater than 20MW, and for their substantial renewal, including the obligation of the administrative authorisation applicant to submit a cost–benefit analysis to adapt the planned facility to high-efficiency cogeneration; and
c Royal Decree 897/2017, adding the regulation of the suspension of supply to consumers (natural persons) in their usual home with contracted power equal to or less than 10kW.

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 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 electrical 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 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, the current Electricity Act 24/2013 and subsequent legislative developments establish and define the role of the different participants in the electricity sector:

a) 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 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.

b) Electricity transporters are companies that have the function of transporting electricity and construction, maintenance and transportation of transformer facilities. As stated above, the management of transport activity is entrusted to Red Eléctrica de España, which is also the system operator.

c) 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.

d) 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 sets out new and specific rules on the PVPC.

e) 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’.

f) The market operator (OMI-Polo Español SA, or OMIE) 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, and the other half is held by the Portuguese company OMIP SGPS, SA.

g) The main function of the system operator (Red Eléctrica de España) 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 RD 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. The majority of this royal decree was repealed and replaced by Royal Decree 244/2019 of 5 April, which regulates the administrative, technical and economic conditions for the self-consumption of electrical energy.

The repealed royal decree also stipulated 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, RD 900/2015 imposed 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 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;
- small consumers with a contracted capacity of no more than 10kW.

However, Royal Decree 244/2019, in order to encourage self-consumption with renewable distributed generation, establishes that self-consumed energy of renewable origin, cogeneration or waste, will be exempt from all types of charges and tolls.

Royal Decree 244/2019 also amended Article 9 of the Electricity Act 24/2013 in respect of self-consumption, as follows:

- A new definition of self-consumption, stating that it shall be understood as the consumption by one or more consumers of electrical energy from generation facilities close to those of consumption and associated with them.
- A new definition of the modalities of self-consumption, reducing them to only two: ‘self-consumption without surpluses’, which at no time may carry out energy discharges to the network, and ‘self-consumption with surpluses’, in which discharges to the distribution and transmission networks may be made.
- Installations for self-consumption without surpluses, for which the associated consumer already has a permit for access and connection for consumption, are exempted from the need to obtain permits for access and connection of generation installations.
- It allows for the development of regulatory mechanisms to compensate for the deficit and surplus of consumers benefiting from self-consumption with surpluses for installations of up to 100kW.
- With regard to the register, the option is to have a register of self-consumption, but it is very simplified. This state-wide register will be used for statistical purposes to assess whether the desired implementation is being achieved, to analyse the effects on the system and to be able to compute the effects of renewable generation on integrated energy and climate plans.

The Spanish Supreme Court 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 the Supreme Court rejected their petitions.

It allocates social tariff costs to company sectors on the basis of the number of customers of their retail subsidiaries. The social tariff covers the difference between the PVPC and a base value that may vary depending on the established categories of vulnerable consumers.

In addition, it creates another group – namely, severely vulnerable consumers – whose supply cannot be interrupted, and whose invoices are co-financed by the relevant administration and by the obligated companies within the sector.

Royal Decree 897/2017, which further developed (RDL 7/2016), was published in the Official State Gazette on 7 October 2017. Royal Decree 897/2017 defines the figure of the vulnerable consumer, associating it, as a general rule, with certain thresholds of income referred to 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.

Royal Decree 897/2017 was further modified by Royal Decree 15/2018 regarding urgent measures for energy transition and consumer protection.

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 of severely vulnerable consumers – namely, consumers at risk of social exclusion – who are those 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 receive the following benefits:

a vulnerable customers: 25 per cent discount;

b severely vulnerable customers: 40 per cent discount;

c severely vulnerable customers at risk of social exclusion: 100 per cent discount; and

d customers accredited by the social services as paying at least 50 per cent of their bills.

iv Transfers of control and assignments

RD 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, RD 1074/2015 amended RD 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 RD 1047/2013. Further, Circular 2/2019 of the CNMC establishes the methodology for calculating the financial remuneration rate for activities associated with electricity transmission and distribution, and the regasification, transmission and distribution of natural gas, and Circular 5/2019 of the CNMC establishes the methodology for calculating remuneration for electricity transmission activity for the period 2020–2025. The latter Circular establishes the methodology for determining the amount to be paid to the companies that own electricity transmission facilities for their construction, operation and maintenance, with homogeneous criteria throughout the state and at the lowest possible cost to the system. The proposed methodology is consistent with that established in RD 1047/2013 for the previous regulatory period but contains several improvements that clarify the rules and promote the efficiency of the transmission companies, both in the construction of the infrastructures and in their operation and maintenance.

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 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 of less 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 are 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 are obliged 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 emoluments 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 RD 1048/2013, which established the methodology for calculating the remuneration of distribution activities.

Furthermore, Circular 2/2019 issued by CNMC establishes the methodology for calculating the financial remuneration rate for electricity transmission and distribution activities, and the regasification, transmission and distribution of natural gas, and Circular 6/2019 of the CNMC establishes the methodology for calculating the remuneration of the activity of electricity distribution. Circular 6/2019 further establishes the methodology for determining the amount to be paid to companies that carry out electricity distribution activities in order to guarantee the adequate provision of the service. This methodology is consistent with that established for the last regulatory period by RD 1048/2013. The new model increases companies’ flexibility in making decisions and it will be applied to all those commercial companies or consumer and user cooperatives that carry out distribution activities. It also includes several improvements that simplify the remuneration and information sent by companies to the CNMC for appropriate regulatory supervision.

**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) the 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.

The aim of Directive 2009/73/CE concerning common rules for the internal natural gas market is to make 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 liquefied natural gas terminals.

Furthermore, the Hydrocarbons Act was amended by Act 11/2013 of 26 July concerning measures to support entrepreneurship and to 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 Hydrocarbons Act.

As stated above, RDL 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 balance between costs and revenues. 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 fixed component for the facility’s availability, which includes annual operating and maintenance costs, depreciation and a financial return; and
- a variable component of continuity of supply, which enables the adjustment of imbalances resulting from fluctuations in demand.

Law 8/2015, 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, Law 8/2015 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 States 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, Law 8/2015 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 if these areas are intended for an activity other than hydrocarbon extraction.

Royal Decree 984/2015 (RD 984/2015) of 30 October regulates the organised gas market and third-party access to natural gas system installations. It contains the basic regulations for the operation of this new organised gas market, and other measures, such as the inspection procedures for gas installations. In compliance with Article 32 of RD 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, the 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 RD 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 of 21 December 2017 issued by the Spanish Constitutional Court 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, 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 justify approving a Royal Decree-Law in this regard.

In addition, in the context of the energy transition at both European and national levels, it was necessary to adopt a clear, stable and predictable regulatory and institutional framework that would provide legal certainty for all natural and legal persons involved in the energy sector. Thus, in connection with the foregoing, it should be noted that the European Commission initiated an *ex officio* investigation into the transposition of Directive 2009/72/EC and Directive 2009/73/EC into Spanish law, to assess the possible lack of conformity with EU legislation and concluded that the incorrect transposition of the internal market directives had led to significant litigation before the Supreme Court between the national regulator and the government, which was detrimental to the general interest and entailed legal uncertainty and institutional instability for all the agents involved in the sector.

Therefore, Royal Decree 1/2019 puts an end to this situation, implementing a distribution of competences that respects the Community framework, providing the CNMC with the necessary independence for the exercise of its functions.

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 Electricity Law 54/1997 and the current Electricity Act 24/2013 (Article 14.8) and Royal Decree 1/2019. 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 principles:

*a* 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’;

*b* 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;

*c* 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

*d* the remuneration is determined for each regulatory period (of 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 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.

Reference should be also made to:

a Circular 2/2019 of CNMC, establishing the methodology for calculating the financial remuneration rate for electricity transmission and distribution activities, and regasification, transmission and distribution of natural gas;
b Circular 3/2019 of CNMC, establishing the methodology for the operation of the wholesale electricity production market and the management of systems operation;
c Circular 4/2019 of CNMC, establishing the methodology for the remuneration of the electricity system operator;
d Circular 5/2019 of CNMC, establishing the methodology for the calculation of the remuneration of the activity of electricity transmission;
e Circular 6/2019 of CNMC, establishing the methodology for calculating the remuneration of the activity of electricity distribution;
f Circular 7/2019 of the CNMC, which approves the standard installations and the unitary reference values for operation and maintenance by fixed asset element to be used in the calculation of the remuneration of the companies that own electricity transmission installations;
g Circular 8/2019 of CNMC, establishing the methodology and conditions for access and allocation of capacity in the natural gas system; and
h Circular 9/2019 of CNMC, establishing the methodology for determining the remuneration of natural gas transportation facilities and liquefied natural gas plants.

v Security and technology restrictions
Security in relation to transportation facilities for 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 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 networks’.

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 relating 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 established in
2007, and the results of integration in the market have been obvious: whereas 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 that 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 until 2005, almost all 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, the 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 rose 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 its 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, and growth in wind production coinciding with intense rainfall.

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 European Union 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 (Red Eléctrica de España) to ensure continuity and security of supply;

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;

ë autonomous communities, which also have direct responsibilities for regulating their electrical systems; and

f the European Union, which establishes the general framework of the electrical system in all Member States through directives and legal regulations.
Royal Decree 949/2001 (amended by RD 984/2015 on organised gas market and third-party access and by Royal Decree 335/2018, which modifies several royal decrees regarding the natural gas sector), which regulates third-party access to gas infrastructure and establishes an integrated economic system of 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.

Further regulation is established by the following:


b. Ministerial Order ETU/1283/2017 of 22 December, on the tolls and fees associated with third-party access to natural gas facilities, and payments in respect of regulated activities for 2018;

c. Ministerial Order ETU/1367/2018 of 20 December, on the tolls and fees associated with third-party access to gas facilities, and the remuneration of regulated activities for 2019; and

d. Ministerial Order TEC/1259/2019 of 20 December, on the remuneration of storage activity and the tolls and fees associated with third-party access to gas facilities for the year 2020.

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 the 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 a contributor of energy, and jeopardising the recovery of investment. Incentives for investment and the availability of service, established in Order ITC/3127/2011 of 17 November (modified by Ministerial Order ETU/1133/2017 of 21 November, Ministerial Order ETU/971/2017 of 17 October, Ministerial Order TEC/1366/2018 and Ministerial Order TEC 1258/2019), have not generated sufficient economic signals to encourage investment in new back-up power in the region of 500 hours per year, which highlights the need to revise that target.
In particular, a procedure to assist in the security of supply 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 balance between production and demand (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 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 government presented a draft Proposal of Order regulating an incentive for investment in the improvement of environmental performance 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 those 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 of 30 April had previously attempted to limit the increase of the aforementioned general tariff deficit; however, it was not sufficient. 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, the aim of Royal Decree-Law 2/2013 was to mitigate the tariff deficit by modifying the remuneration system of regulated activities and 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 situations that define the electricity sector at any given period, with the objective of maintaining the sustainability of the electrical system’.

RDL 9/2013 abolished the former remuneration system based on a regulated tariff (the only one in existence since Royal Decree-Law 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 essentially carried into the Electricity Act 24/2013.

Accordingly, Section 5 of Article 14 of the Electricity Act (modified by Royal Decree 1/2019) determines that the remuneration for generation activities includes the following concepts:

a correspondent remuneration for participation in the daily and intraday market for generation;
b the system adjustment services required to guarantee a suitable supply to the consumer;
c when applicable, remuneration through the capacity remuneration mechanism;
d when applicable, additional remuneration for generation activities carried on in the electricity systems of non-peninsular territories; and
e when applicable, specific remuneration for the generation of electricity using renewable energy sources, cogeneration and waste.

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:

a 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
b 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 the standard power plant.

This specific remuneration, which 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’.
RD 413/2014 defines the concept of ‘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 running from 14 July 2013 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 in 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. Last, 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 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; and
- an update to the technological indication coefficients, with figures from the previous three years.

In addition, Ministerial Order TED/171/2020 of 24 February updates the remuneration parameters of standard installations applicable to certain facilities producing electricity from renewable energy sources, cogeneration and waste, for the purposes of their application to the regulatory period starting on 1 January 2020.

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 that specific remuneration regime. Finally, by virtue of a 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 electrical energy from renewable energy sources. By a resolution dated 19 May 2017, the General Directorate of Energy Policy and Mining awarded the 3,000MW to mainly renewable energy producers of wind and photovoltaic power.

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 a resolution dated 27 July 2017, the General Directorate of Energy Policy and Mining awarded the relevant capacity.

After the three auctions were held, all megawatts 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, which promotes the use of energy from renewable sources by 2020, from both an environmental and an economic point of view.

On 1 August 2015, the Official State Gazette published RD 738/2015, which mainly regulates electricity production activity and the dispatch procedure in non-mainland electricity systems. RD 738/2015 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. RD 738/2015 also implements matters already contained in Law 17/2013 of 29 October 2013 to guarantee supply and increase competition in these systems.

RD 738/2015 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 RD 738/2015 is subject to the European Commission not raising any objections with regard to its compatibility with EU law.

On 13 February 2016, RD 56/2016 was published in the Official State Gazette partially transposing Energy Efficiency Directive 2012/27/EU. RD 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:

- employ more than 250 workers; or
- have a 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.

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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. These 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.

The Administrative Energy Audit Register was created in 2016 through RD 56/2016 by the Ministry of Energy, Tourism and the Digital Agenda (now the Ministry for Ecological Transition and the Demographic Challenge).

It is also interesting to mention Ministerial Order ETU/360/2018 of 6 April, establishing the values of remuneration for operations corresponding to the first natural semester of 2018 and approving a standard installation, and establishing its corresponding remuneration parameters, applicable to certain installations for the production of electrical energy from renewable energy sources, cogeneration and waste, and Ministerial Order TED/171/2020 of 24 February, updating the remuneration parameters of standard installations applicable to certain installations producing electricity from renewable energy sources, cogeneration and waste, for the purposes of their application to the regulatory period starting on 1 January 2020.


## 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 for improving energy efficiency by 20 per cent in 2020 within the European Union compared with the baseline situation (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, 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 a 20 per cent reduction in energy use by 2020 compared with 2009.

At a national level, the main energy efficiency measures are based on the Spanish Energy Efficiency Strategy (E4) for the period 2004–2012, which has developed in several plans: 2005–2007 Action Plan, 2008–2012 Action Plan and 2011–2020 Action Plan. 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:

1. legislative actions, generally far-reaching and representing a complex set of recommendations, regulations, rules of functioning, constraints and generally binding rules;

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b incentive measures for carrying out audits and analysis of consumption of the technologies used, and promoting investment in equipment to increase energy efficiency; and
c 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 Action Plan, some of the key energy efficiency measures stated in the 2011–2020 Action Plan 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 a technological development is the new interconnection grid established between Spain and France. A €700 million project of common interest that doubles the electrical connection capacity between the two countries has been completed. It was co-financed by both countries through the incorporation of the company INELFE (half of which is owned by Red Eléctrica de España and half 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 2019 are summarised as follows:

a January 2019: urgent measures were adopted to bring the powers of the CNMC into line with the requirements arising from EU law in relation to Directives 2009/72/EC and 2009/73/EC concerning common rules for the internal markets in electricity and natural gas.

b April 2019: administrative, technical and economic conditions of the self-consumption of electrical energy were updated.

c November 2019: urgent measures were adopted for the necessary adaptation of remuneration parameters that affect the electricity system and which respond to the process of ceasing the activity of thermal generation plants.

d The CNMC approved several circulars in the energy and gas sectors for the regulatory periods 2020–2025 and 2026–2031.
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, in both the electricity and the 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 during the next 20 years; once defined, this plan should remain in place for that length of time.
Chapter 23

TAIWAN

Chung-Han Yang and Chengkai Wang¹

I OVERVIEW

Taiwan, as an island, imports around 98.5 per cent of its energy,¹ which is crucial to the rapidly transforming economy. Owing to a long-standing dependence on energy imports and political restrictions, Taiwan’s power generation system has difficulties in creating an electricity grid network to connect with other countries or regions. Hence, since a lack or an excess of electricity generation would not be balanced with outbound and inbound electricity flows, Taiwan’s electricity grid network is an independent one.

To build a ‘nuclear-free home’, the Tsai administration intended to reform the power sector and the whole electricity market structure through the Electricity Act 2017.² The main goal of this regulatory reform is to ultimately phase out nuclear power, increase renewable energy in electricity generation and retailing, and examine the open market mechanism with the power sector reform. Following approval of the new Electricity Act by the Legislative Yuan, many foreign investors will be closely following these policy trends. For instance, manufacturers care about whether Taiwan is able to deliver a sufficient and stable electricity supply at reasonable prices. And other potential investors are evaluating new commercial opportunities in the procedures of power market liberalisation, generation of green energy and nuclear decommissioning.³

In recent years, the authors and colleagues have been working closely with the Taiwanese government and two major state-owned energy giants – China Petroleum Corporation Taiwan (CPC Taiwan) and Taiwan Power Company (Taipower) – on a variety of significant projects. Therefore, this chapter presents observations on the latest regulatory and policy changes, electricity market reforms, energy trade (especially liquefied natural gas (LNG)), renewable energy development and relevant commercial opportunities.

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II REGULATION

i Energy transition
Energy transition is still under way. According to the Taiwan Bureau of Energy’s statistics in 2019, renewable electricity accounted for 5.6 per cent of the aggregate produced electricity and 13.93 per cent of the aggregate installed generating capacity in Taiwan. Although the provision of the Taiwan Electricity Act on halting nuclear power plants was abolished in 2019, the Tsai administration seems to keep moving forward with its energy policy of phasing out nuclear power in Taiwan. During this transition, the Tsai administration’s outlook for the fuel mix for power generation in 2025 is 50 per cent natural gas, 30 per cent coal and 20 per cent renewable energy.

The ultimate goal of this transition is to achieve Taiwan’s Intended National Determined Contribution, voluntarily published after the 2015 Paris Climate Accord, which stated that annual carbon emissions should be reduced by 20 per cent by 2030 and by 50 per cent by 2050, as compared with 2005. This ambitious goal will require a reduction of around 53 million tonnes of carbon dioxide equivalent by 2030 and 133 million tonnes by 2050. To achieve all these policy goals requires a well-designed regulatory framework and strong political supports.

ii The regulators
The Bureau of Energy, Ministry of Economic Affairs is Taiwan’s major government authority for energy issues. Operating based on its statutory scope of authority, the Bureau of Energy is responsible for the design and management of Taiwan’s energy policy and relevant regulation, prediction planning and promotion of supply and demand of energy, the management of energy corporations, the review of energy rates, research, development and popularisation of renewable energy and new energy technologies, the promotion of energy efficiency and conservation measures, among other things.

Taiwan set up a Office of Energy and Carbon Reduction under the Executive Yuan in 2016. This aim of this new office is to enhance the policy integration between different government agencies and implement concrete measures for the low-carbon energy transition.

6 The amendment to Article 95 of the Taiwan Electricity Act is effective as of May 2019. In theory, Taiwan is no longer obliged by law to eliminate nuclear power by 2025. However, the Tsai administration has expressly rejected the extensions of the two operational nuclear power plants, both of which will reach the end of licences by 2025.
8 id.
10 Executive Yuan, Department of Information Services, ‘Executive Yuan to set up energy and carbon office’ (June 2016), at https://english.ey.gov.tw/Page/61BF20C3E89B856/f5e3677e-a7df-4b99-b850-319482c49b8f.
iii Regulatory structure

In successfully implementing the above-mentioned energy policy goals, Taiwan has already established five major categories of energy laws and regulations: the Energy Management Act, the Petroleum Administration Act, the Natural Gas Business Act, the Electricity Act and the Renewable Energy Development Act.

Energy regulations and policies in Taiwan are therefore promulgated pursuant to the authorisation by each category of the major energy laws, and govern the promotion of various energy issues.

iv Ownership and market access restrictions

Taiwan has a long history of state-owned power supply – Taipower was established in May 1946. The electricity sector has been regulated by Taipower for several decades, and the company’s position as a monopoly maintains relatively low prices.

Since 1990, liberalisation of the electricity market has followed models and examples of reform in other developed and developing countries. However, the procedure in Taiwan has progressed very slowly and there has not been a public consensus in support of power market liberalisation. The latest revision of the Electricity Act, in 2017, mainly focused on opening up the market for green energy, which has made it difficult to formulate a free market in a short period or to gain support from other regional power markets, leaving several challenges still unresolved.

v Transfers of control and assignments

Taipower operates all electricity grid and transmission networks in the country and generates around 80 per cent of Taiwan’s electricity. According to the Electricity Act 2017, this state-owned entity should undergo its first corporate institutional restructuring and end a 70-year monopoly on the sale of electricity.

To improve the company’s efficiency, Taipower will be separated into two major operational divisions: one for power generation and one for electricity transmission, distribution and sale. Under these two major divisions, there are four distinct units: conventional power generation, nuclear power generation, transmission, and distribution and service. These restructuring measures aim to clarify each unit’s obligations and optimise efficiency. In the future, Taipower will also be requiring each unit to provide individual financial statements to improve cost management.

This significant institutional arrangement of Taipower means that other power suppliers will be able to sell electricity directly to consumers. Under the previous system, private companies could only sell electricity to Taipower, which charged a transmission handling

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15 See Electricity Act 2017, Article 6, fourth paragraph.
fee and would then distribute it at a price it had set. However, not all the details have been worked out at this stage, and the idea of privatising Taipower will require further study. The whole process began in 2017 and will take another three to six years to complete.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

Taiwan’s electricity market has not been fully liberalised. Currently, the island’s electricity transmission and distribution networks are all operated by Taipower. However, a number of articles in the Electricity Act 2017 foresee the future direction of reform.

i Vertical integration and unbundling

To achieve the goal of a steady supply of electricity, Taipower will need to be restructured as a parent holding company, which will set up two subsidiary companies to oversee (1) electricity generation and (2) electricity transmission and distribution.

ii Transmission/transportation and distribution access

Like Taipower, the electricity transmission and distribution enterprise will be a state-owned corporation and a single entity. The scope of its business operation covers the entire country. The electricity transmission and distribution enterprise will be responsible for managing the dispatch of electric power by giving priority to the grid connections that allow access to the renewable energy on the condition that the power systems remain safe and stable.

The new enterprise may not engage in the generation or retailing of electricity and cross holdings of shares in the enterprises will not be permitted. However, the engaging restriction would not apply if the electricity industry regulatory authority approves otherwise. In those circumstances, the electricity transmission and distribution enterprise would be permitted to run the electricity retailing utility enterprise concurrently.

The electricity transmission and distribution enterprise may engage in business pursuits other than those in the electricity industry on the condition that those business pursuits neither affect the operation of the corporation as an electricity transmission and distribution enterprise nor compromise the maintenance of fair competition. It would also require approval by the electricity industry regulatory authority.

To perform the tasks assigned in the preceding paragraph, the electricity transmission and distribution enterprise shall prepare a draft of regulations to govern the ‘scope, item, procedure, norm, cost-sharing, emergency response and information disclosure of the electric power dispatching’ in line with the electric power dispatching principals drawn up by the

17 Electricity Act 2017, Article 6, fourth paragraph.
18 id., at Chapter 1, Article 5, first paragraph.
19 id., at Article 8, first paragraph.
20 id., at Article 6, first paragraph.
21 id., at Article 6, second paragraph.
regulatory authority. This draft shall be submitted to the electricity industry regulatory authority for approval. A similar review process shall also apply to any future amendment of these regulations.22

iii Rates
A renewable energy-based electricity generating enterprise, or a retailing enterprise that requires the power grids to distribute the power generated or purchased for sale, may request the service of the electricity transmission and distribution enterprise for electric power dispatching, and pay a service fee based on the total amount of electricity dispatched.23 Further, the electricity transmission and distribution enterprise shall charge the respective enterprise that uses its electricity supply infrastructure a fee based on the amount and the rates of the resupplied electricity.24

The two aforementioned fees shall be assessed according to the Electricity Carbon Emission Factor and submitted to the Electricity Tariff Examination Council for review and approval.25 A discount may be given on the prescribed fees, based on the Electricity Carbon Emission Factor. The rules governing any such discount shall be established by the central competent authority.26

To ensure a safe and stable supply from the power system, the electricity transmission and distribution enterprise shall provide the ancillary services required to meet the needs of the electric power dispatching by applying to the electricity generation enterprise and employing self-use power generation equipment as required.27

The electricity transmission and distribution enterprise may charge fees for these ancillary services, which will be based on the Electricity Carbon Emission Factor and submitted to the Electricity Tariff Examination Council for review and approval.28

IV ENERGY MARKETS
i Electricity market reforms
Amendments to the Electricity Act approved by the Executive Yuan in October 2016 relaunched reforms of the electricity market and demonstrated that the procedure would need to be implemented in two stages.

Restructuring the power sector
The aim of the first stage of power sector reform (from 2017 to 2020) was to allow renewable energy producers to sell their electricity directly to customers, either via their own transmission and distribution lines or through the existing electricity grid network set up by Taipower.29 Taiwan has ambitious goals for developing renewable energy. The Tsai administration has

22 id., at Article 8, second paragraph.
23 id., at Article 10, first paragraph.
24 id., at Article 10, second paragraph.
25 id., at Article 10, third paragraph.
26 id., at Article 10, fourth paragraph.
27 id., at Article 9, first paragraph.
28 id., at Article 9, second and third paragraphs.
Taiwan

invested around NT$1.4 trillion for 20 gigawatts (GW) of installed solar photovoltaic (PV) and 5.5GW of offshore wind by 2025.\textsuperscript{30} Liberalising the green power market in this first stage is recognised as being key to accelerating development of renewable energy without causing increases in prices for consumers or the ruination of Taipower’s finances.\textsuperscript{31}

Under the Taiwan Bureau of Energy’s plan, the second stage of reform is to be carried out over six years (from 2019 to 2025), including the restructure of Taipower into a holding company with two entities: a power generation corporation and a transmission and distribution corporation. Although electricity generation will be further opened up for private investment, both entities under Taipower would still be run and regulated by the state.

The effects of this restructuring of Taipower could be even more far-ranging. The government has scheduled the separation of the accounting system from the power enterprise within two years and completion of the separation of corporates within six to nine years.\textsuperscript{32} This institutional change would set the foundation for subsequent reforms.

\textbf{Possible effects on electricity rates, power markets and society}

For a long time, electricity in Taiwan has been supplied by the vertical integration of the state-run Taipower. According to statistics for 2017 compiled by the International Energy Agency, the power price rate for households was the second lowest in the world and its industrial power price rate was the seventh lowest globally.\textsuperscript{33}

Before launching the new round of power sector liberalisation, the government stated that it would not increase electricity prices; further, the amendments to the Electricity Act cover price regulation and provide for a special fund to stabilise electricity prices. The amendments also guarantee annual net profits for electricity generators, suggesting that if the market does not allow for payment of a premium for green energy, the government will purchase the electricity.

Currently, the government still has a monopoly in the market and it can easily control electricity prices by Taipower’s vertical integration. As open market mechanisms are introduced, the opening up of power generation and sales in stages may not be allow for a fully competitive market to be created immediately. Also, as commentators have pointed out: ‘Opening the market would increase the exchange costs, combining with the government’s feed-in tariff and system cost to promote renewable energy, the electricity price is bound to go up.’\textsuperscript{34}

\textbf{Challenges ahead}

Based on developments in the power market so far (between 2017 and 2020), the relevant green power procurement regulations are not yet attractive enough to activate a whole new electricity market. For instance, detailed regulations relating to the Renewable Energy Portfolio Standard (RPS) have not been published.

\begin{itemize}
\item \textsuperscript{31} id.
\item \textsuperscript{32} ‘Taipower to restructure for first time in 70 years’, \textit{Taipei Times}, at https://www.taipeitimes.com/News/biz/archives/2016/01/05/2003636433.
\item \textsuperscript{34} Tsay, I-S and Chen, P-H, ‘A dual market structure design for the reform of an independent power grid system – The case of Taiwan’, Science Direct, Energy Reports, Vol. 5 (November 2019), pp. 1603 to 1615.
\end{itemize}
At this stage, there are still very few private power retailers in Taiwan’s electricity market, which may also be a result of the lack of specific qualifications and clear review criteria for electricity retailers. Therefore, power generators still cannot enjoy the full advantages of electricity market reform if they wish to sell electricity to end consumers through Taipower’s current transmission and distribution grid lines. Taipower should consider pushing forward the liberalisation of the electricity market by supplying renewable-based electricity to end users, rather than just functioning as an electricity retail utility company.

For the next stage of power market reform to succeed, many relevant regulations and policies need to be revised and improved. In addition to the implementation methods for the RPS, energy regulations regarding power transmission and distribution, application standards and requirements for power retailers should be the priorities for future power policy planning. Experiences in countries that have undergone power sector reform demonstrate that establishing a regulatory ecosystem of fair market competition is a necessary condition for the success of reform in Taiwan, and for the benefit of society and citizens.

ii Liquefied natural gas trade and gas markets

Because of the limited availability of renewable energy and the need for backup power generation capacity in the island, the role of liquefied natural gas (LNG) in Taiwan’s power generation mix will grow significantly by 2025.

Development of Taiwan’s LNG trade

Taiwan has only about 0.78 per cent indigenous natural gas production for its consumption, and imports 99.22 per cent of its requirement from other jurisdictions. In 2016, Taiwan imported more than 700 billion cubic feet of LNG, which makes Taiwan the world’s fifth-largest LNG importer.35

The major suppliers are Qatar, Malaysia, Indonesia, Australia, Papua New Guinea and the United States,36 accounting for about 90 per cent of LNG imports in 2016.37 Taiwan purchased much of its LNG under long-term contracts. For example, Qatar, the world’s leading exporter of LNG, supplies Taiwan in this way, and has even established a joint venture between its state-owned company RasGas and ExxonMobil (based in Houston, US).38

CPC Taiwan is the major importer of LNG. In recent years, CPC Taiwan has continued to diversify its gas supply sources after signing long-term LNG supply contracts and joint ventures with the capacity owners in Australia, the United States and Papua New Guinea.39 In 2014, Taipower was given government approval to procure LNG itself. In the future, some

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36 id.
38 id.
of the new gas-fired projects will use LNG bought by Taipower. For instance, Taipower signed long-term contracts and completed the procurement process with several international LNG suppliers for Taipower’s Taichung and Hsieh-Ho projects before the end of 2019.

Regarding LNG procurement strategies, both CPC Taiwan and Taipower mainly apply long-term contracts, supplemented by spot purchase. To diversify the types of LNG suppliers, both portfolio suppliers and project suppliers are taken into consideration (although portfolio suppliers are preferred) during evaluation to secure supply and ensure competitiveness. Current policy aims to purchase at least 20 per cent of contract volume from the United States. Finally, in respect of diversification on price index, the contract price is linked to both the Japan Crude Cocktail and Henry Hub to avoid the risk of a single price index.

**Natural gas market and regulation**

CPC Taiwan currently owns almost all the LNG unloading, transmission and storage facilities in Taiwan and is therefore still the largest natural gas supplier to the power generation sector. 41

CPC Taiwan reviews changes in the cost of imported LNG monthly, in accordance with the government-regulated gas pricing system. 42 If the range of the monthly adjustment is within 3 per cent or less than 6 per cent accumulated for three consecutive months, CPC Taiwan has its own full authority to decide the price adjustment and, after an adjustment is announced, CPC Taiwan just needs to report to the Ministry of Economic Affairs for information purposes. However, if the range of adjustment exceeds the aforementioned authorised range, CPC Taiwan will need to ask the Ministry of Economic Affairs for approval of its decision. 43

There are two major types of contracts for sales of natural gas on the domestic market: United Contract and Tatan Exclusive Contract. 44 All natural gas supplied to Hsinta, Talin, Nanpu, TungHsiao and Tatan (except for the quantity supplied under the Tatan Exclusive Contract) is under the United Contract system. Pricing under a United Contract is now based on CPC Taiwan’s monthly published price. Pricing under a Tatan Exclusive Contract, on the other hand, is in accordance with the contract formula and is calculated monthly. In 2019, the gas pricing system required Taipower to reduce the cost of electricity generation from gas for gas-fired power purchased from independent power producers (IPP) from NT$3.7 per kilowatt hour (kWh) to NT$2.64/kWh. This level is still significantly higher than the NT$1.9/kWh paid for coal-fired generation purchased from independent power producers but only slightly above Taipower’s average electricity rate to customers of NT$2.56/kWh. 45

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40 Traditionally, buyers in the Asia Pacific have bought LNG at a price indexed to crude oil, a pricing mechanism known as Japan Crude Cocktail.
42 The pricing formula is first proposed by the Taiwan Institute of Economic Research and officially approved by the Electricity and Natural Gas Pricing Committee at the Ministry of Economic Affairs – see https://www.moeaobe.gov.tw/ECW/english/content/Content.aspx?menu_id=1696.
New trends in the LNG trade and infrastructure development

The rapid growth of US shale gas on the global energy market is generating speculation that Taiwan might soon become a main customer. In fact, CPC Taiwan has been purchasing US gas on the spot market since 2017. More recently, the Trump administration has made decreasing US trade deficits with main trade partners a policy priority, and increased sales of LNG is usually viewed as a possible solution for dealing with the trade imbalance.46

It still is not certain whether Taiwan would be a big buyer of US LNG. The first factor is the price. If the US LNG price remains significantly higher than that of other global competitors, the amount of LNG imported from the United States would be constrained. Additionally, both CPC Taiwan and Taipower need to compete for LNG tanker shipments internationally with Japan, Korea and mainland China. This situation also leads to an interest in reducing Taiwan’s LNG trade surplus with the United States.

Regarding the natural gas infrastructure, the government’s official timetable for gas-fired generation expansion is looking precarious. The approval, design, engineering and construction of new natural gas infrastructure projects all take a considerable amount of time. Taiwan’s LNG receiving capacity is one of the major stumbling blocks for any increase in LNG demand.47 Currently, Taiwan has two major receiving terminals, which already need to receive more LNG shipments than their designed capacities. To allocate the increasing LNG demand, the Tsai administration plans to create a third LNG receiving terminal. Taipower aims to add 13.5GW of gas-fired capacity by 2025 (and a further 3.5GW by 2028), though any delays in completion of infrastructure will test the anticipated growth in demand.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

To achieve the 2025 renewable energy target, the Tsai administration is keen to focus on an expansion of solar PV installation and offshore wind farms. In particular, the projection is an increase in solar PV installed capacity to 20GW by 2025. Following the completion of its two-year solar PV promotion plan,48 the government’s focus is on three main short-term strategies: encouraging rooftop PV installation, promotion at both central and local levels, and generating polar power from aquaculture facilities.49

To incentivise solar power installation, the government has promoted a combination of the feed-in tariff mechanism and the ‘photovoltaic-energy service company’ operational model. On 31 December 2019, the government announced that the 2020 feed-in tariff rate for solar PV generation, plus the cost of solar panel recycling, is reduced to between

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48 The two-year solar photovoltaic promotion plan, implemented between July 2016 and December 2018, focused on the construction of demonstration projects and the simplification of operating procedures.

The boom in Taiwanese offshore wind energy is driven by the government’s ambitious renewable energy plan, the Thousand Wind Turbines Project (the Wind Project). This project has three stages: (1) Demonstration Round (2016–2020); (2) Transition Round (2019–2025); and (3) Zonal Development Round (2026–2035). The idea behind this initiative is ‘demonstration first, then zones of potential, and finally zonal development’.

In April 2018, the government announced that the original 3GW offshore wind energy target for the Transition Round was increased to 5.5GW capacity, which is estimated to stimulate US$32 billion in investment.

The Allocation process for the total 5.5GW capacity target was allocated through two phases: Phase 1: selection mechanism for an initial 3.5GW and Phase 2: competitive bidding for the remaining 2GW.

The Phase 1: selection mechanism allocated the 3.5GW capacity with a fixed feed-in tariff for 20 years by adopting the Guidelines for Grid Allocation promulgated by the Taiwan Bureau of Energy in January 2018. The selection criteria include several considerations, such as construction capability, engineering capability, operation capability and, particularly, the promotion of local content and the connection to Taiwanese financial institutions.

On 30 April 2018, the government allocated the grid connection of the initial 3.5GW capacity to 10 offshore wind farms proposed by seven investors through the selection mechanism. The selected offshore wind farms are required to enter into a wind power purchase agreement specifying a 20-year fixed feed-in tariff with Taipower. In December 2019, the government decided to decrease the 2020 feed-in tariff rate for offshore wind power by 7.6 per cent, as compared to the 2019 rate. Thus, the 20-year fixed feed-in tariff for the offshore wind power purchase agreement signed in 2020 is set at NT$5.0946 per kWh. However, the offshore wind power developers have an option to sell the generated power at NT$5.8015 per kWh for the first 10 years and at NT$3.8227 per kWh for the second 10 years.

During Phase 2, allocation of the remaining 2GW capacity (the final figure was 1.644GW) was based on competitive bidding. In contrast to the selection mechanism, there was no local content requirement for this bidding round and the major consideration was the lowest offtake tariff. On 22 June 2018, the government announced that four wind
farms proposed by two investors were awarded the 1,644GW capacity in total through the competitive bidding process. The bidding price for the four wind farms ranged from NT$2.2245 to NT$ 2.5481 per kWh.\(^{56}\)

Beyond the Wind Project’s 2025 target, the government is further expected to launch a target of 10GW offshore wind energy capacity to be operational by 2035. Those policies give positive signals to local and foreign investors that there will be huge developments in offshore wind power and promising business opportunities in Taiwan in the coming decades.

\[\text{ii Energy efficiency and conservation}\]

Faced with growing energy demand, Taiwan’s current energy efficiency management systems set up mandatory programmes and voluntary programmes. The major policy tools adopted for mandatory programmes include: Minimum Energy Performance Standards (MEPS), Energy Efficiency Rating Labelling and Energy Management and Audit. The MEPS were introduced in Taiwan in the 1980s and have been continually updated. Currently, the government has specified 27 product categories for the MEPS requirements.\(^{57}\)

Apart from the mandatory programmes, the government also endeavours to increase public awareness, education and promotion about energy efficiency and conservation. These incentive programmes include subsidies and tax rebates. For example, as part of an amendment to the Taiwan Commodity Tax Act, the government announced an incentive package in 2019. Now customers who purchase selected appliances with high energy efficiency between June 2019 and June 2021 are eligible for a tax rebate of NT$2,000 for each appliance.\(^{58}\)

\[\text{iii Technological developments}\]

Widespread adoption of smart grid technology in Taiwan has played a vital part in the forthcoming evolution of the Taiwan electricity market. To improve the quality and stability of renewable energy supplied to citizens, the government launched a Smart Grid Master Plan in 2012. This long-term plan covers a period of 20 years and aims to develop Taiwan’s smart grid in three stages: (1) Technology Test Stage (2011–2015); (2) Technology Implementation and Promotion Stage (2016–2020); and (3) Technology Extensive Application Stage (2021–2030).\(^{59}\) An estimated NT$139.9 billion will be invested in this Master Plan.

Smart grid installation is proceeding at a rapid pace in Taiwan. According to the latest statistics, 300 intelligent substations (nearly 50 per cent) will be completed in 2020 and a further 603 (100 per cent) will be completed in 2030. In respect of automatic power


\(^{57}\) To encourage customers to purchase products with high energy efficiency, the government first launched a voluntary energy labelling system in 2001. As of March 2019, there are 301 manufacturers with 6,649 products effectively certified with the Energy Label. The mandatory Energy Efficiency Rating Labelling system, which was launched in July 2010, focuses on energy-consuming equipment and appliances, such as air-conditioning units, automobiles and motorcycles. As of March 2019, there are 12 categories of products successfully registered in the mandatory Energy Efficiency Rating Labelling system. For more information about Taiwan’s Minimum Energy Performance Standard requirements, see https://www.moeaboe.gov.tw/ECW/english/content/Content.aspx?menu_id=1535.


\(^{59}\) For more information about the Smart Grid Master Plan, see https://www.moeaboe.gov.tw/ECW/english/content/Content.aspx?menu_id=8678.
distribution switches, 24,000 (86 per cent) switches were completed in 2018 and another 28,000 (100 per cent) will be completed in 2030. In addition, all high-voltage advanced metering infrastructure (about 25,000 households) has been completed and 230,000 low-voltage advanced metering infrastructure was installed in 2018. The government has announced that it will accelerate the installation of one million low-voltage smart meters by the end of 2020.60

As almost half of Taiwanese households are already equipped with smart meters, the technological developments on smart grid will move to focus on the management of demand and innovation on commercial application.61 For example, Taipower has introduced a tiered pricing mechanism that provides discounted tariffs to off-peak users. Further, the Taiwan Renewable Energy Development Act provides a default cost-sharing mechanism between the electricity transmission and distribution companies and the renewable energy generators.62 Thus, a better integration of renewable energy in a sustainable smart grid is a major challenge that must be addressed.63

VI THE YEAR IN REVIEW

The current period of energy development in transition is largely policy driven. Following the successful re-election of Ms Ing-Wen Tsai as President in January 2020, energy transition in Taiwan will continue to introduce substantial power generation capacity from renewable sources, especially solar and wind, and the current policy to phase out nuclear energy will remain.

In early 2019, amendments to the Renewable Energy Development Act imposed a regulatory position statement on large power users. However, it failed to provide further specifications about either power users or renewable energy targets. Further, the renewable energy procurement methods are not clear enough. Whether it is through a renewable energy retailing enterprise or Taipower’s grid, there should be a clearer description of the procurement methods so that the market can operate properly.

The energy policy referendums in November 2018 clearly demonstrated a strong dissatisfaction with coal and air pollution.64 Nuclear energy, on the other hand, found favour with voters. Citizens favoured lifting a ban on nuclear energy past 2025. Despite popular support for environmental protection and renewable energy, several polls show the population’s resistance to a price rise. From 2012 to 2013, higher fuel prices compelled the government to adjust electricity prices, which faced very strong opposition from citizens and

60 Department of Information Services, Executive Yuan, ‘Smart power grid to ensure stable power supply’ (7 November 2019), at https://english.ey.gov.tw/Page/61BF20C3E89B856/27f4ba64-fe9b-47dc-b183-8f2a9718034e.
62 Article 8 of the Renewable Energy Development Act provides: ‘In the situation in which an electricity enterprise connects to the power grid according to the preceding paragraph, the costs of bolstering the power grid in addition to the existing networks may be shared by renewable energy-based electricity generating enterprises and electricity transmission and distribution enterprises.’
a slump in the level of support for the ruling political party, KMT, making it difficult to lower consumption with higher prices. According to Taiwan’s referendum law, the government is obliged to respond to the measures that pass, which illustrates the interesting relationship between democracy and energy policy in Taiwan.

VII CONCLUSIONS AND OUTLOOK

The decarbonisation of energy systems represents not only great regulatory and policy challenges for Taiwan but also increasing business opportunities for international investors. Several major projects are currently being implemented under Taipower’s long-term Power Development Plan, which aims to construct new power plants, and to renew and expand current facilities until 2028. There is great potential for the market, if any foreign entity is able to promote well-proven solutions and commercially available energy technologies for Taiwan’s transition.

Energy from waste (EfW) is a new type of renewable energy, which accounts for around 1.25 per cent of the total electricity generation in Taiwan. Between 2017 and 2022, Taiwan invested NT$9 billion in upgrading 11 EfW incinerators and related treatment facilities and technologies, such as mechanical biological treatment, centralised anaerobic digestion and highly effective decentralised composting. Government policy encourages foreign business partners to participate in the development of growing the EfW industry, which provides opportunities for local–foreign partnerships and other collaborations.

As Taiwan is achieving its ‘free-nuclear homeland’ goal, nuclear power plant decommissioning and nuclear waste management also bring many commercial opportunities. For the successful management of nuclear waste and the decommissioning of nuclear plants, Taiwan requires overseas exemplariness and expertise. Taiwan has explored all possible means and the most viable mid-term and long-term solutions; further international cooperation in the nuclear power regime is indeed imperative for Taiwan.

The 2025 deadline for phasing out nuclear power in Taiwan is approaching. This situation requires proven sources of green energy that can be installed on a large scale within a relatively tight timeframe, as Taiwan moves towards its goal of 20 per cent of electricity generation from renewable energy sources. Also, natural gas will have a more critical role in Taiwan’s future energy mix. It is believed that the amendments to the Electricity Act are potentially transformative, but how well the new system would work remains to be seen. We will be updating Taiwan’s reform progress in future editions of this volume.

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 size (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 (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. This chapter focuses on the UAE’s federal laws and policies relating to the energy sector with a particular focus on the regulation of the electricity sectors in the emirates of Abu Dhabi and Dubai.

The powers of the federal and the emirate governments are enumerated in the State Constitution of 1971. 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.

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 gross domestic product to approximately 36 per cent.

REGULATION

The Federal Ministry of Energy and Industry (the Ministry of Energy) is the primary regulator at the federal level and is 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. 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.
The Federal Electricity and Water Authority (FEWA) 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 works in conjunction with FEWA to implement the federal government's electricity policy in the northern emirates.

**Abu Dhabi**

Abu Dhabi’s electricity sector is regulated by the Department of Energy (DOE) and the UAE Water and Electricity Company (EWEC). The DOE is responsible, *inter alia*, for controlling, supervising and organising the energy sector in Abu Dhabi and for issuing licences to entities engaged in the energy sector.2 EWEC is the sole provider of water and electricity in Abu Dhabi and is empowered to contract with all entities licensed to produce and distribute water and electricity in Abu Dhabi.

**Dubai**

The main authorities regulating the electricity sector in Dubai are the Dubai Electricity and Water Authority (DEWA), the Dubai Supreme Council of Energy (DSCE) and the Dubai Regulation and Supervision Bureau (RSB Dubai).

The DSCE is the primary regulator of the energy sector in Dubai and regulates the exploration, production, storage, transmission and distribution of petroleum products (natural gas, liquid petroleum, petroleum gases, crude oil) and electricity. The DSCE also proposes any and all initiatives relating to the energy sector, which includes privatising 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.

**Northern emirates**

The main regulator in Sharjah is the Sharjah Electricity and Water Authority (SEWA). 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.

FEWA is responsible for the generation, transmission and distribution of electricity in the other northern emirates of Ajman, Ras Al Khaimah, Fujairah and Umm al-Quwain.

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2 The term ‘energy sector’ covers all activities, works and services related to the following: (1) production, treatment, storage, transportation, distribution, supply, sale and purchase of gas, oil and derivatives thereof; (2) generation, storage, transportation, distribution, supply, sale and purchase of electricity of all kinds (clean, renewable, traditional); (3) production, treatment, desalination, storage, transportation, distribution, supply, sale and purchase of water; (4) collection, treatment and disposal of sewage and waste water, and the recycling of treated waste water; and (5) production, storage, distribution and supply of refrigerated liquid for central refrigeration applications.
The Ras Al Khaimah Electricity and Water Authority (RAKEWA) is tasked with the regulation, management, operation and maintenance of power stations, water desalination plants, electricity distribution and transport networks in Ras Al Khaimah. RAKEWA is also responsible for controlling prices of electricity and water 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 the ground. It is 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.

iii Ownership and market access restrictions
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 power sector is no exception to this requirement. While Federal Law No. 19 of 2018 on Foreign Direct Investment (the FDI Law) was promulgated to allow 100 per cent foreign ownership of companies in certain sectors in the UAE, subject to approval of the UAE Cabinet, the FDI Law sets out a Negative List of 13 sectors in which existing laws and restrictions will continue to apply and majority foreign ownership will not be permitted. This includes water and electricity services.

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.

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.

Abu Dhabi
Project companies are usually structured as joint stock companies incorporated in Abu Dhabi. As a matter of policy, although two or more foreign joint venture partners are permitted to own up to 40 per cent of a project company, the DOE ensures that a foreign entity does not own more than 25 per cent of the market by capacity. The most common ownership structure is one in which the DOE incorporates an intermediate holding company to own a 60 per cent stake, which in turn is held by the DOE (10 per cent) and the Abu Dhabi National...
Energy Company PJSC, also known as TAQA (90 per cent). A few project companies have other ownership structures. Recently, project companies have also been structured as limited liability companies.

**Dubai**

Under the Dubai Electricity Privatisation Law, DEWA is authorised to establish project companies, by itself or in collaboration with third parties, for the generation of electricity. Dubai Law No. 22 of 2015 on Regulating Partnerships between the Public and Private Sectors in Dubai, which was enacted in 2015, governs the regulatory framework of public-private partnerships in Dubai. The aim of this Law is to encourage private-sector participation in the development of projects. It sets out, *inter alia*, the terms of partnerships between the public and private sectors and conditions for approval of prospective projects.

To date, several independent power projects (IPPs) have been launched in Dubai in which, typically, DEWA has 51 per cent ownership of the project company and the remainder is owned by one or more private sector entities.

**Northern emirates**

FEWA is authorised under the FEWA Law to establish private power generation plants in the northern emirates. While in the past most projects in these emirates were primarily owned in the public sector, of late there has been a move towards public-private partnerships and a number of projects presently being developed in these emirates are partly owned by one or more private sector entities.

In Sharjah, typically the government of Sharjah (directly or indirectly) would co-own projects with one or more private sector entities. Government sector ownership in Sharjah has been as low as 25 per cent in certain projects.

**Transfers of control and assignments**

Any transfer of control or assignment of an interest in an independent water and power producer (IWPP) requires the consent of the relevant regulator.

Under the relevant electricity laws in Abu Dhabi, a licence may not be transferred unless there is specific permission. Prior consent of the DOE 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 DOE may consider appropriate.

In Dubai, licensed entities are not permitted to transfer or assign their licences without the prior approval of the RSB Dubai. In addition, licensed entities may not dispose of, sell, lease or otherwise transfer, including granting a security interest over, their main assets without prior approval from the 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.

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5 Delmon, Jeffrey and Rigby Delmon, Victoria, *International Project Finance and PPPs: A Legal Guide to Key Growth Markets* (2012), Chapter 16, p. 26. Abu Dhabi National Energy Company PJSC (known as TAQA), in which the Department of Energy [DOE] (formerly ADWEA) owns a 74.05 per cent ownership stake, was established under Abu Dhabi Decree No. 16 of 2005 and serves as ADWEA’s (now the DOE’s) investment arm in the emirate and abroad. Other Abu Dhabi government entities own a further 1.16 per cent of TAQA, with the total government shareholding being 75.21 per cent. The remaining 24.79 per cent of TAQA is owned privately.
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

TRANSCO operates Abu Dhabi’s transmission networks. It supplies electricity from the generation companies to the two distribution companies of Abu Dhabi, each of which was previously wholly owned by ADWEA, and now by the DOE. 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 power shortages faced in the northern emirates, TRANSCO became 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. DEWA’s transmission and distribution network is constantly being expanded as new real estate and industrial projects are set up across Dubai.

During the past few years, DEWA has further enhanced the electricity transmission networks of the emirate. This includes DEWA’s announcements in 2017 to build 97 new 132/11kV substations and three new 400kV substations by 2020. DEWA is also currently building three new 132/11kV substations with 45 kilometres of high voltage (132kV) cables for the World Expo 2020.

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.

In Sharjah, SEWA is the sole purchaser of electricity 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.
**Emirates National Grid**

A project was launched by the Ministry of Energy in 2001 with the purpose of enhancing integration between the various electricity and water authorities in the UAE, and to connect and enable sharing of power between the seven emirates. Each of the electricity and water authorities contributed proportionately to the capital investment required to build the Emirates National Grid (ENG). The ENG is owned by those authorities in the following proportions:

a. **DOE (formerly ADWEA):** 40 per cent;
b. **DEWA:** 30 per cent;
c. **FEWA:** 20 per cent; and
d. **SEWA:** 10 per cent.

Dubai and Abu Dhabi's power grids were connected by the ENG in mid 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 (now the DOE) 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 Grid**

The UAE is also connected to the rest of the Gulf Cooperation Council (GCC) through the GCC Grid, through which it can trade electricity with the other GCC countries. Ideas have been put forward to expand power grids to Egypt and European networks (through Turkey) and trade energy beyond the GCC region. Recently, GCC has announced that it plans to build power lines to Iraq and connect it to the GCC grid. An initial supply of 400kW of power to Iraq is expected.

**ii Transmission/transportation and distribution access**

**Abu Dhabi**

Although the electricity laws in Abu Dhabi contemplate 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**

EWEC (formerly Abu Dhabi Water and Electricity Company (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 EWEC 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 EWEC for its generation costs (in turn paid by EWEC 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; and

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 the components in points (a) to (d) and subtracting the government subsidy.

The rates charged by the state-owned power companies (EWEC, TRANSCO, ADDC and AADC) are subject to government control, exercised via the DOE. The DOE sets the revenue targets, 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 DOE. This calculation requires an estimation of the costs for procuring and dispatching electricity generation to meet the forecast demand. As of 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 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 during the period of peak demand (i.e., 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 (and going forward, EWEC). These PWPAs are discussed further in Section IV.iii.
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 the DOE 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 between 40 and 60 per cent in the applicable rates. The rates as published on the ADDC website for 2018 (revised rates have not been published) are divided according to consumer categories as follows:

- **a** UAE nationals (flats): 6.7 fils per kWh up to 30kWh per day, 7.5 fils thereafter;
- **b** UAE nationals (villas): 6.7 fils per kWh up to 400kWh per day, 7.5 fils thereafter;
- **c** non-UAE nationals (flats): 26.8 fils per kWh up to 20kWh per day, 30.5 fils thereafter;
- **d** non-UAE nationals (villas): 26.8 fils per kWh up to 200kWh per day, 30.5 fils thereafter;
- **e** industrial establishments (below 1MW): 28.6 fils per kWh;
- **f** industrial establishments (above 1MW): 27.0 fils per kWh during off-peak hours, 36.6 fils per kWh during peak hours;
- **g** commercial establishments: 20 fils per kWh;
- **h** governmental offices: 29.4 fils per kWh; and
- **i** farms and ranches: 4.5 fils per kWh.

With effect from 1 January 2018, value added tax (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 Dubai Law No. 19 of 2019 (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 (i.e., the power generation, transmission and distribution companies).

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 three categories: (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.

Since 2011, DEWA has increased electricity rates and pursuant to the Dubai Tariff Decision, introduced a variable fuel surcharge to 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 per 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 fees, sewerage fees and irrigation fees that DEWA collects on behalf of the Dubai municipality. Knowledge fees and innovation fees are also exempted from VAT.6

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 its respective area of operation.

Contracts for power generation are awarded on the basis of a competitive bidding process, administered by the DOE in Abu Dhabi, DEWA in Dubai, SEWA in Sharjah and FEWA in the northern emirates.

ii Energy market rules and regulation

In Abu Dhabi, EWEC is required to contract with power producers for the purchase of all production capacity from licensed operators in the emirate. The DOE is authorised to allow ‘by-pass sales’ from power producers directly to eligible consumers provided that:

a the first independent commercial power generation project in the emirates shall have commenced commercial operations;

b the majority of the shares in the company are privately owned; and

c the DOE 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 (and now the DOE) in Abu Dhabi and all existing producers in the emirate are required to sell their production exclusively to EWEC.

Similarly, power producers in Dubai are obliged 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

EWEC pays the generation companies the tariff agreed under the PWPAs. A PWPA serves both as a grant of concession and an offtake agreement.7


A PWPA usually has a term of about 20 to 25 years from the commencement of commercial operations. Payments to IWPPs by EWEC (formerly ADWEC) under PWPA comprise three main components:

\( a \) capacity (or availability) payments covering the fixed costs of the plant (return on capital, depreciation and fixed operating and maintenance costs);

\( b \) operation and maintenance costs, paid when plant is available for production irrespective of whether and how much the plant produces; and

\( c \) 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 EWEC is required to procure and supply fuel to the electricity producers under the Abu Dhabi Electricity Laws. EWEC 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 PWPA, generation companies must have sufficient backup fuel to enable 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. EWEC is required by the standard PWPA to pay certain other supplementary payments to the IWPPs, such as start-up, shut-down and backup fuel costs. Some PWPA may also have provisions for payment by the relevant party of liquidated damages for delay in performance and of interest on late payments.

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, as part of its Energy Strategy 2050, it aims to increase the contribution of clean energy in the total energy mix from 25 per cent to 50 per cent by 2050 and to reduce the carbon footprint of power generation by 70 per cent.

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 Masdar8 to spearhead the emirate’s renewable energy initiative. Masdar City, a project 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.

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8 Masdar is a wholly owned subsidiary of Mubadala Development Company, one of the Abu Dhabi government’s main investment arms.
Masdar currently produces 17,500MWh of electricity annually, at its solar photovoltaic power plant in Masdar City for the supply of clean power to the project. It has also launched a carbon capture and storage project in the UAE.

**Dubai**

The DSCE developed the Dubai Integrated Energy Strategy 2030 and Dubai Clean Energy Strategy 20509 to enable Dubai to become a global centre for clean energy and green 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, which 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.

In 2013, DEWA and DSCE established Etihad Energy Service Company (Etihad ESCO), which will serve, notably, to retrofit existing buildings and lower the water and energy consumption of those 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 to encourage the generation of electricity using solar panels. This Resolution enables DEWA consumers to supply power to DEWA’s grid by connecting their solar panels. The power supplied to DEWA can then be adjusted against the consumer’s electricity bill.

In 2015, Dubai established the Dubai Green Fund, worth US$27 billion, which provides easy loans to investors in the clean energy sector. DEWA will provide the seed capital for this Fund, with additional investment from the private sector, international banks and large investment companies.

Currently, DEWA is working to develop an Innovation Centre to raise awareness of 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 on solar energy. The Centre will also feature two solar testing facilities, one specialising in testing solar photovoltaic panels, and the other focusing on concentrated solar power. The Centre is currently testing 30 photovoltaic panel types from global specialist manufacturers.

Dubai has also established the Dubai Carbon Centre of Excellence, responsible for encouraging and developing strategies for reducing the emirate’s dependence on carbon fuels and reducing carbon emissions.

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9 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 intention of the Dubai Clean Energy Strategy 2050 is 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.
**Northern emirates**

Several initiatives are under consideration in the northern emirates, such as smart meters and solar plants. Furthermore, Sharjah launched SEWA 2020 Vision in 2016 to enhance power efficiency in sustainable development. The aim was to reduce power and water use by at least 30 per cent by the end of 2020. To achieve this vision, SEWA launched various projects, including 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 to save energy, such as a smart metering system and networks.

**Nuclear energy**


The UAE aims to produce a significant part (approximately 9 per cent) of its electricity from nuclear technology. A nuclear policy was released in 2008, since when the UAE has 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. It 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 the 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, an Abu Dhabi government-owned company, 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. In February 2020, the FANR granted Unit 1 of the Barakah plant a licence to operate. Once the four reactors are online, the facility will deliver up to a quarter of the UAE’s electricity needs.
ii Energy efficiency and conservation

The UAE has one of the highest rates of electricity consumption per capita. This high use 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 use 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 the construction of energy-efficient buildings in the emirate under the Estidama initiative. As 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, the eco-city project in 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, the RSB Dubai has licensed nine energy service companies to retrofit more than 30,000 buildings in the emirate to make them more energy efficient. In 2015, the Emirates Green Building Council issued technical guidelines for retrofitting existing buildings.

In 2016, Dubai and Sharjah launched projects to replace current infrastructure with energy efficient facilities. Both emirates have since been replacing street lights with LED lights. In Dubai, existing buildings have been retrofitted by Etihad ESCO while Sharjah has been replacing and renovating its cables and meters.

In 2016, SEWA created a unit called the Conservation Department with a target to help people conserve 30 per cent of their utility bills over five years by adopting best practices in their use of electricity, water and gas.10 The Green Building Committee of the Ajman Municipality and Planning Department was also formed to support energy conservation efforts.

To attract foreign private investment in the sector, Dubai has created a free zone dedicated to the development of green technologies and energy conservation, 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 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 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 and the DOE also have slab tariffs in place for the northern emirates and Abu Dhabi respectively.

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10 See, e.g., ‘Is your UAE utility bill too high? Reduce it by up to 30%', Emirates 24/7 (26 July 2016), at https://www.emirates247.com/business/energy/is-your-uae-utility-bill-too-high-reduce-it-by-up-to-30-2016-07-26-1.636801.
In October 2018, FEWA signed a memorandum of understanding with Honeywell to drive sustainable development and green economy initiatives in the UAE’s northern emirates. Under this collaboration, FEWA will focus, among other things, on driving significant energy savings (between 10 and 30 per cent) across a range of public sector buildings by adopting advanced energy efficiency technologies.11

In 2019, Abu Dhabi announced a new strategy aimed at reducing electricity consumption by 22 per cent and water consumption by 32 per cent by 2030. The core programmes under this strategy, known as Abu Dhabi Demand Side Management and Energy Rationalization Strategy 2030, include building retrofits, demand response, efficient water use and reuse, building regulations, street lighting, district cooling, standards and labels, energy storage, rebates and awareness.

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, more than 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 have a leading role in the 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, (1) 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, (2) two test technologies for photovoltaic panels and concentrated solar power, (3) a solar testing facility and (4) a training centre and special conference centre for the exchange of information.

In 2018, DEWA signed a memorandum of understanding with Siemens to initiate 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. In January 2019, DEWA and Siemens signed a further memorandum of understanding to cooperate in research and development, exchange expertise and know-how, as well as building national capacities in energy technologies. The focus will be to pursue joint research and development activities in energy technologies, including smart grids, the integration of renewable energy and distributed generation in the

electricity grid, energy storage systems, the internet of things, using artificial intelligence in energy production unit, 3D printing and additive manufacturing, robotics, cybersecurity, robotics and smart buildings, as well as building national capacities in the energy sector.12

VI THE YEAR IN REVIEW

During 2019, an increased number of private sector companies made deals with the electricity and water authorities in the emirates of Dubai, Abu Dhabi, Fujairah and Umm al-Quwain for breakthrough projects. This is in line with UAE’s goal of diversifying economic revenues and boosting the economy after the fall in oil prices in 2014. Of particular interest is the contribution of the private sector in the renewable energy sector. Currently, the UAE has the lowest cost of producing solar power in the world, which can largely be attributed to the collaborations between the UAE government and private companies. The contribution of the northern emirates in the energy sector has also increased as a result of more activity in terms of new projects and smart grids during 2019.

Renewable energy has a major role in the energy sector as projects are increasingly aiming at harnessing the natural resources of the UAE, particularly solar power because of its geographical location. The different phases of the Mohammed bin Rashid Al Maktoum Solar Park are on track and the aim is for it to be home to projects generating up to 5,000MW by 2030. This is in line with the Dubai Clean Energy Strategy 2050.

The UAE has been at the centre of innovation and technology and is now using technology in the power sector. This is evident from several collaborations and memoranda of understanding signed by the federal government and the government of Dubai with innovation companies dealing in technologies such as the internet of things, artificial intelligence and blockchain applications in the power sector for smart energy management.

VII CONCLUSIONS AND OUTLOOK

The UAE is geared up for and appears to be on track to meet its Energy Strategy 2050, which was launched in 2017. Backed by impressive technology, it is well equipped to meet the ever-increasing energy demands and create smart and efficient energy production and use. Energy efficiency is also a top item on the agenda.

In addition to the focus on the energy sector at home, the UAE is also collaborating with and investing in other countries. Masdar has been deploying renewable energy technologies in a number of other countries, including Jordan, Afghanistan and Mauritania. The International Renewable Energy Agency and the Abu Dhabi Fund for Development have collaborated to support renewable energy projects in Rwanda, the Marshall Islands and the Caribbean. The UAE’s efforts are designed to enhance its global leadership position via renewable energy diplomacy that will support access to affordable and sustainable sources of power for millions of people in developing countries around the world.13


13 Mustafa Alrawi, ‘UAE’s commitment to renewable energy can enhance its global leadership role’, The National (17 September 2018), at https://www.thenational.ae/business/energy/uae-s-commitment-to-renewable-energy-can-enhance-its-global-leadership-role-1.771107.
I OVERVIEW

The gas and electricity markets in the United Kingdom (UK) were among the first in the world to become fully liberalised and privatised. The drive towards liberalisation, which encompassed the privatisation of state-owned energy undertakings and the unbundling of the natural monopolies of transmission and distribution infrastructure from the competitive industries of production and supply, was introduced by the Thatcher government through the Gas Act 1986 (the Gas Act) and the Electricity Act 1989 (the Electricity Act). This fundamentally changed the structure of the electricity and gas market structures, which had been under complete public ownership since the commercialisation of electricity and natural gas in the late nineteenth and early twentieth centuries.

The UK joined the European Union (EU) with effect from 1 January 1973 and its electricity and gas market liberalisation measures have arguably had a material influence on the development of the structure of the EU internal energy market, progressing through the First, Second and Third Energy Packages in 1996 (for electricity) and 1998 (for gas), 2003 and 2009 (both for electricity and gas), respectively.

The UK is currently in a period of transition and the energy markets face significant challenges, driven by the simultaneous objectives of decarbonisation and ensuring security of supply and affordable energy, as well as the challenges resulting from Brexit, such as business continuity and security of supply.

II REGULATION

i The regulators

Gas and Electricity Markets Authority

Great Britain’s gas and electricity markets are regulated by the Gas and Electricity Markets Authority (GEMA), which consists of a panel of individuals appointed by the Secretary of State. GEMA is entirely independent from government and has no stakeholder involvement, neither in GEMA’s regulatory nor operational decisions. The powers and duties of GEMA are set out in a range of statutes, including the Gas Act, the Electricity Act, the Utilities Act 2000 (the Utilities Act), the Competition Act 1998, the Enterprise Act 2002 (the Enterprise Act) and the Energy Acts of 2004, 2008, 2010 and 2011. The day-to-day administration of GEMA’s functions are carried out by the Office of Gas and Electricity Markets (Ofgem),

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1 Andreas Gunst and Natasha Luther-Jones are partners and Kenneth Wallace-Mueller is a senior associate at DLA Piper International.
which was formed from the amalgamation of the Office of Gas Regulation and the Office of Electricity Regulation in November 2000. GEMA defines Ofgem’s strategy, sets policy priorities and makes decisions on a wide range of regulatory matters, including price control and enforcement.

The objectives of GEMA are set out in Sections 4AA to 4D of the Gas Act and Sections 3A to 3F of the Electricity Act. The principal objective of GEMA is to protect the interests of existing and future customers. This objective includes promoting the lowering of energy prices, the handling of complaints against suppliers and the protection of vulnerable customers, as well as the broader interests of customers, such as the reduction of greenhouse gases, the security of supply of gas and electricity, contributing to the achievement of sustainable development or the improvement of efficiency and quality of services. Furthering the principal objective of protecting customers’ interests may, whenever appropriate, also include fostering effective competition. For this reason, GEMA has concurrent authority with the Competition and Markets Authority (CMA), the role and powers of which are discussed in detail below. Further, GEMA’s duties also include ensuring that licence holders are capable of financing their activities, a function that is of increasing importance in regulated markets (particularly price-controlled networks and, more recently, supply markets).

The powers and duties of GEMA allow for the regulatory framework to remain responsive to changes in the market. Acting within it statutory remit, GEMA has the ability to modify licence conditions and the various industry codes that contain the detailed operational and technical rules governing the industry; however, this is generally done in a transparent manner and in consultation with market participants. The Secretary of State has the power, by virtue of Section 134 of the Energy Act 2004, to modify licence conditions if it is considered necessary or expedient for the purpose of implementing new trading and transmission arrangements. Under the Gas Act and the Electricity Act, the Secretary of State also has powers to introduce secondary legislation to respond to more structural changes in the market.

**Northern Ireland Authority for Utility Regulation**

Electricity, gas, water and sewerage industries in Northern Ireland are regulated by the Northern Ireland Authority for Utility Regulation (NIAUR). The NIAUR is an independent non-ministerial government department that carries the obligation to protect short-term and long-term interests of electricity, gas, water and sewerage consumers in respect of pricing and standard of service. Further duties of this authority include the promotion of a robust and efficient water and sewerage industry, the delivery of high-quality services, the promotion of competition, and the promotion of the development and maintenance of an economic and coordinated natural gas industry.

Northern Ireland operates a separate wholesale electricity market to that of Great Britain, known as the single electricity market (SEM), which is integrated with the wholesale electricity market of the Republic of Ireland. To comply with the European Third Energy Package, the SEM was reformed in October 2018, giving rise to a new set of trading arrangements between the governments of the Republic of Ireland and Northern Ireland referred to as the Integrated Single Electricity Market (I-SEM). Under I-SEM, wholesale electricity in the Republic of Ireland and Northern Ireland is traded on an all-island basis, whereby the island of Ireland is treated as one for many regulatory purposes. The market is jointly regulated by the NIAUR and the Commission for Regulation of Utilities in the Republic of Ireland. The decision-making body that governs the market is the SEM Committee.
Competition and Markets Authority

The Competition and Markets Authority (CMA) was established in April 2014 under the Enterprise and Regulatory Reform Act 2013 (ERRA). It regulates the entire United Kingdom and is responsible for strengthening business competition and reducing anticompetitive activities. The CMA is an independent non-ministerial department. In April 2014, it brought together the existing competition and consumer protection functions of the Office of Fair Trading and the responsibilities of the Competition Commission.

As mentioned above, GEMA has concurrent powers with the CMA in regard to competition in the energy sector. They work closely together as the ERRA requires any sectoral regulator to consider the impact under competition law before making use of its sector-specific powers. By virtue of Section 5 of the Enterprise Act, the CMA functions by conducting studies of the functions of competition within a given market in the UK as a whole, rather than conducting investigations on specific actions of companies. When the findings of a market study give rise to reasonable grounds for suspecting that a feature – or combination of features – of a market prevents, restricts or distorts competition, the CMA can initiate a targeted investigation. For the CMA to carry out a market-wide investigation in any of the electricity or gas sector markets, Ofgem may refer any of those markets to the CMA or the CMA may instruct Ofgem to transfer a case.

Other relevant regulators

In addition to the aforementioned regulators, a key role in Great Britain’s energy market is carried out by the following regulators and government departments.

The Department for Business, Energy and Industrial Strategy (BEIS), although by definition not a regulator, plays a key part in the regulation, organisation and management of the energy market. BEIS is a department of the Government of the United Kingdom that was created in 2016, taking over from the Department of Energy and Climate Change, and is supported by 41 agencies and public bodies. The Secretary of State is responsible for BEIS, which is accountable to Parliament on matters including security of supply and sustainability in Great Britain’s energy sector. In light of the integration of the Northern Irish energy sectors into the I-SEM, the department responsible for the energy sector in Northern Ireland is the Department for the Economy.

The Oil and Gas Authority (OGA) was established in April 2015 as an executive agency of BEIS, with the aim to maximise the economic recovery of the oil and gas resources available in the UK. In October 2016 however, the OGA was incorporated as an independent government company, with BEIS being its sole shareholder.

The OGA has the power to regulate the exploration and development of the UK’s offshore and England’s onshore oil and gas, the UK’s carbon and gas storage and offloading activities. The OGA also has a critical role in encouraging investment in the UK, promoting opportunities that transition to a lower carbon economy and influencing a culture of greater collaboration within the energy industry. To fulfil its role, the OGA has been given a range of powers under the Petroleum Act 1998, the Energy Act 2011 and the Energy Act 2016.

The Health and Safety Executive is a national independent regulator responsible for regulation and enforcement of health and safety in the workplace and for producing guidance and carrying out research in relation to occupational risks.

The Office for Nuclear Regulation (ONR), an independent statutory corporation established in April 2014, is the regulator for the UK nuclear industry. The ONR reports to the Department for Work and Pensions; however, it works closely with BEIS. The objective
of the ONR is to provide efficient and effective regulation of the nuclear industry, holding it to account on behalf of the public. This includes granting nuclear site licences, regulating the transport of nuclear materials and ensuring compliance with safeguarding obligations for the UK.

The Financial Conduct Authority (FCA) is the UK authority responsible for the regulation of firms offering financial services. By virtue of the broad definition of financial services in the Financial Services and Markets Act 2000, certain energy products are captured and therefore a variety of electricity and gas market participants are subject to their oversight. These market participants must either become authorised with the FCA or seek one of a number of available exemptions, such as for transmission system operators (TSOs) or for the provision of ancillary services. The FCA is additionally responsible for the oversight of the anti-market abuse regime in the energy sector.

Environmental regulation in the UK is a devolved function, with England, Wales, Scotland and Northern Ireland each adopting a different approach. In England (and in Wales until 2013), the Environment Agency (EA) is responsible for the protection and enhancement of the environment. It is a non-departmental public body that is organised into eight directorates. The Department for Environment, Food and Rural Affairs is partly responsible for the funding of the EA and is responsible for the appointment of the chairman and the board. Environmental affairs are the responsibility of Natural Resources Wales in Wales, the Scottish Environment Protection Agency in Scotland, and the Northern Ireland Environment Agency in Northern Ireland.

Finally, a key role in the development of energy infrastructure in the UK is played by the local planning authorities (LPAs). If market participants wish to develop an energy project, consent generally needs to be obtained from the relevant LPA, which is normally the borough, district or unitary council for the area, as required under either the Planning Act 2008 or the Town and Country Planning Act 1990.

ii Regulated activities

The electricity and gas sectors are structured in a similar manner, in that they operate through a hierarchy of statutes, statutory instruments, licences and industry codes under the supervision of Ofgem to ensure the correct functioning of the regulatory framework. Both the Gas Act and the Electricity Act set out a general prohibition of carrying out a licensable activity without a licence. A breach is triable either way at the instruction of the Secretary of State or GEMA, punishable by a fine up to the statutory maximum if tried summarily and an unlimited fine on indictment.

Licences are granted and administered by Ofgem and always correspond to the entity carrying out the activity rather than the specific asset. As such, licences do not attach to an asset or the land on which an asset is situated and therefore they cannot automatically transfer on the sale of the asset or land.

Under certain circumstances, an entity may be granted an exemption from the licence requirement. Exemptions are made by statutory instrument and take the form of either a class exemption, which is available to all provided that certain requirements are met, or a specific exemption, which is personal to a specific licence holder. In line with the principle of unbundling and certification requirements under the European Third Energy Package, a licence holder may not hold a generation or supply licence if he or she already is in possession of a transmission, distribution or interconnection licence.
Licences in both the gas and electricity sectors are subject to standard licence conditions (Section 8 of the Gas Act and Section 8A of the Electricity Act). These conditions apply to all licence holders, although some licences may be granted subject to special conditions, or have certain standard conditions disapplied or amended. The breach of a licence condition entitles Ofgem to revoke the relevant licence.

**Electricity**

Section 6(1) of the Electricity Act states that a licence is required by an entity that wishes to carry out the following activities:

- Generation of electricity;
- Participation in the transmission of electricity;
- Distribution of electricity;
- Supply of electricity to premises;
- Participation in the operation of an electricity interconnector; and
- Provision of a smart meter communication service.

Licences may be limited in geographical area and supply licences may differentiate between the supply to domestic and non-domestic (i.e., industrial and commercial) premises. In practice, Ofgem grants fewer licences for supply to domestic premises as these licences include strict conditions relating to the provision of particular services to customers.

As provided above, one of the two ways in which an entity may be exempt from the requirement to hold a licence is by falling within a specific class that need not obtain a licence. These are set out in the Electricity (Class Exemptions from Requirement for a Licence) Order 2001. By way of example, two commonly used class exemptions are those for generating stations with capacity of less than 50MW, and on-site supply to premises, which is available to embedded generators supplying directly to the site where the generating station is situated.

**Gas**

Sections 5 and 7 to 7B of the Gas Act require a licence to be held to carry out the following activities:

- Transportation of gas (i.e., the conveyance of gas through pipes to premises or to a pipeline system operated by another gas transporter);
- Operation of a gas interconnector;
- Shipping of gas (i.e., the making of arrangements with a gas transporter for gas to be put into, conveyed through or taken out of that gas transporter's pipeline system);
- Supply of gas; and
- Provision of a smart meter communication service.

As with electricity licences, gas licences may be limited in geographical area and supply licences differentiate between domestic and non-domestic customers. The rules applying to exemptions from the requirement to hold a licence when carrying out a licensable activity are the same as under the electricity regime: class exemptions are set out in the Gas (Exemptions) Order 2011 and specific exemptions may be issued via statutory instrument by Ofgem or the Secretary of State.
Storage and development

In respect of the storage of gas and electricity, the provisions in the relevant statutes differ. Gas storage, while being subject to regulation, is not separately licensed. The provisions on electricity storage are currently in development, with Ofgem working with industry stakeholders.

A licence under the Gas Act or the Electricity Act authorises the licence holder to carry out the specified activity; however, it does not convey any other rights. As such, a licence does not entitle the entity to construct infrastructure. When developing a power station, gas pipeline or electricity network, for instance, separate licences and consents need to be obtained from relevant authorities with respect to, *inter alia*, land and access rights, planning permission and decommissioning.

Codes

The standard licence conditions require holders to be a party to one or more industry codes that set out technical rules and procedures for specific areas key to the operation of Great Britain’s energy industry. All industry codes have a similar legal structure, in that they take the form of a standard document or contract and new parties accede to these through an accession agreement. These industry codes have initially been prepared by the Secretary of State; however, these documents are maintained by dedicated entities, which are responsible for any modifications through industry consultation and consent by Ofgem.

There are nine industry codes that apply to the electricity sector, of which the following four are of greatest relevance:

- The Balancing and Settlement Code (BSC), to which all generation and supply licence holders must be a party and which is administered by Elexon, contains rules for wholesale trading and settlement of electricity. Non-physical traders who are not licensed also need to accede to the BSC.
- The Connection and Use of System Code (CUSC) sets out the main rights and obligations of connection to, and use of, the national transmission system, and additional provisions on ancillary services and balancing services. The code administrator of the CUSC is National Grid Electricity System Operator Limited (NGESO) as TSO.
- The Grid Code sets out technical rules for matters such as connection conditions, scheduling, dispatch, operational liaison and safety coordination, and all material technical aspects of connections to, and the operation and use of, the transmission system. All licensed generators and transmission operators are required to sign both the CUSC and the Grid Code. The Grid Code is administered by NGESO.
- The Distribution Connection and Use of System Agreement (DCUSA) is a multi-party contract between licensed electricity generators, suppliers and distributors, and regulates the connection to and use of the electricity distribution networks. The code administrator of the DCUSA is Electralink.

In addition to the national industry codes, a number of EU network codes for electricity exist under the remit of Regulation (EC) No. 714/2009 (recast as Regulation (EU) 2019/943), the aim of which is the harmonisation of technical, operational and market rules governing the European electricity grids. These set out the rules for matters such as system operation, balancing activities, demand connection, grid connection for generators, and capacity allocation and congestion management. As EU Regulations, these network codes currently have direct applicability to the UK, prior to its complete withdrawal from the EU, and
therefore exist in parallel with the national industry codes outlined above. Under the European Union (Withdrawal) Act 2018, these network codes have been transposed into national law and shall remain in effect post-Brexit.

With respect to the gas sector, there are five industry codes, the most central of which is the Uniform Network Code (UNC). The UNC is a contractual framework that forms the basis of arrangements between the owners and operators of the gas transportation systems in Great Britain and the users of these systems. It is administered by the Joint Office of Gas Transporters.

Similarly to the electricity sector, EU network codes for gas were introduced by Regulation (EC) No. 715/2009. These network codes facilitate cross-border network access and market integration and, as EU Regulations, directly apply in the UK. As with the electricity network codes, the gas network codes have been transposed into national law under the European Union (Withdrawal) Act 2018.

In addition to connection agreements that accede the relevant parties to the UK national industry codes, a number of agreements regulate entry to and exit from the network, including network exit agreements and turndown agreements.

iii Ownership and market access restrictions

Although there are no specific restrictions concerning the foreign ownership of electricity companies or assets in the UK, an additional certification process requires the assessment of whether foreign ownership or control (i.e., a licence holder from a country that is not a Member State of the European Economic Area (EEA)) poses a security of supply risk, in the UK or any other EEA Member State. This assessment is to be carried out by Ofgem in consultation with the European Commission and BEIS.

Depending on the outcome of Brexit, this assessment regime is likely to be extended to investors from outside the UK.

iv Transfers of control and assignments

All licences contain a provision permitting assignment; however, the assignment requires the prior written consent of Ofgem. Obtaining this consent would involve the assignee of the licence satisfying the Secretary of State that it can meet the licence obligations, which, in practice, involves an almost identical procedure to that required when applying for a new licence. There are no specific restrictions on change of control in any of the licences; however, transmission, distribution and interconnection licences do contain provisions that create a regulatory ring fence around the regulated asset. This provides an additional layer of control for Ofgem.

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2 The European Economic Area includes all 27 EU Member States and also Iceland, Liechtenstein and Norway. It allows them to be part of the EU’s single market.
III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

As mentioned in Section I of this chapter, Great Britain was a pioneer in the legal separation of electricity generation and supply from transmission and distribution. Having been one of the first to be fully privatised and unbundled, the model served as an example for many other markets and jurisdictions.

The unbundling requirement was introduced under the Utilities Act 2000 and was part of the restructuring of the market following the privatisation and restructuring of the individual business units of British Gas in the 1990s. With the entry into force of the European Third Energy Package in September 2009 and the requirement for TSOs to be certified as complying with ownership unbundling, the concept of unbundling became an EU-wide concept.

Although the Gas Act and the Electricity Act both prohibit licensed gas transportation, electricity transmission, and gas and electricity distribution and interconnector assets from holding any other licence, this requirement does have material differences under the respective acts. Under the Gas Act, gas transmission and distribution activities are both dealt with by provisions relating to gas transportation, and there is no distinction between them. However, the requirement to keep generation and supply separate from transmission and distribution exists identically under the Gas Act and the Electricity Act.

ii Transmission/transportation and distribution access

Electricity sector

Transmission and distribution

With the implementation of the British Electricity Trading and Transmission Arrangement in 2005, the operation of three transmission networks in Great Britain was taken over by the National Grid group. This introduced a single electricity transmission system for the whole of Great Britain (the national electricity transmission system (NETS)) and divided the transmission role between the TSO, currently NGESO, and the existing transmission system owners.

National Grid Electricity Transmission plc (NGET) holds the transmission licence as owner of the transmission system in England and Wales, and the networks in northern Scotland and southern Scotland are owned by Scottish Hydro Electric Transmission plc and Scottish Power Transmission Limited respectively. In Northern Ireland, the TSO is SONI Limited and the licensee as owner of the transmission system is Northern Ireland Electricity Networks Limited.

The activities of both the TSO and the transmission system owner are licensable, whereby a TSO must additionally be certified. Transmission owners are obliged to make their transmission systems available to the TSO, which in turn is responsible for their operation, including the balancing of supply and demand and the dispatch of generation. Under the Electricity Act, transmission licence holders are obliged 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. Furthermore, as discussed in Section II.ii, the activities of transmission and distribution are to a large extent regulated through the industry codes.
The TSO licence granted to NGESO provides not only detailed obligations for the licence holder but also regulates third-party access to the NETS, in that NGESO may not discriminate between any persons or class of persons in the provision of use of the system or in the carrying out of works to the system.

Ofgem has also established a competitive offshore transmission owner (OFTO) regulatory regime, whereby licences are granted – through a competitive tender process – to the owners of offshore transmission assets that connect offshore wind farms to the NETS. The aim of the offshore transmission regime is to support the government’s renewable energy targets, and the use of a competitive tender process ensures that generators are linked to efficient and competitive transmission services. The tender process has therefore resulted in lower costs and higher standards of service for generators and consumers.

Ofgem plans to introduce greater competition to onshore electricity transmission with new, separable and high-value onshore transmission assets to be tendered based on a similar mechanism to the offshore transmission regime. There is currently no clear indication as to when this competitively appointed transmission owner (CATO) regime is to be introduced.

**Distribution network operators**

The distribution network in the UK carries electricity from the high-voltage NETS to industrial, commercial and domestic users along lower voltage lines. The individual networks are organised along geographical lines with various regional monopolies. Historically these lines follow the boundaries of the former publicly owned electricity boards. There are 12 licensed distribution network operators (DNOs) in England and Wales and two in Scotland, which are owned by six different corporate groups, namely Electricity North West Limited, Northern Powergrid, SSE, SP Energy Networks, UK Power Networks and Western Power Distribution. There is one further DNO in Northern Ireland. In addition to these, Ofgem also grants licences to a number of smaller networks owned and operated by independent network operators, which are commonly granted for business and commercial parks.

To distribute electricity through the network, each DNO must hold an electricity distribution licence. Each DNO also owns and operates the local electricity network.

In respect of the obligations of DNOs, the Electricity Act states that they must develop and maintain efficient, coordinated and economical systems of electricity distribution and facilitate competition in the supply and generation of electricity. The distribution licences subject DNOs to specific obligations in their licence conditions, and they also must comply with the relevant industry codes. Furthermore, DNOs must offer a connection between their distribution system and any premises when requested to do so by the owner of the premises and they are prohibited from discrimination.

**Gas sector**

**Transportation**

The owner and operator of the gas transmission network, a national transmission system (NTS), is National Grid Gas plc (NGG). The NGG licence covers the entire transmission system in Great Britain, in a similar manner as for the electricity sector, whereby the licence restricts ownership of the gas networks to NGG.

In contrast to the electricity sector, there is no separate licensable activity for the distribution of gas. A transportation licence covers both the high-pressure NTS and the lower-pressure gas distribution networks (GDNs). The transportation of gas requires a transporter licence, the obligations of which include the requirement to develop and maintain
an efficient and economical pipeline system, to provide a connection to that system and to convey gas to third parties. The Gas Act also imposes a general duty to facilitate competition in the supply of gas and to avoid discrimination of system users. The individual licences held by gas transporters provide supplemental detailed and technical provisions to those contained in the Gas Act.

**Distribution**

The gas distribution system is organised in a similar manner to the electricity distribution system, with eight GDNs, each covering a separate geographical region of Great Britain. These eight networks are owned and managed by four companies, namely Cadent Gas Limited (which owns four GDNs), Northern Gas Networks Limited (which owns one GDN), Wales & West Utilities Limited (which owns one GDN) and SGN (which owns two GDNs). In addition to these companies, and similarly to the electricity distribution system, there are several smaller networks owned and operated by independent gas transporters, located within the areas covered by GDNs.

**iii Rates**

Network assets are subject to price control, regulated by Ofgem, which is implemented by licence conditions in each respective licence. The current price control model is referred to as the RIIO model, which stands for ‘revenue set to deliver stronger incentives, innovation and outputs’. The RIIO price control sets out the revenue network companies may recover and what they are expected to deliver within eight-year price control periods (from 2015 to 2023 for electricity distribution and from 2013 to 2021 for transmission and gas distribution). The process of RIIO price control includes network companies presenting a business plan detailing how they intend to meet the objectives, followed by an evaluation and (if successful) approval by Ofgem. The outputs are set out in the licence, to provide transparency of costs to consumers and reflect enhanced engagement with stakeholders.

In respect of charging in the electricity sector, system users are subject to three types of transmission charges:

- **a** 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;
- **b** transmission network use of system (TNUoS) charges: to recover the revenue for the transmission system owners, which is either NGET, the Scottish transmission owners, OFTOs, and in future any owners under the CATO regime;
- **c** distribution network use of system charges: to recover revenue for the distribution system owner; and
- **d** balancing services use of system charges: to recover the cost of balancing the transmission system.

Each type of charge is payable to NGET for connection and use of the transmission system. For the distribution system, similar charges arise. They are referred to as distribution use of system charges.
iv Security and technology restrictions

While some jurisdictions have legislative acts in place to bolster their national grid against threats, including terrorist or cyberattacks, there is no regime specific to energy infrastructure in the UK. Legislative measures, however, ensure security of supply, such as in the case of a cybersecurity threat affecting an energy utility company’s operational capability. The Secretary of State for BEIS has powers to take control of fuel and electricity supplies by an order under Sections 1 and 2 of the Energy Act 1976.

The main government authority in the area of security and technology is the Centre for Protection of National Infrastructure, which has the role of identifying and mitigating vulnerabilities in the national infrastructure that could be exploited, including energy infrastructure.

IV ENERGY MARKETS

i Development of energy market

Electricity

The UK electricity market has been fully privatised and liberalised since the early 1990s. With state control giving way to market competition, the government began to focus on strategic choices, including generation capacity planning, and choice of fuels and sites. Today, electricity market participants have the freedom to choose the terms on which they trade and the price at which they trade. The market operates on the basis of bilateral contracts, which may be executed over the counter or over an exchange.

Electricity is traded between generators, suppliers and trading entities via the NETS. Although any entity granted a licence will need to become a party to the BSC, entities that are not licence holders may also accede. These include, in particular, non-physical traders (i.e., those that do not take physical delivery of electricity), such as banks or trading houses.

Most trades of electricity are made under the industry standard Grid Trade Master Agreement (GTMA), under the ISDA Master Agreement (published by the International Swaps and Derivatives Association) with the GTMA annex, or under bespoke power purchase agreements.

One of the factors determining the direction of development of Great Britain’s electricity market are the market coupling measures provided for in EU legislation, particularly those set out in the European Third Energy Package and the new Clean Energy Package (finalised in 2019). To date, the UK has taken significant steps to implement coupling measures; however, with the outcome of Brexit still being uncertain, future developments (or acts to revert coupling measures) are yet to be seen.

Gas

Gas may be traded by gas shippers at entry points to and exit points of the NTS. When gas is traded at entry points, it may be traded under standard terms and conditions, the Beach 2000 terms or under bespoke gas sales agreements. The terms on which the trade takes place are not subject to specific regulatory requirements, but since entry point trade involves a physical transfer of the title to gas – and therefore provisions relating to title, quality and pressure, and those determining the damages payable by the party that fails to fulfil its contractual

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3 Standard Terms and Conditions for the Sale and Purchase of Natural Gas for UK Short Term Deliveries at the Beach 2000.
obligations – in practice, it is more common for parties to use the Beach 2000 terms rather than individually tailored agreements. Only licensed shippers may inject gas into the NTS; however, shippers that only trade gas within the NTS (i.e., do not take gas beyond the entry point or exit point) do not need to hold a shipping licence.

Similarly to the electricity market, developments in the gas market are materially influenced by reforms brought by the EU gas regime. The implementation of Regulation (EC) No. 715/2009 required the European Network of Transmission System Operators for Gas (ENTSOG) to develop EU-wide network codes that seek to remedy cross-border network and market integration issues. ENTSOG is responsible for the development of these network codes and, prior to Brexit, was responsible for the monitoring and analysis of their implementation in Great Britain.

ii Energy market rules and regulation

As described above, the regulation of the energy markets is largely set out in industry codes such as the Grid Code, the CUSC or the BSC for electricity or the UNC for gas. Compliance by individual market participants with the industry codes is governed through the licence conditions, which require the respective licence holder to accede to and comply with the relevant industry codes.

Depending on the nature of the market participant or the transaction, financial market regulation may additionally apply. This was introduced through the Markets in Financial Instruments Directives I and II (MiFID I and MiFID II), implemented in the UK as the Financial Services and Markets Act 2000. There has been an increasing trend towards the regulation of energy trading under financial market regulations, particularly as MiFID II has significantly narrowed the exemptions available to commodity derivatives trading firms.

Another development introduced through EU law is in respect of market manipulation and insider trading. The Regulation on Wholesale Energy Market Integrity and Transparency (REMIT) requires market participants in wholesale supply and transportation or transmission of physical gas and electricity to disclose inside information and avoid (actual or attempted) market manipulation and abuse. REMIT substantially increases Ofgem’s power in the area of market transparency, making it a criminal offence to breach certain provisions under the REMIT.

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 and gas. The volumes, but not other commercial details, of the resulting trades are notified to the system and market operators, and any imbalances between the notified supply and demand are priced and settled. Trading takes place on a half-hourly basis with gate closure set one hour ahead of real time, upon which participants notify the system operator of their intended final physical position. After this point, no further contract notification can be made and settlement is based on the gate closure positions.

Market developments

In respect of both electricity and gas, the energy supply market is dominated by the six biggest energy companies – known as the Big Six\(^5\) – which provide 95 per cent of the energy in Great Britain. Concern has been raised that this market share may be harmful to competition.

In the electricity market, this concern led Ofgem to carry out a retail market review, which resulted in new standards of conduct at the retail consumer level (e.g., transparency to allow consumers to compare tariffs more easily). As problems in the electricity supply market persisted, Ofgem placed additional obligations on large suppliers in respect of their trading strategies. Consequently, there was a rise in the number of new entrants; however, these new players soon failed, as the increased number of failures among smaller independent suppliers proved. Furthermore, as part of the efforts to attain healthy competition, Ofgem launched the implementation of a major project in the electricity market under the UK’s Electricity Market Reform (EMR) programme in 2013. The EMR involved, *inter alia*, a capacity market to ensure security of electricity supply and a feed-in tariff with contracts for difference (FiT CfD) to promote renewable generation development.

In November 2018, the capacity market mechanism was tested in the European Court of Justice (ECJ) case *Tempus Energy Ltd and Tempus Energy Technology Ltd v European Commission* (T-793/14) of 15 November 2018. The claimant, Tempus Energy, a UK-based demand side response (DSR) provider, claimed that the European Commission did not properly conduct its investigations to ensure that the UK’s proposed capacity market scheme was consistent with EU State Aid rules. The claimant further argued that the scheme did not equally treat DSR providers and battery storage operators with generators with respect to providing capacity. Following judgment in favour of the claimant by the General Court, the capacity market was suspended for one year while the Commission repeated its investigation and ultimately deemed the capacity market consistent with State Aid rules. Consequently, the suspension was relieved in late 2019 with a release of withheld payments to capacity market participants.

**V RENEWABLE ENERGY AND CONSERVATION**

i Development of renewable energy

Renewable energy developments and related technologies have benefited from the support of the UK government for three decades. By the early 1990s, the energy market had been fully liberalised, which enabled the progressive entry of independent power producers to the market. Almost simultaneously, the Non-Fossil Fuel Obligation came into effect, which was replaced by the Renewables Obligation (RO) in 2002. The RO has been closed to all new generation as of 31 March 2017. Since then renewables support has been delivered primarily through the FiT CfD mechanism under the EMR programme, which was launched by Ofgem in 2013. Of further relevance at national level are the Climate Change Act 2008, by which the UK has committed to a reduction of greenhouse gas emissions, and the climate change levy (CCL), which was introduced in 2001 and is a levy on UK business collected by energy suppliers.

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\(^5\) The Big Six are SSE, EDF Energy, British Gas, npower, E.ON UK and Scottish Power.
Renewables obligation
The RO scheme was introduced in England and Wales in 2002 and administered by Ofgem. The RO places an obligation on suppliers to source a minimum percentage of electricity supplied each year from renewable generation. Compliance with this obligation is demonstrated through the purchase of renewable obligation certificates (ROCs), which represent a volume of electricity generated by an accredited generator. ROCs were issued by Ofgem in respect of 1MW of renewable source electricity generated by accredited generators and further sold from generators to either traders or suppliers. If the minimum number of ROCs to be held is not met by the supplier, a buyout price is to be paid as a penalty.

As mentioned above, the RO has been closed to all new generation from 31 March 2017.

Feed-in tariffs for contracts for difference
CfDs were introduced as part of the EMR scheme and are currently the main support instrument available for renewable generation in the electricity sector. CfDs are contracts agreed between low-carbon generators and Low Carbon Contracts Company Limited (LCCC), a government-owned private company. CfDs provide a steady income to eligible generators by paying difference payments against a predetermined strike price; if the electricity market price is below the strike price, the generator receives the difference between the strike price and the market price and, consequently, if the market price rises above the strike price, the generator will need to pay the difference to the LCCC. This strike price mechanism reduces the generator’s exposure to the volatility of electricity prices and, therefore, provides bankability for the project by lowering the cost of debt and the equity capital required. An eligible generator is, broadly, any renewable or nuclear generator.

Feed-in tariffs
The FiT scheme was introduced in 2010 with the purpose of promoting the deployment and use of small-scale generation (less than 5MW). Suppliers that join the FiT scheme – either voluntarily or compulsorily for those that supply more than 250,000 domestic users – become FiT licensees. The mechanism provides that owners of eligible small-scale renewable generation plants receive a payment from FiT licensees for each unit of electricity provided to that FiT licensee, which in turn passes on costs to consumers. A fixed payment is made for electricity that is generated on-site, which is referred to as the ‘generation tariff’, and another payment is made for any unused electricity that the generator exports to the grid, namely the ‘export tariff’.

The FiT scheme was subject to major reform in late 2015 (including, inter alia, a reduction of tariffs and the introduction of quarterly deployment caps) but was fully closed to new applicants as of 1 April 2019.

EU renewable energy regime
The Renewable Energy Directive (RED) 6 is the core EU act for renewable energy promotion and sets the rules to achieve the EU renewables target of 20 per cent by 2020. This has been transposed into UK law through various statutes and statutory instruments, including

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6 Directive 2009/28/EC.

In December 2018, the recast Renewable Energy Directive (RED II)\(^7\) entered into force, raising the overall EU target for renewable energy sources consumption by 2030 to 32 per cent. RED II will take effect in June 2021 (which is therefore also the deadline for the UK to transpose RED II into national law), at which point the RED will be repealed. In light of Brexit, the adoption of these new measures by the UK will depend on whether it has, by the end of the Brexit transition period, transposed the new provisions contained within the RED II. If so, since the UK’s national renewables target exceeds that prescribed at EU level, the position under RED II in the UK would remain unaffected by what the final position under Brexit turns out to be.

\section*{ii Energy efficiency and conservation}

As noted above, the CCL, introduced in 2001, is a levy on electricity delivered to non-domestic consumers and has the aim of incentivising businesses to become more energy efficient in how they operate, thus helping to reduce their overall emissions. To be eligible to pay a reduced CCL main rate, a business must be an energy-intensive business and must have entered into a voluntary climate change agreement with the EA. A business with energy-intensive industrial processes (e.g., metallurgical and mineralogical processes) can get a 90 per cent reduction for electricity consumed and a 65 per cent reduction for gas.

The Renewable Heat Incentive (RHI) scheme was introduced by the government to promote energy efficiency through promoting renewable heat usage. The RHI operates in a similar manner to the FiT system with the aim of levelling the cost of renewable heat with that of heating from fossil fuels by providing successful participants with periodic payments calculated in terms of £/kWh of eligible renewable heat or biomethane produced. Although originally introduced only for non-domestic buildings, the RHI was extended to domestic buildings in April 2014. Support is given for 20 years to non-domestic buildings and for seven years to domestic buildings. The RHI is due to end for new applicants on 31 March 2021, with no indication yet from the government on how it will encourage low carbon heating after that date, or the supply chain on which it relies.

\section*{iii Technological developments}

In light of the UK's commitment to decarbonisation and increasing renewable generation capacity, a key area for development in the UK market is security of supply and system flexibility, in particular the ability of NGESO to respond appropriately to electricity imbalances. This requires increased access to system usage data in timeframes that are as close to real time as possible.

The development of smart meters has been an important part of enabling this transition. Energy suppliers are responsible for replacing gas and electricity meters with smart meters, which provide the consumer with near real-time information on the energy used and thus aids in saving energy. Although the original requirement was that suppliers had until 2020 to provide smart meters to all consumers, this deadline has been extended to 2024.

\footnote{Directive (EU) 2018/2001.}
One area in particular that has seen significant growth in the UK is the electricity storage industry. The UK is considered a market leader in this respect, with corresponding new technological developments emerging. The number of applicants to build battery storage projects is continuing to increase rapidly: the total capacity of battery storage planning applications has soared from nearly 6,900MW in late 2018 to more than 10,500MW in early 2020. Various technologies are being used for the storage of electricity, including hydrogen, ammonia and compressed air.

A further development that is important to improved flexibility was highlighted by the Tempus ECJ case. DSR is a service that focuses on the consumption of electricity rather than its generation, whereby instead of ramping up generation to correct an increase in demand, certain consumers could temporarily reduce their consumption for non-essential purposes and processes. In its judgment, the ECJ held that the Commission’s investigation into compliance of the UK capacity market with State Aid rules should have considered whether DSR was treated as an equivalent to generation technology.

VI THE YEAR IN REVIEW

The past year has been dynamic for the UK energy markets. The 11-month Brexit negotiation period and the associated preparations for the full withdrawal of the UK from the EU have been key; however, there have been other important developments, several of which are highlighted below.

As detailed above, the ECJ Tempus case has been a significant development, with the UK capacity market being suspended as the Commission repeated its investigation of the scheme compliance with State Aid rules. Following a positive decision, Ofgem reinstated the capacity market, allowing deferred payments to be made to participants.

In November 2019, Ofgem carried out its Targeted Charging Review, which is expected to replace the current electricity charging system in 2020 or 2021. The details of the proposal remain under consideration; however, these changes generally aim to create equality in the market and reduce the overall costs of electricity market operation. Key proposals include fixed network charges being introduced to create a fair system for more flexible and less flexible users, the removal of embedded benefits for generators and the passing on of TNUoS to consumers, with the aim of reducing generation costs and, therefore, wholesale prices.

On 9 August 2019, Great Britain suffered a major electricity blackout following a lightning strike on a transmission circuit north of London and the simultaneous reduction of supply of two generators totalling 1,378MW. Despite calling on backup power, the scale of the generation loss required NGESO to disconnect approximately 1 millions customer so that the normal frequency range could be reinstated and thereby ensure system stability.8 Although this was an unusual incident, it demonstrated the value of ancillary services to system stability and the need for further investment in security of supply and flexibility services.

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VII CONCLUSIONS AND OUTLOOK

During the past four decades, the UK energy markets have generally served as a model for energy market liberalisation. This extends through the privatisation of the electricity and gas sectors in the 1980s, the introduction of modern and liquid electricity and gas markets, the facilitation of subsidy-free renewable energy technologies through the use of corporate PPAs, and the development of flexibility mechanisms such as the capacity markets.

The UK has made ambitious commitments to the continuing threat of climate change, which have been formalised in its nationally determined contributions under the Paris Agreement, as well as the promotion of advanced technology throughout the energy sector.

At the time of writing, future development of the energy markets is uncertain. The UK is currently within the 11-month Brexit transition period, during which the UK and EU aim to agree upon a post-Brexit cooperation agreement. However, because of the covid-19 outbreak in the first half of 2020, the pace of these negotiations appeared to have slowed down.

With the European Union (Withdrawal) Act 2018, the UK has carried across the body of European Union law into national law that seeks to ensure legal continuity post-Brexit. There are various questions, however, that depend on the outcome of the cooperation agreement negotiations, particularly in relation to continued operation of and trade across the electricity and gas interconnectors with the UK’s neighbours, as well as continued access to the single market for electricity and gas, and continued participation in the EU Emissions Trading System.

The policies of BEIS and Ofgem suggest that the UK remains committed to further developing low-carbon, stable and competitive energy markets. However, it remains to be seen whether the UK will voluntarily remain in alignment with EU energy policy and market structures, or whether it will elect to develop its own energy policy, and at what speed.

It is likely that indications of the future policy development will only crystallise after the elapse of the Brexit transition period and the full withdrawal of the UK from the EU.
OVERVIEW

Energy regulation in the United States is complex, broad and enforced by a variety of federal and state government 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 give an overview of the nature and scope of energy regulation and markets.

REGULATION

i The regulators

Multiple federal and state agencies, departments and other government entities regulate US energy development, the ownership, control and operation of electric energy assets, and natural gas and oil production, gathering, transmission, transportation and distribution, including with respect to the rates, terms and conditions of wholesale and certain 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 established as the Federal Power Commission) to license hydroelectric facilities and to regulate (1) wholesale sales of electric energy and natural gas, (2) the transmission of electric energy in interstate commerce and (3) the 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 (EP) Acts of 1992 and 2005, the Public Utility Holding Company Act of 2005 and the Department of Energy Organization Act of 1977 (the DOE Organization Act).

The Nuclear Regulatory Commission is an independent federal regulatory agency established by Congress to formulate policies and regulations governing nuclear reactor

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United States

and materials licensing and safety. The Nuclear Regulatory Commission’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.

The Department of Energy (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’. DOE is led by the Secretary of Energy, a member of the President’s cabinet. FERC is an independent regulatory agency within DOE and, under the DOE Organization Act, DOE and FERC have sometimes overlapping and sometimes separate authorities under their relevant organic statutes, including the FPA and the NGA. For example, under the NGA, DOE is responsible for issuing authorisations to import and export natural gas to and from the United States, including liquefied natural gas (LNG), while 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, the Environmental Protection Agency, the Army Corps of Engineers, the Commodity 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 and local 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 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 service on natural gas and oil pipelines. Entities making sales of FERC-jurisdictional products or services obtain rate approval from FERC. FERC rates for electricity 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
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 the abandonment of existing) interstate natural gas pipeline and storage facilities, and 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, among other things, to 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 electricity 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 electricity 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 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 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 DOE’s NIETC designation authority under the FPA remains unclear as a result of judicial decisions in the US Courts of Appeals.

The PHMSA regulates the safety of most US pipelines and LNG terminals. Although it is responsible for enforcement of US laws setting minimum pipeline and LNG safety standards, the 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 under the Outer Continental Shelf Lands Act of 1953, as amended in 1978. 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 has jurisdiction over the gathering of oil by pipelines if the gathering is part of a movement of the oil in interstate commerce. FERC may regulate a natural gas 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, the 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, including in the energy industry, 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, including 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 ownership or control over electricity transmission and generation facilities as well as the rate schedules pursuant to which electric energy or transmission service is provided. In reviewing a proposed transfer of electricity transmission or generation facilities and associated rate schedules, FERC must determine whether the transaction is consistent with the public interest, including the effects on competition (examining horizontal market power, vertical market power and barriers to
entry), rates and 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.

The 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 the PHMSA regulations, including drug-testing, record-keeping 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 affirmatively provide net benefits to the public.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration, unbundling and open access

During 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:

1. producers that sold natural gas to pipeline companies;
2. 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
3. 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 a transporting pipeline or its affiliates). Congress then passed the Natural Gas Wellhead Decontrol Act of 1989, lifting price controls on sales of natural gas by producers, and FERC 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 No. 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. Further, 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 United States, Canada and Mexico).

FERC has continued to implement reforms to liberalise US natural gas markets by requiring compliance with 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. At the same time, 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.

Electricity sector

The electricity sector was also initially dominated by vertically integrated franchised monopolies. Until the early 1990s, vertically integrated electricity 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 resources 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 electricity 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 electricity 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 electricity utility, federal power marketing agency, or any other person generating electric energy for wholesale sale, open and non-discriminatory access to their transmission facilities. As envisioned by Congress,
this 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
- 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, issued in 2011, adopted significant reforms of its rules on transmission planning and cost allocation established previously in Order No. 890. Order No. 1000 sought to address significant 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 more reliable, efficient and cost-efficient solutions. The major reforms of Order No. 1000 include:

a 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;
b 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 (RPS);
c 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
d 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. 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 (the DC Circuit). In 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.

During the course of several years, the US electricity industry has evolved to become more dependent on natural gas caused by relative decreases in natural gas prices alongside 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 electricity industries interact. In response, in 2015, FERC issued Order No. 809 adopting proposals to modify the scheduling practices used by interstate natural gas pipelines to provide additional contracting flexibility to firm natural gas transportation customers through the use of multiparty transportation contracts and revised nomination timelines.

### 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 and at rates that are ‘just and reasonable.’ 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 20th 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 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. Although 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 under certain conditions, including holding open seasons or solicitations for transmission service, demonstrating regional reliability and operational efficiency benefits and requirements that service be provided without undue discrimination or preference.

FERC is also charged with determining a just and reasonable rate of return on equity (ROE) for owners of FERC-jurisdictional transmission facilities. Historically, FERC established a ‘zone of reasonableness’ through a discounted cash flow (DCF) methodology to estimate a utility’s allowed ROE in its cost-of-service rates and selected an appropriate ROE for transmission owners within that zone of reasonableness based on various factors. FERC typically selected the midpoint within the zone of reasonableness as the base ROE, with the potential to add to that if a proposed transmission facility satisfied the requirements for an incentive-based adder. However, in Opinion No. 531 issued in 2014, FERC made a ruling on a complaint challenging the base ROE for transmission owners in New England and, citing ‘anomalous capital market conditions’ resulting from the 2008 financial crisis, changed its method for determining the base ROE in that case and selected a base ROE at the midpoint of the upper half of a zone of reasonableness. In 2017, in *Emera Maine v. FERC,* the DC Circuit vacated and remanded Opinion No. 531, finding that FERC had failed to sufficiently explain that (1) the existing base ROE was unjust and unreasonable, and (2) FERC’s setting of a replacement ROE at the midpoint of the upper half of the zone of reasonableness using the DCF methodology, rather than the midpoint of the overall zone of reasonableness, was just and reasonable. In response to *Emera Maine* and in a proceeding concerning complaints challenging the base ROE for transmission owners in the Midwest, FERC initially decided to use a hybrid approach combining four separate methodologies for estimating a utility’s ROE–DCF, the capital asset pricing model (CAPM), expected earnings and the risk premium model. However, in late 2019, FERC issued Opinion No. 569 in the

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2 854 F.3d 9 (DC Cir 2017).
same proceeding, ordering the use of a hybrid approach equally weighting the results of its DCF and CAPM methodologies to establish the zone of reasonableness broken into risk-based quartiles (under which an existing base ROE is rebuttably presumed to be just and reasonable if it lies within the range of ROEs for the risk quartile for the relevant utility or utilities). This new method resulted in significantly lower base ROEs for the transmission owners in that case, and Opinion No. 569 is being challenged by a large number of transmission owners.

In 2005, Congress amended the FPA to direct FERC to develop rate incentives to encourage certain transmission development. In 2006, FERC issued regulations in Order No. 679 to provide, case by case, a variety of cost-of-service rate incentives for new transmission projects that improve reliability or reduce cost. In 2012, FERC issued a policy statement providing further guidance on incentive-based rates for electric transmission. The incentives available under the regulations and 2012 policy statement include incentive rates of return on equity for new investment (which is an adder to the base ROE as determined under FERC’s applicable methodology for determining a utility’s base ROE), 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. In March 2019, FERC issued a notice of proposed rule-making to consider changes to its electricity transmission rate incentive regulations and policy, including a possible shift in its focus on granting incentives from the current project risks and challenges nexus test to an approach based on the benefits to electricity consumers.

Since 2000, FERC has also permitted certain merchant electricity 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 up front or assured continuing 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 (instead relying on broad open solicitations with less strict parameters) 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 these investigations, typically targeting a few pipelines once a year or in alternate years. 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 reduce its rates voluntarily).

Gas 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’) 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.

Pipelines under FERC’s jurisdiction that transport fossil fuel liquids (oil pipelines) may charge cost-based rates, or they may charge market-based rates if they can show that they lack significant market power in their 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 rates above those paid by uncommitted (walk-up) shippers, and all shippers had an opportunity to contract for the new capacity in an open season conducted by the pipeline company.

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 north-east and Midwest 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 government 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 the PHMSA. The PHMSA
regulates pipeline facilities pursuant to its pipeline safety programme, which is implemented in cooperation with the states. Although the 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 the PHMSA to regulate intrastate pipelines. If a state's law does not meet the federal minimum safety standards, the 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 sensitive security and critical energy infrastructure information from disclosure to the public, including electronic copies of the 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 leaves considerable discretion to market participants to determine an ISO’s or RTO’s governance structure, geographical scope and type of market services.

The following seven ISOs and RTOs currently operate in the United States: 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 under the FPA, as it is deemed to be electrically isolated from the rest of the transmission grid in the continental United States. (Similarly, Alaska and Hawaii are not subject to FERC’s regulatory oversight under the FPA, as their respective electricity transmission systems are not connected to the interstate transmission grid in the continental United States.)

Each ISO and RTO offers different energy products in its organised markets. While all the existing ISOs and RTOs administer some form of bid-based markets for one or more energy products (i.e., when 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. The forward capacity markets are structured differently in each ISO and RTO, and the details associated with the ancillary service markets for these ISOs and RTOs differ as well. For example, following severe weather in 2013–2014 in the east 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 proposing significant changes to their forward capacity market rules. ISO-New England’s proposed changes, referred to as performance incentive or pay for performance, were adopted in 2014, and PJM’s proposed changes, referred to as capacity performance, were adopted in 2015. All capacity resources that clear ISO-New England’s market became subject to pay for performance requirements beginning with the delivery year that commenced in June 2018. All capacity resources that clear the PJM market are subject to capacity performance requirements beginning with the delivery year 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, and the financial assurances required to be posted by proposed capacity resources.

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. As a general matter, the independent market monitor within each ISO and RTO provides independent oversight over certain market issues, including with respect to market structure, conduct and performance issues. ISOs and RTOs 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 ISOs nor RTOs a Western Energy Imbalance Market (Western 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 and British Columbia, Canada are active participants in the Western EIM and portions of the electric grid in two other western states plan to join by 2021.

### ii Wholesale energy market rules and regulation

Each ISO and RTO develops its own market rules through the market participants’ stakeholder approval process. Market rules for all ISOs and RTOs must be filed with and approved by FERC prior to implementation, except for ERCOT, whose market rules are subject to the exclusive jurisdiction of the Public Utility Commission of Texas.

### 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 when market participants are located within an applicable ISO or RTO (i.e., bidding or offering into the organised wholesale markets and scheduling flows through the ISO or RTO), 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
financially settled purchases and sales. 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 quarterly reports.

iv  Natural gas and oil commodity and transportation markets

Unlike in the electricity sector, there are no formal FERC-approved organised wholesale markets for oil and natural gas.

Sales of natural gas or oil commodities may be accomplished through trading platforms, such as the Intercontinental Exchange or bilateral contracts. As with purchase and sale agreements for electricity, bilateral agreements can be in the form of physical purchases and sales or financially settled purchases and sales. Some contracting parties use standardised industry form agreements, such as those developed by the North American Energy Standards Board, and others negotiate individual contracts.

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 Interstate Commerce Act, FERC historically has refrained from involvement in crude oil marketers’ use of interstate oil pipelines – except to ensure 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. In January 2018, FERC granted rehearing of this order for purposes of further consideration requested by numerous parties, but it has not yet ruled on the merits
of the rehearing requests. 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. That request is currently pending before FERC.

v Retail energy market regulation

Retail energy markets are regulated at the state and local levels. Across much of the United States, retail consumers 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. Since the mid 1990s, there has been 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 North-East, 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, and 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 states, which had a severe negative effect on the financial conditions of the restructured utilities in California and ultimately compelled the state to become a significant buyer of last resort in the wholesale electricity markets and ended retail competition for most retail consumers in California. Following this 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 2018, 16 states and the District of Columbia allow for retail competition. However, regulators in New York State 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 whether retail suppliers should be completely prohibited from serving their current product offerings to mass-market customers. In 2019, New York instituted new rules that restrict mass-market retail competition by imposing additional requirements that retail suppliers must satisfy to offer mass-market retail service and introducing new limitations on the types of products that retail suppliers may offer to mass-market customers. Since the early 2000s, a number of states have allowed for the creation of community choice aggregation (CCA) arrangements, whereby a local entity, often one 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 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 85 per cent of retail electric load served by
the state's investor-owned utilities will participate in these arrangements by the end of 2025. As of 2019, nine states had CCA-enabling laws and as of 2017 there were estimated to be approximately 750 CCAs serving about 5 million customers in eight states which then had CCA-enabling laws.

V RENEWABLE ENERGY AND CONSERVATION
i Development of renewable energy
The United States does not have a single comprehensive policy 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. In 2014, the Environmental Protection Agency issued regulations regarding carbon dioxide 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 carbon dioxide per megawatt-hour of generation output. The Clean Power Plan proposed in part increased generation output from renewable energy resources, and 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 Trump administration took initial steps in 2017 to repeal the Clean Power Plan and proposed the Affordable Clean Energy Rule (referred to as the ACE Rule) in August 2018 to replace it. These steps culminated on 8 July 2019 in a final rule repealing the Clean Power Plan and replacing it with the ACE Rule. The latter is more narrow in scope than the Clean Power Plan, only applying to coal-fired electricity generating units. The ACE Rule removed numerical standards and targets for carbon dioxide reductions in favour of state standards for electricity generating units, and prevents states from adopting market-based or flexible compliance mechanisms (i.e., emission reduction credits or allowances) between electricity generating units to satisfy the standards. The final rule does not provide presumptively approvable standards or model plans, but instead calls on states to set standards based on unit-specific considerations. The rule became effective on 6 September 2019 and is currently subject to legal challenges by several state attorneys general.

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 (but not solar and fuel cells) for 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 EP Act of 1992 and was extended to include projects commencing construction prior to 1 January 2020, with a step down of the credit amount for projects commencing construction after 31 December 2016. The estimated tax credit at the beginning of the programme was 1.9 cents per kilowatt-hour (kWh), drawing down to 1 cent/kWh for projects commencing construction in 2019. The PTC was extended in December 2019 for projects commencing in 2020 at an estimated tax credit of 1.5 cents/kWh. The ITC was first implemented under the EP Act of 2005 and was most recently extended until 2022, with a gradual step down of the credits between 2019 and 2022. To be eligible for the 30 per cent ITC, a commercial solar photovoltaic system must have commenced construction on or before 31 December 2019. The tax credit will decrease to 26 per cent for systems commencing construction in 2020, 22 per cent for systems commencing construction in 2021, and 10 per cent for systems commencing construction in 2022 or thereafter. 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 between 2009 and 2013 (between 2009 and 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 that commenced construction 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 expenditure by the federal government. The federal government estimates that as at July 2012 it had provided approximately US$13 billion in cash grants for more than 45,000 renewable energy projects, although the majority of the funding was awarded to larger wind projects.

The DOE’s Loan Programs Office (LPO) has operated various loan guarantee programmes for advanced technology and clean energy projects established under Title XVII of the EP Act of 2005 and Sections 1703 and 1705 of ARRA. As of early 2019, the LPO has approved more than US$30 billion in loans and loan guarantees for more than 30 projects, and has more than US$40 billion available for loans and loan guarantees. As at January 2017, the LPO had issued solicitations making available up to US$4.5 billion in loan guarantees to support innovative renewable energy and efficient energy projects. The LPO also has solicitations outstanding for advanced fossil energy projects, advanced nuclear energy projects, advanced technology vehicles manufacturing and tribal energy development projects. As at February 2020, LPO has US$8.5 billion in loan guarantee authority for advanced fossil energy projects, including carbon capture 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, such as Hawaii and, more recently, Virginia, have target levels as high as 100 per cent by 2045) and the types of energy resources that qualify (e.g., fuel cells, waste energy, combined heat and power, 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 electricity systems) to supply excess generation to their retail electricity supplier in exchange for credits against their retail electricity bills for periods of more than 12 months, and sometimes longer. 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 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, which 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. Similarly, legislators and regulators in some states, such as Louisiana, have enacted measures to pay the ‘avoided cost’ rate that is the average locational marginal price for the utility (i.e., lower than the retail rate). In 2018, Connecticut passed a law that would end net metering, only to reverse course in June 2019, providing an extension to the programme until 2021. 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 and installation cost rebates or performance-based payments for solar and certain other renewable resources (e.g., wind, fuel cells and combined heat and power).

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 the past and has been proposed in various pieces of legislation. However, given current fiscal concerns and related political disagreements about the nature and role of federal financial support for clean energy, the prospects for this type of legislation remain unclear. At the same time, state-based RPS, net metering, tax incentive and rebate programmes for distributed renewable generation resources appear poised to remain in place or be expanded in many states, at least in part, for the foreseeable future. Moreover, a number of states and local governments are actively considering establishing, and since 2011 several 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.

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 electricity 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 recovery 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 allow recovery of and on these investments through special charges included on the customer’s retail utility bill. A similar type of 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 issued Order No. 745 in 2011 to encourage demand responsiveness through market pricing mechanisms. In Order No. 745, FERC required that the ISO-organised and RTO-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 ISOs and RTOs were still given flexibility as to how to implement these market incentives. ISOs and RTOs 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 the Order exceeds FERC’s jurisdiction under the FPA, as it seeks to regulate retail sales of electricity by requiring ISOs and RTOs 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 the Order 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 payments by ISOs and RTOs 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”’. 

VI THE YEAR IN REVIEW
i Electricity
Numerous states have implemented ambitious energy policies aimed at reducing carbon emissions and increasing the amount of energy generated from renewable resources and energy storage resources on the grid. Corporate offtakers also entered into a record number of power purchase agreements with clean energy resources. Both FERC and state regulators
continued to grapple with how best to accommodate advanced technologies, such as battery storage, the continuing evolution of the mix of resources that supply electric energy, capacity and ancillary services, and increased regional transmission planning. Fossil-fuelled generators again comprised nearly all retirements in 2019 and are increasingly being replaced by renewable resources despite continued attempts by the executive branch of the federal government to prevent ‘baseload’ generators from retiring. FERC, state regulators, grid operators and utilities also dealt with historically low wholesale electricity prices, California wildfires and California’s largest investor-owned utility’s bankruptcy (again).

**States accelerate policies to address climate change**

Since President Trump announced his intent to withdraw the United States from the Paris Agreement in 2017, states have increasingly responded with their own policies to address climate change. Hawaii had passed legislation in 2015 calling for all of its electricity to come from renewable resources by 2045. In 2018, California passed State Bill 100, which requires that 100 per cent of the electricity consumed in the state must come from carbon-free sources by 2045. In June 2019, New York passed the Climate Leadership and Protection Act, requiring a 100 per cent carbon neutral power system by 2040, and an 85 per cent reduction in GHGs by 2050. New Mexico, the District of Columbia, Maine, Nevada, Washington and Puerto Rico have also recently set 100 per cent clean energy targets. Governors in Colorado, Connecticut, Illinois, Rhode Island, Massachusetts, Minnesota, New Jersey and Wisconsin have also each committed to achieving 100 per cent carbon-free electricity, with targets for achieving that goal ranging from 2030 to 2050. These advances are indicative of the recent trend to increase RPS across the country. In 2018, 10 states increased their RPS, and in 2019, the District of Columbia, New Mexico, Nevada and Maryland increased their targets as well. In March 2020, the Virginia General Assembly passed a bill committing the commonwealth to a 100 per cent renewable energy target by 2040.

States are also innovating in their regulatory policies to promote clean energy technologies beyond setting overall targets for renewable or carbon-free electricity. For example, in January 2019, the New Hampshire Public Utilities Commission affirmed a plan to use a network of behind-the-meter batteries in homes. In June 2019, Maine enacted a law to incentivise 375MW of new distributed generation. At least five states have so far adopted targets specifically for energy storage, including New York, which has a current target to procure 3GW of energy storage capacity by 2030. Virginia’s recent bill committing the commonwealth to 100 per cent renewable energy by 2040 also includes an energy storage deployment target of 2.7GW by 2035.

The NYISO and utility regulators in New York also 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. The NYISO issued its proposal to implement such a system in December 2018. If such a mechanism is developed, it will have to be filed with and approved by FERC before it can be implemented.

**Offshore wind solicitations**

Since Rhode Island’s 30MW Block Island Wind Farm became the first operational offshore wind farm in the United States in 2016, there has been continued interest and investment in offshore wind in various coastal states. Since 2018, several north-eastern states created or increased their commitment to offshore wind energy. For example, the New Jersey Board of Public Utilities held a solicitation in September 2018 for 1.1GW of offshore wind generation...
capacity and selected a 1.1GW project in June 2019. In February 2020, New Jersey Governor Phil Murphy announced an expansion of the initiative with the goal of acquiring 7.5GW of offshore wind generation capacity by 2035. New York issued a solicitation for 800MW in November 2019. In summer 2019, New York passed a law mandating 9GW of offshore wind generation capacity by 2035. Massachusetts selected winning bidders for a solicitation for 800MW of offshore wind capacity in 2018 as well, and in August of that year passed into law an offshore wind target of 3.2GW by 2035.

The US Bureau of Ocean Energy Management, which oversees offshore renewable energy development in federal waters on the Outer Continental Shelf, completed an auction that raised US$405 million for leases covering 390,000 acres of federal waters off the coast of Massachusetts. Rhode Island has also continued its commitment to offshore wind power, announcing the winning bid to a 400MW solicitation in May 2018. Connecticut agreed to purchase 200MW of offshore wind in June 2018 and announced plans to purchase an additional 100MW in December of that year. Connecticut enacted a law requiring 2GW of offshore wind by 2030, and the state announced a deal in 2019 to develop an 800MW project. In April 2019, Maryland passed the Maryland Clean Energy Jobs Act, which requires the development of 1,200MW of offshore wind by 2030. In September 2019, Virginia's Governor called for 2.5GW of offshore wind power by 2026. California, Delaware, Hawaii, Maine, New Hampshire and North Carolina have all also expressed interest in offshore wind, with varying levels of development. There is even interest in offshore wind for inland waters, as there are current plans for offshore wind development in Lake Erie near Cleveland, Ohio.

The continued rise of energy storage

The deployment of energy storage resources in the United States nearly doubled in 2019, with approximately 523MW of energy storage capacity installed. The amount of energy storage in the United States is expected to more than double in 2020 to over 1,400 MW, and by 2021, deployments are expected to exceed 3.6GW. At least five states have now adopted specific targets for energy storage, with New York’s target of 3GW by 2030 being the most ambitious to date. Other states have included energy storage in their planning processes and competitive solicitations. For example, the California Public Utilities Commission approved Pacific Gas and Electric Company’s (PG&E) proposal in November 2018 to replace two retiring natural gas-fired generators with four battery energy storage projects, two of which would become the two largest in the world once placed in service. This landmark solicitation marked the first time a utility and its regulator sought to replace retiring power plants with battery energy storage systems.

To accommodate the increased implementation of electric storage resources, FERC issued Order No. 841 in 2018 and directed ISOs and RTOs to remove barriers to the participation of electric storage resources in the organised wholesale electricity markets by requiring the ISOs and RTOs to establish market rules that facilitate the participation and take into account the physical and operational characteristics of electric storage resources. All six ISOs and RTOs, other than ERCOT, filed implementation plans with FERC in 2019 to comply. Order No. 841 is currently subject to appeal from some state PUCs and certain utilities who argue, in part, that (1) FERC does not have the authority to set terms and conditions for energy storage resources located behind-the-meter or interconnected to local distribution facilities, (2) FERC’s decision to not permit states to opt out of Order No. 841.
was arbitrary in light of FERC affording states such a carve-out regarding demand response participation in wholesale markets, and (3) the order violates the 10th Amendment to the US Constitution.

**Fossil-fuelled generator retirements**

Since the beginning of 2015, approximately 47GW coal-fired capacity has retired, with effectively no new coal capacity coming online. An estimated 4.1GW of coal capacity retired in 2019, accounting for more than half of all anticipated power plant retirements for the year. In 2007, coal-fired generation capacity totalled 313GW across 1,470 generators. In the subsequent 10 years, 529 of those coal-fired generators, with a total capacity of 55GW, retired, and that trend continued in 2018 and 2019. Projections for 2020 show scheduled capacity retirements of 11GW, which will primarily be driven by coal (51 per cent), followed by (mostly older) natural gas (33 per cent) and nuclear (14 per cent) generating resources. An estimated 42GW of new capacity additions will start commercial operation in 2020, with solar and wind representing the vast majority of additional capacity, at 18.5GW and 13.5GW, respectively. New natural gas generation is expected to add an additional 9.3GW of capacity in 2020.

In August 2017, in response to a request from the Secretary of Energy, the staff of DOE issued a study regarding the wholesale electricity markets and grid reliability in which they found that the wholesale markets, especially the organised markets administered by ISOs and RTOs, 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 ISOs and RTOs to establish tariff mechanisms providing for the purchase of energy from generation resources and the recovery of costs and a return on equity for the resources located in an ISO or RTO 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, a large number of parties submitted comments opposing the proposed rule (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 ISOs and RTOs, which remains pending. The Trump administration has since continued to evaluate other proposals to keep certain baseload plants in service that may otherwise face retirement.

**Capacity markets and state-subsidised generation resources**

FERC has explored how states’ preferences for certain generation resources have affected capacity markets since as early as 2013 when it opened a proceeding to explore the topic. Since then, both ISO-New England and PJM have developed their own proposals to address the competitive effects of states subsidising certain resources with mixed results. In March 2018, FERC approved ISO-New England’s proposed change to its capacity market rules, referred to as the Competitive Auctions with Sponsored Policy Resources, which provides 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 auction.
substitution auction and permanently exit the capacity market. The order, however, approved the changes by a divided vote of the five FERC commissioners with two dissenting votes and a concurrence.

After failing to reach a consensus among its stakeholders, PJM submitted two options to FERC in April 2018 and requested that FERC pick one of them. The first option, the capacity repricing proposal preferred by PJM, would create a second stage of the capacity auction where bids received from subsidised resources would be repriced without the resource’s subsidy to create the resource’s competitive price. The second option, referred to as MOPR-Ex, would have expanded PJM’s existing minimum offer price rule (MOPR) to new and existing resources that received subsidies, with some exceptions. In June 2018, FERC issued an order responding not only to PJM’s proposals but also to a complaint filed by a group of power producers in 2016 that also sought an expansion of PJM’s MOPR to existing generators that were receiving state subsidies. Rather than accept either of PJM’s proposals, FERC rejected both as inadequate with respect to addressing the competitive effects of state-subsidised resources on its capacity market and went further by finding PJM’s existing capacity market framework to be unjust and unreasonable. FERC also found, however, that it could not make a determination as to what would be an acceptable replacement based on the record before it and instead instituted a paper hearing for parties to submit additional arguments and evidence regarding what the replacement should be. FERC did preliminarily find that modifying two aspects of the PJM capacity market may provide for an acceptable replacement, namely expanding the MOPR to new and existing subsidised generators with few or no exceptions and also implementing a resource-specific fixed resource requirement alternative whereby a subsidised resource could choose to be removed from the capacity market, along with a corresponding amount of load, but continue to participate in PJM’s energy and ancillary services markets so as to accommodate state-sponsored resources without requiring load-serving entities to pay for capacity twice. Hundreds of filings were submitted in these proceedings and in December 2019, FERC, based on the determination that out-of-market payments provided by states to support operation of certain generation resources threaten the competitiveness of PJM’s capacity market, directed PJM to expand the MOPR to apply to any new or existing resource that receives, or is entitled to receive, a state subsidy (with some exceptions). Application of a MOPR to a resource’s market bid makes it less likely that the resource will be awarded a capacity supply obligation and therefore receive capacity payments. In the December 2019 order, FERC outlined certain exemptions from the expanded MOPR, including (1) existing renewable resources that are participating in state renewable portfolio programmes, (2) existing demand response, energy efficiency and storage resources, (3) existing self-supply resources and (4) competitive resources that do not receive state subsidies. In its compliance filing submitted in March 2020, PJM expanded on the list of state subsidies that will not trigger application of the MOPR and indicated that it would work with the internal market monitor for PJM and resource owners to maintain that list. PJM also proposed a compressed schedule to complete its delayed capacity auctions. The proposal remains subject to ongoing litigation at FERC and, ultimately, an order from the Commission.

Cybersecurity

An increased focus on cybersecurity in the energy sector has materialised after several high-profile intrusions affected multiple companies with nuclear power plants in the United States in 2017. As noted in Section III.iii, NERC is the nation’s ERO in charge of developing
and enforcing reliability standards for the bulk power grid, including Critical Infrastructure Protection (CIP) standards that address physical and cybersecurity. On 25 January 2019, NERC published a notice of penalty to an unnamed utility for a record-high total of US$10 million after citing some 127 violations of reliability and security standards between 2015 and 2018. Violations of CIP standards were the most frequently violated. NERC also issued a US$2.7 million fine, on 31 May 2018, on one utility that reportedly left user names, passwords and grid information unsecured. As more grid resources have become decentralised, NERC has increased its focus on supporting the security of supply chains and is working with utilities to ensure the security of information and communications technology as well as industrial control system equipment. NERC is now considering expanding its existing CIP standards, which already require entities possessing medium- and high-impact cyber systems to ensure supply chain risks are being managed through the procurement process, to include supply chain risks associated with additional categories of assets not currently subject to existing supply chain standards.

**Judicial review of FERC enforcement cases**

FERC has substantial civil penalty authority under the FPA, including the ability to issue civil penalties in excess of US$1 million per violation per day in addition to requiring disgorgement of ill-gotten gains. In the event that FERC finds an entity liable, under the FPA the entity has the ability to force FERC to litigate the matter in federal district court. There has been substantial litigation regarding the scope of the district court’s review of FERC’s findings, with FERC arguing that the district court’s review should be limited to FERC’s findings based on the administrative record created by FERC (i.e., akin to an appellate type of review). District courts, however, have repeatedly and unanimously ruled against FERC, holding that they are to conduct a trial *de novo*, governed by the Federal Rules of Civil Procedure and the Federal Rules of Evidence. In February 2020, the US Court of Appeals for the Fourth Circuit issued a decision regarding the statute of limitations for certain FERC enforcement cases. The FPA creates two procedural options by which FERC can assess civil penalties: (1) after a hearing before a FERC administrative law judge; or (2) after adjudication in federal district court. The Fourth Circuit ruled that the statute of limitations period commences on the date the alleged violator chooses to pursue its claims federal district court (if it chooses that route). The ruling effectively allows FERC to investigate past alleged unlawful conduct without time limitation.

**The continuing transformation of the public utility business model**

Several states have 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 have continued their efforts to implement their Reforming the Energy Vision (REV) initiative, which calls for ‘animating markets’ at the distribution level so that retail customers and third parties (e.g., energy service companies, retail suppliers and demand-management companies) can monetise the economic values that distributed resources can provide to the overall electricity system in New York. This initiative also tasks the electricity 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 electricity 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 have implemented rules on a wide range of issues relating to the REV initiative, including a new benefit–cost framework for electricity distribution utility expenditures on investments in distributed system platforms, procurement of a ‘value stack’ compensation model for distributed energy resources, energy efficiency programmes, development of community distributed generation and CCA arrangements, changes in net metering programmes, a reassessment of New York’s approach in encouraging the deployment of large-scale renewable energy generation, and 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. New York has adopted a goal of having 70 per cent of the electricity consumed in New York to come from clean energy sources by 2030 and an 85 per cent reduction in GHG emissions by 2050. Relatedly and as discussed in Section V, New York’s governor has committed to achieving 100 per cent carbon-free electricity in the state by 2040. Regulators have indicated that changes in their rate-making practices for electricity 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 rate-making changes for electricity 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.

Zero emission credit and coal encouragement programmes

Regulators in New York have 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, concluding 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 the state 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 in New Jersey have established a similar ZEC compensation mechanism for existing nuclear generation facilities in New Jersey. Both the New York and Illinois programmes were subsequently challenged 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.

In 2018, the US Courts of Appeals for the Second and Seventh Circuits upheld the ZEC programmes in New York and Illinois, respectively. In Electric Power Supply Association v. Star, the Seventh Circuit held that the Illinois nuclear subsidy programme was not pre-empted by federal law because it does not require the subsidised generation to participate in the
FERC regulated markets. While the Seventh Circuit found that the Illinois programme ‘can influence the auction price only indirectly’, the court held that ‘because states retain authority over power generation, a state policy that affects price only by increasing the quantity of power available for sale is not preempted by federal law’. In *Coalition for Competitive Electricity v. Zibelman*, the Second Circuit noted that the plaintiffs conceded that the New York nuclear subsidy programme did ‘not expressly mandate that the plants receiving ZEC subsidies bid into the NYISO auctions’. The Second Circuit also held that any distortions to the wholesale market are ‘(at best) an incidental effect resulting from New York’s regulation of producers’. Accordingly, the Court held that the ‘Plaintiffs have failed to state a plausible claim for conflict preemption’. The Supreme Court of the United States issued orders in April 2019 denying petitions for review of the Second and Seventh Circuits’ decisions.

In addition, states have also moved to provide subsidies and incentives to other traditional generating resources. In July 2019, Ohio enacted a law designed to subsidise two large nuclear energy plants owned by FirstEnergy Solutions Corporation, and to provide ratepayer-backed funding for two coal-fired plants operated by Ohio Valley Electric Corporation. In March 2020, the Indiana legislature passed a bill that was subsequently signed into law by the governor that could slow the retirement of any legacy generation plant owned by a public utility exceeding 80MW in capacity by requiring several months’ prior notification to, and review by, the Indiana Utility Regulatory Commission. Similarly, in March 2020, West Virginia enacted a law that would reduce the tax rate on coal-fired generating units in service before 1995 that agree to stay online until 1 July 2025 to 45 per cent of their official capacity.

**Green tariffs and corporate power purchases**

Green tariffs are programmes offered by utilities, typically in states without retail choice, that allow larger commercial and industrial customers to buy both the energy from a renewable energy project and the environmental benefit from such generation (e.g., renewable energy certificates) in a long-term, fixed price structure. These programmes help corporate entities in states without retail choice programmes to meet their sustainability goals. Since the first green tariff was proposed by NV Energy in Nevada in 2013, 23 green tariffs in 17 states have been proposed or approved, with two denied by the relevant state public utility commission. In 2018, Kansas, Kentucky, Minnesota and Virginia each adopted green tariff programmes.

These programmes vary in their implementation. Some allow customers to choose market-based rates pegged to the wholesale price, while others let organisations engage directly with the renewable power project. Further still, some programmes use a ‘sleeved’ power purchase agreement, whereby the utility passes a physical power purchase agreement that it has signed with a renewable energy project to the consumer. Green tariffs are now being used in particular by a number of larger information technology firms, including Apple, which purchases from NV Energy’s GreenEnergy Rider programme, and Google, which uses Duke Energy’s green tariff.

It has been another record year for corporate clean energy contracts, which accounted for 19.5GW, up from 6.53GW in 2018. Many companies have aggressive clean energy goals. For example, Visa committed in 2018 to 100 per cent renewable energy by the end of 2019, and Sony expanded its 100 per cent renewable goals to China and North America.
**PG&E bankruptcy**

California faced historically destructive wildfires in 2017 and 2018, with more than 8,000 wildfires burning approximately 1.8 million acres in 2018 alone. Facing liability from these fires, California’s largest investor-owned utility, PG&E, filed for Chapter 11 bankruptcy on 29 January 2019. On 28 February 2019, PG&E announced it would record a US$10.5 billion charge related to third-party claims in connection to the Camp Fire in its full year and fourth quarter 2018 financial reports, and an additional US$1 billion pre-tax charge related to 2017 wildfires. In March 2020, a court approved a US$23 billion plan under which PG&E would emerge from bankruptcy by June. California had made PG&E’s ability to access a state wildfire insurance fund contingent upon the company exiting bankruptcy by the end of June. PG&E previously entered bankruptcy in 2001 following the California energy crisis.

The PG&E bankruptcy also raises jurisdictional questions between the bankruptcy court and FERC relating to the ability of PG&E as a debtor in bankruptcy to reject FERC-jurisdictional wholesale power contracts, an ability that debtors have under the federal Bankruptcy Code with regard to executory contracts. In January 2019, FERC issued a declaratory order asserting that it has concurrent jurisdiction with the bankruptcy court regarding the disposition of these types of contracts, such that PG&E would need to obtain approval from both FERC, under its applicable standard of review, and the bankruptcy court, under its applicable standard of review, to reject such an agreement. In the bankruptcy court, PG&E sought and was granted a preliminary injunction against FERC to prevent it from exercising its asserted concurrent jurisdiction. The injunction proceeding has been appealed to the Ninth Circuit Court of Appeals. California regulators have also asserted that the California Public Utilities Commission’s permission would be needed by PG&E to avoid contractual commitments with clean energy resources or else it would interfere with the state’s clean energy goals, and have considered splitting up PG&E’s natural gas and electric divisions into separate companies. The bankruptcy proceeding remains pending and is expected to continue for at least two years.

In a similar proceeding, the Sixth Circuit Court of Appeals found that bankruptcy courts do have jurisdiction over FERC-approved contracts.

**ii Natural gas and hydrocarbon 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 constructed, with FERC’s approval, large amounts of new infrastructure to serve the new production and transport the gas to markets. FERC’s approval of large new pipeline projects essentially peaked in 2017, with fewer projects since then. The number of pipeline projects characterised by FERC as ‘major’ that have been issued certificates of public convenience and necessity was 36 in 2016, 35 in 2017, 29 in 2018 and 23 in 2019. Looking only at the pipelines with capacity of more than 1 billion cubic feet per day, FERC certificated six in 2016, nine in 2017, two in 2018 and six in 2019. And for pipelines more than 100 miles long, FERC certificated three in 2016, seven in 2017, two in 2018 and two in 2019. The largest pipelines certificated in 2019 were all approved in conjunction with LNG export projects, including six of the ‘major’ pipelines, all six of the pipelines with capacity of more than 1 billion cubic feet per day, and both of the pipelines that are more than 100 miles long.
Recent litigation regarding FERC permitting pipelines and LNG facilities

Pipeline certificate proceedings have increasingly become heavily contested, with significant opposition to many projects from certain environmentalist organisations and landowners. Decisions regarding many of the recent pipeline certificates have also led to divisions among the FERC commissioners, with the Republican commissioners (who have been a majority since 2017) generally approving project proposals and Democratic commissioners often submitting dissenting or concurring opinions raising concerns about a project, usually regarding environmental impacts (especially about GHGs) but also about the need for the projects.

The increased opposition to pipeline projects has also led to frequent appeals of both FERC’s certificate orders and related decisions by other agencies issuing required environmental permits for the projects. Some of the most important recent appellate decisions concerning pipeline projects are summarised below.

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 North-East. 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 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 before approving any one of them. The DC Circuit remanded the case to FERC, which involved one of the already built and operating segments, 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 supplementary 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 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 reapproved the project after providing a supplementary 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 – two of the five FERC commissioners dissented. In subsequent pipeline certificate proceedings, the extent to which FERC needs to consider GHG emissions associated with upstream production and downstream consumption of natural gas has frequently been a contested issue.

A number of state regulators responsible for issuing water quality determinations under the federal 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 in 2017 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 a more recent case involving the Constitution Pipeline proposed to be constructed in Pennsylvania and New York, the Second Circuit declined to decide a challenge to New York’s failure to issue a water quality determination under the Clean Water Act, instead requiring that the pipeline first seek a waiver from FERC. FERC initially denied the pipeline’s waiver request because the New York 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. In 2019, however, FERC reversed itself and ruled (in a 2-1 decision) that the New York agency had waived its authority under the Clean Water Act, holding that the pipeline withdrawals and resubmissions of its application did not extend the one-year period for state action or waiver. Notwithstanding, FERC’s finding that the New York agency had waived its authority under the Clean Water Act, the Constitution Pipeline project was cancelled in early 2020. Other FERC-approved natural gas pipelines continue to face judicial challenges to administratively issued environmental permits that continue to delay construction, including the two largest pipeline projects approved by FERC in 2017, namely the Atlantic Coast Pipeline and Mountain Valley Pipeline.

One of the largest pipelines certificated by FERC in 2018, the PennEast Pipeline, has faced a different kind of permitting challenge. In September 2019, the Court of Appeals for the Third Circuit agreed with New Jersey that the power of eminent domain conveyed with an NGA certificate does not provide authority to seize or condemn state lands, including both state-owned land and land where the state has non-possessory property rights under conservation easements and restrictive covenants. In response, PennEast filed a petition for declaratory order with FERC, which FERC granted in early 2020. FERC (in another 2-1 decision) held based on statutory interpretation and legislative history that certificates do allow for condemnation of property in which a state owns an interest, adding an explanation asserting that the Third Circuit’s decision would have profoundly adverse effects on the development of the interstate pipeline system and significantly undermine how the industry has operated for decades. While FERC’s ruling does not alter the Third Circuit’s decision, PennEast is utilising FERC’s ruling to try to obtain review of that decision by the Supreme Court of the United States.

Oil pipeline rates
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 give 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 have defined the limits of oil pipelines’ rate 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 2019, FERC ruled that an oil pipeline’s initial rates for new service cannot be treated as settlement rates even if shippers agree to those rates. Instead, the pipeline must justify initial rates by providing either (1) cost-of-service support for the rates or (2) an affidavit that a non-affiliated shipper that intends to use the service agrees to the rates.

A court decision in July 2016 has had broad implications for the interstate pipeline industry. In United Airlines v. FERC, the DC Circuit sided with pipeline shippers that challenged FERC’s income tax allowance policy, which had been in place since 2005. That policy 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 held that the Commission failed to demonstrate that there was no double recovery of income tax costs when permitting SFPP, LP (SFPP), a wholly owned subsidiary of an MLP, to recover both an income tax allowance and an ROE using the DCF methodology. The Court observed that an income tax allowance would provide SFPP revenues for entity-level, corporate taxes that SFPP does not pay, and that SFPP’s investors already recover their income taxes through the DCF-determined ROE. Given this apparent double recovery of income taxes, the Court vacated FERC’s orders and remanded the case for further proceedings.

After accepting additional evidence and arguments from interested parties, FERC issued two orders on remand in March 2018. In those orders, FERC found that permitting an MLP pipeline to recover both an income tax allowance and a DCR-determined ROE results in a double recovery of investors’ tax costs. Accordingly, the Commission announced that generally it will not permit MLPs to include an income tax allowance in their cost-of-service rates. On rehearing of the Revised Policy Statement and in a related case, SFPP, LP, the Commission held that MLPs that no longer include an income tax allowance in their rates can ‘zero out’ their accumulated deferred income tax balances without refunding those amounts to ratepayers. These orders are now on review in the DC Circuit. In the meantime, FERC has announced that other pass-through entities may be allowed to recover the income tax allowance in cost-based rates but only if they successfully address the double-recovery concern expressed in United Airlines and the Revised Policy Statement.

Lower taxes

In March 2018, FERC also issued orders initiating a rule-making and a notice of inquiry to evaluate whether the reduction of the federal corporate tax rate from 35 per cent to 21 per cent should be reflected in individual oil and natural gas pipelines’ cost-based rates or require other changes to pipeline rates. In July 2018, FERC issued a final rule (Order No. 849) that required 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 encouraged 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.

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3 827 F.3d 122 (DC Cir 2016).
5 164 FERC ¶61,030 (2018).
6 Opinion No. 511-D, 166 FERC ¶ 61,142 (2019).
FERC reserved the right to investigate potential over-recovery by gas pipelines that did not voluntarily reduce their rates. FERC also clarified that a pipeline organised as a pass-through entity is considered subject to federal corporate income tax (and thus may include an income tax allowance in rates) if all its income or losses are consolidated on the federal income tax return of a corporate parent. In compliance with the rule, gas pipelines filed the informational reports. Some pipelines voluntarily reduced rates as part of negotiated settlements with customers, and FERC initiated investigations into the reasonableness of certain pipeline rates after concluding that the pipelines might be substantially over-recovering their cost of service. In most cases, however, FERC elected not to take any action regarding pipelines that did not modify their rates.

In the March 2018 orders, FERC also announced that oil pipeline rates will be reduced to reflect lower income tax rates prospectively in FERC’s next round of five-year rate-indexing adjustments in 2020, to be effective as of 1 July 2021. In the interim, liquids pipeline shippers may file complaints if they believe the pipelines’ rates are unreasonable, and liquids pipelines that initiate rate changes must comply with the lower corporate income tax rates and new rule applicable to pipelines organised as flow-through entities.

**LNG export terminals**

Between 2013 and 2017, FERC 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. Six of the LNG export projects (five of which were existing LNG import facilities that added liquefaction for export purposes) are in at least partial operation as of early 2020.

In 2019, FERC authorised a large second wave of LNG export projects. In February 2019, FERC authorised the Venture Global Calcasieu Pass Project, its first new LNG export project in more than two years. During the rest of 2019, FERC authorised 10 more LNG projects, plus another in early 2020, acting on almost all the proposed second wave projects (leaving only the very large Alaska LNG project which remained pending at FERC). All the LNG project authorisation orders include numerous conditions and require close FERC supervision of construction activities. Certain of the FERC authorisation orders have been challenged on appeal.

While the second wave of LNG export projects have received FERC approvals (as well as export authorisations from DOE, as discussed below), they continue to face the interrelated challenges of obtaining binding agreements with customers and financing. Just two LNG export projects reached positive financial investment decisions in 2019 and are engaged in significant construction activity under FERC oversight: the Calcasieu Pass Project and Golden Pass, which was authorised by FERC in 2017.

Several of the initial round of FERC orders approving LNG export projects were appealed to the DC Circuit by the Sierra Club and similar non-government 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 effects. 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 United States, 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 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 geographical area.

In 2016, FERC denied applications to construct the Jordan Cove LNG export terminal in south-west 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. The project’s proponents filed a new application in September 2017 with supplementary evidence demonstrating market support for the pipeline. In March 2020, FERC approved the new application to construct and operate, with the Pacific Connector pipeline to connect to the terminal, finding them not inconsistent with the public interest. Shortly before FERC’s approval, the Oregon Department of Land Conservation and Development (DLCD) denied the project applicants’ request for a state-issued coastal zone permit under the federal Coastal Zone Management Act (CZMA). The applicants have appealed the DLCD’s ruling to the Secretary of the US Department of Commerce (who oversees certain aspects of states’ administration of the CZMA), asking that the Secretary override the DLCD ruling under the Secretary’s authority under the CZMA.

In August 2014, 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. 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), which found that the additional exports would be marginally beneficial to the US economy.

In September 2014, 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. DOE will consider properly submitted protests of changes in control relating to existing authorisations or pending applications for authorisations to export to countries with no free trade agreement (FTA), but will take no action unless it determines that the change in control renders the underlying authorisation at issue inconsistent with the public interest.

Under that policy, DOE has consistently authorised LNG projects, after they receive FERC authorisation for construction and operation, to export LNG to all countries not specifically prohibited from receiving LNG from the United States (i.e., countries not subject to US trade sanctions), including countries without FTAs to which the United States is a party, that require national treatment for trade in natural gas (non-FTA countries). DOE issued 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. Later in 2017, DOE commissioned a new macroeconomic study of the effects of LNG exports. The study
was issued for public comment in June 2018 and DOE responded to those comments in December 2018. Like the prior DOE studies of the issue, the 2018 study concluded that the United States will experience net economic benefits from LNG exports.

Relying in part on this study, DOE authorised LNG exports to non-FTA nations for all the LNG export projects authorised by FERC in 2019. In each instance, DOE issued the export authorisation promptly following issuance of the FERC action, taking longer only when FERC issued numerous approvals around the same time. All DOE export authorisations are very similar, with its analysis focused largely on the general benefits of LNG exports with relatively little analysis of the merits of specific project factors.

Environmental groups have 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 effects 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 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.

In June 2018, DOE issued a final rule to provide for accelerated approval of applications for small-scale exports of natural gas, including LNG, from export facilities to non-FTA countries. The final rule provides that DOE, upon receipt of a complete export application, will grant the application if (1) the application proposes the export of no more than 51.75 billion cubic feet of natural gas per year, and (2) the proposed export qualifies for a categorical exclusion under DOE’s NEPA regulations.

**Presidential permits for cross-boundary energy facilities**

Presidential permits are required for the construction and operation of energy facilities that cross the international borders with Canada and Mexico, including facilities for the transmission or transportation of electricity, natural gas, crude oil and petroleum products. The authority to issue Presidential Permits has been delegated by the President to the Secretary of Energy for electricity, to FERC for natural gas and to 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 2017. FERC and the Secretary of Energy, acting through 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.

In contrast, the presidential permit process for the Keystone XL pipeline has been the subject of protracted litigation. This 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 in the United States, to refineries on the US Gulf Coast. An application for a permit was filed with the Department of State in May 2012. After several years of deliberation by the Department of State and relevant federal agencies, and an attempt by Congress to get involved in the approval process, the Obama administration’s
State Department denied the application in November 2016. After the Trump administration took office, the Department of State reversed course and issued a presidential permit in March 2017. In November 2018, however, the US District Court for the District of Montana found that a supplementary environmental review from the Department of State was required, and placed an injunction on pipeline construction. In March 2019, President Trump revoked the prior presidential permit and issued a new one. Nevertheless, in April 2019, a new lawsuit was filed in the District of Montana challenging the new permit. The complaint asserts that the new permit is invalid because it purports to grant permission to construct the pipeline over portions of federal land that are properly under the jurisdiction of the Bureau of Land Management, does not contain a finding that the President’s authorisation was in the national interest, does not include a fact-based explanation of the decision to grant the authorisation, and grants authorisation without requiring compliance with federal environmental and procedural laws. On 15 April 2020, the US District Court for the District of Montana granted in part the plaintiffs’ motion for partial summary judgment in ruling that the US Army Corps of Engineers’ 2017 reauthorisation of Nationwide Permit 12 (NWP 12) violated the Endangered Species Act because the Army Corps failed to complete a programmatic consultation with the US Fish and Wildlife Service and the National Marine Fisheries Service regarding the environmental effects of the reauthorisation. At the time of writing, further litigation is anticipated regarding the District Court’s ruling on NWP 12.

Keystone XL has received several state and local approvals for the portion of the pipeline located in the United States, including from state regulators in Montana and South Dakota. The Nebraska Public Service Commission’s approval, which was initially granted in 2017 and required the pipeline to use an alternative route in the state, was ultimately upheld by the Nebraska Supreme Court in August 2019. However, Keystone XL has yet to receive all its necessary county-level approvals in Nebraska. In addition, Keystone XL has filed numerous condemnation claims in Nebraska, some of which have been challenged in state court by landowners.

**Rules on transporting crude oil and LNG by rail**

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 established, among other matters, operating standards for crude oil conditioning equipment and prohibited operators from blending lighter hydrocarbons into crude oil before shipment. The 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 crude oil. The PHMSA and 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 their type, 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 the Department of Transportation (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 rail companies 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. Further
rules were proposed in October 2019 that would permit the bulk transport of LNG in certain
types of rail tank cars.

**Pipeline safety**
The PHMSA also regulates pipeline safety and has adopted more stringent safety standards
following several accidents. Under agreements with certain state agencies, the 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.

Under current PHMSA regulations, the maximum administrative civil penalties for
violation of the pipeline safety laws and regulations is US$2 million. 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 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 wilful violations of the Pipeline
Safety Act (PSA). 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 the PHMSA’s pipeline safety programme until 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’. Funding authorisation for the pipeline safety programme lapsed
in October 2019, despite several bills introduced to continue it. The programme continues
to operate under the Further Consolidated Appropriations Act of 2020 that includes pipeline
safety appropriations for fiscal year 2020.

**New final rule for underground natural gas storage facilities**
Accidents have also precipitated new regulations for natural gas storage facilities. A
high-profile leak of methane gas from the Southern California Natural Gas Company’s Aliso
Canyon–Porter Ranch underground storage field in October 2015 led to calls for increased
regulation of underground natural gas storage facilities. In June 2016, Congress enacted
the Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2016.
Among other things, the Act required the 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 the standards
are compatible with the minimum standards prescribed in the Act. In December 2016, the
PHMSA published an interim final rule that revised existing federal pipeline safety regulations relating to downhole facilities, including wells, well bore tubing and casing at underground natural gas storage facilities. The interim final rule also incorporated certain recommended practices of the American Petroleum Institute into the 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. In February 2020, the PHMSA published a final rule, incorporating many of the comments and concerns received, including modifying compliance timelines, clarifying the states’ regulatory role and reducing reporting requirements. The final rule formalises requirements for operators to implement integrity management programmes and to conduct risk assessments for underground natural gas storage facilities. The 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 final rule applies to intrastate storage facilities and requires states to update their safety regulations to include the specified recommended practices. The final rule became effective in March 2020.

The State of Texas and the Texas Railroad Commission had petitioned the US Court of Appeals for the Fifth Circuit for review of the interim final rule. In 2017, the Fifth Circuit Court of Appeals had granted an abeyance in anticipation of the final rule. Now that the final rule has been issued, the case will probably resume.

**Three new PHMSA final rules**

The PHMSA has been active in the rule-making process. In October 2019, it issued three final rules that were each several years in the making: (1) Safety of Gas Transmission Pipelines: Maximum Allowable Operating Pressure Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments Rule (the Gas Pipelines Safety Rule); (2) Safety of Hazardous Liquid Pipelines Rule; and (3) Enhanced Emergency Order Procedures Rule.

Work preceding promulgation of the Gas Pipelines Safety Rule began in April 2016, when the PHMSA published proposed revisions to its safety regulations for onshore natural gas transmission and gathering pipelines, to address incidents like the San Bruno rupture. The 2016 proposal received a significant number of comments and was re-evaluated before publication of the final rule. The final rule broadens the scope and strength of the PHMSA’s natural gas pipeline safety regulations by adding new assessment and repair criteria for gas transmission pipelines, and by extending those protocols to pipelines located in newly designated moderate consequence areas (i.e., areas where an incident would pose a risk to human life through an impact circle containing five or more buildings intended for human occupancy, a highway and other occupied areas). In addition, the rule:

- codifies requirements for pipeline operators periodically to assess certain gas transmission pipelines outside high concentration areas to monitor, detect and remediate pipeline defects and anomalies;
- requires reporting of exceedances of the maximum allowable operating pressure (MAOP) of gas transmission pipelines;
- requires certain devices on in-line inspection, launcher or receiver facilities that can safely relieve pressure in the barrel;
requires the use of a device that can indicate whether the pressure has been relieved in the barrel; and

e requires operators of certain onshore steel gas transmission pipeline segments to reconfirm the MAOP of those segments.

The Gas Pipeline Safety Rule comes into effect in July 2020.

The Safety of Hazardous Liquid Pipelines Rule extends reporting requirements to certain hazardous liquid gravity and rural gathering lines not previously regulated by the PHMSA. It requires inspections of pipelines in areas affected by extreme weather or natural disasters, extends the use of leak detection systems to all regulated hazardous liquid pipelines and requires integrity assessments at least once every 10 years for onshore hazardous liquid pipeline segments located outside high concentration areas. This rule also comes into effect in July 2020.

The Enhanced Emergency Order Procedures Rule affects the PHMSA’s role during an emergency. Here, the PHMSA may issue an emergency order without advance notice or opportunity for a hearing. Additionally, the PHMSA may impose emergency restrictions, prohibitions or other safety measures on owners and operators of gas or hazardous liquid pipeline facilities, but only to the extent necessary to abate the imminent hazard. This rule stems from a 2016 interim final rule and has been updated to respond to comments received, including, for example, clarifying that an emergency order is not to be used as a substitute for notice and comment rule-making, and must be issued only to the extent necessary to abate the imminent hazard. This rule became effective in December 2019.

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, pipeline development, cost allocation, renewable development and integration, and many other issues. The variety of energy industry participants and regulators, and the geographical differences across the United States, can provide an opportunity for the development of innovative policies but this heterogeneity may also lead to disjointed or overlapping regulatory obligations and may ultimately undermine the development of a uniform national energy policy.
I OVERVIEW

This review provides for the overview of the power energy sector of Uzbekistan, being currently subject to a large-scale transformation. It purposefully omits a detailed description of other energy markets, for example the natural gas market, as this would require a separate in-depth analysis owing to the multiplicity of major reforms ongoing in the country.

To begin with, the installed capacity of Uzbekistan power plants exceeds 12.5GW, making Uzbekistan one of the few energy-independent countries in Eurasia. The Uzbek power sector depends heavily on the country’s gas and oil industry, as hydrocarbons (mainly, natural gas) contribute to about 97 per cent of the country’s energy balance with the remaining 3 per cent being hydropower, coal and charcoal. There are almost 40 hydropower stations in Uzbekistan, but only nine of them have an energy capacity of more than 50MW and the relevant potential is likely to be limited, as water resources are shrinking. Currently, there are no nuclear power stations within its territory of Uzbekistan. However, the commissioning of the first nuclear power station, being constructed in cooperation with Russia’s Rosatom, is scheduled for 2028–2029.

The legal and economic structure of the power industry of Uzbekistan is relatively simple. Proceeding from the assumption that the provision of electric power is a natural monopoly where the single state-owned monopolist can be the most efficient supplier, the Uzbek government has long maintained a model where the single incumbent – JSC Uzbekenergo – has been responsible for the power generation, transmission, distribution, dispatch management, and retail sales, operating through its affiliates in each region of the country. Over the past years, however, the government has become increasingly dissatisfied with the performance of the industry and currently, seeks to enhance competition within the sector. On 1 February 2019, it was announced that the energy sector would be reformed and JSC Uzbekenergo would be restructured.2

Currently, JSC Uzbekenergo is a central, vertically integrated, state-owned holding company, controlling more than 40 utility companies. Each of these utility companies performs one or more of the above functions – the power generation, long-distance transmission, distribution, dispatch management or retail sales. The company used to cooperate closely

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1 Iroda Tokhirova is an associate at Kosta Legal Law Firm. The chapter was co-written by Maxim Dogonkin, formerly a senior associate at Kosta Legal Law Firm. The information in this chapter was correct as at May 2019.

2 Presidential Decree No. PP-4142 of 1 February 2019, at www.lex.uz/ru/docs/4188746.
with JSC Uzbekneftegaz, which is the state-owned holding company and the sector regulator in oil and gas. The latter recently lost some of its powers, which were transferred (along with some powers of the JSC Uzbekenergo) to the Ministry of Energy.

The Presidential Decree providing for the unbundling, privatisation and attraction of foreign investment to the power industry was signed on 27 March 2019. According to this, JSC Uzbekenergo will cease to exist and three recently established joint-stock companies will completely replace the holding company, as explained below.

Current policy priorities in the sector include:

a maximising energy savings through rehabilitation and modernisation of existing power energy facilities and the introduction of energy-efficient technologies and equipment in various sectors of the economy to reduce costs and improve competitiveness;

b commercialising utility operations to improve performance. The government plans to continue de-monopolisation and deregulation of the power sector to increase competition. It prioritises the provision of open access to power transmission lines for power-generation companies;

c attracting private-sector investments to satisfy increased investment needs and to address the problem of depreciation;

d reducing the dependence on natural gas. The government is striving to increase the share of other energy sources by converting a number of gas-fired thermal plants to coal-fired, constructing new coal-fired power plants and increasing the share of renewable energy; and

e reducing the environmental impact of the power industry by relying on renewable energy.

II REGULATION

i The regulators

Institutional framework

The regulatory functions used to be entrusted to JSC Uzbekenergo are now in the hands of several state regulators. Since a substantial share of the Uzbekistan’s power production is dependent on natural gas, recently the government has brought the majority of relevant powers in power energy and oil and gas under sole management of the Ministry of Energy.4 The Ministry was established on 1 February 2019 and is responsible for, among other things, the preparation and implementation of energy policies, plans and programmes in the above industries in coordination with its affiliated institutions: Uzenergoinspektsiya, Uzneftegasinspektsiya, the Agency for Development of the Nuclear Industry (UzAtom) and the Non-Commercial Organisation for Implementation of Production Share Agreements.

Some of the Ministry’s other functions, as provided by relevant laws, include the regulation and supervision of the functioning of the power energy, gas, nuclear and renewable energy industries, the monitoring of the energy consumption efficiency, and implementation of projects under production share agreements. The above-mentioned Uzenergoinspektsiya and Uzneftegasinspektsiya control compliance with relevant state standards in the power energy and gas industries respectively.

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4 See footnote 2, above.
The main regulators also include the Ministry of Finance, exercising price regulation and general control over financial flows within the state controlled sector, and the Cabinet of Ministers, approving the Rules for the Electricity Use (REU) and the Rules for the Gas Use as well as monitoring investment programmes in the industry.

Additionally, the Uzbek Agency for Standardisation, Metrology and Certification controls compliance with power energy efficiency and energy quality standards, whereas the State Antimonopoly Committee oversees how natural monopolies adhere to market rules and regulations, including the rules for price setting.

**Legal framework**

The main legislative acts for the industry are the Law on Electricity\(^5\) and the Law on Efficient Use of Power Energy,\(^6\) which determine the main state policies and the structure of the sector as well as set rules and restrictions for the country’s energy markets. The Law on Natural Monopolies\(^7\) provides for some relevant rules for companies in the industry, empowering the Antimonopoly Committee to monitor and to punish anticompetitive activities of natural monopolies and to ensure a balance between interests of consumers, the state and energy companies.

The Regulations on Provision of Energy Services\(^8\) determine the rules for the provision of services related to ensuring energy efficiency by the state-owned monopolist the National Energy Saving Company under energy services contracts that have to be entered into by state agencies and state-owned enterprises. The Rules for Using Power Energy and the Rules for Using Natural Gas\(^9\) set the rules regulating relations between utility providers and purchaser of power energy and natural gas respectively. According to the Rules, standard form contracts must be applied across these sectors, as developed jointly by JSC Uzbekenergo, the Antimonopoly Committee and controlling agencies Uzenergoinspektsiya and Uzneftegasinspektsiya, mentioned above. Some basic rules for contacts on power supply are also set in Articles 468 to 478 of the Civil Code.

The legal framework for renewable energy remains underdeveloped and is partially covered only in subordinate legislative acts (some Presidential Decrees and Resolutions of the Cabinet of Ministers), which mainly relate to the provision of particular tax incentives to companies operating in the sector. A draft of the fully fledged Law on Renewable Energy Sources was passed by the Uzbek parliament on 3 May 2019, and is now awaiting approval by the President. Among other things, it regulates measures for the state support and development of renewable energy and creates a legal basis for state control over the sector. In August 2018, the parliament was preparing to review the draft on the second reading,\(^10\) but there has not been any further information in this regard.

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6 See www.lex.uz/acts/2054.


9 Annexes 1 and 2 to the Resolution of Cabinet of Ministers No. 22 of 12 January 2018, at www.lex.uz/docs/3505787.

Regulated activities
In general, generation, transmission, local supply, operation and retail sales in the power industry do not require special licences. In practice, however, the access to the markets is in many ways blocked. Hence, the transmission may only be performed by state-owned enterprises, which are also entrusted with centralised dispatch management, whereas local distribution networks are effectively in the hands of the state. Both categories of state-owned entities used to be controlled by JSC Uzbekenergo, but that control now is to be divided between JSC National Power Grids of Uzbekistan (the long-distance transmission) and JSC Regional Power Grids (the local distribution). Although private entities are able to engage in the generation of power energy, their access to the Single Power Grid (Uzbekistan’s country-wide grid) requires the obtainment of a special permit. The rules for obtaining such a permit are, however, obscure and in practice, it may be impossible to get one unless an agreement is reached with the sector regulator (previously JSC Uzbekenergo and now the Ministry of Energy). Note that if legal entities and individuals produce power energy for their own use, they may trade in it but only using their own grid, since they are not allowed to connect to the Single Grid.

Recently, nevertheless, several regulations have been revealed for public discussion, setting some clearer rules for private generators, including the rules for access to the Single Power Grid. It is, however, hard to predict an exact time when these regulations will be adopted.

Speaking of retail sales, state-owned enterprises may provide private entities with the right to accept payments for electricity from consumers (i.e., act as intermediaries).

Since the construction of power plants and transmission lines is not licensed, special permits for each particular project may be required as, under Uzbek law, these are ‘potentially dangerous [for employees, the society and the natural environment] industrial objects’.

Ownership and market access restrictions
As noted above, all facilities in the industry are now owned by the state. The Law on Electricity of 2009 laid the foundation for the legal unbundling in the industry, but privatisation was not pursued. Nevertheless, the above-mentioned structural ownership unbundling that will end in the liquidation of JSC Uzbekenergo and the establishment of three power energy companies are expected to preface massive privatisation. It seems that the priority in this regard will be given to foreign investors with solid experience in the power industry.

Currently, Uzbek law does not preclude foreigners from acquiring stakes in national energy companies.

Transfers of control and assignments
State shares in JSC Uzbekenergo are managed by the State Agency for Property Management (the Agency). As for the company’s subsidiaries and affiliates, they may be owned by just JSC Uzbekenergo or both the company and the Agency (i.e., dual control is exercised in some cases).

Pursuant to Uzbek law, state shares be may transferred to private parties for performing management functions based on special standard form contracts. Such management is usually closely supervised by the Agency. To our knowledge, no such contracts in the power industry have been concluded.

Privatisation processes are governed by separate rules. State property is generally privatised through holding open auctions and tenders. The starting price varies and may be
set as a fixed sum, as some fixed sum and the commitment of a potential owner to invest a particular amount into developing the object, or as the commitment to invest only. To commence privatisation, a privatisation programme must be approved by the President and the Cabinet of Ministers. Usually direct negotiations between potential private (whether local or foreign) investors and relevant sectoral regulators (in the case of the power industry, this would be the Ministry of Energy) precede all privatisation deals.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling
As noted above, JSC Uzbekenergo has been a single, vertically integrated monopolist engaged in all types of activities in the power industry. The majority of Uzbekistan’s power generation, transmission and distribution assets are owned and operated by subsidiaries of this state-owned company. Generally, all major generating companies represent separate legal entities owned by JSC Uzbekenergo. Its other subsidiary, Energostish, acts as the single buyer of power energy from generating companies and the single wholesaler to local distributors. Uzelectroset, controlling seven high-voltage operators, acts as the main dispatch manager and transmitter of power energy based on contracts with Energostish. Local distributors also acting as retailers are represented by 14 territorial joint-stock companies owned by JSC Uzbekenergo. Based on the changes of 27 March 2019, the JSC National Electricity Grids of Uzbekistan will replace both Energostish and Uzelectroset, taking over as the single intermediary between generating companies, the majority of which will come under the control of JSC Thermal Power Plants, and local distributors, which will be controlled by JSC Regional Power Grids.

ii Transmission and transportation, and distribution access
As explained above, access to the single power grid for producers and consumers is provided on the basis of special permits granted by subsidiaries of JSC Uzbekenergo, based on relevant state rules and standards, and has to be financed and organised by those requesting access. As almost no private grids exist, there is no alternative to this procedure and for all major endeavours a pre-agreement with JSC Uzbekenergo or its subsidiary or affiliate is recommended.

iii Rates
The Ministry of Finance is the state body responsible for setting tariffs in the power industry. In doing so it acts based on the Regulations on Tariff Groups of Consumers of Electrical and Heat Energy, which establishes three types of tariffs and 10 groups of consumers, thus setting basic principles for defining tariffs.

The three types of tariffs applied are:

a single-rate tariffs – usually the fee per 1kW/h of active power energy supplied to customers;

double-rate tariffs – the annual payment for 1kW of the maximum power capacity declared for consumption by customers and the fee for 1kW/h of supplied electricity; and

differential (time-of-use) tariffs – local distributors have the right to differentiate power energy tariffs based on the time of day (peak hours, half-peak hours or night load) and seasons (summer and winter periods), provided that customers have multi-tariff metering devices.

Ten of the above consumer tariff groups include industrial enterprises with a connected capacity of up to 750kW, industrial enterprises with a relevant capacity of more than 750kW, budget organisations, consumers using electricity for domestic needs, consumers using electricity for heating and others.

Some discounts are provided to socially vulnerable consumers, based on relevant decrees of the President. Such discounts are secured by the state subsidising local distributors, selling electricity at a discount.

Generally, based on some assessment by external experts, tariffs set by the Ministry remain significantly below the market level and are not able to satisfy ever-growing demands for investment.

### iv Security and technology restrictions

Operators of power grids have the obligation to inspect and to maintain power grids; to reconstruct, transform or stop using power grids in a timely manner if they do not satisfy the safe-use requirements; to put up, repair or change signs related to power grids; and to take effective safety measures for power grids not in operation.

Other obligations for operators are in place under the Law on Electricity. Hence, power grids must be operated based on the principles of safety, high quality and economy. Power grids must be maintained so that the power supply remains uninterrupted and stable. Pursuant to the Law on Efficient Use of Energy, energy producing and consuming facilities along with the energy itself are subject to standardisation and certification. Further, the Law on the Protection of Nature, the Law on Ecological Control and the Law on the Protection of the Atmosphere impose the obligation on entities in the energy sector to take pre-emptive measures to decrease levels of potential environmental impact.

At the moment, concerns about cybersecurity and data processing have not come to the forefront with respect to the power industry. Some basic things are only partially addressed in bilateral and international treaties to which the country is a party, including the Shanghai Cooperation Organisation’s agreement on cooperation in the field of ensuring international information security and the India–Uzbekistan agreements on the development of cooperation.

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IV ENERGY MARKETS

i Contracts for sale of energy

Currently, relevant contracts for the supply of power energy may only be concluded between state-owned distributors and consumers, albeit private entities have the right to act as intermediaries in accepting payments under such contracts. As noted above, standard form contracts are used, as developed by JSC Uzbekenergo and the aforementioned state agencies. To become a valid consumer of energy, a particular consumer has to meet certain criteria (e.g., it must have the equipment necessary for the connection to territorial power grids and have metering devices installed). Prices under the contract are non-negotiable and are subject to state regulation.

The Rules for Using Power Energy, cited above, contain a number of provisions that have to be reflected in standard contracts. Thus, legal entities are allowed to purchase energy only after making the 100 per cent advance payment. Power supply contracts with legal entities also have to contain a provision on the payment of penalties to local power distributors in the amount of 50 per cent of the respective tariff for the amount of energy consumed in the relevant billing period in excess of the fixed amount set in the power supply contracts for more than 5 per cent. Likewise, if at the end of the billing period, the actual power load for a consumer exceeds the amount set in the power supply contract by more than 5 per cent, recalculation has to be made with respect to the load and the additional charge of 50 per cent of the tariff for the period may be imposed.

There are no separate rules that may potentially govern the supply of power energy by private generating companies. As for now, general rules for such contracts as provided by Articles 468 to 478 of the Civil Code will apply. It is highly likely, however, that a separate set of regulations will be developed.

ii Market developments

Apart from the unbundling and the privatisation reforms mentioned above, some other changes will have an impact on Uzbekistan’s power energy market.

Currently, as briefly noted above, Uzbekistan has no nuclear power stations. However, despite some previous reluctance to use nuclear energy, the Uzbek government has adopted the Concept for Development of Nuclear Energy for 2019–2029, envisaging the construction of a nuclear power station with the total capacity of 2.4GW. Russia’s Rosatom is going to be engaged to lead the project.

Under the total restructuring of the power industry projected by the reforms of 27 March 2019, a modern multidisciplinary project organisation, JSC UzEnergoEngineering, will be established. Among other things, it will engage in the design of power grids with a voltage of 0.4–500kV with the use of innovative technologies and the latest experience in the field.

Some other significant legal changes that are likely to seriously affect the market include: the provision of access to the single power grid to independent (private) producers of energy; incentives aimed at increasing the market share of generators using renewable energy; and changes in the tariff system with more market indicators being taken into account.

V  RENEWABLE ENERGY AND CONSERVATION

i  Development of renewable energy

Currently, the renewable energy sector is almost non-existent in Uzbekistan (not taking into account hydropower stations), as renewable sources are not used on an industrial scale. In 2009, Uzbekistan signed the Statute of the International Renewable Energy Agency (IRENA) and became a member of IRENA as a result. Nevertheless, the development of the renewable energy industry has not accelerated until recently.

Some basics of Uzbekistan’s policy on renewable energy, as mentioned above, are set forth in several presidential decrees and the Law on the Efficient Use of Energy. As noted, the draft Law on Renewable Sources of Energy is expected to be approved soon.

In 2017–2018, owing to environmental concerns and resource depletion (particularly of natural gas), the government focused its attention on renewable energy again, and since then several attempts have been made to improve the legal framework for the industry. The lack of single institutional and legal frameworks seems to be the main contributor to the poor performance of the sector.

Therefore, on 26 May 2017, the President approved the state programme on developing renewable energy and boosting energy efficiency for 2017–2021. Its priorities include fostering the use of renewable sources, switching away from fossil fuels and ensuring the universal installation of energy-efficient technologies. Solar energy is expected to become the key source for the development of the energy sector by 2030 followed by hydro and wind power. Tax incentives are intended to be provided to projects in the field.

As regards hydropower, in May 2017 most of JSC Uzbekenergo hydropower generation assets were transferred to the newly established joint-stock company Uzbekhydroenergo. On 2 May 2017, the Programme of Measures for Further Development of the Hydropower Sector for 2017–2021 was adopted, addressing approved projects for the construction of new hydroelectric power plants and the modernisation of existing ones, and the provision of tax incentives for the period up to 1 January 2022 with respect to imported equipment that is required for the above construction and modernisation projects. As mentioned above, in comparison with the wind and solar energy generation, the hydropower industry is relatively well developed in Uzbekistan.

ii  Energy efficiency and conservation

Uzbekistan’s policy on energy efficiency is covered by the Law on the Efficient Use of Energy. The Law focuses on conservation of energy resources and their rational use. To achieve these goals, the Law provides for some mandatory obligations for users, producers and distributors of power energy. Thus, for example, energy-producing and consuming facilities, and energy itself, are subject to standardisation and certification.

For the purpose of the rational use of energy, the government provides businesses and individuals with the following benefits:

a  customs duties and taxes on the import of special equipment, tools and materials, the use of which significantly increases the efficiency of energy use;

b  preferential loans for implementing national, sectoral and regional targeted programmes and projects in the field of rational use of energy;

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c financial grants for intersectoral research and development activities, the implementation of pilot projects on the production of energy efficient equipment; and

d feed-in tariffs for energy for legal and natural persons that ensure the reduction of energy consumption based on set standards or manufacture competitive products while maintaining energy consumption levels, which are below some set thresholds.

iii Technological developments

As has been noted, renewable energy is still a developing sector. Although Uzbekistan seems to have remarkable potential in terms of expanding its use of renewable energy resources, particularly solar energy, currently there are only a few legal acts encouraging technological developments in the sector, as discussed above.

In terms of energy efficiency, the government has expressed its interest in implementing smart grid projects that would enable the remote monitoring and control over electricity meters and energy consumption.

To give an example of some development initiatives, the Resolution of the Cabinet of Ministers No. 633 of 8 August 2018[^18] shows that the government is interested in attracting private investors into the design, financing, construction and operation of photovoltaic energy production facilities in Uzbekistan for a projected amount of US$1 billion based on public-private partnership mechanisms. One of the projects related to the Resolution is the construction of a solar photovoltaic power plant with an energy capacity of about 100MW in the Samarkand region of Uzbekistan.

Further, the government is developing the Intelligent Electricity Metering project in cooperation with Korean KT Corporation, and plans to instal smart electricity metering devices in most regions of Uzbekistan. These works are expected to be completed by 2021.

VI THE YEAR IN REVIEW

Some of the key developments of 2018 and 2019, which have been described in part above, are covered in the following legal acts:

a Presidential Decree No. PP – 4249 of 27 March 2019 and Resolution of the Cabinet of Ministers No. 685 of 25 August 2018: measures to attract private direct investments, including foreign ones, in the energy sector by selling shares of respective joint-stock companies;

b Presidential Decree No. PP – 4249 of 27 March 2019 and Presidential Decree No. PP – 3107 of 30 June 2017: structural transformations and unbundling in energy and oil and gas;


d Presidential Decree No. PP – 4142 of 1 February 2019: providing for the establishment of the Ministry of Energy;

e Presidential Decree No. PP – 3981 of 23 October 2018: the installation of modern electronic metering devices, enabling remote reading and control over power energy consumption;

[^18]: Resolution of the Cabinet of Ministers No. 633 of 8 August 2018, at www.lex.uz/ru/docs/3860084.
Resolution of the Cabinets of Ministers No. 633 of 8 August 2018: incentives for private investors designing or constructing photovoltaic plants and public-private partnership mechanisms in the field;

Resolution of the Legislative Chamber of Oliy Majlis of the Republic of Uzbekistan No. 1833-III of 14 July 2018: the draft Law on Renewable Energy Sources;

Resolution of the Cabinet of Ministers No. 444 of 12 June 2018: the introduction of simplified procedures for obtaining licences in the oil and gas sector. Under the Resolution, the Ministry of Energy has accumulated regulatory powers that previously had been distributed among several state regulators;

Presidential Decree No. PP – 3102 of 26 May 2017: the programme of measures for furthering the development of renewable energy and enhancing energy efficiency in 2017–2021; and


VII CONCLUSIONS AND OUTLOOK

As the current energy policy of the government demonstrates, Uzbekistan will focus on diversifying its energy resources, developing the renewable energy sector and attracting private investments with foreign companies.

As regards the legislation in the area, we expect the draft Law on Renewable Energy Sources to be approved by the President soon. Given active development of the legislation on public-private partnership and privatisation trends in the industry, it is likely that the energy sector will also be affected by the adoption of new regulations for private players, which will clarify rules for private generators and other interested businesses (e.g., by streamlining the rules for access to the single power grid). It is also highly likely that the government will come up with some new incentives for private investors.

Overall, Uzbekistan’s energy strategy and targets for 2030 can be summarised as follows:

- proceeding with the unbundling and the de-statisation in the industry, including the reforming of tariff setting;
- furthering privatisation in the energy sector by attracting private foreign and local direct investment, and simplifying the rules for access to the industry for private players;
- repairing and reconstructing depreciated energy facilities with the support of private direct investments;
- extending the use of smart grids and energy-efficient technologies;
- increasing the share of renewable energy sources and in particular supporting the construction of solar energy stations; and
- commissioning a nuclear power station.
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