The Energy Regulations and Markets Review

The Energy Regulations and Markets Review
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THE ENERGY REGULATION AND MARKETS REVIEW

SIXTH EDITION

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David L Schwartz
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In our sixth year of writing and publishing *The Energy Regulation and Markets Review*, we have seen dramatic changes in global energy policies. Notwithstanding President Trump’s announcement that the United States will withdraw from the Paris Agreement, and the referendum in the United Kingdom to leave the European Union, there have been continued efforts to reduce greenhouse gases (GHGs) by the signatories to the Paris Agreement. There is still a significant need to invest in infrastructure, and we have seen significant investment throughout the supply chains in the oil, gas and power sectors globally. The Fukushima nuclear incident continues to impact energy policy, and we continue to see extensive liberalisation of the energy sector.

I  CLIMATE CHANGE DEVELOPMENTS

With respect to climate change efforts, the Paris Agreement went into effect on 4 November 2016, and thus far, 148 countries have ratified the Agreement. President Trump has recently announced that the United States would be withdrawing from the Paris Agreement, but we continue to see significant carbon reduction efforts, such as increased development of renewable resources, as well as energy efficiency and demand reduction measures, globally, including in the United States.

In Europe, the European Union adopted ‘A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy’, and it is expected that there will be a large amount of European secondary legislation to increase the amount of renewable resources. While the United Kingdom voted to exit the European Union, the United Kingdom continues to invest heavily in offshore and onshore renewable projects, and has been particularly active in the battery storage sector to round out intermittent renewable production, offset demand and arbitrage energy prices. President Macron has stated his intent to have France fulfil its goals of closing all coal fired power plants within five years and doubling the capacity of wind and solar renewable generation. Denmark continues to seek to have renewable energy meet all of its electricity demands by 2050. The Netherlands has a goal of reducing GHGs by at least 25 per cent by 2020, and is closing at least two coal-fired power plants. Germany undertook significant steps to increase reliance on renewable energy resources.

China released a plan to have 15 per cent of its energy supplied by non-fossil fuels, 20 per cent from natural gas and no more than 58 per cent from coal by 2020. Korea’s goal is to cut GHGs by 37 per cent by 2030. India announced a goal to have at least 40 per cent of its installed electric capacity powered by non-fossil fuels. Japan and Australia are working to improve energy efficiency and conservation and to increase reliance on renewable
energy supply. The United Arab Emirates continues its efforts to reduce its carbon footprint, announcing a goal of having 25 per cent of its capacity from renewables by 2030, and 75 per cent by 2050. Australia is adding significant new renewable resources. Even the United States is seeing significant investment in renewable energy development. While the Trump Administration is seeking to reverse the Obama Administration's Clean Power Plan, individual states are moving forward to achieve reduced reliance on fossil fuels and greater reliance on renewable energy, including California and New York, which are seeking a 50 per cent renewable portfolio standard goal by 2030, and Hawaii, which is seeking 100 per cent reliance on renewables by 2045.

II INFRASTRUCTURE DEVELOPMENT

For many countries, reliable energy supply is the primary concern, regardless of fuel source. Rural electrification and system reliability remain priorities in Indonesia, Mozambique, Angola, parts of Nigeria and Central and West Africa and we are seeing significant efforts to pursue electric generation projects in those regions. Iran is seeking approximately US$200 billion in investments for its oil and gas industries over a five-year period, and Iraq is seeking approximately US$18 billion in foreign investments over a three-year period. Turkey is aggressively diversifying its energy industry and building infrastructure, including the TANAP pipeline from the Caspian Sea to Europe, and is pursuing shale gas opportunities. Malaysia is constructing a 2,000MW coal plant to meet its growing energy demands. South Africa has taken steps to add 863MW of coal generation, and is seeking to add over 3,000MW of natural gas-fired generation. Denmark has a new North Sea Agreement to secure future exploration and production of hydrocarbons from the North Sea, and Cyprus, Mozambique, Lebanon and Mexico are establishing mechanisms to license offshore oil and gas exploration and production.

III NUCLEAR POWER GENERATION

Six years after the Fukushima disaster, Japan has shut down 45 out of its 48 nuclear power stations pending new detailed safety reviews. Germany continues its phase out all nuclear generation, and has agreed to assume the responsibility for nuclear waste management following shut-down, decommissioning and dismantlement by existing owners. France is seeking a reduction of nuclear power generation to 50 per cent of total electricity production within five years. Switzerland and Korea are planning to limit the life of their nuclear generation units. On the other hand, Turkey is continuing with development of the Akkuyu nuclear power plant, and the United Arab Emirates is still proceeding with construction of the Barakah nuclear power plant, both of which are expected to be operational in 2020. The United Kingdom continues to push forward with the Hinckley Point C new nuclear facility. South Africa is facing substantial resistance to its efforts to develop 9,600MW of new nuclear generation capacity. In the United States, the early retirement of certain nuclear plants has been driven by cost and power market considerations, rather than safety concerns. Some nuclear owners in the United States have sought state subsidies in New York, Illinois, Ohio and Pennsylvania, among others, in order to avert premature retirements. Illinois and New York have implemented legislative and regulatory payment programmes for nuclear facilities in those states, but they are currently being challenged in federal district court on constitutional grounds.
IV  LIBERALISATION OF THE ENERGY SECTOR

We have seen significant energy sector regulatory reforms in many countries. Australia is continuing to move toward retail choice, and is seeking to implement a new energy market operator and market rule change committee. Italy is seeking to develop more competitive retail markets. Spain has been engaged in regulatory reforms to reduce its ‘tariff deficit’ and re-establish the correlation between costs and rates. Portugal continues to work on liberalising its electricity and gas markets. Japan is actively working on developing competitive retail electric and gas markets and is seeking to unbundle electric transmission and gas transportation sectors to improve competition. And we are seeing continued efforts to partially privatise state-owned energy companies in the United Arab Emirates, Turkey, Brazil and Colombia.

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

David L Schwartz
Latham & Watkins LLP
Washington, DC
June 2017
Chapter 1

EUROPEAN UNION OVERVIEW

Charles Morrison, Nigel Drew and Andreas Gunst

I OVERVIEW

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

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

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

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

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

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

d the promotion of energy efficiency.

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

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

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

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

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

- 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.

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

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

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

II EUROPEAN ELECTRICITY AND GAS REGULATORY SYSTEM

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

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

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

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

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

III ELECTRICITY

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

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

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

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

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

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

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

iii Network codes
Network codes7 are technical rules designed to address key priorities specified by the European Commission.8 These aim to develop and harmonise specific aspects of the European energy networks, including capacity allocation, balancing supply and demand, requirements of generators and transmission networks, and security of supply.

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

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

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

market codes, which encourage a transparent and competitive pan-European
marketplace for electricity and capacity in all timescales, and stimulate generator
diversification and infrastructure optimisation.

At the time of writing, five electricity network codes have entered into force. The network
code on Capacity Allocation and Congestion Management (CACM)\(^9\) sets out methods
for allocating capacity in day-ahead and intra-day timescales, and designates Nominated
Electricity Market Operators as coupling operators, and sets out their tasks as well as tasks
for TSOs relating to single day-ahead and intraday coupling. CACM includes detailed
provisions on terms, conditions and methodologies on capacity allocation and congestion
income distribution.

The network code Forward Capacity Allocation\(^{10}\) sets out methods for allocating
capacity in the forward markets, and aims to promote effective long-term cross-zonal
trade with long-term cross-zonal hedging products for market participants, optimise the
calculation and allocation of long-term cross-zonal capacity, provide non-discriminatory
access to long-term cross-zonal capacity, ensure fair and non-discriminatory treatment of
TSOs and market participants, and enhance the transparency and reliability of information.

The network code Demand Connection Code\(^{11}\) 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 High Voltage Direct Current Connections\(^{12}\) 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 Requirements for Generators\(^{13}\) provides requirements for newly constructed generators,
as well as notification procedures and compliance provisions.

At the time of writing, the three remaining network codes – Electricity Balancing,
Emergency and Restoration, and System Operations – are in the final phases of the legislative
procedure.

\(^9\) Commission Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion
management.

\(^{10}\) Commission Regulation (EU) 2016/1719 establishing a guideline on forward capacity allocation.

\(^{11}\) Commission Regulation (EU) 2016/1388 of 17 August 2016 establishing a Network Code on Demand
Connection.

\(^{12}\) Commission Regulation (EU) 2016/1447 of 26 August 2016 establishing a network code on requirements
for grid connection of high-voltage direct current systems and direct current-connected power park
modules.

\(^{13}\) Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection
of generators.
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, with the Directive regulating the designation of DSOs, their tasks, and the option for Member States to designate closed distribution systems.

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

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

ii Gas Access Regulation

The Gas Access Regulation establishes the European Network of Transmission System Operators for Gas (ENTSO-G), 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, infra). In addition, it establishes the free and non-discriminatory access of third parties to gas transmission networks on the European natural gas markets, thereby enforcing the principle of free competition.

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

iii Network codes

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

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14 As established for the gas market by the Gas Access Regulation.
15 The development process for natural gas network codes is identical to that for electricity; however ENTSO-G is tasked with performing the stakeholder consultations and drafting of the network code based on the framework guidelines.
The network code on Capacity Allocation Mechanisms (CAM)\(^\text{16}\) was recast in March 2017, updating the previous regulation to include the offer of incremental capacity and removing provisions on tariffs that have been included in a separate network code. CAM regulates the principles of cooperation between TSOs in adjacent EU Member States, and the allocation of firm capacity. Allocation provisions are divided into allocation methodology, standard capacity products and capacity auction systems over different time frames. It furthermore regulates the bundling of cross-border capacity, incremental capacity, interruptible capacity and capacity booking platforms.

Gas Balancing in Transmission Networks\(^\text{17}\) sets out detailed provisions for a gas balancing system, trade notifications and allocations, operational balancing procedures, and on nomination and re-nomination procedures. The balancing procedures include provisions on short-term standardised products and the establishment of a trading platform for their procurement, as well as incentives for TSOs to undertake efficient balancing actions.

Congestion Management Procedures (CMP)\(^\text{18}\) are fundamentally guidelines addressing third-party access services concerning TSOs, the principles of capacity-allocation mechanisms and congestion management procedures, and their application in the event of contractual congestion, as well as setting out the technical information necessary for network users to gain effective access to the system.

Interoperability and Data Exchange (IO)\(^\text{19}\) regulates interconnection agreements, providing that adjacent TSOs mutually agree upon 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, as well as provisions for gas quality and odorisation.

Tariff Harmonisation\(^\text{20}\) aims to homogenise gas transmission tariffs within the European Union, promoting fair and objective tariffs, providing methodologies on reference prices, reserve prices, clearing price and payable price, provisions on reconciliation of revenue, pricing of bundled capacity and capacity at virtual interconnection points, consultation and publication requirements, and tariff principles for incremental capacity.

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

### iv Gas Security of Supply Regulation

The Gas Security of Supply Regulation\(^\text{21}\) aims to prevent a disruption of natural gas supply to the European Union and to ensure a coordinated response if necessary. It regulates the

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18 Annex 1 to the Gas Access Regulation.
responsibility for security of gas supply, the establishment of a Preventive Action Plan and an Emergency Plan by Member States, and the content of national and joint preventive action plans.

Two common standards have been established under the Gas Security of Supply Regulation: the infrastructure standard and the supply standard. The Regulation further provides for the enabling of bidirectional capacity in interconnectors, and the provision of a regular risk assessment by designated national authorities, as well as the establishment of emergency plans and crisis levels, union and regional emergency responses, an obligation for information exchange by Member States, and a monitoring obligation for the Commission.

The Regulation guarantees that all households (known as protected customers) are protected in a disruption event; however, under certain conditions Member States may include small and medium-sized enterprises and essential social services. The Gas Coordination Group is established to facilitate the coordination of measures concerning security of gas supply, which is chaired by the Commission and includes representatives of the Member States, ACER and ENTSO-G.

In February 2016, the Commission published its proposal for a recast Gas Security of Supply Regulation, which includes:

- the introduction of a 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;
- the introduction of a shift towards a regional approach in the design of security of supply measures and risk assessment;
- the introduction of transparency requirements for long-term gas contracts in particular;
- the improvement of coordination between Member States; and
- the reinforcement of cooperation with EU neighbours, including the Energy Community, in security of supply measures.

At the time of writing, the proposal is progressing through the ordinary legislative procedure.

V  PETROLEUM

Oil and Gas Licensing Directive

The Oil and Gas Licensing Directive\(^22\) sets out common rules that aim to ensure competitive and non-discriminatory access to third parties to prospect, explore and produce hydrocarbons within the territories of the Member States.

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

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

\(^{22}\) Directive 94/22/EC on the conditions for granting and using authorisations for the prospection, exploration and production of hydrocarbons.
Member States are obliged to submit information pertaining to the authorisation to be published in the Official Journal of the European Union. This information includes the duration of the authorisation, the specific area, and selection criteria. Furthermore, Member States are obliged to submit an annual report on the areas opened, authorisations granted, details of entities holding the authorisations and information regarding the reserves available in their territory.

ii Oil Stockholding Directive

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

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

VI TEN-E REGULATION

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

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

PCIs may benefit in a number of ways, including through:

- accelerated and more efficient permit granting procedures;
- improved regulatory treatment on the national level;
- streamlined environmental assessment procedures;
- increased public participation via consultation; and
- access to grants from the Connecting Europe Facility.

In 2015, a total of €650 million in grants was granted to 35 PCIs. Receiving PCI status furthermore increases the attractiveness to external investors.

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23 Directive 2009/119/EC imposing an obligation on Member States to maintain minimum stocks of crude oil or petroleum products.

An applicant project must meet a series of criteria to be considered a PCI, in that it has to:

a. have significant benefits for at least two Member States;

b. contribute to market integration and further competition;

c. enhance security of supply for the European Union; and

d. reduce CO2 emissions.

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

VII RENEWABLE ENERGY DIRECTIVE

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

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

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

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

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

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

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

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

VIII ENERGY EFFICIENCY DIRECTIVE

The Energy Efficiency Directive\textsuperscript{26} aims to promote energy efficiency across the European Union in order to meet the European Union 2020 goal of 20 per cent target on energy efficiency, thereby removing barriers that limit efficiency in the supply and use of energy.

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

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

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

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

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

IX DECARBONISATION

i Emissions Trading Directive

The European greenhouse gas emissions allowance trading scheme (Emissions Trading Scheme, ETS) was established by the Emissions Trading Directive\textsuperscript{27} with the aim of significantly reducing greenhouse gas emissions through a cap-and-trade scheme.

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

\begin{itemize}
  \item[26] Directive 2012/27/EU on energy efficiency.
  \item[27] Directive 2003/87/EC establishing a scheme for greenhouse gas emission allowance trading within the Community.
\end{itemize}
surrender and cancellation of allowances throughout the European Union; the validity of allowances; guidelines for monitoring and reporting of emissions; and verification of reports submitted by operators. Allowance allocation decisions are to be made available to the public, and Member States must establish allowance registries, and they are further subject to reporting obligations. The Commission is required to designate a central administrator that is to maintain an independent transaction log, recording the issue, transfer and cancellation of allowances.

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

X THE CARBON CAPTURE AND STORAGE (CCS) DIRECTIVE

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

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

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


XI ENERGY MARKETS

Following the global financial crisis of 2008/09, the European Union has adopted a number of legislative instruments to stabilise the financial markets, limit price volatility of commodities and ensure that markets have sufficient capital. It is not the aim of this chapter to discuss financial regulations; however, while not energy-specific, it should be kept in mind that the energy market is affected by European financial markets legislation.31

Along with the Third Energy Package and REMIT,32 this legislation has introduced additional obligations for energy markets including reporting obligations, transparency requirements, the treatment of certain types of energy or emissions allowances as financial instruments or derivatives, organisational requirements for markets, the introduction of new trading venues, the mandatory use of regulated markets for certain products and a clearing obligation for certain trades.

XII FURTHER PROPOSALS UNDER THE WINTER PACKAGE

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

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

XIII FUTURE DEVELOPMENTS

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

The European Union has already set mandatory targets to increase the share of renewable source energy in the European energy mix, which are in line with the target of

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the Paris Agreement. Following the ratification of the Paris Agreement, the Winter Package would appear to make 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 TEU following the result of the Brexit referendum in June 2016. This has started a two-year negotiation window for the EU and UK to agree on the terms of UK withdrawal and potentially the EU–UK cooperation mechanism. The UK government has given a clear indication for a ‘hard’ Brexit, whereby membership of the European Economic Area Agreement has been excluded. Notwithstanding the effects of Brexit on the UK energy sector, the regulatory landscape in the EU is likely to remain largely unchanged; however, certain issues may arise as part of the proceedings. These may include the adaptation of the ETS to account for the withdrawal of the EU’s second-largest emitter, as well as issues involving connection to the newly-established UK energy sector. The Brexit negotiations will doubtless be complex, and the exact nature of any possible effects on the EU energy sector remains unclear.
Chapter 2

OVERVIEW OF CENTRAL AND WEST AFRICA

Pascal Agboyibor, Bruno Gay, Doux Didier Boua and Gabin Gabas

I OVERVIEW

i Electricity sector

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

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

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

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

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

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

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

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4 The CEMAC is composed of six Member States: Cameroon, Chad, the Central African Republic, Equatorial Guinea, Gabon and the Republic of the Congo.
5 The ECCAS is composed of 11 Member States: Angola, Burundi, Cameroon, the Central African Republic, Chad, the Republic of the Congo, the Democratic Republic of the Congo, Gabon, Equatorial Guinea and São Tomé and Príncipe. It can be noted that, through its Decision No. 15/CEEAC/CCEG/XIV/09 dated 24 October 2009, the ECCAS adopted the Central African Regional Electricity Market Code. This code, however, does not yet seem to have been implemented by the Member States.
6 The ECOWAS is composed of 15 Member States: Benin, Burkina Faso, Cape Verde, Gambia, Ghana, Guinea, Guinea-Bissau, Ivory Coast, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leone and Togo.
7 The WAEMU is composed of eight Member States: Benin, Burkina Faso, Ivory Coast, Guinea-Bissau, Mali, Niger, Senegal and Togo.
8 The electricity sector is notably governed: in Benin, by the 2004 Agreement revising the Benin-Togo code of electricity and by Law No. 2006-16 dated 27 March 2007 establishing the code of electricity and complementing the Benin-Togo code of electricity; in Burkina Faso, by Law No. 053/2012/AN dated 17 December 2012 establishing the general regulation of the subsector of electricity and Decree No. 2014/636/PRES/PM/MMME/MEF dated 29 July 2014 establishing the closing conditions for public service delegation contracts, the granting conditions of licences and authorisations and conditions for the declaration of facilities in the subsector of electricity; in Cameroon, by Law No. 2011/022 dated 14 December 2011 governing the electricity sector and Decree of Implementation No. 2012/2806/PM dated 24 September 2012; in Chad, by Law No. 014/PR/99 dated 15 June 1999 concerning the production, transmission and distribution of electric energy and Decree No. 11/281/PR/PM dated 5 April 2011 electing the Société Nationale d’Électricité as public service concession holder for the electricity sector; in the Ivory Coast, by Law No. 2014/132 dated 24 March 2014 establishing the code of electricity, Decree No. 2014-291 dated 21 May 2014 relating to the terms and conditions applicable to concession agreements for the performance of electricity production, transmission, dispatching, importation, exportation, distribution and marketing activities; in the Democratic Republic of the Congo, by Law No. 2014/011 dated 17 June 2014 concerning the electricity sector; in Gabon, by Law No. 08/93 setting the legal status of the production, transport and distribution of drinking water resources and electric energy; in Guinea, by Law No. L/93/039/CTRN concerning the production, transmission and distribution of electric energy, as well as Decree No. D/2001/098/PRG/SGG dated 18 December 2001 establishing the reorganisation of the electricity sector during the transitory period; in Mali, by Order No. 00-019 dated 15 March 2000 establishing the organisation of the electricity sector; in Niger, by Law No. 2003-004 dated 31 January 2004 establishing the code of electricity and its Decree of
ii Oil and gas sector

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

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

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

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

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

II REGULATIONS

i National and regional regulators

Electricity sector

National regulatory authorities

Except for Guinea, all the states have legislation providing for the creation of a regulation authority in the electricity sector. Some of these national authorities may have only been set up very recently, or may even not be effective yet.

Among the recurring missions of the various national regulation authorities, one may highlight the following:

a monitoring that operators comply with the applicable regulations;
b intervening in the setting or approval of electricity tariffs;
c ensuring compliance with competition rules in relation to power production, transport and distribution;
d preserving customers' interests;


Guinea established a National Council for Power, a consultative body whose mission is to assist the minister in charge of energy on topics relating to energy policy.

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

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

As is the case in Chad.
promoting competition and private sector participation according to objective, transparent and non-discriminatory (e.g., third-party access to transmission networks and customers’ access to the power supply) conditions;

taking part in the awarding of contracts via the setting up of tendering processes;

proposing amendments to the state relating to both the institutional and regulatory frameworks; and

implementing dispute resolution mechanisms (such as conciliation or arbitration) between the electricity sector’s participants (between operators or between operators and customers).

Regional regulatory authorities

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

Oil and gas sector

National regulatory authorities

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

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

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

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

Regional regulatory authorities

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

ii Regulated activities

Electricity sector

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

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

Generally, the public service concession holder must comply with the following obligations:

a guarantee a permanent and continuous supply of electricity under the best pricing conditions;

b comply with the principles of equality of treatment and electricity market access; and

c ensure a satisfactory coverage of power supply across the country.

No. 96-669 dated 29 August 1996 establishing the petroleum code; in the Democratic Republic of the Congo by Law No. 15-012 dated 1 August 2015 establishing a general regime applicable to hydrocarbons; in Gabon, by Law No. 011/2014 dated 28 August 2014 regulating hydrocarbons; in Guinea, by Law No. L/2014/N°034/AN establishing the petroleum code; in Mali, by law No. 2015-035 dated 16 July 2015 establishing the organisation of exploration, production and transport of hydrocarbons; in Niger, by Law No. 2007-01 dated 31 January 2007 establishing the petroleum code; in the Republic of the Congo, by Law No. 28-2016 dated 12 October 2016 establishing the hydrocarbons code (at the time of writing, decrees implementing the code have not yet been published) and by Law No. 6-2001 dated 19 October 2001, modified by the order dated 1 March 2002, concerning the refining, import, export, transit, re-export, storage, massive export, distribution and sale of hydrocarbons and of derived products; in Senegal, by Law No. 98-05 dated 8 January 1998 establishing the petroleum code, Law No. 98-31 dated 14 April 1998 concerning the activities of importing, refining, storing, transporting and distributing hydrocarbons, and Law No. 2010-22 establishing the orientation of the biofuels sector, and Law No. 2011-529 dated 26 April 2011 setting the terms of use of the natural gas obtained from the wells of the national subsoil; and in Togo, by Law No. 99-003 dated 18 February 1999 establishing the hydrocarbons code in the Republic of Togo.

16 The West African Pipeline Authority (WAPA) in particular regulates the project operated by the West African Gas Pipeline Company Limited (WAPCo).

17 Importing electricity is sometimes also considered a public service.

18 Although the legislation of Cameroon, Mali, Niger, Senegal and Togo provides that the delegation of public service for electricity can only be established via concession agreements.

19 This is the case between Burkina Faso and Sonabel, for example.
The public service of electricity delegation is typically governed by a convention, including specifications, the purpose of which is to determine, in particular:

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

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

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

Oil and gas sector

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

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

21 For instance, in Benin, with the Société Nationale de Commercialisation des Produits Pétroliers (SONACOP), which is wholly owned by the state and acts in the procurement, storage, transport and marketing of refined products sectors; in Cameroon, with the Société Nationale de Raffinage (SONARA), which is 82 per cent controlled by the state and acts in the domestic retailing and importation of petroleum products, and the Société Camerounaise des Dépôts Pétroliers (SCDP), which is 51 per cent owned by the state and acts in the storage of oil products sector; in Central African Republic, with the Société Pétrolière Centrafricaine (PETROCA) and the Société Centrafricaine de Stockage de Produits Pétroliers (SOCASP), which is 51 per cent owned by the state; in Chad, with the Société des Hydrocarbures du Tchad, which is wholly owned by the state; in Ivory Coast, with the Société Nationale des Opérations Pétrières de Côte d’Ivoire (PETROCI), and the Société Ivoirienne de Raffinerie (SIR), which is 45.74 per cent owned by
Overview of Central and West Africa

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

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

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

**Distinction based on the subsector concerned**

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

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PETROCI and 1.54 per cent by the state and acts in the refining and importation of crude oil as well as the importation of refined products; and the Société de Gestion des Stocks de Sécurité (GESTOCI); in the Democratic Republic of the Congo, with the Congolaise des Hydrocarbures, which is wholly owned by the state; in Gabon, with the Gabon Oil Company (GOC), which is wholly owned by the state; the Société Gabonaise de Raffinage (SOGARA), which is 25 per cent owned by the state, which acts in the refining sector; and the Société d’Entreposage de Produits Pétroliers (SGEPP), which is 25 per cent owned by the state, and acts in the storage sector; in Guinea, with the Société Guinéenne de Pétroles, which is 7 per cent owned by the state; in Niger, with the Société Nigérienne des Produits Pétroliers (SONIDEP), which is a state-owned company; in the Republic of the Congo, with notably the Société Nationale des Pétroles du Congo (SNPC), which is wholly owned by the state; and the Congolaise de Raffinage (CORAF), which is wholly owned by SNPC; and in Senegal, with the Société des Pétroles du Sénégal (PETROSEN), which is wholly owned by the state; and the Société Africaine de Raffinage, which is 46 per cent owned by PETROSEN; and with the Sénégalaise de Stockage (SENSSTOCK), which is 66 per cent owned by PETROSEN.

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

Hydrocarbons rights and titles

Hydrocarbons titles are either exploration or exploitation titles. These titles are granted by the state through administrative acts (generally ministerial orders or presidential decrees) to companies that demonstrate the technical and financial capacities required to carry out the necessary petroleum operations.

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

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

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

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

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

- cover the perimeter of the hydrocarbons titles to which they refer (exploration title and, as the case may be, exploitation title);
- are concluded for the term of the exploration title (and, as the case may be, exploitation title to which they apply);

24 The term of exploitation titles ranges from 20 to 35 years depending on the applicable legislation. States also regulate prospecting activities, which are generally non-ground-disturbing and do not grant the holder the exclusive right to obtain an exploration or exploitation title. This chapter does not cover such prospecting authorisations.

25 Authorities competent for granting these titles may vary from one country to another. Exploration titles are generally granted by the minister in charge of hydrocarbons, and exploitation titles are granted by the president.

26 Remarkably, certain legislation (e.g., that of Niger and the Republic of the Congo) provides that exploration and exploitation titles can only be granted to companies specialising in the hydrocarbons sector. Other legislation sets forth additional capacity-related conditions with respect to companies acting as operators.

27 Both exploitation concessions and permits are exploitation titles, which derive from exploration permits. Exploitation concessions are not to be confused with the concession agreements that may attach to them.

28 Temporary authorisations to exploit are, for example, provided in the legislation of Benin, Cameroon, the Central African Republic and Ivory Coast.
set the minimum work obligations of the holder during the various phases of the project, as well as the conditions in which exploration and exploitation will be carried out;

provide for the stipulations relating to the transfer of rights and obligations deriving from the hydrocarbons titles;

set the tax and customs regime applicable to the holder;

set the obligation for the holder in respect of local content;\(^{29}\)

provide for the participation of the state or state-owned entities in all or part of the petroleum operations and, as the case may be, to the capital of the holder;\(^{30}\) and

may stipulate dispute resolution, and, in particular, arbitration provisions.

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

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

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

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

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

iii Ownership, participation and restrictions

Ownership

Electricity sector

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

\(^{29}\) Such as engaging by preference with local contractors or hiring local employees.

\(^{30}\) Legislation generally allows states to participate in hydrocarbons projects (via the acquisition of interests in the title or acquisition of shares in the company holding the title).

\(^{31}\) For instance, in Cameroon: Articles 7 and 8 of the petroleum code; in the Central African Republic: Article 7 of the petroleum code.

\(^{32}\) This is the case in particular in Benin, Cameroon, the Central African Republic, Chad, Guinea and the Republic of the Congo.

\(^{33}\) This is, for instance, the case in Cameroon in relation to economic and fiscal stabilisation; in Mali in relation to legal, economic and financial stabilisation; in Niger in relation to legal, economic and fiscal stabilisation; and in the Central African Republic in relation to ‘contractual conditions’.

\(^{34}\) This is the case in the Republic of the Congo, Mali and Senegal.
Overview of Central and West Africa

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

The states’ legislation also provides for specific rules applicable to the access or occupation of land required for carrying out the project, as well as the related rights and obligations of the holder within or outside the perimeter of its title.

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

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

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

Oil and gas sector
Assignment of the hydrocarbons title
States’ legislation provides rules relating to the transfer of hydrocarbons titles that vary depending on whether they relate to an exploration title or an exploitation title. The states provide for compulsory rules governing the transfer to third parties of hydrocarbons title held by the holder. Generally, such a transfer will have to be approved by the competent authority

\(^{35}\) Some states also refer to the continental shelf (Ivory Coast, for instance).

\(^{36}\) Cameroon is one of the only states that addresses this issue and, for instance, merely requires a declaration to the Regulation Agency in the event of changes in the concessionaire’s shareholding structure.
prior to the transfer. Legislation commonly provides that unapproved transfers are sanctioned (1) by the nullity of the act providing for such transfers; or (2) the possible withdrawal of the hydrocarbons title itself.

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

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

Besides the assignment of hydrocarbons titles themselves, legislation generally provides for the possibility to transfer all or part of the rights and obligations deriving from the hydrocarbons titles or oil agreements. Most of the time, these transfers are conditional on prior authorisation. In addition and similarly to what is provided for with regard to assignments of hydrocarbons titles, legislation generally provides that unapproved transfers of such rights and obligations may be sanctioned (1) by the nullity of the act providing for such transfers; and (2) the possible withdrawal of the hydrocarbons title, or the termination of the oil agreement from which these illegally transferred rights and obligations derive.

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

Market access restrictions

Electricity sector

Production

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

Transmission

Transmission is generally reserved by law for a single concessionaire,\(^{37}\) whether or not wholly state-owned. When this segment is opened to the private sector, it is fairly common that the

\(^{37}\) For example, the case with the Compagnie Électrique du Bénin (CEB) in Benin and Togo, the Société Nationale d’Électricité du Burkina (SONABEL) in Burkina Faso, the Société Nationale d’Électricité (SNE) in Chad, the Société d’Énergie et d’Eau du Gabon (SEEG) in Gabon or the Société Nationale d’Électricité (SENLEC) in Senegal.
national or incumbent company’s monopoly will remain. It can be further noted that the opening of this segment to the private sector is sometimes partially allowed in areas that are not covered by the national or incumbent company.  

_Distribution_

Access to the power distribution market varies from one state to another. However, even when legislation opens up this segment to the private sector (whether in whole or for areas that are not covered by the national or incumbent company), structural weaknesses of the market or exclusivity clauses in concession agreements do not always allow full implementation of such liberalisation. It is, therefore, common for _de facto_ monopolies to survive the reforms.  

_Oil and gas sector_

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

Lastly, certain legislation provides that the company holding an exploitation title is required to give priority to satisfying the needs of domestic consumption.

**III TRANSPORT AND DISTRIBUTION**

i _Vertical integration_

**Electricity sector**

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

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

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

39 This is, for instance, the case in Gabon, Benin and Togo, insofar as the perimeter concerned is not covered by the concession of the SEEG or the CEB.

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

41 Local and temporary delegation of the transmission activity is allowed, however.
ii  Transmission, transport and distribution access

Electricity sector

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

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

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

Oil and gas sector

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

Lastly, and subject to excess capacity being available, third parties may be granted the right to access transport infrastructure on a non-discriminatory basis.

iii  Terminalling, refining and processing

Oil and gas sector

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

iv  Tariffs and rates

Electricity sector

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

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

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

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

IV INTERCONNECTIONS AND REGIONAL POOLS

i Electricity sector

Within the states, electricity markets are underdeveloped. In Central and West Africa several bilateral or regional initiatives aim at developing a regional energy market supported by interconnections between states, and at implementing power pools.

Central Africa

Within the framework of the CEMAC, the Regional Economic Program (REP) implements various actions aimed at interconnecting electric grids between Member States and developing hydroelectric potential up to the total capacity of 25,000MW by the year 2025. This should enable the creation of an energy self-sufficient region with the additional opportunity to sell any excess production to Nigeria and other West African countries via a connection to the West African Power Pool (for more information about the WAPP, see below).

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

West Africa

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

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

43 The Regional Electricity Regulatory Authority (RERA).
V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

Although some states did adopt legislation promoting renewable energy sources,\(^{44}\) they generally do not have current practical implications as far as the energy sector is concerned.

VI THE YEAR IN REVIEW, CONCLUSIONS AND OUTLOOK

i Electricity sector

Current projects

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

In 2016 and early 2017, ongoing and newly announced projects include:

\(a\) thermal plants in Benin (400MW in Maria Gléta), Cameroon (345MW in Limbé) and Ivory Coast (700MW in San Pedro and 372MW in Songon);

\(b\) several hydroelectric dams in Benin (147MW in Adjarala), Cameroon (485MW in Kpep, 420MW in Nachtigal, 270MW in Song Dong and 211MW in Memvé’lele), the Central African Republic (200MW in Ndjaména), the Democratic Republic of Congo (240MW in Busanga) Gabon (70MW in Ngounié and 52MW in Woleu-Ntem), Guinea (300MW in Koutoutamba and 90MW in Fomi), the Ivory Coast (275MW in Soubré), Mali (140MW in Gouina), Niger (125MW in Kandadji) and Senegal (120MW in Sambangalou); as well as

\(c\) several hybrid solar-thermal power plants in Ivory Coast (700MW in Daoukro) and in Mali (80MW in Gaoua).

A thermal plant (100MW in Gorou Banda) was commissioned in Niger in early 2017.

Although their impact is on a smaller scale, states’ appetite for solar power projects keeps growing every year. Many solar power projects were announced, including: in Burkina Faso (33MW in Zagoutou and 11MW in Zano), in Cameroon (10MW in Guider and 10MW in Maroua), in Mali (33MW in Ségué) and in Senegal (30MW in Santhiou-Mekhène, 29MW in Medina Dakhar, 20MW in Malicounda). In that regard, it should be noted that the largest IPP solar plant in Sub-Saharan Africa (excluding South Africa) was commissioned in Senegal (20MW in Bokhol) in the course of the year.

Rural electrification

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

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\(^{44}\) As, for example, in Senegal, with Law No. 2010-21 dated 20 December 2010 relating to renewable energy and Law No. 2010-22 dated 15 December 2010 relating to the biofuel sector.
These agencies are typically supported by a rural electrification fund whose purpose is to help finance the connecting rural infrastructures. Such funds are financed by state allocations, lenders, gifts and bequests, loans, royalties, licence fees paid by operating companies and taxes paid by end users.

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

**Regional electricity market**

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

The implementation of the West African electricity market aims to integrate the ECOWAS national power systems into a single market, for the purpose of stimulating electricity exchanges between the Member States.

### ii Oil and gas sector

**New legislation**

**Republic of Congo**

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

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

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

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

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

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

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

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45 The Energy Facility is a co-financing instrument that was established in 2005 to support projects aimed at increasing access to sustainable and affordable energy services for the poor living in rural and peri-urban areas in African, Caribbean and Pacific (ACP) countries.

46 The code is available on the website of the Secretary General to the Government at the following address: www.sgg.cg/imageProvider.asp?private_resource=2588&fn=jo_es2016_08.pdf
Whereas the former legislation gave production-sharing contracts a pivotal role (while suggesting that other types of contracts could have been used), the code expressly provides that petroleum contracts are comprised of both production sharing and service contracts.

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

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

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

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

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

Lastly, petroleum contracts are approved (no longer ratified) by Parliament, but the code expressly mentions that such approval does not allow the parties to derogate from the code or its implementing instruments.

Projects based on local and regional initiatives

On a local basis

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

On a regional basis

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

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

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

John A Trenor

I INTRODUCTION

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

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

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

II LONG-TERM GAS SALES AND PURCHASE AGREEMENTS

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

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

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

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

i  Supply commitments and ‘take-or-pay’ obligations

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

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

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

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

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

ii  Flexibility rights

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

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4 Although there is no commonly adopted standard-form long-term GSPA, several organisations such as the Association of International Petroleum Negotiators offer a number of model contracts, including model gas supply agreements with price review clauses, that are influential in the oil and gas industry.

The flexibility terms – if any – can vary considerably by contract and whether the gas is supplied by pipeline or by LNG tankers, also known as LNG carriers. Where gas is supplied via pipeline, parties can agree to provide for yearly, seasonal, quarterly, monthly, daily or even hourly flexibility (or any combination thereof). Parties may also agree to provide buyers with the limited ability to reduce their take-or-pay volumes in a particular year (i.e., to reduce the minimum annual quantity). Other contracts offer the buyer no flexibility, requiring the buyer to take delivery of the same volume of gas each hour of every day of every year and providing no option to vary the minimum annual quantity. With respect to long-term LNG contracts, parties typically agree on a scheduled volume per shipment but may negotiate upward or downward flexibility, subject to logistical constraints such as cargo capacity, storage and capacity at the reliquefaction facility, etc. The parties can also agree to other flexibility regarding scheduling or destination, again depending on logistical constraints.

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

iii Contractual term
The term (i.e., the duration) of a long-term GSPA can vary widely. Many contracts provide for a term falling somewhere in the range of 10 to 30 years, with contractual terms of 20 or 25 years perhaps the most prevalent.6 Some contracts that have been agreed more recently have somewhat shorter terms, with 10 to 15 years becoming more common,7 and even shorter terms becoming prevalent for LNG sales.8 Some contracts may contain an express provision for incremental limited extension of the term for a number of years (either by agreement, or at the election of one party).

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

Given their duration, long-term GSPAs often do not set a fixed price but instead use a pricing formula pursuant to which the price may vary over time. One type of price formula commonly agreed sets forth a negotiated base price (P0), which is indexed to the prices for a basket of competing alternative fuels (often including oil products such as gasoil or heavy fuel oil, although some contracts have been priced by reference to wholesale electricity prices, coal and other indices). Under these formulae, the contract price varies as the prices of these alternative fuels vary.

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

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

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

v Price review clauses

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

vi Dispute resolution

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

III THE RECENT INCREASE IN GAS PRICING DISPUTES

As noted above, the price for gas being bought and sold under these long-term GSPAs has often been set via a price formula in which an agreed base price ($P_0$) is indexed to the published market prices for a basket of competing alternative fuels (often including oil-based fuels). This approach to pricing is said to reflect the relationship between natural gas and oil products, including the fact that natural gas prices in end-user markets have traditionally been priced by reference to the price of competing oil-based fuels.

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

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

Buyers reacted in a number of ways. Some sought to minimise their offtake under their existing contracts to the extent permissible under their take-or-pay obligations. 11 And some commenced price reviews, seeking a variety of revisions to reduce the contract

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

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

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

IV THE ANATOMY OF A GAS PRICING DISPUTE

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

i Process and procedure

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

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

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

ii Triggering a revision

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

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

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

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

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

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

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

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

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

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

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12 See Section II.v, supra.
13 See Section II.v, supra.
e whether the asserted change in circumstances was within the control of one or both of the parties (such an argument may potentially arise where a party arguably is in a position to bring about or to act to prevent the change);
f what weight should be given to any mandatory considerations or benchmarks that the parties must take into account, and how those mandatory considerations or benchmarks are to be assessed in practice;
g what market (e.g., the gas markets in which country or countries) and what market level (e.g., the import level, wholesale level, end-user level, etc.) should be considered when assessing the asserted change in circumstances;
h whether the asserted change in circumstances is in fact already reflected in the existing price; and
i whether the asserted change in circumstances ‘justifies’ a revision of the contract price.

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

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

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

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

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

The adjustment phase can potentially give rise to a number of disputes between the parties, including:
a what the stipulated standard actually means (for example, what is required for a proposed revision to be considered fair and equitable, as in the clause in the Atlantic LNG case);
b how any specified benchmarks or other mandatory considerations should be taken into account (for example, what market indices or other sources of data relating to import prices should be considered), what weight should be given to these factors and in which market or at which market levels these considerations should be assessed;
what the permissible scope of revision is and what limitations there are regarding the revision (for example, some price review clauses state that only revisions to the contract price provisions are permitted in a price review, whereas some occasionally provide that other provisions of the contract may also be revised; parties may also disagree as to whether the particular contract permits a complete replacement of the existing price formula or only adjustments); to what extent other provisions of the contract (for example, regarding volume, flexibility, security of supply, term of the contract, etc.) must be taken into account in determining what adjustment to the contract price provisions should be made; and whether, taking into account the determinations made with respect to the issues identified above, the proposed revision actually satisfies the stipulated standard and appropriately restores the balance of the parties’ original bargain.

iv Consequences of gas price disputes progressing to arbitration

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

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

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

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

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

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

V THE FUTURE OF GAS PRICE DISPUTE RESOLUTION

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

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

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

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

None of these alternative mechanisms seems to have found much favour in the industry to date. Although it remains uncertain whether any of these (or other) alternative dispute mechanisms will gain much traction in the future, at present, they seem unlikely to
significantly displace traditional arbitration of gas price review disputes. This suggests that many parties to long-term GSPAs continue to be attracted to the benefits of traditional arbitration over these potential alternatives. And, while traditional arbitration continues to play a central role, it remains for the participants in that process to focus on ways to ensure that it results in the most effective, efficient, and satisfactory means possible to resolve the inevitable price disputes that continue to arise under long-term GSPAs.
Although 2015 was a monumental year in the history of the world’s efforts to address climate change, with the signing of the Paris Agreement to reduce greenhouse gas (GHG) emissions globally, 2016 brought a more mixed outlook with the US election, signalling a domestic reversal of course on climate issues (that was realised in the spring of 2017).

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

Instead, advocates for climate change action are shifting their attention to the pursuit of a fundamentally new course of action above and beyond the established commitments to reduce GHGs. Increasingly, they are pursuing economic damages, compensation and other remedies directly against energy producers, not only for current and future GHG emissions, but also for an historic accounting of emissions spanning decades, and in some cases centuries. This new wave of climate change initiatives takes several forms, which are described below. However, all these efforts share certain commonalities and challenges in their pursuit of what these groups label ‘climate change justice’ and constitute the beginning of a new era of climate change advocacy in which remedies are sought from energy companies directly. Ultimately, these actions face numerous legal challenges and likely insurmountable hurdles before courts and other bodies, but at the same time various groups have indicated that they are not deterred or discouraged from advancing new push-the-envelope arguments in pursuit of such claims, which will be an increasing focus in 2017 and beyond.

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

For more than a generation, proponents of climate change action promoted capping the increase in the planet’s temperature by a certain amount (usually 2°C or less) by limiting emissions of the GHGs they attribute to the increases. The focus to date has been on regulators as the primary actors: specifically, pursuing various government agencies at national, provincial and local levels to enact regulations and laws to reduce GHG emissions from sectors they oversee by either imposing energy efficiency requirements on certain sectors

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(and thus reducing GHG emissions) or capping GHG emissions to some extent by source or region. The best known examples of such programmes are various fuel efficiency standards for motor vehicles in the US and elsewhere, Europe’s EU ETS cap-and-trade system, California’s AB 32 cap-and-trade programme and a cap-and-trade programme in the northeast United States called the Regional Greenhouse Gas Initiative (RGGI).

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

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

The 2016 US presidential election, however, could have significant repercussions for the implementation of the Paris Agreement. Under President Obama, the US took aggressive regulatory action to address climate change, including programmes to reduce GHG emissions from motor vehicles, power plants and the oil and gas sector. In particular, the ‘Clean Power Plan,’ which required significant emissions reductions from fossil fuel-fired power plants, is viewed as a key component of any US plan to implement the Paris Agreement. The INDC submitted by the US calls for a 26–28 per cent reduction by 2025. After taking office, President Trump announced plans to review and potentially rescind the Clean Power Plan and other climate change regulations issued by the Obama administration. Further, President Trump announced his intent to withdraw from the Paris Agreement. Such actions would impose a significant roadblock on the successful implementation of the Paris Agreement’s GHG emission reduction goals.

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

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

II THE EVOLVING FOCUS ON ACCOUNTABILITY FOR CLIMATE CHANGE

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

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

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

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

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

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

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

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

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

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

In accordance with the measures set out by the National Energy Security Policy and Strategy,² the Angolan government is committed to reforming the energy industry. With this intention, among other measures, in the electricity industry the government is mainly focusing on:

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

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

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

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2 Put into force by Presidential Decree No. 256/11 of 29 September.
The Angolan electricity system is divided into two separate segments:

a. the Public Electricity System (PES), which encompasses the Electricity National Transmission Network (NTN)\(^3\) and all generation and distribution infrastructures tied to the NTN; and

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

The commercial relations between the aforementioned agents is governed by the General Electricity Law\(^4\) and the Commercial Relationships Regulation.\(^5\)

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

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

In turn, HV\(^6\) distributors sell electricity to medium-voltage (MV) distributors who then sell electricity to low-voltage (LV) distributors, who in turn sell the electric power to the customers, therefore acting as suppliers.

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

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

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

i The regulators
The IRSEA, created by Decree No. 4/02 of 12 March and its governance, currently governed by the provisions of Presidential Decree No. 208/14 of 18 August, is the Angolan regulatory authority in the electricity sector, a public institute with management, administrative and financial independence, responsible for regulating the activities of generation, transmission, distribution and sale of electricity in the PES.

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

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

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

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

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

The concession for exploration and production, after the public tender procedure, is granted by concession decree, issued by the Angolan government, awarding the national concessionaire Sonangol 8 the right to develop a specific oil concession.

All successful companies that wish to explore for and produce oil or natural gas in Angola have to form an association with Sonangol in one of three possible ways: incorporation of a joint company, a consortium agreement or a production-sharing agreement 9. The concession agreement must subsequently be signed by the parties within 30 days of the publication of the concession decree.

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

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

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

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

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

**Construction of electric facilities**

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

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

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

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

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

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

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10 Meaning generation, transmission or distribution facilities.
11 At present, the Ministry of Energy and Water.
In certain cases – mostly construction of small facilities that do not interfere with public domain terrains or assets – there may be an exemption from obtaining the establishment licence, or both the establishment and exploration licences.

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

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

**Concession agreements**

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

**Licences**

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

**Generation**

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

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

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

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

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

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

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

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

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

**Distribution**

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

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

**Supply**

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

### iii Ownership and market access restrictions

**Oil and gas**

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

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14 Or 120 days, in the case of a hydropower generation unit.
15 Except for settlements with more than 50,000 inhabitants or networks with a maximum peak power required by the system equal or greater than 4MW, in which case the right is awarded via concession agreement, under the terms of Article 5 of the Electric Power Distribution Regulation (Decree No. 45/01 of 13 July).
companies may become associates of Sonangol, and if the association is made via incorporation of a joint company, or via consortium agreement, Sonangol is legally required to hold an equity participation greater than 50 per cent.  

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

Electricity

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

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

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

iv Transfers of control and assignments

Oil and gas

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

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

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

Electricity

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

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

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

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

Oil and gas

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

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

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

The activity of overseeing the oil-derived products system\(^\text{18}\) is subject to a legal unbundling regime.

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

In 2007, an agreement was made to develop the Angola LNG Project,\(^\text{19}\) where Sonagas is a partner. Angola LNG operates one of the world’s most advanced liquefied natural gas (LNG) processing facilities in Soyo, in Zaire province, under a consortium of companies that includes Sonangol (22.8 per cent), and subsidiaries of Chevron (36.4 per cent), Total (13.6 per cent), BP (13.6 per cent) and ENI (13.6 per cent).

Electricity

In the electricity industry, the main public players are, after the formal unbundling of the public entities of the electricity sector effected by Presidential Decree No. 305/14 of 20 November, Rede Nacional de Transporte de Electricidade, EP (RNT) (which is responsible for managing the NTN, for the global management of the system, offtake and acting as market operator), Empresa Pública de Produção de Electricidade, EP (PRODEL) (which is responsible for the operation, under a public service regime, of publicly owned power generation facilities) and Empresa Nacional de Distribuição de Electricidade, EP (ENDE), whose sole purpose is the distribution and supply of electricity in the PES.

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\(^{18}\) Currently developed by Sonangol Logística, EP.

\(^{19}\) More information about this project can be found at www.angolalng.com.
This reorganisation stemmed from the National Energy Security Policy and Strategy, whereby the government has approved an ambitious reform plan for the electricity sector, which foresees provision of access to electricity for between 50 and 60 per cent of the population by 2025.20 As part of the reform, the government envisaged:

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

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

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

**ii Transmission/transportation and distribution access**

**Oil and gas**

Under the Law for the Transport and Storage of Oil and Natural Gas,21 operators of oil and gas pipelines have an exclusive right to develop these infrastructures.

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

**Electricity**

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

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

The Networks Access Regulation acknowledges the network access rights of:

- entities that are tied to the PES and hold concession agreements or licences to generate electric power under the terms of the Electric Power Generation Regulation;
- entities that are not tied to the PES and hold a concession agreement or a licence to generate electric power;
- tied customers under the terms of the Electric Power Supply Regulation;
- non-tied customers who are recognised as such under the Commercial Relations Regulation; and

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20 Today, only around 30 per cent of the Angolan population has access to electricity.
21 Enacted by Law No. 26/12 of 22 August.
e self-producers or producers for private supply who intend to exercise their right of providing electric power through access to PES networks, as well as the entities that are supplied by these.

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

According to the Commercial Relations Regulation, the NTN concessionaire is responsible for operating and maintaining the NTN, managing the national electric system and acting as a commercial agent.\(^\text{22}\) Also, the commercial relations between non-tied agents and the PES are centralised in the NTN concessionaire.

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

### iii Terminalling, processing and treatment

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

Investment, however, has been limited (the main investment in the industry is the Angola LNG project),\(^\text{23}\) mainly because of great legal and regulatory uncertainty.\(^\text{24}\) To address these uncertainties, Presidential Decree No. 256/11 of 29 September sets the development of the legal and regulatory framework for these activities as a primary goal for the strategic orientation of the oil and natural gas industries.

Recent developments have been made with the publication in 2012 of the Law for the Transport and Storage of Oil and Natural Gas. It is a first step, but the natural gas industry is in great need of regulatory progress to provide certainty and clarity to the development of activities such as terminalling, processing and treatment of natural gas, as well as access conditions by third parties to LNG facilities.

### iv Rates

Rates for transmission and distribution of electricity are established in accordance with the Tariffs Regulation,\(^\text{25}\) put into force by the IRSEA. Rates are uniform for the entire country, the application of different tariffs being prohibited for customers in the same tariff category. The IRSEA sets the maximum tariffs and hence the maximum prices for the provision of transmission or distribution services.

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

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


\(^{24}\) An example is the fact that there is as yet no concession model specific to natural gas exploration and production.

\(^{25}\) Presidential Decree No. 4/11 of 6 January.
The calculation of the allowed revenues of NTN transmission concessionaires includes:

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

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

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

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

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

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

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

### Security and technology restrictions

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

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

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

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

i Contracts for sale of energy

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

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

ii Energy market rules and regulation

Only the entity in charge of overseeing the oil-derived products market (Sonangol Logística) is entitled to import oil-derived products to the Angolan market. This entity preferentially buys its oil-derived products from Refinaria de Luanda (a refinery operating under a special regime). In addition, the entity in charge of overseeing the oil-derived products market is committed to the role of last-resort supplier of oil-derived products, thus having the obligation to provide oil-derived products to retail suppliers at the price set administratively by the IRDP.

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

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

The Angolan government considers renewable energies to be a key element in the development of the country’s electric system, particularly in rural areas. The country has high potential in terms of renewable resources, mainly in terms of hydro and solar power. Solar power will play an important role in providing electricity to rural areas, while large hydropower projects are intended to be connected to the NTN supplying the PES. The country is also undertaking a wind power study to ascertain the potential of this energy source.

The electric power industry in Angola is urgently in need of major financial investment in the area of power generation. As a result, Angola is now seeking to create attractive conditions for private investors to participate in the development of the electric power industry. This goal is now expressly set out in the reformed General Electricity Law, which states that ‘temporary economic advantages’ may be granted to renewable energy promoters.

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

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

For smaller projects, the use of feed-in tariffs will be the main mechanism of remuneration for generation capacity in isolated systems (under 10MW).
Presidential Decree No. 88/13 of 14 June recently established the Strategic Plan for New Environmental Technologies, which is divided into two perspectives, a transversal and a sectoral perspective. The governmental body in charge of implementing this project is the General Directorate for Environmental Technologies.

The transversal perspective aims essentially to promote, disseminate, foster and raise the population’s awareness regarding the use of environmental technologies in Angola, mainly by (1) developing information campaigns using social media, (2) implementing information campaigns in schools and local communities, (3) creating a platform to share information between entities related to the environmental technologies industries, and (4) promoting the country’s adherence to an international sustainability index.

The sectoral perspective focuses on promoting and implementing tailored measures and actions according to economic sector, including specific programmes for the following sectors: (1) real estate and construction, (2) agriculture and forestry, (3) industry, (4) energy and water, (5) oil and (6) transportation.

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

ii Technological developments

During 2013, the government committed to successfully complete a pilot project for solar power villages – the Aldeia Solar de Cabiri. This project is being financed by Sonangol, which invested around US$30 million, and aims to test a solar village concept that could be implemented throughout the country, especially in rural areas. The project was inaugurated in 2014.

By the end of 2013, the Angolan authorities had foreseen that the construction of the first wind farm in Angola would begin in the near future, after the wind studies were completed. Located in the municipality of Tômbwa, the wind farm will be developed under a PPP regime and will add 100MW to the country’s installed capacity.

The government approved a series of agreements regarding the construction and development of generation, transportation and distribution of electric power, namely a generation project in the city of Malanje26 and the construction of transportation grids between Cambambe and Catete, and Cambambe and Gabela.27

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

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

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26 Approved by Presidential Order No. 57/13 of 26 June.
27 Approved by Presidential Order No. 49/13 of 15 May.
VI THE YEAR IN REVIEW

The main issue the Angolan energy market faces continues to be low oil prices. This significant change in prices has put downward pressure on Sonangol’s financial prospects, as well as on the Angolan economy at large, which has seen a low rate of growth relative to the boom years of the past decade.

However, 2016 has seen a slight improvement in oil prices and new significant discoveries of oil and natural gas, which has somewhat alleviated the country’s economic situation. Throughout most of 2016, Angola has also become the largest oil producer in the African continent.

Nevertheless, Presidential Decree No. 109/16 has determined that:

a Sonangol would be the only awarding entity of concessions in the oil and gas sector;
b a government agency (the Oil Sector Agency) has been created to regulate the oil and gas sector; and
c Sonangol’s equity holdings (including participations in upstream oil concessionaires) shall be transferred out of the company and supervised by a new government agency (the Council for the Monitoring of the Oil Sector).

The aforementioned decisions have yet to be regulated (and are thus not in force), but it is public knowledge that Sonangol’s organic and governance restructuring is currently ongoing.

VII CONCLUSIONS AND OUTLOOK

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

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

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

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

Despite recent economic headwinds, the country has all the conditions to create a sustainable and prosperous energy industry. Its economy is steadily growing and the country is rich in natural resources. Now, it needs to create attractive conditions for new investors, and a business environment that inspires trust and security in its players.
Chapter 6

AUSTRALIA

*Clare Pope, Samantha Smart, Fiona Meaton and Leah O’Connell*

I OVERVIEW

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

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

Within WA, the ‘on grid’ energy market has three main regulators, which seek to ensure the energy market operates in a competitive, efficient, fair and commercial manner. These regulators are: the Independent Market Operator (IMO), which is performed by the Australian Energy Market Operator (AEMO); the Economic Regulation Authority (ERA); and the Clean Energy Regulator (CER). However, the WA network regulator’s role is set to shift from the ERA to the Australian Energy Regulator (AER) from 2018, pending legislative approval and other regulatory processes.

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

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

- approving access arrangements for the SWIS, which set out the price, terms and conditions on which Western Power (as network owner) can charge generators and customers to access the SWIS transmission and distribution services;
- administering the licensing regime, which involves issuing licences to entities generating, transmitting, distributing or retailing electricity, monitoring and enforcing compliance with licence conditions and approving customer protection measures; and

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monitoring the effectiveness of the market and reporting to the Minister for Energy about the behaviour of participants in the wholesale energy market (WEM) (the market where retailers buy electricity from generators) to make sure that they are complying with market rules.3

In 2014, the Minister for Energy oversaw the Electricity Market Review (the 2014 Review), which was designed to assess the current industry structure, regulatory arrangements and options for reform. The overarching objectives of the 2014 Review were to reduce the cost of production and supply of electricity (without compromising safe and reliable supply) as well as to reduce government exposure to energy market risks. Following the outcome of the 2014 Review, the government has set out to facilitate long-term stability in the electricity industry and encourage continued investment from large private-sector participants.4

Natural gas and coal-fired power stations remain the major source of electricity generation capacity in WA; however, the abundance of solar and wind energy throughout WA, and the continued improvement in the technological efficiency of renewable energy as well as the increase in providers of battery storage to support the reliability of renewable energy, provides the perfect platform for expanding the utilisation of alternative forms of energy. In fact, with 200,000 solar arrays currently installed, the sheer volume of rooftop solar capacity in WA is such that solar power already comprises the state’s de facto largest power station.5 As such, this chapter will focus on the energy regulation of renewable electricity generation facilities including solar, wind and battery storage.

II REGULATION

i The regulators

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

The ERA is established under the Economic Regulation Authority Act 2003 (WA) as an independent statutory authority designed to oversee the energy industry in WA and ensure that all parties abide by the relevant regulations. It issues licences to providers of various sources of energy, including electricity. In addition, the ERA monitors and publicly reports on industry performance, including the WEM; taking enforcement action when required. It also

has authority through various codes\(^7\) 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.\(^8\)

The Clean Energy Regulator Act 2011 (Cth) established the CER, a non-corporate Commonwealth entity for the purposes of the Public Governance, Performance and Accountability Act 2013 (Cth). As an independent statutory authority, the CER is comprised of the chair and members, who set the ‘strategic direction’\(^9\) 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.\(^10\) Accordingly, the CER has administrative responsibilities for the National Greenhouse and Energy Reporting Scheme (NGERS) under the National Greenhouse and Energy Reporting Act 2007, the Emissions Reduction Fund (ERF) under the Carbon Credits (Carbon Farming Initiative) Act 2011, the Renewable Energy Target (RET) under the Renewable Energy (Electricity) Act 2000, and the Australian National Registry of Emissions Units under the Australian National Registry of Emissions Units Act 2011.\(^11\)

**ii Regulated activities**

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

- construct or operate generating works;
- construct or operate a transmission system of a voltage of 66kV or higher;
- construct or operate a distribution system of a voltage of less than 66kV;
- sell electricity to customers; or
- construct or operate any combination of generation, transmission, distribution and retail activities for the purpose of supplying electricity to customers other than through the SWIS.\(^12\)

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

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

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10 Note 7, supra.
12 Electricity Industry Act 2004 (WA) Section 4; Economic Regulation Authority, Licence Application Guidelines and Form (November 2016), 2.
Where a licence application is made to the ERA in the form prescribed by the EI Act, the ERA must, within 90 days, grant or renew the licence or approve the transfer of a licence if it is satisfied that the applicant has, and is likely to retain, the financial and technical resources to undertake the activities authorised by the licence. When exercising this power, the ERA is required to consider the overall public interest, including but not limited to considerations involving the environment, social welfare and equity, economic and regional development, and the interests of customers generally.13

iii Ownership and market access restrictions

The Electricity Networks Access Code 2004 (the Access Code) is established under the EI Act and provides the framework for the independent regulation of certain electricity networks in WA.14 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.15 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:

a  the ERA, users and applicants to understand how the service provider established the proposed arrangement; and

b  the ERA to form an opinion as to whether the proposed access arrangement complies with the Access Code.16

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

iv Transfers of control and assignments

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

The ACCC has previously expressed concerns about the accumulation of market power through merger activity in the electricity sector, as well as the potential for anticompetitive conduct to ensue from the vertically integrated structures.17

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13 Ibid. Section 8(5).
14 Economic Regulation Authority, Guidelines for Access Arrangement Information (06 December 2010), 1.
15 Electricity Networks Access Code 2004 (WA) Section 2.1.
16 Electricity Networks Access Code 2004 (WA) Section 4.1, Section 4.48.
Those investors who are either based overseas or owned by a foreign entity must apply to the Foreign Investment Review Board (FIRB) for approval from the Federal Treasurer where they are seeking to acquire a ‘substantial interest’ in an Australian company (i.e., 20 per cent or more), assets of an Australian business or Australian land. The acquisition of electricity generation or distribution assets in WA by foreign persons and companies is likely to trigger a requirement for FIRB approval. Once FIRB is notified, the board will consider the proposed transaction and assess whether it is against the ‘national interest’. New requirements introduced in 2016 allow FIRB to consult with other government departments to determine whether the proposed transaction is within the national interest. The Australian Taxation Office and the ACCC are among the departments that have been actively assessing foreign investment proposals.\(^\text{18}\)

On the recommendation of FIRB, the federal Treasury may then issue a notice of no objection or, where the transaction is against the national interest, disallow the proposed transaction, or impose conditions on how it may be conducted.\(^\text{19}\) The FIRB approval process generally takes 40 days from the time the application is made; however, FIRB may extend this period for complex applications.

### III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

**i Vertical integration and unbundling**

There is a significant degree of vertical integration in WA with Synergy, a state-owned corporation, owning or controlling the majority of generating plants on the SWIS while also supplying over half of the state’s consumable load.\(^\text{20}\) Western Power, as another state-owned entity, then owns and operates the distribution network.

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

**ii Transmission/transportation and distribution access**

Pursuant to Chapter 12 of the Access Code, Western Power sets the technical rules for the SWIS in terms of transmission and distribution. These rules establish various performance and technical requirements relating to the power transmission and distribution systems.\(^\text{21}\) As a network provider, Western Power is responsible for approving the connection of new ‘embedded’ generation systems to the SWIS. A system can only be connected once all of the applicable connection eligibility criteria have been met, as a means of ensuring that the quality and reliability of supply is of an appropriate standard. The connection of new generation systems may also be subject to the completion of overall network upgrades or the installation of new infrastructure to ensure network capacity is large enough to service

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18 Australian Financial Review, ‘ATO to test national interest’ (1 April 2016).
19 Foreign Acquisitions and Takeovers Act 1975 (Cth) Section 17.
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.22

Similarly, Horizon Power sets the technical rules for the NWIS and non-interconnected systems in the north of WA. Renewable electricity generators seeking to distribute their electricity through the NWIS are required to complete a Renewable Energy Electrical System Connection Application Form. This application allows Horizon Power to assess whether the facilities meet the technical requirements and provides an opportunity for electricity generators to participate in Horizon Power’s Renewable Energy Buyback Offer (discussed below). If the application is accepted, it forms the basis of the contractual relationship between Horizon Power and the generator.23

iii Rates

Pursuant to the Electricity Industry (Licensing Conditions) 2005 (the Electricity Licensing Conditions), WA government-owned retailers must offer eligible customers a buy-back scheme. This ensures that residents, schools and non-profit organisations with renewable energy systems can sell their excess energy to Synergy (a state-owned enterprise that sells electricity to retail customers in the SWIS) and Horizon Power. Subject to specific requirements, the retailers establish their own terms and conditions (including rates) for buying excess energy and are responsible for running the Renewable Energy Buyback Scheme (REBS). The objective of the REBS is to provide eligible customers who own renewable ‘systems’ with a framework to sell the energy that their systems export and to ensure owners receive ‘fair and reasonable’ terms, conditions and rates for exported energy.24

The Electricity Licensing Conditions define an eligible customer as:

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

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

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

- the wholesale cost of electricity for the retailer;
- line-loss reductions provided by distributed renewable energy;
- peak reductions provided by distributed renewable energy;
- capacity benefits provided by renewable energy; and
- the costs to retailers in running REBS.25

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

iv Security and technology restrictions

As a general principle, all primary equipment on the transmission and distribution system must be protected so that if an equipment fault occurs, the faulted item is automatically removed from service by circuit breakers or fuses. Protection systems must be designed so that, if there is a fault, unnecessary equipment damage is avoided and any reduction in terms of power transfer capability or level of service to users is minimised. The scale and changing nature of electricity networks now dictates that security is of greater significance. The roles of key electricity sector stakeholders are changing with a gradual shift toward a shared responsibility for network security, with customers becoming generators that use distributed generation technologies, and vendors assuming new responsibilities to provide advanced technologies as well as their own security mechanisms. With these changes, all stakeholders are becoming responsible for ensuring the continued overall security and resilience of the broader grid, including through:

a facilitating public–private partnerships to accelerate cybersecurity initiatives for the grid of the 21st century;

b 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;

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.

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

IV ENERGY MARKETS

i Development of energy markets

The WEM is a capacity market, with each retailer required to acquire capacity credits from the AEMO, or generators directly, to match their individual capacity requirements. These capacity requirements are based on estimates made by the AEMO in relation to the overall

26 Note 20, supra, at 2.9.1.
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.28

After determining the amount of reserve capacity required, the AEMO places obligations on market customers (i.e., retailers) to purchase capacity credits equivalent to their forecast contribution to peak demand. Those supplying electricity into the network earn ‘capacity credits’ by providing capacity to the system and, where that generation arises from renewable sources, can also earn Renewable Energy Certificates (RECs), which is the general term used to cover small-scale technology certificates and large-scale generation certificates. These are created in the CER’s REC Registry to be bought, sold, traded or surrendered. Commonly referred to as ‘green products’, they can be bought by customers along with the electricity as part of a bundled power purchase arrangement so that customers can use them to meet their own obligations to surrender RECs or sold to the AEMO through a capacity auction.29

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

ii Energy market rules and regulation
The structure and processes that constitute the WEM in WA are established through the WEM Rules. The WEM Rules were developed by the Office of Energy (which has since become the Public Utilities Office), with substantial support from a number of expert teams comprising representatives from industry and government. The WEM Rules detail the roles and functions of the AEMO (in its role as the IMO), System Management and other governance bodies, and guide the operation of the market including the trading and dispatch of energy and settlement.30

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

Bilateral contracts are agreements formed between wholesale market suppliers and wholesale market consumers (i.e., retailers and directly connected loads) for the provision of energy and serve to provide the holders with certainty over their settlement position with

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respect to that transaction. Once a bilateral contract submission is accepted, the energy is 'scheduled' and the ensuing demand forecast. The AEMO report allows market participants to revise their bilateral contract positions.\footnote{Independent Market Operator, Wholesale Electricity Market Design Summary (24 October 2012), https://www.aemo.com.au/-/media/Files/PDF/wem-design-summary-v1.4-24-october-2012.pdf.}

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

iv Market developments

A number of market developments are currently being considered and implemented via the Electricity Market Review, which was launched by the former Minister for Energy on 24 March 2015. Having identified the urgent need to address the problem of high and increasing costs of electricity services, detailed industry and energy market reform plans are now being implemented by the state government.

The key reforms include:

a Network regulation: this will look at transferring regulation of the Western Power network, including: price, connection and access, from the WA regime to be regulated under the National Electricity Law and National Electricity Rules. This will mean that WA operates under the same rules and regulations as the NEM. The proposed time frame to transfer regulation has not been achieved; however, it is expected to come into effect in 2018, pending legislative approvals.

b Institutional arrangements: this involves seven broad projects including investigating the merits of replacing the five Market Objectives with the singular National Electricity Objective, replacing the Western Australian Energy Disputes Arbitrator and Western Australian Energy Disputes Board with more cost-efficient dispute resolution bodies and procedures, and establishing a WA reliability panel, which is expected to formally commence in 2018. System management functions and market operation functions have already been transferred to the Australian Energy Market Operator and the new market rule change committee has been established, with the appointment of the first initial panel members in January 2017.

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

d Wholesale electricity market improvements: this involves two broad projects: reform to the Reserve Capacity Mechanism to address the manner in which the capacity price and volume is determined; and reforms to existing energy market operations and processes, which were announced in July 2016. The reforms to energy market operations and processes include introducing security-constrained dispatch, a later gate closure period and a shorter dispatch cycle, facility bidding and the development of co-optimised energy ancillary services.\footnote{Department of Finance, Electricity Market Review – Phase 2 (27 April 2017), https://www.finance.wa.gov.au/cms/Public_Utllities_Office/Electricity_Market_Review/Electricity_Market_Review_-_Phase_2.aspx.}
The long-term success of these reforms, measured by their ability to reduce energy prices, as well as the viability of these reforms long term, is something that will be closely scrutinised in the years to come.

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

The reforms included:

- a transitional arrangements to reduce capacity payments to power stations and demand-side management (DSM) providers because of current levels of excess capacity;
- b the introduction of an ‘auction’ by 2021, at the latest, to achieve efficient levels of electricity capacity in the market;
- c updated requirements for DSM providers so that services are more readily able to be called upon, and therefore more effective for the market; and
- d improved incentives to maintain power stations to ensure they are ready to supply electricity immediately, as required.

The reforms that will be implemented, together with significant reductions in costs of the electricity businesses over the coming years, will go towards fixing the problem of surplus energy within the SWIS going to waste. Accordingly, in the interests of removing excess capacity, it is proposed that Synergy will also reduce its plant generation capacity by 380MW by 1 October 2018.33

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

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

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

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

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

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

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

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

The RET has already been largely responsible for a growth in large-scale wind and solar photovoltaic projects. Similarly, the Australian Renewable Energy Agency (ARENA), established by the federal government in 2012, and the Clean Energy Finance Corporation (CEFC), function to improve the competitiveness of renewable energy technologies and increase the supply of renewable energy in Australia.

ARENA has an $8 million budget to invest in supporting renewable energy projects until the year 2022 to:

a. fund renewable energy projects;

b. support research and development activities; and

c. support activities that facilitate the capture and sharing of knowledge.

In September 2016, ARENA announced funding to construct 12 new large-scale solar photovoltaic plants across Australia. Similarly, the CEFC intends to mobilise capital


35 Ibid.
investment in renewable energy in Australia by investing in organisations and projects using clean energy technologies. In 2015, CEFC committed up to $15 million in finance to the DeGrussa solar-hybrid project in WA.

ii Energy efficiency and conservation

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

iii Technological developments

Owing to rising electricity costs, environmental awareness and emerging technology, consumers are demanding a more reliable, sustainable and economically efficient electricity network. In March 2015, ARENA contributed $3.3 million to a four-year trial of a Synergy pilot project that combines rooftop solar photovoltaic with battery storage at a new housing development north of Perth. This trial, which is currently under way, includes a new tariff option for consumers and has the potential to be replicated in future residential developments across Australia because of its centralised lithium ion battery storage capabilities. Western Australia is also set to construct its first thermal energy to waste facility and Australia’s largest distributed energy resource microgrid. The $400 million energy-to-waste project aims to reduce the amount of landfill by using revolutionary thermal technology to incinerate waste and convert it into energy. The facility will aim to generate approximately 35MW of electricity, which is the equivalent of powering around 35,000 homes.

The former state government also announced the development of Australia’s largest energy resource microgrid, which combines traditional energy sources with wind and solar power and battery storage. It is expected to deliver more than 50 per cent of Onslow’s electricity needs with renewable energy and will be closely monitored to assess the viability of

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replicating the project across WA. Similar pioneer projects are also under way throughout the state, including those utilising wave energy technologies that convert ocean swell into zero-emission renewable power and desalinated fresh water. In 2013, the WA government approved plans to build a 40MW tidal power station in the west Kimberly, which would be the state’s first utility-scale ocean energy plant. These projects are indicative of the demand for alternative sources of energy, as well as the need for energy storage to become more cost-effective so as to promote more renewables being included in local electricity grids. They also demonstrate a gradual psychological shift towards prioritising the use of renewable energy.

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

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

VI THE YEAR IN REVIEW

In response to the state government’s reform programme for the electricity industry and recommendations made in an options paper prepared by a review committee, the former Liberal–National government sought to begin taking steps to limit future electricity price increases for households and businesses. Notable developments include the completion of the transfer of system management functions and market operation functions to the Australian

43 Note 37, supra.
44 Note 37, supra.
Energy Market Operator and the creation of a new market rule-change committee. One of the central aims of the reforms was the introduction of a choice of electricity retailers for households and small business customers, with the gas services industry providing an example of how a competitive market could benefit consumers (this is known as full retail contestability). The government is also in the process of transferring the regulation of the Western Power electricity network to the national regulator; however, the expected time frame for this transfer to the AER has not been achieved. As a result, Western Power will continue to be subject to the current state-based regulatory framework in accordance with the Access Code for the immediate future. A transition to the AER will provide the benchmarks and incentives for Western Power to meet national best-practice standards in operations, efficiency and cost. However, at the same time, the former government announced that it would not split the state-owned electricity business Synergy and that WA would not join the national electricity market.45

In October 2016, the former state government announced that Western Power, in consultation with the ERA, had changed its technical rules, making it easier for commercial solar photovoltaic systems to be installed both onto rooftops and into its network. These changes are expected to significantly reduce the cost of commercial-scale rooftop solar installations and are intended to enable the next phase of the solar revolution.46

VII CONCLUSIONS AND OUTLOOK

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


I OVERVIEW

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

The main power source used in Brazil is hydropower (61 per cent of the electricity mix, excluding small plants), while thermal power plants play an important role in complementing the mix and assuring security of supply (28 per cent of the mix). In addition, alternative power sources, notably wind, biomass and solar, have gradually increased their share and gained additional importance in the electricity portfolio. Renewable energy has more recently been encouraged by net metering policies, and has become more competitive over the past few years, as evidenced by the latest power auctions.

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

II REGULATION

i The regulators

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

The governmental body responsible for formulating public policies within the energy and mines sectors is the Ministry of Mines and Energy (MME). There are currently other arms of the federal government that play an important role in this sector, namely:

1 José Roberto Oliva Jr is a partner and Carolina Queiroz Pereira Dantas de Melo is an associate at Pinheiro Neto Advogados.

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

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

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

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

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

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

ii Regulated activities

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

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3 In a way, the companies were already subject to regulation before the creation of ANEEL, but the previous governmental bodies lacked effectiveness since they were not granted with autonomy and were part of the central government, which also controlled the state-owned companies that were the main service providers within the sector at the time.
Power generation may be operated by means of a concession of use of public assets, a public service concession (former concessions fall within this regime), an authorisation, or even a communication. The regulatory licence required and the applicable regime depend on the plant’s installed capacity, the power source and the reservoir’s size (a requirement for hydropower plants).

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

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

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

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

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

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

Please refer to the table below for a general summary of the regulatory licences required from private investors to enter the Brazilian power generation segment:

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

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

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

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

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

iii Ownership and market access restrictions

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

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

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

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

In addition, there are specific restrictions for the organisation of power companies in the economic group. Unbundling, adopted by the sector since its restructuring in the 1990s and further deepened in the 2004 regulatory reform, restricted the activities of distribution companies in the regulated market, forbidding their participation in other activities of the supply chain. As such, generation companies operating in the interconnected system cannot be affiliated with, or controlled by, any distribution companies of the interconnected system.
iv Transfers of control and assignments
As a rule, the transfer of the regulatory licence or of the controlling interest\(^6\) of the industry’s participants is subject to ANEEL’s prior consent, mainly to adhere to the bidding process and transparency principles.

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

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

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

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

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

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

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

\(a\)
generation;
\(b\)
transmission;
\(c\)
sale to non-captive consumers;
\(d\)
direct or indirect participation in other companies, except for the funding, implementation and management of financial funds for the provision of service; and
\(e\)
activities unrelated to the purpose of the concession, except for the cases provided by law or in the concession contract.

\(^{6}\) 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.
The legislation has not imposed, however, the unbundling between the segments of generation and transmission, which has remained bundled up in some economic groups.

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

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

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

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

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

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

IV ENERGY MARKETS
i Development of power markets
The 2004 restructuring process that established a new regulatory framework for the Brazilian power sector has established two markets in which participants are able to sell power: the regulated market, and the free market.

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

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

There are three types of auctions in the regulated market:

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

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

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

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

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

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

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

Recently, new legislation has been enacted to allow new-project auctions to be conducted as from the third until the seventh year after the bid.

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

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

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

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

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

Recently, new legislation has been enacted to allow auctions for existing projects to be conducted in the same year or up to the fifth year after the bid.

Note that ‘A’ is the year in which the plant must enter operation and start delivering power to the grid.

There are also renewable energy auctions, conducted between years A-1 and A-5 exclusively for contracting new or existing projects that rely on renewable sources. In the latest bids, this type of auction has been contracting power originated from SHPPs, wind and biomass plants.

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

### ii Energy market rules and regulations

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

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

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

b also 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 (originating from the plants’ own power generation) available for sale.

The operation of the Brazilian interconnected system may cause the 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 financial exposure of these participants for reasons they cannot manage, such as the Energy Reallocation Mechanism, applicable to hydropower plants.

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

8 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.

9 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.

10 While in the regulated market the assured capacity represents the limit available for sale, participants in the free market are able to sell an amount above the assured capacity if they have executed PPAs to cover the total amount sold.
Contracts for sale of energy

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

The contracts’ effective terms depend on each type of auction and power source, and may vary from 15 years to 30 years for new-project auctions, from 1 year to 15 years for existing-project auctions, and for up to 35 years in back-up energy auctions. The PPAs may be executed under two modalities: quantity or availability. Under quantity contracts, sellers assume hydrological risks (variations between the amounts contracted and effectively produced) and deliver the power sold at the submarket where the plant is located. Under availability contracts, buyers assume the risks deriving from the plant’s unavailability resulting in a production lower than the amount contracted.11

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

Market developments

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

V RENEWABLE ENERGY AND CONSERVATION

Development of renewable energy

One of the most important regulatory policies adopted to encourage the development of renewable power was Proinfa, an incentive programme to encourage the use of alternative power sources, created by Law 10,438/2002. This programme was based on feed-in

11 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.
mechanisms to contract wind, biomass and SHPP projects for a 20-year period. According to information provided by the EPE, a total of 3,300MW was successfully contracted under Proinfa.

Recent information provided by the EPE, in its 2024 Energy Plan, shows an average growth in the installed capacity of renewable power (wind, SHPPs, biomass and solar) of 10 per cent annually, and that wind power is the source whose participation through auctions has most grown since 2009. The EPE has also stated in the referred plan that, while wind power has become more competitive in price, competitiveness of SHPPs has decreased particularly because of environmental and construction risks. As for solar energy, its installed capacity is still not significant but is expected to grow.

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

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

ii Energy efficiency and conservation

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

In addition, since January 2015 power rates have been subject to a band pricing scheme, which, by allowing customers to be charged more when the system incurs higher generation costs, represents an important incentive for demand reduction. Moreover, a new pricing scheme will be available for certain consumers as from January 2018 (others will have the option at later dates), allowing them to pay different rates according to the time and the day of the week of their consumption.


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

In terms of technological developments, the Brazilian market has taken some important steps towards the implementation of smart grid technologies. In addition to regulations on the band pricing scheme, ANEEL has established a net metering policy for renewable micro and mini distributed generation,\(^{15}\) and has issued regulations imposing a future obligation for distribution companies to install electronic metering for Group B\(^{16}\) consumers. These measures, taken to allow the integration between power supply and communications technology, aim at improving the quality of service provision and reducing operational costs and technical losses in power supply.\(^{17}\)

VI THE YEAR IN REVIEW

As a result of an improvement in the hydrological conditions, in 2016 the market experienced a different price scenario from the one seen in previous years during the water-shortage crisis. Although not as high as then, the PLD has lately been subject to some fluctuations, particularly because of some periods of rather scarce rainfall, which have put upward pressure on prices. In addition, a change in the pricing parameters for calculating PLD should keep it at a high level as from May 2017, but prices are expected to fall again as from November 2017.\(^{18}\)

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

The privatisation auction of Celg Distribuição, the first of several distribution companies belonging to state-owned Eletrobras to have their controlling interests auctioned, was conducted in November 2016, and the Italian company Enel made the acquisition for 2.187 billion reais.\(^{19}\) In addition, a back-up energy auction was conducted in September 2016, and 30 projects of small hydropower plants with a total installed capacity of 180.3MW were successfully contracted at the average price of 227.02 reais/MWh (1.07 billion reais of investment).\(^{20}\) During the period in review, two transmission auctions were also successfully conducted:

\(^{15}\) Under this policy, possible excess of the 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.


\(^{18}\) Information provided by CCEE. Available at: https://www.ccee.org.br/portal/faces/pages_publico/noticias-opiniao/noticias/noticialeitura/contentid=CCCEE_387242&afrLoop=76017762433362%40%3Contentid%3DCCCEE_387242%26_afrLoop%3D76017762433362%26_adf.ctrl-state%3D585b834fd4k_57. Accessed on 19 April 2017.


\(^{20}\) All the information on projects contracted, value of investment, and price was provided by EPE on its website: www.epe.gov.br. Accessed on 19 April 2017.
in October 2016, the bid contracted 6,126km of transmission lines and substations (investment of 11.6 billion reais);\(^a\) and

more recently, on 24 April 2017, the bid contracted 7,068km of transmission lines and substations (investment of 12.7 billion reais).\(^b\)

The political and economic challenges that the country faced during the year did not prevent mergers and acquisitions transactions from being successfully carried out, such as:

- the acquisition of the controlling interest in CPFL Energia by State Grid;
- the acquisition of AES Sul Distribuidora, held by AES Group by a company belonging to CPFL Group;
- the acquisition by China Three Gorges of hydropower assets belonging to Duke Energy; and
- the acquisition of the shares held by Pattac and Servinoga in Atlantic Energias Renováveis by the British fund Actis, consolidating its ownership position of the company.

### VII CONCLUSIONS AND OUTLOOK

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

After the privatisation of Celg Distribuição, the market is currently anticipating the privatisation of the other distribution companies belonging to state-owned Eletrobras, which are expected to have their controlling interests auctioned in the near future. Recent new legislation has even improved rules for such privatisation auctions.

The government has continued to send positive signals to investors in relation to auctions. In addition to allowing the participation of small-scale hydropower plants smaller than SHPPs with a capacity higher than 1MW\(^c\) for the first time in the regulated market, the government has established more attractive conditions for new transmission concessions by increasing the length of the construction period and some of the cap revenues of the bid, as evidenced in the latest auctions, which had more private players as bidders. After a judicial battle that will soon come to an end, a new bid to grant new concessions for the operation of former hydropower plants that had not been renewed under the terms of Provisional Measure 579/2012 (later converted into Law 12,783/2013) is also expected to take place this year. Moreover, the BNDES has approved new attractive financing conditions for the financing of renewable energy projects.

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\(^a\) Information available at ANEEL’s website. Available at: www.aneel.gov.br/web/guest/sala-de-imprensa-exibicao-2/-/asset_publisher/zXQREz8EVlZ6/content/id/15084826. Accessed on 19 April 2017.

\(^b\) Information available at ANEEL’s website. Available at: www.aneel.gov.br/sala-de-imprensa-exibicao/-/asset_publisher/XGPXSqdMFHre/content/leilao-da-aneel-proporcionara-mais-de-r-12-7-bilhoes-de-investimentos-em-transmissao-em-19-estados/656877?inheritRedirect=false&redirect=http%3A%2F%2Fwww.aneel.gov.br%2Fsala-de-imprensa-exibicao%3Fp_p_id%3D101_INSTANCE_XGPXSqdMFHre%26p_lifecycle%3D0%26p_state%3Dnormal%26p_mode%3Dview%26p_col_id%3Dcolumn-2%26p_col_count%3D2. Accessed on 24 April 2017.

\(^c\) In past auctions, power sources that have usually been allowed to participate included SHPPs, but in this auction hydropower plants with a capacity even lower than SHPPs were also entitled to participate.
From a financial perspective, investors should be able to adopt original alternatives for financing (e.g., infrastructure debentures), given that the government has been increasing interest rates and will most likely significantly reduce its participation in the sector by either reducing funds made available for certain types of investments or restricting investments from state-owned companies, notably those of the Eletrobras group. This is one more reason why the market expects the sale of minority stakes held by Eletrobras in some of its various affiliates. Specifically with regard to distribution companies, opportunities may arise from recently renewed concessions or from the privatisation of state-owned companies.

The strength of the Brazilian market’s institutions will certainly play an important role in its gradual recovery and stability. EPE estimates that investments in power generation in the years 2015–2024 will amount to 268 billion reais – with 27.2 per cent of that in hydropower, 58.1 per cent in renewable energy (SHPPs, biomass, wind and solar) and 14.7 per cent in thermal – and another 108 billion reais in power transmission.24

In sum, the Brazilian power sector should be viewed as a target for long-term investments, to the extent that investors are knowledgeable of the characteristics inherent in each type of investment and accurately assess the risks involved.

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Chapter 8

CHINA

Monica Sun and Hao Su¹

I OVERVIEW

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

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

China’s prominent role in the global energy market underlines the importance of understanding China’s domestic energy regulation regime and its market structure. This chapter aims to provide an overview of China’s energy market and regulatory regime with a focus on oil and gas, power, and renewable energy from a foreign investment perspective. We have endeavoured to state China’s energy regulation and practice on the basis of the materials available to us as of April 2017.

II REGULATORY REGIME

i Regulators

Oil and gas

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

The National Development and Reform Commission (NDRC) is in charge of setting out and implementing policies in respect of the oil and gas sector. It is also responsible for approving certain investment projects. The National Energy Administration (NEA) was

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established under the NDRC, with broad duties ranging from drafting energy strategies, proposing reform advice, implementing the management of energy sectors to approving overall development plans (ODP) for a specific oil or gas project.

The Ministry of Commerce (MOFCOM) was previously in charge of review and approval of making, and amendments of, all production-sharing contracts (PSCs). This approval is no longer required, and instead record filing at MOFCOM is necessary.

**Power**

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

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

**Other regulators**

Other regulators include:

a. the Ministry of Environmental Protection (MEP): takes charge of administering and enforcing environmental protection matters in China;

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

c. the State Administration of Work Safety: responsible for overseeing and administering work safety nationwide.

**ii Laws and regulations**

China has many laws and regulations governing its energy sector, including:

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

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

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’.

Measures for the Supervision and Review of Natural Gas Pipeline Transportation Pricing Costs (for Trial Implementation) (2016) provide that the price administration department under the State Council shall be in charge of the supervision and review of pipeline transportation pricing cost following the principle of legality, the principle of relevance and the principle of rationality.

The Electric Power Law (1996, amended 2009 and 2015) is the main legislation governing the electricity sector.

The Circular on the Reform Plan for Power Prices (2003) sets out the targets for the power price reform and is followed by the Regulation on Feed-in Tariffs (2005), the Regulation on Power Sales Price (2005) and the Regulation on Transmission and Distribution Price (2005).


The Regulations on Electricity Regulation were issued in 2005 to strengthen and improve electricity regulation, focusing on maintaining the order of electricity markets and promoting the development of the electric power industry.

The Administrative Regulations on Permits for the Power Industry (2005) focus on maintaining the order of the electricity markets and promoting the development of the electric power industry.

The Opinions regarding Further Reform of the Electric Power Regime (2015) set out the plan for further reform.

The NDRC and NEA Circular on Issuing Supporting Documents for Electric Power System Reforms (2015) provides implementation measures for the reform of the power regime.

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

In addition, there are numerous regulations and rules enacted by various administrative authorities, to define specific procedures or particular issues with respect to the electricity sector under the framework of the main law and regulations.
**Renewables**


d. The NEA Notice on Facilitating the Development of Geothermal Power (2013) is aimed at promoting the development and utilisation of geothermal power.


f. The Administrative Regulation on Guaranteed Purchase of Renewable Energy-generated Power in Full Amount (2016) sets out detailed rules to guarantee the purchase of renewable energy generated power (excluding hydropower).


**iii Regulated activities**

**Oil and gas**

As mentioned above, exploration and production activities are subject to exploration and exploitation licences issued by the MLR.

In upstream oil and gas exploration and exploitation, foreign companies should partner with and enter into PSCs with legally designated national oil companies (for details, see Section II.iv, *infra*).

Pipeline design and construction is subject to review based on criteria related to safety, environmental protection, optimal land use and economic feasibility. The construction of oil and gas pipeline networks must be approved by the NDRC or its local branches. The qualifications of the enterprises and personnel engaged in the design, installation, use and inspection of pipelines must be accredited by the General Administration for Quality Supervision, Inspection and Quarantine or its local counterpart as the case may be.

A business permit is required to engage in crude oil storage or trading; or refined oil wholesale, retail or storage.

**Power**

Power companies are required to obtain electric power business permits issued by NEA. Electric power business permits are divided into three categories depending on the type of business:

a. a power generation permit for power generation companies;

b. a power transmission permit for power transmission companies; and

c. a power supply permit for power supply companies.

A company applying for an electric power business licences must demonstrate that it has the financial capability and personnel with the required experience. In addition, power companies must obtain approval for each specific power project from relevant authorities and comply with environmental regulations to be issued with the electric power business licence.
Exemptions are available for the power generation permit. The NEA granted the following power plants by notice issued in April 2014:

a  distributed generation projects registered or approved by the NEA;

b  small hydropower stations with single-station generating capacity below 1MW;

c  new-energy generation projects such as solar, wind, biomass, ocean power and geothermal power with generating capacity below 6MW;

d  power projects with comprehensive use of heat and pressure by-products; and

e  captive power plants without direct combustion of fossil fuel and that are dispatched by dispatching organisations at city level or below.

iv  Ownership and market access restrictions

Oil and gas

The state has ownership over all mineral resources within the territory of China. Pursuant to the Mineral Resources Law, a licensing regime has been adopted and the MLR has the authority to grant exploration licences and production licences. Applicants for exploration licences or exploitation licences must be approved by the State Council to engage in oil and gas exploration and production activities. The approved companies are national oil companies (NOCs) and include China National Petroleum Corporation (CNPC), China Petrochemical Corporation (Sinopec) and China National Offshore Oil Corporation (CNOOC). However, the state has been integrating energy reform in Xinjiang province since November 2016, which includes reducing market access restriction. In particular under the reform, the state will further encourage diversified entities to enter into oil and gas exploration and production activities. It remains to be seen whether such trial reform will successfully introduce more private capital into the upstream sector.

Foreign companies can partner with designated Chinese oil companies (usually CNPC, Sinopec or CNOOC) through the PSC regime to invest in onshore and offshore exploration and production in China.

Regarding unconventional oil and gas, exploration and exploitation of coalbed gas generally follows the regime for conventional oil and gas – exploration licences and exploitation licences are granted to designated companies and foreign companies can invest through the PSC regime. Both the licencing regime and PSC regime, however, apply to shale gas exploration and exploitation by foreign investors. Foreign companies can partner with Chinese companies holding an exploration licence of a shale gas block or establish a joint venture with a Chinese partner to bid for the licences directly.

The Foreign Investment Industrial Guidance Catalogue (the Catalogue) is issued by the NDRC and MOFCOM, setting out encouraged, restricted and prohibited activities and sectors. Any activity or sector not included in the Catalogue is permitted. Projects that are encouraged benefit from simpler approval procedures and can also benefit from customs incentives. Restricted activities and sectors must generally be approved at higher levels of government, which means that approvals can be harder to obtain. Sino-foreign joint venture cooperation in the exploration and development of shale gas is 'encouraged' under China's current Foreign Investment Industrial Guidance Catalogue (2015). This allows foreign investment in shale gas to receive certain tax and administrative benefits. MOFCOM’s Notice on Development Plan of Shale Gas has an additional requirement that foreign investors should have expertise in the exploration and production of shale gas. Neither the Catalogue nor the Notice requires Sino-foreign joint ventures to be majority controlled by Chinese partners; however, this is a requirement in the MLR’s second bid round. Accordingly, under
the current regime, a Sino-foreign joint venture engaged in shale gas extraction must be controlled by the Chinese partner or partners. However, as the PSC regime is more established through the conventional oil and gas cooperation, in practice, most sino-foreign cooperation on shale gas exploration and exploitation still follows the PSC regime. The State Council issued new measures to expand the opening-up and positive utilisation of foreign capital in January 2017, including relaxing the entry restrictions on foreign investors in unconventional oil and gas (e.g., oil shale, oil sands and shale gas). In addition, the new draft Catalogue issued in December 2016 for public comment until 6 January 2017 (the 2016 Catalogue draft) proposed new market entry opportunities for special oil and gas: exploration and development of oil shale, oil sands and shale gas will not be limited to Sino-foreign equity joint ventures and Sino-foreign cooperative joint ventures.

The midstream oil and gas industry, however, is dominated by NOCs. CNPC controls nearly all the long-distance pipelines in China, including the West-East Pipeline. The CNPC website shows that the CNPC’s crude oil and natural gas pipelines in China accounted for nearly 70 per cent and 78 per cent of the nation’s total respectively by the end of 2014. In December 2015, CNPC combined a sprawl of pipeline operations in a single company with a registered capital of 80 billion yuan, aiming to improve efficiency and boost the value of the businesses. It is considered a step towards potential divestment in future, as well as a prologue to the government’s bigger plan to reform the energy regime in China, including to strip oil companies of their pipeline assets and set up a national pipeline company or regional pipeline companies that would own and operate oil and gas pipelines.

Construction of new imported LNG receiving terminals is subject to central government approval. Most of the LNG terminals are owned and operated by NOCs. In recent years, private entities as well as foreign entities have started to participate in this sector as well. Currently, there is one LNG terminal in operation that has been established by private investment, and two in construction. See Section III.ii, below, for details of third-party access to infrastructure.

The downstream oil and gas sector is still dominated by NOCs. Sinopec has focused on downstream activities, such as refining and distribution, with these sectors making up over 70 per cent of the company’s revenues in recent years.

**Power**

The main market players in the power industry include power companies (among which the five large state-owned generators are China Huaneng Group, China Datang Corporation, China Huadian Corporation, China Guodian Corporation and China Power Investment), grid companies (namely, State Grid Corporation of China and China Southern Power Grid Co.), and ancillary companies engaged in power engineering and construction (China Energy Engineering Group Co. and Power Construction Corporation of China).

The main opportunities for foreign investors in the power industry lie in the construction and operation of power stations with certain technologies and renewable energy. Specifically, the following types of business in the power industry are ‘encouraged’ in the Catalogue:

- **a** construction and operation of ultra-supercritical power stations with single unit power of 600,000kW or more;
- **b** construction and operation of power stations for heat-power co-generation units of back-pressure (extraction-back) type, heat-power-cool multi-generation units, and heat-power co-generation units of 300,000kW or more;
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;

construction and operation of projects of power generation via integrated gasification combined cycle and other clean coal power generation projects;

construction and operation of power generation projects with single unit power of 300,000kW or more that use fluidised bed boilers and coal gangue, middling, and coal slurry;

construction and operation of hydropower stations for the primary purpose of power generation;

construction and operation of nuclear power stations (the Chinese party must hold a controlling interest);

c) construction and operation of new-energy power stations (including solar energy, wind energy, geothermal energy, tidal energy, wave energy and biomass energy); and

d) construction and operation of a power grid (the Chinese party must hold a controlling interest). This was previously a ‘restricted’ item under the 2011 Catalogue.

The Catalogue restricts the following two types of power plants connected to small grids:

power plants utilising coal-fired and steam condensation thermal generator sets whose single generator capacity is 300,000kW at most; and

thermolectric power stations utilising coal-fired steam condensation and extraction thermal generator sets whose single generator capacity is 100,000kW at most.

The above types of power plants (in the case of thermolectric power stations, the capacity threshold is 200,000kW) connected to large grids fall into the prohibited category for foreign investment. However, according to the 2016 Catalogue draft, foreign investment into the above types of power plants would be removed from the ‘restriction’ and ‘prohibition’ categories.

Transfers of control and assignments

The transfer of exploration rights and exploitation rights for non-oil or gas resources is allowed provided that the following conditions are met:

two full years have passed since the issue of the exploration licence, or the discovery of the mineral resources available for further exploration or exploitation in the exploration zone; or one full year has passed since the exploitation enterprise began exploitation;

the specified minimum input for exploration has been fulfilled;

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

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

a transferee of mineral exploration rights or exploitation rights should meet the qualifications of a mineral exploration right applicant or exploitation right applicant prescribed in the Measures for Area Registration Administration of Mineral Resources Exploration and Survey or the Measures for the Registration Administration of Mineral Resources Exploitation.

The MLR will decide whether to approve the transfer within 40 days after receipt of the application. The transfer contract will take effect as of the day of approval.
There is no regulatory requirement for transfer of participating interest under a PSC. Previously, any amendments to the PSC were required to be approved by MOFCOM. This requirement was abolished in 2013 and now only record filing with MOFCOM is required. In practice, Chinese PSCs often provide that the consent of a foreign investor is required if the NOCs propose to take over the production operations before foreign contractors full recovery of the development costs. After the full recovery of the development costs incurred in accordance with the ODP of any oil or gas field within the contract area, the NOCs may, at any time, have the right by giving a written notice to the foreign contractor to take over the production operations.

Transfer of power generation units in operation requires a change to the power business licence, which shall be approved by the NEA. The NEA will review if the requirements for granting the relevant licences are satisfied.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling
The State Grid and China Southern Grid control the transmission, distribution and sale of power in China. Under the current power regime, grid companies purchase power from power generation companies at the regulated feed-in tariffs and sell power at the regulated power sales prices.

The ongoing power price reform, however, aims to separate the sale of power from grid companies. The Opinions regarding Further Reform of the Electric Power Regime (2015) and the NDRC and NEA Circular on Issuing Supporting Documents for Electric Power System Reforms (2015) provide that power generators will enter into agreements directly with retailers or users with term contracts or spot trades, with the power price being freely negotiated between the parties. The transmission tariff will be regulated by the government on a ‘cost plus reasonable profits’ basis. According to the Notice by the NDRC regarding Comprehensive Promotion of Pilot Reform of Transmission and Distribution Tariff (2016), this reform is now carried out in most provinces.

Since 2009, the user-generator direct trading system has been put on trial in more than 20 provinces. Companies with high electricity consumption (such as aluminium electrolysis and steel plants) can purchase electricity directly from generators. The price paid by such consumers is composed of the power purchase price negotiated between the generator and the consumer (under a power purchase contract), the transmission and distribution price paid to the grid company (under a service contract) and government surcharges. The Opinions regarding Further Reform of the Electric Power Regime (2015) also set out further goals for the development of this user–generator direct trading system.

ii Transmission/transportation and distribution access

Oil and gas
China established the third-party access scheme in the Third-party Access Measures for a trial period of five years. In addition, The Regulation on Construction and Operation of Natural Gas Infrastructure (2014) encourages investment into natural gas facilities.

Under the Third-party Access Measures, pipeline and facility operators should equally open pipeline networks and associated facilities to third parties if operators have surplus capacity and, in the case of multiple users, non-discrimination principles should apply, but priority should be given to contracts already in place. The facilities to be opened 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.

The Third-party Access Measures also state that pricing authorities should decide the service fee for such access. It remains to be seen how the Measures will be implemented in practice. We also note that a new policy is likely to be issued by Chinese government, which allows all oil and gas players access to natural gas infrastructure owned by national oil companies. It is therefore worth keeping an eye on the latest developments.

**Power**

A grid operator must ensure non-discriminatory and fair opening 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 feed-in tariff.

Grid companies must ensure non-discriminatory and fair access to their grid to qualified power plants.

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

- 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 these RPG projects at a higher feed-in tariff.

iii Rates

**Oil and gas**

According to Measures for the Administration of Natural Gas Pipeline Transportation Prices (for Trial Implementation) (2016) and Measures for the Supervision and Review of Natural Gas Pipeline Transportation Pricing Costs (for Trial Implementation) (2016), pipeline transportation fees are regulated by the NDRC using the principle of ‘allowed cost plus reasonable profits’.

**Power**

In theory, the rates that the grid companies charge end users seek to recover power purchase costs and fees for transportation, distribution and sale services, power losses and the like. However, in practice, the rates are set by the government and vary depending on the type of user and the region.

iv Security and technology restrictions

Oil and gas pipeline owners and operators have obligations under the Oil and Natural Gas Pipeline Protection Law, including those to patrol, inspect and maintain the pipelines; to
upgrade, transform or stop using those pipelines that do not satisfy the safe use requirements in a timely manner; to post, repair or change signs related to the pipeline; and to take effective safety protection measures for a pipeline not in operation.

As gas pipelines are considered to be ‘specialised equipment’ under the specialised equipment regulatory regime, a pipeline operator is required to hold a Specialised Equipment Registration Certificate. In addition, both natural gas and gas pipelines are considered to be ‘hazardous material’ under the hazardous material regulatory regime. The ‘producer’ of hazardous material is required to hold a Production Safety Permit and the ‘trader’ of hazardous material is required to hold a Hazardous Material Operation Permit. However, it is not clear whether the pipeline owner and operators will be considered producer or trader of hazardous material.

Power grid operators also have security obligations under the Electricity Law. The power grids shall be operated in accordance with the principles of safety, high quality and economy. Power grid operations must be maintained in an uninterrupted and stable way, with a stable supply of electricity guaranteed.

IV ENERGY MARKETS

i Development of energy markets

The price of product oil and natural gas is regulated by the NDRC. However, as the State Council clearly pointed out in its notice regarding lowering real economic business costs in August 2016, one of the essential plans is to liberalise the prices in competitive sections (in particular, to speed up market-oriented reform in oil and natural gas).

As mentioned above, under the current regime, grid companies purchase power from power generation companies at regulated fixed prices and sell power to the customers at regulated fixed prices. Generation is dispatched on a fair and equal basis.

Under the ongoing power price reform, the Chinese government is exploring the possibility of opening up electricity markets. The aim at this stage is to establish a mid-to-long-term market and a spot market.

ii Energy market rules and regulation

Oil and gas

To engage in crude oil storage or trading, or refined oil wholesale or retail, a business permit issued by MOFCOM is required. There are certain requirements for applicants to obtain a business permit, including a certain amount of registered capital, long-term supply agreements, and stable sales channels and facilities. Foreign-invested enterprises may also apply for permits.

State trading enterprises and non-state trading enterprises may engage in the importation of crude oil and refined oil. MOFCOM publishes a list of state trading enterprises, and companies outside that list may become a non-state trading enterprise if they:

- 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 2017 is 87.6 million tonnes. In 2015, MOFCOM also issued a notice setting out the detailed requirements for refineries to import crude oil, including requirements regarding equipment, product quality, safety management and personnel.

Use of imported crude oil was previously limited to NOCs. In February 2015, however, the NDRC issued a notice breaking the monopoly. Local refineries can now apply to use imported crude oil if they meet certain requirements, including requirements regarding equipment, product quality and safety management. Twenty-one refineries have obtained a permit from the NDRC to use imported crude oil so far.

There is no market entry restriction on the import or export of gas.

In addition, trading of oil and gas requires safety permits under, for example, the hazardous material regulatory regime.

**Power**

Sale of power to customers is currently largely controlled by the State Grid and China Southern Grid through their subsidiaries. Under the power price reform, however, we expect to see more participants in the market. Apart from the user–generator direct trading system, the NDRC and NEA Circular on Issuing Supporting Documents for Electric Power System Reforms (2015) also allows independent power supply companies to participate in the market provided that certain conditions, including on total assets, equipment and expertise, and the electric power business licence issued by NEA, are met.

### iii Contracts for sale of energy

**Oil and gas**

There are two types of government regulated prices:

1. government fixed price; and
2. 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:

1. a benchmark price with a float range;
2. maximum price;
3. minimum price;
4. the rate of price difference; and
5. the profit rate.

When a foreign company invests in upstream oil and gas through the PSC regime, parties would normally agree in the PSC that the NOC will sell the foreign investor’s share of oil and gas on its behalf. Usually the price is determined by reference to the prevailing price in an arm’s-length transaction for a long-term sales contract of similar quality of crude oil in the main world oil markets with adjustment to be made for quality, delivery, transportation, payment and other terms, and expressed as ‘free on board’ price at the delivery point in China.

Upstream crude oil prices and gas prices are not regulated, while refined oil prices and natural gas prices at city gate are subject to government regulation:

1. the retail and wholesale of gasoline and diesel, as well as sale of gasoline and diesel to wholesale business, railway customers and transportation customers are subject to the governmental guidance price; and
China

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

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

The government caps the price of natural gas at the city gate while the ex-factory price can be negotiated between parties. The prices of shale gas, coalbed gas, coal gas, liquefied natural gas and fertiliser gas are determined freely by suppliers and consumers. In order to accelerate the gas price reform, the state started a trial regime in Fujian province in November 2016. According to such trial regime, the city gate price will be decided based on negotiation between suppliers and consumers, which means it will not be subject to the government guidance price.

**Power**

Power prices are set by the government, taking into account the power purchasing cost, the loss from power transmission and distribution, power transmission and distribution price and government funds. The prices vary depending on a number of factors including season, peak hour, region and type of user (namely, residential user, agricultural user and industrial and commercial user).

Customers are allowed to participate in the power market if certain criteria are met, and may choose to enter into power purchase agreements with (1) power supply companies, or (2) directly with power generators. The terms and conditions of these agreements can be freely negotiated between two parties.

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

**V RENEWABLE ENERGY AND CONSERVATION**

As part of government policies in response to climate change and in line with China’s commitments to the international community, the State Council set an objective to control energy consumption to 5 billion tonnes of standard coal in the 13th Five-Year Plan period (2016 to 2020). The NDRC also set Mid and Long Term Plans for renewable energy development: 10 per cent of the total energy consumption should be sourced from renewable energy by 2010, and 15 per cent by 2020. The midterm target (10 per cent by 2010) has been achieved.

In addition, the Chinese government has established a clean development mechanism fund to support construction and industrial activities that are beneficial to strengthen proper responses to climate change since 2010. The construction and operation of power stations using renewable energy is encouraged under the 2015 Foreign Investment Catalogue.

Under the current power regime, the government sets higher feed-in tariffs (FITs) to encourage power generation from renewable energy. The table below sets out the feed-in tariffs for wind, biomass and solar power.
### Other incentives include:

1. **Surcharges collected from end users**, which are used to subsidise the difference between feed-in tariffs and the benchmark price for desulphurised coal generators, operations and maintenance for independent public power systems, and costs for connecting renewable energy generators to power grids.
2. **Favourable loans** with financial discounts for renewable energy projects listed in the guidance catalogue for renewable energy industry development.
3. **Subsidies** for renewable energy development in areas such as new-energy vehicles, building-integrated solar photovoltaic systems, wind turbines and biomass power generation; and
4. **Tax incentives**.

Also, the NDRC approved a nuclear project in March 2015 marking the official relaunch of nuclear projects in China. The Mid and Long-Term Development Plan of Nuclear Power by the State Council set the target for nuclear power at installed capacity of 58 million kW and 30 million kW under construction by 2020, which means a shortfall of 39 million kW. The industry is expecting a large wave of investment into nuclear power in the near future. In March 2016, Shenhua, China’s largest coal producer, was reported to be in talks with leading Chinese nuclear developers China National Nuclear Corporation and China General Nuclear Power Corporation on taking stakes in domestic nuclear projects, as part of its efforts to diversify into cleaner forms of energy.

In order to help reduce government subsidies to the renewables sector, the NDRC, together with the Ministry of Finance and the NEA, issued a Circular on the Trial Implementation of the Renewable Energy Green Power Certificate Issuance and Voluntary Subscription Transaction System (the Green Power Certificate Circular) in January 2017. According to the Green Power Certificate Circular, solar and wind power producers would apply for and be issued tradeable certificates for the renewable electricity generated by them. Renewable energy users are encouraged to buy such certificates at an agreed price through negotiation or a bidding process. Solar and wind power producers who have sold their certificates would no longer receive a direct subsidy for the corresponding electricity. The NDRC have indicated that the state may launch a mandatory green certificate scheme in 2018.

### VI THE YEAR IN REVIEW

The G20 Energy Ministerial Meeting was held at the end of June 2016, on the subject of ‘building a low-carbon, intelligent and shared energy future’. It is one of the most important measures since China signed the Paris Agreement, a treaty dealing with greenhouse gases emissions mitigation, on 22 April 2016. The Paris Agreement has been approved by the Standing Committee of the National People’s Congress and came into force on 4 November 2016.
In line with China's above commitment to the international community, the State Council released the 13th Five Year Plan for Energy Development (2016 to 2020) in February 2017, listing future energy strategies for an efficient, clean and safe energy system. According to the Plan, the annual primary energy consumption will be capped at an amount equivalent to 5 billion tonnes of standard coal by 2020. The Plan sets goals on future energy structure, with at least 15 per cent of energy supplied from non-fossil fuels, 20 per cent supplied from natural gas and at most 58 per cent from coal by 2020.

China also continues towards achieving the marketisation of its energy supply. On the one hand, after publishing regulations on transportation pricing for natural gas pipelines in October 2016 and starting a trial regime regarding the marketisation of a city gate natural gas price in the Fujian province, the Chinese government made big steps in natural gas price reform. On the other hand, as encouraged by the NEA, NOCs published details of their oil and gas infrastructure – a material development in opening access to oil and gas pipeline facilities. At the same time, the ongoing power price reforms have enjoyed sweeping progress. In September 2016, the NDRC significantly expanded the scope of a pilot provincial power grid in light of the transmission and distribution price reforms. In addition, pilot programmes for the reform of the electricity sale sector have also been expanded. After the establishment of the Beijing Electricity Trading Centre and the Guangzhou Electricity Trading Centre in March 2016, more and more electricity trading centres have been set up in order to provide platforms for power trading.

In 2016, the Chinese coal mine industry focused on reducing excessive industrial capacity by closing small local coal mine companies and reorganising big coal mine SOEs. The NDRC also emphasised that its goal in the near future is to promote industry upgrading and transformation by reorganising big coal mine SOEs. Such an industry goal is consistent with the 13th Five Year Plan for Energy Development (2016 to 2020), pursuing a more efficient, clean and safe energy system in China.

The power reform promoted by the NDRC and the NEA has also obtained support from SOEs. A case in point is State Grid's announcement in December 2016 that it will launch a number of measures including carrying out incremental distribution of investment in business by way of mixed ownership and the relatively independent operation of trading entities.

The attempted efforts of the Chinese government to reform the energy regime in China and to introduce competition into the domestic market provides both challenges and opportunities to foreign investors interested in this market. Shale gas, for instance, is an area in which foreign investors take different views. While Shell decided to give up on its shale acreage in China, BP signed its first two PSCs for shale gas exploration, development and production in the Sichuan Basin with CNPC in March and July 2016.

VII CONCLUSIONS AND OUTLOOK

The regulatory environment is changing fast in China, and the energy sector is no exception. Both the economic restructuring plan and the development of green-energy technology have had a profound influence on the energy industry. Various stakeholders and their demands contribute to innovation in the industry, while also adding complexity to the reform process. With reforms taking place in the regulatory regime and the restructuring of the market ongoing, it is vital to keep a close eye on energy regulation in China.
I OVERVIEW

In past decades, the energy sector in Colombia has been one of the main pillars of development and growth of the country’s economy while contributing significantly to the national budget, which is devoted to infrastructure and social development, as a result of the collection of royalties, taxes and dividends.

The country is now a target of international investment, holding a high investment rating and low perceived risk, also having extensive trade relations and an attractive business environment. Furthermore, with the ongoing implementation of the peace process with the Armed Revolutionary Forces of Colombia (FARC) ending an armed conflict of over 50 years, Colombia has become even more attractive to foreign investors.

As a result of the issuance of the Colombian Constitution in 1991, the Colombian electricity sector has been transformed from a sector with total governmental ownership into a clearly separate sector in terms of the roles of service providers or utilities and regulation, policymakers and control and oversight agencies. Since then, the electricity sector has existed on three main levels. First the Ministry of Mines and Energy (MME), which governs policy and establishes the long-term plans for the whole sector. Second, the Energy and Gas Regulation Commission (CREG), which sets out the rules and roles of each of the participating agents, while also focusing on quality and price for the end user. And third, the Superintendency of Domiciliary Public Utilities (SSPD) 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 70 per cent of the installed capacity, followed by thermal power stations operating with coal and gas with a share of 21 per cent. The remaining energy is obtained and supported by other sources such as cogeneration, with a share of 0.46 per cent; and wind, which only adds 0.14 per cent.

In terms of connectivity, the Colombian electricity sector is divided as follows: on the one hand, the National Interconnected System (SIN), which comprises generation plants, the interconnection network, the regional and interregional transmission networks

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1 Jose V Zapata is a partner and Daniel Fajardo is an associate at Holland & Knight.
and distribution networks, all connected to each other; and on the other hand, the non-interconnected zones, where electric service is not provided by the national network but by independent small-scale systems.

II REGULATION

i Regulators

The Colombian Constitution, issued in 1991, conferred legislative power on Congress and granted regulatory power to the national government, which in turn exercises such power through the regulatory entities that serve the energy sector via decrees and resolutions.

Specifically, the determination of policies and issuance of regulation is undertaken by several government entities, as follows:

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

On the other hand, the administration and issuance of particular regulations in the electricity sector is dealt with by the following technical entities:

a CREG, a special administrative body created in 1994, is in charge of the regulation and promotion of competition between the entities involved in the electricity sector and the regulation of electricity and gas utilities. Pursuant to Laws 142 and 143 of 1994, the following specific functions are assigned to CREG:

• promoting fair market competition;
• setting out the conditions for deregulation of the electricity sector regarding a competitive market;
• determining and approving interconnection and usage charges and tariffs for the transmission and distribution of electricity;
• defining the regulated and unregulated end-user markets;
• setting out the regulations for the operation, planning and coordination of the national transmission system; and
• issuing the technical regulations with respect to quality, reliability and security of electricity;

b the UPME is a special administrative unit attached to the MME in charge of planning the energy mining sector in coordination with other agents in the sector and supporting the MME in achieving its goals and objectives;

c the Institute for Planning and Promotion of Energy Solutions for Non-Interconnected Areas is responsible for the promotion, development and implementation of energy efficient, viable and sustainable solutions that meet the needs of non-interconnected zones; and

d the SSPD is a government agency that oversees public utilities companies that operate within the Colombian territory. Among other functions, the SSPD is in charge of:

• supervising the quality and efficiency of all public service companies;
• taking over public utilities companies when the companies are financially non-viable or when the service rendered is at risk; and
• imposing sanctions on the companies subject to surveillance, and in particular with respect to electricity companies as result of a violation of the code of operations of the electricity sector.

In addition to the above-mentioned entities, the following entities provide consultation and technical assistance in the electricity sector:

a The National Operation Council, responsible for determining the technical standards for the efficient operation and integration of the SIN; and

b the Commercialisation Advisory Board, created by CREG as an advisory entity for the monitoring and review of the commercial aspects of the wholesale energy market (MEM).

The Superintendence of Industry and Commerce (SIC) is the authority in charge of investigating and sanctioning commercial restrictive practices, as well as authorising the mergers of companies operating within a single sector and market.

ii Regulated activities

Environmental permits

From an environmental perspective, the development of works and activities related to electricity or nuclear energy requires a prior licence or environmental permit to be granted by the National Environmental Licensing Authority (ANLA) or regional entities, depending on the sector, type of project and area where it is developed.

Furthermore, the main regulation in relation to environmental authorisations is Decree 1076 of 2015, which, among others, defines the environmental authority in charge of granting the environmental licence, depending on the type of project and the installed capacity (MW) of the specific project.5

Pursuant to Decree 1076 of 2015, an environmental licence is the authorisation granted by the competent environmental authority for the execution of a project, work or activity, which can cause serious deterioration of natural resources or the environment or introduce significant modifications to the landscape. Environmental licences include all permits, authorisations and concessions for the use of renewable natural resources throughout the duration of the project, work or activity, and any requisites for the initiation of the work, project or activity subject to an environmental licence.

Pursuant to the ILO Convention 169 and Colombian regulations, should ethnic communities be located within the area of influence of the project, a prior consultation process with such communities must be undertaken prior to the issuance of the environmental licence. Prior consultation suspends the proceeding with respect to the environmental licence.

Electricity: regulated activities

It is of utmost importance to note that, pursuant to the Colombian Constitution, electricity generation, interconnection, transmission and commercialisation activities are considered public utilities to be provided under Colombia’s authority and supervision and governed by the constitutional principles of free economic activity, free private initiative, free competition and private ownership.

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5 Article 2.2.2.3.2.1, Decree No. 1076 of 2015.
The primary electricity regulation is contained in Laws 142 and 143 of 1994, which were enacted in a context of severe energy insufficiency and outages. Until 1995, electricity services were provided by the state through the company Interconexión Eléctrica SA (ISA) and other government-owned entities, with minor participation of the private sector. The power sector was reformed to introduce market economy principles, assigning the state the role of regulator. ISA was spun off into two companies: ISA the transmission company with system and market operating functions, and Isagen, a new company for electricity generation.

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

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

iii Ownership and market access restrictions
First and foremost, in Colombia, there are no limitations or prohibitions for foreign participation or investment in the electricity sector. The only sectors in which foreign investment is prohibited are national security and defence and processing and disposal of toxic, hazardous or radioactive waste, as specified by Article 6 of Decree 2080 of 2000, further amended by Decree 2466 of 2007.

Nevertheless, pursuant to Article 471 of the Code of Commerce, foreign companies willing to undertake permanent business in the country are required to constitute a branch with local address in Colombia. Moreover, according to Law 142 of 1994, enterprises providing public utilities, such as companies participating in the electricity sector, must be constituted as public utilities companies.

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 segregated activities. Furthermore, Article 74 of Law 143 of 1994 expressly prohibits companies involved in the electricity sector to engage in more than one activity except for commercialisation, which can be developed along with other activities of the electricity sector.

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

- electricity generators are not allowed to have an equity participation of more than 25 per cent in distribution companies;
- no company can have market participation above 25 per cent in the generation activity;7
- no company is allowed to directly or indirectly own more than 25 per cent of the equity of a company involved in commercialisation of electricity.8

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6 See Article 56 of Law 143 of 1994.
7 See CREG Resolution 60 of 2007.
8 See CREG Resolution 24 of 2009.
iv  Transfers of control and assignments

With respect to mergers and acquisitions, it is important to note that all companies involved in the electricity sector are subject to the general competition and antitrust regime provided for in Law 1340 of 2009.

Pursuant to Article 9 of Law 1340 of 2009 and Resolution 10930 of 2015 issued by the SIC, certain mergers, consolidations or integrations require either to be approved or to be notified to the SIC.

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

a  whenever the transaction creates any form of integration. Any transaction to acquire ‘control’ over assets or shares of other companies leading to the creation or reinforcement of market power constitutes a merger;

b  the parties of the transaction in Colombia jointly or individually have, in the year prior to the transaction, a level of total assets or operational income equal to or above 60,000 minimum monthly Colombian legal wages (approximately US$14,754 million);

c  whenever the companies involved in the transaction are dedicated to the same activity or participate in the same vertical value chain; and

d  whenever at the time of notice companies have

- 20 per cent or less market participation; or

- 20 per cent or less participation in the same vertical value chain.

Notice must be submitted as a pre-completion requirement of the transaction. However, this filing does not constitute a merger clearance by any means. Mergers will require approval of the SIC when they meet the first three above-mentioned conditions and the market participation of the companies individually or jointly equals or exceeds 20 per cent of the relevant market under Colombian jurisdiction.

Approval has to be submitted as a pre-completion requirement of the transaction; the SIC’s clearance is therefore a mandatory condition in order to proceed with completion of the transaction.

In addition to the above, Article 34 of Law 142 of 1994 mandates that companies involved in public utilities must avoid unjustified privileges and discriminatory acts and must refrain from undertaking any act or transaction that has the capacity, purpose or effect of generating unfair trade or restricting competition or abuse of dominant position. The SSPD is the entity in charge of monitoring compliance of the aforementioned obligation and imposing sanctions.

II  TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i  Vertical integration and unbundling

As indicated above, the electricity Law 143 of 1994 and CREG regulation establish unbundling rules restricting horizontal and vertical integration of utility companies that provide electricity services. Integration rules indicate the following:

a  utility companies incorporated before Laws 142 and 143 of 1994 can develop more than one activity under separate accounts for each business; and

b  utility companies constituted after the enactment of Laws 142 and 143 of 1994 can only undertake, at the same time, complementary activities such as generation-retailing
or distribution retailing, and are prohibited to simultaneously perform activities of
generation transmission, generation-distribution, transmission-distribution and
transmission-retailing.

With respect to horizontal integrations, according to Resolution 128 of 1996 of the CREG,
a single company may not own more than 25 per cent of country’s generation, retailing and
distribution activities.

ii Transmission/transportation and distribution access

The electric power system consists of an interconnected grid – the SIN – that supplies about
95 per cent of the overall demand. The remaining demand (non-interconnected zones) is
typically supplied by local small electricity generation plants that operate on fossil fuels
(gasoline and diesel).

The SIN has a total length of 24,981.73 kilometres comprised as follows:

a. the SIN;
b. the regional transmission system; and
c. the local distribution system.

The National Transmission System is a multi-owner network that has the unique characteristics
of a natural monopoly, with ISA holding the largest share.9

The grid system supply, provided by the National Transmission System, enables the
coordination of the generators while reducing the amount of backup generating capacity and
reserves. Pursuant to applicable regulations, transmission is defined as the transportation of
electricity at a tension level equal to or greater than 220kV. Networks operating at less than
220kV are part of the distribution activity, the main function of which is to transport the
electric energy to the end user. Moreover, the electric distribution system is integrated by
networks, substations that operate at voltages lower than 220kV and do not belong to the
National Transmission System.

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

In addition to the above, Colombia is interconnected with both Ecuador and
Venezuela, which has fostered the development of energy security standards while allowing
these electricity markets to operate in a coordinated manner.

iii Rates

Pursuant to Article 23 of Law 143 of 1994, CREG:

c) Defines the methodology for the calculation of rates for access and use of electric grids as well as the
rates for services related to connection and coordination which are carried out by regional dispatch
centres and the national dispatch centre.

9 The state owns about 62 per cent of Isagen’s shares and private investors own 31 per cent.
d) Approves the rates to be paid in relation to access and use of electric grids as well as the rates for services related to connection and coordination which are carried out by regional dispatch centres and the national dispatch centre.

Further, Article 88, numeral 1 of Law 142 of 1994 provides that:

Companies should adhere to the formulas that CREG periodically defines to fix their rates, except in the exceptional cases listed below. According to cost studies, the regulatory commission may establish maximum and minimum tariff caps which are mandatory for companies; while it may also define methodologies for determining rates and whether it is appropriate to apply the regime of regulated or supervised rates.

In relation to the regime of regulated and supervised rates, Article 11 of Law 143 of 1994 establishes a regulated liberty regime according to which rates for generation, interconnection, transmission, distribution and commercialisation of electricity within the national territory is set and limited by the criteria and methodology of CREG.

While each company negotiates its own rate, as mentioned above, rates are capped at the maximum rate established by CREG. Generally speaking, for affixing rates to be charged for utilities, CREG establishes the methodology and procedure for the calculation of the rate including costs associated to such rate. Thus, resolutions that set rates include the costs assumed by the provider of such service as well as the methodology used for regulating such cost.

Furthermore, Article 87 No. 9 of Law 142 of 1994 provides that rates fixed by CREG are valid for five years and thus have to be adjusted every five years. The current rates are those set by way of Resolution 097 of 2008 issued by CREG. While it is evident that such Resolution 097 of 2008 was issued more than five years ago, it should be noted that a modification and adjustment proposal has already been drafted and has not yet been approved.

iv Security and technology restrictions

The main concern in terms of security of the electricity sector in Colombia is related to physical security of the oil and energy infrastructure. For several decades, infrastructure was a common target for guerrilla groups related to the armed conflict within the country. Attacks to pipelines as well as energy towers were frequent; they implied serious damages, paralysis of some parts of the system and impacted production levels gravely, affecting vulnerable populations. A decrease and eventual halt in attacks to oil and energy infrastructure is expected as a result of the implementation of the peace process with FARC, and as a result of possible negotiations with the National Liberation Army.

While recent developments in terms of peace have substantially diminished attacks to oil platforms, pipelines and energy towers, in 2014, before the negotiation and subsequent implementation of the peace process with FARC, the Colombian government created a task force for the protection of infrastructure including pipelines, energy towers, oil platforms and infrastructure in general, which was named COPEI. Among the various outcomes of the implementation of such task force were the creation of a special operation centre and the distribution of a daily report including possible threats and events.
IV ENERGY MARKETS

i Development of energy markets

The Colombian energy market is based on a competitive market model that is basically open to access through the MEM. The MEM is a market in which generators, transmitters and wholesale energy consumers and unregulated users participate with the main purpose of trading energy blocks through the SIN.

The MEM is divided into long-term and short-term transactions, depending on the needs of those participating in the MEM and the terms for such negotiations. For example, long-term participants opt for bilateral agreements while short term agreements usually refer to next-day purchases between all of the generators of the market, which are subject to explicit regulations. These kind of transactions usually cover the spot market.

Oversight of the MEM is led by the SSPD, which created the Oversight Committee of the MEM in 2006.

A substantial amount of electricity that is generated in Colombia is traded through the MEM via wholesale transactions, as all of the generation companies are obliged to participate in the MEM with all of their generation plants and units that are connected to the SIN.

Retail companies that sell directly to end users are also required to carry out their electricity transactions through the MEM.

ii Contracts for sale of energy

As explained above, the MEM is divided into long-term and short-term transactions. While long-term transactions usually involve bilateral agreements, short-term transactions (referred to as ‘on spot transactions’) usually involve negotiations of daily price offers along with hourly availability. The prices at which electricity is offered reflect the variable costs of generation as well as opportunity costs.

Firm energy obligation (OEF) auctions

Allocation of OEF between the different generators and investors is effectuated through dynamic auctions. OEFs are the resulting links from the auctions, according to which generators must generate a daily amount of electricity, as long as the obligation is in force. When the stock market price exceeds the price of shortage, the OEF price is determined by descending clock auctions.\(^{10}\) The purpose of such auctions is to allocate firm energy obligations (between the generators and investors), thus ensuring reliability in long-term firm energy supply at efficient prices.\(^{11}\) Auctions are held three years prior to the date when the firm energy is required. The time between the announcement of the auction date and the end of the obligation term consists of three stages: (1) the prequalifying period; (2) the planning period; and (3) the obligation effectiveness period, the total of which varies from one to 20 years.\(^{12}\)

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10 Article 2, CREG Resolution 071/2006.
**Bilateral contracts**

The bilateral contracts market is primarily a financial market, as its function is to reduce exposure of the generator and end user to short-term price volatility. Such contracts are freely agreed commitments acquired by generators and commercialisation companies to sell and buy electricity. Energy is delivered 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 such agreements is that the contract specifies the amount of energy that will be used on an hourly basis. Aside from that requirement, there are no restrictions on the electricity that a generator or commercialisation company may specify in the contracts, or the time frame covered by such agreements. Energy purchases made through such contracts, intended for regulated users, are governed by rules that guarantee competition among generators, while the prices and conditions on such contracts intended for non-regulated users are freely negotiated and agreed by the parties.\(^{13}\)

**Spot market**

In the spot market the transmission network is neutral, thus implying that the generator makes its price offer for each day and its availability declaration for each hour, without considering the state of the transmission network. The resources that will be dispatched in order to comply with the hour-by-hour demand are selected according to the most economic offers. This dispatch is known as the ideal dispatch, as it diverges from the real dispatch, which considers the restrictions that may affect the transmission network. The ideal dispatch is determined once finalised by the National Dispatch Centre. It considers real demand and availability, not taking into account physical and technical restrictions imposed by the transmission network. Price offers presented by the generators must reflect the variable costs of generation and opportunity costs. The spot price is the price of the last resource used to meet the total energy demand every hour, which establishes the price at which all inframarginal 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.\(^{14}\)

### 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.

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The law defines unconventional sources of energy as environmentally sustainable energy resources that are globally recognised but not widely used or marketed, such as nuclear or atomic energy, unconventional sources of renewable energy and those determined by UPME. Further, it defines as unconventional sources of renewable energy as sources of energy that meet the above characteristics and are also renewable energy resources, such as biomass, small hydroelectric, wind, geothermal, solar, sea and solid waste that is not susceptible to being reused and recycled and which UPME has deemed to be environmentally sustainable.

Law 1715 of 2014 classifies activities related to the production and use of non-conventional energy sources (mainly non-renewable energy) as matters of public utility and social interest, with the purpose of facilitating certain requirements, processes and access to benefits in urban planning, territorial planning, environmental planning, economic development and the right to compulsory expropriation, etc. It also assigns competencies to entities such as the ANLA and regional autonomous corporations to establish rapid evaluation cycles for projects related to non-conventional sources of energy, and for matters pertaining to this law.

This Law is especially relevant as it authorises small and large-scale energy self-generators to surrender their surplus to the distribution and transport network, in accordance with the regulations of CREG, and the allocation of energy credits to small-scale energy self-generators using non-conventional sources of renewable energy. Such credits may be negotiated with third parties, in accordance with the regulations issued by CREG. The fund for non-conventional renewable energies and the efficient management of energy (FENOGE) has also been established to finance programmes and projects in this area.

Law 1715 of 2014 sets out important fiscal, customs and accounting incentives for companies investing in projects of non-conventional sources of energy.

In fiscal matters, it offers an annual reduction in the income tax, for five years after the taxable year in which it makes the investment: 50 per cent of the total value of the investment made, without exceeding 50 per cent of the net income of the taxpayer determined before subtracting the value of the investment.

For these purposes, the taxpayer must obtain a certification of environmental benefit issued by the Ministry of Environment and Sustainable Development. In addition, national or imported equipment, elements, machinery and services that are intended for the pre-investment and investment for the production and use of energy from unconventional sources and for the measurement and evaluation of potential resources will be excluded from the VAT. For these purposes, a certification from the Ministry of the Environment must be provided stating the equipment and services that will benefit from this award, according to the list established by the UPME.

With respect to custom incentives, Law 1715 provides that those who import machinery, equipment, materials and supplies destined exclusively for pre-investment and investment in projects from non-conventional sources of energy are entitled to obtain an exemption with respect to tariff duties.

Finally, as an accounting incentive, companies participating in generation activities with non-conventional energy sources can enjoy the accelerated depreciation benefit, at a depreciation rate of no more than 20 per cent per annum, applicable to machinery, equipment and civil works necessary for pre-investment, investment and operation of such sources, provided that they have been acquired or constructed exclusively for that purpose, and after the validity of this law.
For its full implementation, Law 1715 requires regulation in different governmental entities affected by the measures of the law. Thus, to date, the following aspects have already been regulated, according to the information published by the Ministry of Mines and Energy on its website www.minminas.gov.co:

\( a \) Resolution 1312 of 11 August 2016 of the Ministry of Environment and Sustainable Development, which adopted the terms of reference for the preparation of the environmental impact study in projects for the use of wind energy sources and other aspects;

\( b \) Resolution 1283 of 8 August 2016 of the Ministry of the Environment and Sustainable Development, which establishes the procedure and the requirements of the certification of environmental benefit to obtain the tax benefits granted by law;

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

\( d \) Decree 2143 of 2015 issued by the Ministry of Mines and Energy in relation to the definition of the guidelines for the application of incentives established in Chapter III of the law.

**ii Energy efficiency and conservation**

The energy efficiency area of the MME developed the Programme for the Rational Use of Energy and the Use of Renewable Sources of Energy, which aims for energy efficiency and establishes targets for unconventional renewable energies in the SIN, as stated in Law 697 of 2001.

The most recent regulatory advance can also be found in Law 1715 of 2014 which, among other things, orders the MME, together with the Ministry of Environment and Sustainable Development and the Ministry of Finance, to jointly develop an action plan for the development of technical regulations with respect to renewable energies; consumer information on the energy efficiency of processes; facilities, services, products and manufactured products; and information; as well as to promote campaigns on the use of renewable energy sources.

In addition to the above, Law 1715 provides that the national government and public administrations should establish energy efficiency objectives in public buildings and plans and actions of efficient energy management.

**iii Technological developments**

In addition to the tax and customs incentives created by way of regulation issued in response to Law 1715 of 2014, and certain programmes to provide electricity and the use of unconventional renewable resources in remote areas, no significant regulatory additional developments have been made in the areas of renewable energy and conservation.

**VI THE YEAR IN REVIEW**

In the Colombian energy sector, 2016 will be memorable for two events in particular. On the one hand, the partial privatisation of Isagen, and on the other, the energy shortages as result of dry weather caused by El Niño.

One of the most significant events of 2016, not only in the energy sector but also in the country’s economy, was perhaps the sale of 57.6 per cent of the state-owned shares in
Isagen to Brookfield Asset Management for 6.5 trillion pesos. This money is to be used by the government to fund a highway building programme known as the ‘4G’ plan. In addition, in March 2016, Empresas Públicas de Medellín, a company owned by the municipality of Medellín that provides electricity, gas, water, sanitation and telecommunications services, and Empresa de Energia de Bogotá, decided to sell their stakes in Isagen (13.1 per cent and 2.5 per cent respectively) to Brookfield Asset Management.

In terms of electricity, the high temperatures and lack of precipitation resulting from El Niño have dried off the rivers that power the nation’s grid. In fact, as result of El Niño, Colombia has had to import energy imports from Ecuador and to temporarily increase thermal generation. Furthermore, unpopular measures such as an increase in energy rates and sanctions regarding high consumption were imposed by the government, whereby high-consuming end users were fined as a result of excessive consumption.

VII CONCLUSIONS AND OUTLOOK

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

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

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

\[a\] attracting greater investment in the electricity sector;
\[b\] promoting unconventional renewable resources, aiming to achieve self-sustainable and permanent energetic sources;
\[c\] advancing regional electric integration; and
\[d\] increasing the installed capacity and effective generation and reliability.
Chapter 10

CYPRUS

Elena Ioannides and Dimitris Papapolyviou1

I OVERVIEW

Cyprus is a Member State of the European Union (EU); therefore, its national legislation and policy regarding energy regulation and the energy markets reflects the relevant EU framework. Nevertheless, Cyprus’ size and remote geographical position, in relation to the other continental EU Member States, as well as the fact that Cyprus has virtually no domestic production of any conventional primary sources of energy, provides for a domestic energy market that is still emerging and is in the initial stages of reaching the envisaged liberalisation and competition levels.

The entire supply of electricity to households and industry is currently provided by the state-owned Electricity Authority of Cyprus (EAC), as there are no private undertakings supplying electricity to the Cyprus market. The provisions of the Electricity Directive2 have been effectively transposed into domestic legislation by the Regulation of the Electricity Market Law 122(I)/2003, as amended (the Electricity Market Law). This permits possible competitors of the EAC to enter the domestic market; however, no such entrance has taken place to date.

The provisions of the Natural Gas Directive3 have also been transposed into domestic law through the Regulation of Natural Gas Market Law 183(I)/2004, as amended (the Natural Gas Market Law). However, there is currently no infrastructure to support the import of natural gas into Cyprus and, as a result, there is no network for its supply in the market.

Furthermore, Cyprus is heavily dependent on petroleum imports for the production of electricity, given that there is no domestic production of conventional energy resources and there is a lack of electricity and natural gas interconnections with other EU Member States and neighbouring countries. As only 8.4 per cent of electricity is currently produced from renewable sources, Cyprus, therefore, has a high exposure to oil price volatility.4

Cyprus has taken steps to tackle the dependency on imports by authorising undertakings interested in exploring its exclusive economic zone (EEZ) to conduct hydrocarbon exploration activities. The authorisations are granted pursuant to the Hydrocarbons (Prospecting, Exploration and Exploitation) Law 4(1)/2007 (the Hydrocarbons Law), which transposes

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1 Elena Ioannides is a partner and Dimitris Papapolyviou is an associate at Dr K Chrysostomides & Co LLC.
2 Directive 2009/72/EC.
3 Directive 2009/73/EC.
the provisions of the Oil and Gas Licensing Directive\(^5\) into Cyprus Law. There is currently one commercial natural gas field in the Cyprus EEZ,\(^6\) which is expected to come online around 2020.

II REGULATION

i The regulators

The Electricity Market Law\(^7\) and the Natural Gas Market Law\(^8\) established the Cyprus Energy Regulatory Authority (CERA), pursuant to the respective provisions of the Electricity Directive\(^9\) and of the Natural Gas Directive.\(^10\) CERA is the competent authority overseeing and regulating the electricity and natural gas markets in Cyprus. CERA also promotes and safeguards competition in the energy market, ensures the quality in energy supply and encourages the use of renewable energy sources.

CERA is a separate legal entity and independent from any other public or private entity (political or otherwise). In addition, it takes autonomous decisions, including in relation to the implementation of its annual budget allocations to ensure it has adequate human and financial resources to carry out its duties. CERA’s functions, operations and decision-making processes are governed by regulations issued by CERA, without requiring prior consent or approval by the Council of Ministers.

**Electricity**

An exhaustive list of CERA’s regulatory powers is set out in the Electricity Market Law\(^11\) in relation to Cyprus’ electricity market. The powers vested in CERA to carry out its duties include, among others:

a. the issuance, revocation, control and amendment of authorisations granted pursuant to the Electricity Market Law;

b. the issuance of decisions and regulations;

c. the issuance of binding decisions on electricity undertakings;

d. the power to investigate and act as dispute settlement authority in relation to any disputes that may arise between the licence holders; and

e. to impose effective, proportionate and dissuasive penalties on electricity undertakings that fail to comply with their obligations pursuant to the Electricity Markets Law or binding decisions issued by CERA.

As stated above, owing to Cyprus’ market size and isolated geographical position, the liberalisation of the electricity market has not yet been effected in actual terms, despite the existence of the relevant legal prerequisites facilitating the same. The electricity market is currently monopolised, as the EAC is the sole supplier. CERA issued two regulatory decisions

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5. Directive 94/22/EC.
6. Aphrodite field, currently owned by a joint venture consisting of Noble Energy, Delek Group, Avner Oil Exploration and Royal Dutch Shell (BG Gas at the time of acquisition).
7. Section 4, Electricity Market Law.
8. Section 4, Natural Gas Market Law.
10. Article 39, Natural Gas Directive.
11. Section 25, Electricity Market Law.
in January 2017, to expedite the implementation of the new electricity market model in Cyprus and attract competition in the production and supply of electricity in Cyprus. In both regulatory decisions, CERA expressed its concerns regarding the delay of the commercial implementation of the new electricity market model inspired by the EU Target Model.

Pursuant to Regulatory Decision 01/2017, CERA instructed the transmission system operator (TSO) to proceed with the following actions:

\( a \) to cover its human resources needs until the end of June 2017, in order to allow it to carry out its duties and proceed with the implementation of the new electricity market model;

\( b \) to submit the Rules that will govern the sale and purchase of electricity between authorised persons to CERA and to the Minister of Energy, Commerce, Industry and Tourism for their approval; and

\( c \) to procure a tender for the supply of purchase software and hardware. Furthermore, CERA called the TSO to implement several actions, such as, personnel training, preparation of market manuals and operational procedures of the transmission system by July 2019.

Pursuant to Regulatory Decision 02/2017, CERA instructed the EAC’s Network Business Unit, which is the transmission system owner, to provide the TSO with the necessary human resources until the end of April 2017, to effectively carry out its duties in relation to the implementation of the new electricity market model.

**Natural gas**

The Natural Gas Market Law grants CERA’s powers and duties in relation to the regulation of the Cyprus natural gas market. As there are currently no undertakings supplying natural gas in the Cyprus market, CERA’s powers are not yet exercisable. Nevertheless, CERA has been granted the relevant powers deriving from the Natural Gas Directive, such as:

\( a \) the issuance of binding decisions on natural gas undertakings;

\( b \) the power to impose effective, proportionate and dissuasive penalties on natural gas undertakings that fail to comply with their obligations, pursuant to the Natural Gas Market Law or other binding decisions issued by CERA; and

\( c \) to monitor and review the conditions to access the network as well as storage services.

The main sources of law and regulation for the electricity and the natural gas markets in Cyprus are:

\( a \) the relevant statutory provisions of the Electricity Market Law and the Natural Gas Market Law, respectively;

\( b \) CERA’s regulations, regulatory decisions and rules; and

\( c \) orders issued by the Minister of Energy, Commerce, Industry and Tourism.

An additional source of regulation for the electricity market is the Electricity Market Rules issued by the TSO, pursuant to the Electricity Market Law.  

12 Application of a binding time frame for the commercial implementation of the new electricity market model.
13 Instructions to the transmission system owner to provide resources to Cyprus TSO.
14 Section 7, Natural Gas Market Law.
15 Section 80(1), Electricity Market Law.
Hydrocarbons

Pursuant to the Hydrocarbons Law, the Council of Ministers is the competent authority entrusted with granting licences for exploration and exploitation activities regarding hydrocarbons within Cyprus’ EEZ. The Cyprus EEZ is currently divided into 13 blocks. Exploration and production-sharing contracts have been signed in relation to eight of the blocks so far. Cyprus’ third licensing round was announced in March 2016 and three more exploration and production-sharing contracts were signed for blocks six, eight and ten of Cyprus’ EEZ in April 2017.

ii Regulated activities

Electricity

The Electricity Market Law prohibits the exercise of any of the following activities by any person who has not been authorised by CERA:

a. construction of an electricity generating plant or the generation of electricity;
b. supply of electricity to eligible customers;
c. supply of electricity to non-eligible customers;
d. execution of any of the duties of the TSO, pursuant to Section 60 of the Electricity Market Law;
e. execution of any of the duties of the distribution system operator (DSO), pursuant to Section 53 of the Electricity Market Law;
f. execution of any of the duties of the TSO, pursuant to Section 46 of the Electricity Market Law; and

g. execution of any of the duties of the DSO, pursuant to Section 51 of the Law.

CERA may also grant an exemption in relation to the obligation for obtaining an authorisation for the construction of an electricity generating plant or the generation of electricity, as well as the supply of electricity to eligible customers. Such exemptions may be granted for:

a. the generation of electricity for self-usage up to 1MW;
b. the generation of electricity from renewable sources of energy up to 5MW; and

c. the supply of electricity from a specific person, the total power of which does not exceed 0.5MW for each generation plant.

For an authorisation to be granted, CERA applies the applicable licensing-related regulations, any guidance issued by the Minister of Energy, Commerce, Industry and Tourism in relation to the government policy, as well as the list of criteria exhaustively prescribed in the Electricity Market Law. The said criteria include, among others:

a. the primary source of energy to be used in the electricity generating plant;
b. the qualifications, technical and financial capacity of the applicant to carry out the activity for which the application is filed;

c. energy efficiency;

16 Section 5(1), Hydrocarbons Law.
17 OJ 2016/C 110/03.
18 Section 34, Electricity Market Law.
19 Section 35, Electricity Market Law.
20 Section 38, Electricity Market Law.
the security of the electricity network, of the electricity generation plants and electricity lines;
the location of the electricity generation plants and the relevant use of land; and
the protection of the environment including the reduction of emissions to the land, soil and air.

Natural gas

The Natural Gas Market Law\textsuperscript{21} expressly prohibits the exercise of any of the following activities by any person who has not been authorised by CERA:

\(a\) construction and exploitation of natural gas facilities, storage facilities, pipeline networks, pipelines and relevant equipment;
\(b\) execution of any of the duties of the owner of the natural gas facilities, storage facilities, pipeline networks, pipelines and relevant equipment;
\(c\) execution of any of the duties of network operation;
\(d\) supply of natural gas, including to wholesale customers;
\(e\) supply of natural gas to eligible customers;
\(f\) supply of natural gas to non-eligible customers;
\(g\) execution of any of the duties of the operator of the import, storage, transmission and distribution of natural gas network; and
\(h\) execution of any of the duties of the owner of the import, storage, transmission and distribution of natural gas network.

CERA applies the following criteria, as well as any guidance that the Minister of Energy, Commerce, Industry and Tourism issues in relation to the applicable government policy,\textsuperscript{22} in relation to the granting of a licence to carry out any of the above-mentioned natural gas related activities:

\(a\) security of the facilities and of the natural gas networks;
\(b\) protection of the environment;
\(c\) location of the factory or of the terminal or of the coastal liquified natural gas station;
\(d\) capacity of the applicant, including its technical and financial capacity;
\(e\) energy efficiency in the context of financial efficiency;
\(f\) public benefit obligations pursuant Section 39 of the Natural Gas Market Law; and
\(g\) the significance of the project for the natural gas market.

Hydrocarbons

Pursuant to the Hydrocarbons Law,\textsuperscript{23} any person prospecting, exploring for or exploiting hydrocarbons within Cyprus’ EEZ without a relevant licence, or in breach of the terms of an existing licence, commits an offence punishable by up to two years’ imprisonment, by monetary fine of up to €1.71 million, or both.

A prospecting licence grants the licensee exclusive prospection rights over a defined area in Cyprus’ EEZ, pursuant to the terms and conditions thereof.

\textsuperscript{21} Section 8(1), Natural Gas Market Law.
\textsuperscript{22} Section 10, Natural Gas Market Law.
\textsuperscript{23} Section 22, Hydrocarbons Law.
An exploration licence grants the licensee exclusive exploration rights over a defined area in Cyprus’ EEZ, pursuant to the terms and conditions thereof, and in case of discovery of a commercial field, the right to obtain an exploitation licence.

An exploitation licence grants the licensee exclusive exploitation rights as regards hydrocarbons in a defined area of the Cyprus EEZ, pursuant to the terms and conditions thereof.24

The specific criteria for the granting of a licence during a licensing round are published in the Official Gazette of the Republic of Cyprus and the Official Journal of the EU. Such criteria may relate to national security or the public interest, the technical and financial capacity of the applicant, the applicant’s approach to the licensed activities to be carried out, the consideration offered by the applicant and the applicant’s previous performance in the context of another licence. Following the transposition of the Offshore Health and Safety Directive25 into Cyprus Law, the Council of Ministers now also examines the applicant’s capacity to perform in relation to health and safety issues.

Once the licensing round is concluded, the government invites the successful applicant or applicants to enter into negotiations regarding the entry into an exploration and production-sharing contract (EPSC)26 between the Republic of Cyprus and the selected applicant or applicants.

iii Ownership and market access restrictions

Electricity

For a natural person to apply for a licence pursuant to the Electricity Market Law, he or she has to be both a citizen of and resident in an EU Member State. Legal entities residing in EU Member States (e.g., companies incorporated pursuant to the legislation of an EU Member State and having their registered offices, central management and their main establishment within the EU) may apply for a licence pursuant to the Electricity Market Law.

According to its Decision 856/2013, CERA does not currently accept any applications for the granting of a licence or for an exemption for the construction of electricity generating plants, either using conventional fuels or renewable energy sources.

Natural gas

Furthermore, pursuant to the Council of Ministers’ Decision dated 18 June 2008, applications requesting licences to construct natural gas facilities cannot be examined by CERA, nor can the respective licences be issued by it. The Natural Gas Public Company (NGPC), a state-owned enterprise, is the sole entity currently responsible for the import, storage, distribution, transmission, supply and trading of natural gas and for the management of the distribution and supply system of natural gas in Cyprus.

According to the current policy in relation to the supply of natural gas to the Cyprus market and the development of the natural gas network, the NGPC has to ‘secure sufficient natural gas supplies, at the lowest possible prices, to cover the needs for electricity power generation.

24 Section 14, Hydrocarbons Law.
25 2013/30/EU.
generation and subsequently to also supply commercial and industrial consumers as well as households.\textsuperscript{27} The gas network will initially consist of three pipelines connected to the gas import hub and to the three existing electricity generating plants (located in Vasilikos, Moni and Dekelia).\textsuperscript{28}

**Hydrocarbons**

Both EU-based legal entities as well as non-EU legal entities may apply for a licence pursuant to the Hydrocarbons Law. Nevertheless, the Council of Ministers may, following an approval from the Council of the EU, deny the granting of a licence to an undertaking that is controlled by a non-EU country or a non-EU citizen, provided that the said non-EU country does not treat EU undertakings in a proportionate manner regarding access to licensing for hydrocarbons’ prospecting, exploration and exploitation activities.\textsuperscript{29}

**iv Transfers of control and assignments**

**Electricity**

Pursuant to the Regulation of the Electricity Market (Licence Issuance) Regulations of 2004,\textsuperscript{30} if a licence holder wishes to transfer his or her licence to another person, the following conditions must be met:

- the licence holder must apply to CERA at least three months before the date of the proposed transfer or assignment and set out the reason for the transfer, as well as the identity of the transferee;
- the transferee must follow the procedures for the application for a licence pursuant to the applicable regulations;
- the licence holder’s application for the transfer of its licence and the respective application of the transferee must be published; and
- all the applications, together with the relevant documents, should be made available to CERA for inspection.

**Natural gas**

A similar procedure is prescribed in the Regulation of the Natural Gas Market (Licence Issuance) Regulations of 2006,\textsuperscript{31} in relation to the transfer of any regulated asset pertaining to the natural gas market. Nevertheless, as explained above, owing to the Council of Ministers’ decision dated 18 June 2008, no licences are being issued pursuant to the above regulation and thus, the transfer provisions cannot be applied.

**Hydrocarbons**

A licence granted pursuant to the Hydrocarbons Law can be transferred or assigned, provided that the Council of Ministers approves such transfer or assignment.\textsuperscript{32} When examining a

\textsuperscript{28} According to NGPC’s calculations, the initial stage of the above project is estimated to cost approximately €60 million.
\textsuperscript{29} Section 29, Hydrocarbons Law.
\textsuperscript{30} Regulation 18(1).
\textsuperscript{31} Regulation 15.
\textsuperscript{32} Section 27(1), Hydrocarbons Law.
transfer or assignment request, the Council of Ministers considers whether the requested transfer may affect national security, the technical and financial capacity of the transferee or the assignee to carry out the licensed activities, and whether the transferee or assignee may comply with any other terms and conditions imposed by the Council of Ministers at its discretion.\(^{33}\)

### III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

#### i Vertical integration and unbundling

The EAC’s Networks Business Unit, currently owns both the distribution system and the transmission system in Cyprus, while it is also the country’s DSO. As the EAC is serving a small isolated system, Cyprus has decided not to apply the provisions of the Electricity Directive in relation to the unbundling of distribution system operators.\(^{34}\)

Furthermore, the provisions of the Electricity Directive in relation to the unbundling of transmission systems and transmission system operators are also not applied in Cyprus.\(^{35}\)

Pursuant to the Electricity Market Law,\(^{36}\) the EAC provides the personnel of the TSO. The TSO’s personnel are supervised by the TSO’s director, who is appointed by the Council of Ministers, while the TSO’s budget is covered by the EAC’s budget.\(^{37}\)

The TSO is an independent body that cannot engage in the production, distribution or supply of electricity in Cyprus and the EAC, in its capacity as the transmission system owner, cannot instruct nor direct the TSO in relation to any of the TSO’s duties.\(^{38}\) In addition, to safeguard its independence, the TSO cannot participate in the corporate structure of an electricity undertaking that is directly or indirectly responsible for the daily operation of production, distribution and supply of electricity in the Cyprus market.

Following Cyprus’ financial recession and the bail-in in 2013, the privatisation of the EAC was approved by the Council of Ministers in order to ameliorate the country’s financial position. Nevertheless, the privatisation plan, which involved several stages\(^{39}\) and was supposed to be concluded by September 2017, does not seem to be proceeding as planned, given that it has been opposed by the EAC’s workers’ unions and heavily criticised by the opposition to the government.

#### ii Transmission/transportation and distribution access

Third-party access to the transmission and to the distribution facilities is permitted, provided that the said third parties hold a relevant licence. The transmission system owner,\(^{40}\) the

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33 Pursuant to this provision, the Council of Ministers authorised the acquisition of 30 per cent of Aphrodite field by Delek Group and Anver Oil and Gas in 2013, and a further 35 per cent by BG Gas in 2016.

34 Article 26(4), Electricity Directive.

35 Article 44(2), Electricity Directive.

36 Section 60(1), Electricity Market Law.

37 Section 61, Electricity Market Law.

38 Section 64(1), (2), Electricity Market Law.

39 According to the privatisation plan, the EAC should have been, among other things, unbundled into distinct legal entities by June 2015, while by December 2015 it should have been transformed from a public law body to distinct companies limited by shares.

40 Section 48, Electricity Market Law.
TSO\textsuperscript{41} and the DSO\textsuperscript{42} are not allowed to act in a discriminatory manner in relation to the transmission network users. In practice, given the EAC’s monopoly in the supply of electricity, currently the only connected users in the transmission and distribution systems are the producers of energy from renewable energy sources and self-generating power plants.

\text{iii Rates}

According to the Electricity Market Law,\textsuperscript{43} the rates are calculated according to Regulations and the methodologies issued by CERA. The rates should reflect the expenses incurred by the undertaking as well as a reasonable rate of return or profit margin. CERA has to ensure that the licence holders are able to recover all reasonable expenses from their activities, such as the fuel costs, overheads and capital expenses.\textsuperscript{44}

\text{iv Security and technology restrictions}

The security of the electricity network and of the electricity generating plants, as well as the protection of public health and safety, are expressly identified as some of the main criteria CERA has to consider before granting a licence, pursuant to the Electricity Market Law.

The provisions of the Seveso III Directive\textsuperscript{45} have been transposed into Cyprus Law through the Health and Safety at Work (Major Accidents Hazard Involving Dangerous Substances) Regulations of 2015. Pursuant to the said Regulations, the facility’s operator is required to set out a major accident prevention policy, to ensure a high level of protection of human health and the environment.

In relation to hydrocarbons licensing, as discussed above, both the national security and the public interest are taken into consideration by the Council of Ministers when examining an application, as well as the applicant’s capacity to perform in relation to health and safety matters.

Similarly, as Cyprus has also transposed the Offshore Safety Directive, both the Ministry of Agriculture, Rural Development and Environment, which is the competent authority regarding the Offshore Health and Safety Directive, as well the operator of an offshore facility, must have effective major accident prevention policies in place, in relation to potential risk that may arise from offshore activities within Cyprus’ EEZ.

\section{ENERGY MARKETS}

\text{i Development of energy markets}

As mentioned above, the supply of electricity is currently solely provided by the EAC, while there is no supply of natural gas in the market at all. Subsequently, no organised markets have been developed in Cyprus, despite the existence of the relevant regulatory framework.

\textsuperscript{41} Section 52(3), Electricity Market Law.
\textsuperscript{42} Section 55, Electricity Market Law.
\textsuperscript{43} Section 32, Electricity Market Law.
\textsuperscript{44} Ibid.
\textsuperscript{45} 2012/18/EU.
ii Energy market rules and regulation

Pursuant to the Electricity Market Law,\textsuperscript{46} the Electricity Market Rules provide the mechanisms, rates and other terms and conditions that may be applied in cases where the licence holders purchase or sell electricity. The scope of the current Electricity Market Rules, published in January 2009, is as follows:\textsuperscript{47}

- to facilitate the TSO to carry out its duties pursuant to the Electricity Market law;
- to regulate the mechanism pursuant to which the market participants can make energy transactions;
- to allow the calculation of payments and their settlement, in relation to energy and ancillary services;
- to set the method under which the settlement and pricing shall take place; and
- to provide the Electricity Market Rules as prescribed by the Electricity Market Law.

As discussed above, pursuant to CERA's Regulatory Decision 01/2017, the TSO was instructed to submit to CERA and to the Minister of Energy, Commerce, Industry and Tourism, for their approval, a new draft of the Electricity Market Rules by April 2017, and is also expected to take all necessary steps to ensure that the new electricity market model can be implemented by July 2019.

iii Contracts for sale of energy

Pursuant to the current Electricity Market Rules,\textsuperscript{48} all offers to purchase and to sell power are made by the respective market participants to the TSO – the entity responsible for deciding which offers to purchase power and which offers to sell power will be accepted. The TSO is also responsible for achieving sufficient and balanced electricity supply levels for the market.\textsuperscript{49} The Electricity Market Rules also provide the minimum requirements to be contained in each offer for purchase or sale of power.\textsuperscript{50} The maximum price of an offer to sell power should not exceed the last highest regulated price that was submitted for the sale of power by 10 per cent, and is agreed between CERA and the dominant participants.\textsuperscript{51} The system in place has not produced the anticipated results with regard to investment attraction, which is one of the main reasons behind CERA's decision to request the drafting of new electricity market rules by the TSO.

iv Market developments

The implementation of the new electricity market model is expected to encourage the development of the electricity market in Cyprus, by attracting new participants and investors to the market that shall actively engage in the production, purchase and sale of power in Cyprus.

In relation to the natural gas market, it is not clear whether any market developments should be expected in future years, since even if a natural gas import hub is to be created, the NGPC shall have the exclusive right to distribute and sell natural gas in the Cyprus market.

\textsuperscript{46} Section 81, Electricity Market Law.
\textsuperscript{47} Chapter A, General Provisions, Rule 2.2.1.
\textsuperscript{48} Chapter E, Balance Mechanism, Rule 4.1.
\textsuperscript{49} Chapter E, Balance Mechanism, Rule 5.1.1.
\textsuperscript{50} Chapter E, Balance Mechanism, Rule 4.2.1.
\textsuperscript{51} Chapter E, Balance Mechanism, Rule 5.1.2.
V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

The provisions of the Renewable Energy Directive\(^{52}\) have been transposed into Cyprus law by the Law on Promotion and Encouragement of use of Renewable Energy Sources 112(1)/2013 (the Renewable Energy Law). Pursuant to the Renewable Energy Law, Cyprus has identified the following two binding national targets in relation to renewable energy:

a. renewable energy must cover at least 13 per cent of Cyprus’ gross energy consumption by 2020; and

b. renewable energy must cover at least 10 per cent of net transport energy consumption.

In recent years, the Ministry of Energy, Commerce, Industry and Tourism has provided grants and support schemes to encourage use of renewable energy to both households and industry. On 8 August 2016, the plan ‘Solar Energy for All’ was enacted, which encourages the installation of small solar panels on rooftops and on the ground (up to 5kW), which will be connected to the electricity network.\(^{53}\) In 2016, 8.4 per cent of the total energy production in Cyprus was produced from renewable energy sources such as solar power, biomass and wind farms.\(^{54}\)

Pursuant to CERA Decision 1549/2016, it was announced that for electricity-generating facilities using renewable energy sources and producing 1–20kW, the applicant may be discharged from his or her duty to obtain an exemption pursuant to Section 35 of the Electricity Market Law, discussed above. The above decision is expected to incentivise and encourage the use of renewable energy sources in Cyprus.

ii Energy efficiency and conservation

The provisions of the Energy Efficiency Directive\(^{55}\) have been transposed into Cyprus law through the provisions of Energy Efficiency Law 31(I)/2009 (the Energy Efficiency Law).

The Energy Efficiency Law provides a set of measures for the promotion of energy efficiency in Cyprus in order to facilitate the provision of energy services offered by energy savings companies (ESCOs), as well as from other energy service providers.

The provision of energy services, such as energy audit services, have been steadily increasing in the past years, while energy savings contracts are being negotiated between ESCOs and owners of industrial facilities, both as energy performance contracts as well as power purchase contracts.

With regard to energy conservation, pursuant to the Regulation of the Energy Performance of Buildings Law 2006, which transposed the Energy Performance of Buildings Directive,\(^{56}\) minimum requirements in relation to energy performance of new buildings or of buildings that are renovated on a great scale, with a surface exceeding 1,000m\(^2\), have to comply with the maximum factor of transmittance, the inclusion of a provision regarding the use of renewable sources of energy, the installation of solar heating panels to produce warm water in residential buildings and the issuance of an energy performance certificate of at least

\(^{52}\) 2009/28/EC.

\(^{53}\) The electricity produced shall be set-off with the existing EAC pursuant to a net-metering scheme.

\(^{54}\) See footnote 4, supra.

\(^{55}\) 2012/27/EU.

\(^{56}\) 2010/31/EU.
class B. Furthermore, the Ministry of Energy, Commerce, Industry and Tourism has set the target that every building to be constructed after 31 December 2020 must have almost zero energy consumption.

VI THE YEAR IN REVIEW

The two regulatory decisions of CERA, discussed above, comprise the most notable developments in the energy regulation sector, as it appears that CERA is willing to effectively carry out its duties by requesting the regulated entities perform their statutory obligations with a view to expediting the establishment of a truly competitive and functional electricity market.

VII CONCLUSIONS AND OUTLOOK

The most notable energy-related development in Cyprus in the past year would be the signing of three EPSCs between the Republic of Cyprus and the successful applicants in the country’s third licensing round. This vote of confidence, given by major oil and gas companies to Cyprus’ EEZ at a time of recession for the oil and gas market, shows the potential for more gas findings therein. The prospects of more offshore gas findings will, undoubtedly, positively affect the downstream energy market in the long term.

It would seem that the development of Cyprus’ electricity market has not progressed at the envisaged pace during the past year, owing to the delay in the EAC’s privatisation, as well as the implementation of the new electricity market model. Nevertheless, following CERA’s recent regulatory decisions, described above, one could argue that the regulator is taking steps to ensure the development of the electricity market. Nevertheless, no major changes are expected until 2019, given the time frame of the above regulatory decisions.
Chapter 11

DENMARK

Nicolaj Kleist

I OVERVIEW

The Danish energy demand is met by domestic natural gas resources and oil, coal imports, and domestic renewable energy sources such as waste, woodchips, wind and biogas. There is no large hydropower or nuclear power production in Denmark.

The first oil and gas exploration licence was granted in 1935, and since then oil and gas have been exploited in Denmark. In 1966, hydrocarbons were discovered in the North Sea, and in 1972 the first oil was produced. During the first 50 years, exploration of oil was carried out under sole-right concessions, but in 1983 competitive licensing rounds were introduced and the first licences with more than one concession holder were awarded in 1984 – the latest in 2005/2006. Oil and gas activities are governed by the Subsoil Act, which lays down the basic framework for oil and gas exploration and production.

The first comprehensive legislation governing electricity supply entered into force on 1 January 1977. Electricity activities are mainly governed by the Electricity Supply Act, which lays down the basic framework for electricity production and supply. The aim has been to ensure electricity supply in accordance with the principles of security of supply, economics, and environmental and consumer protection. Access to cheap electricity and consumer influence on the administration of electricity sector assets; promoting sustainable energy use, including in connection with energy savings and use of combined power and heating; lasting and environmentally compatible energy sources, as well as securing effective use of financial resources; and creating competition on the markets for production and trade in electricity are essential elements in the legislation.

The long-term goal of Danish energy and climate policy is to have the total energy demand covered by renewable energy by 2050. The total share of renewable energy in electricity consumption is expected to be approximately 80–85 per cent in 2020 and for district heating consumption approximately 95 per cent. Wind power alone is expected to cover up to 53–59 per cent of electricity consumption in 2020, compared with approximately 42 per cent in 2015.

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2 Act No. 960 of 13 September 2011 on the Use of Danish Subsoil.
3 Consolidated Act No. 418 of 25 April 2016 on the Supply of Electricity.
II REGULATION

i The regulators

The overall administrative responsibility for the energy sector lies with the Danish Minister for Energy, Utilities and Climate (the Minister). Part of the Minister’s authority has been delegated to the Danish Energy Agency (DEA). The DEA is responsible for the entire chain of tasks linked to energy production and supply, transportation and consumption, including energy efficiency and savings as well as national carbon dioxide targets and initiatives to limit emissions of greenhouse gases. In cooperation with the Minister, the DEA prepares the majority of the bills and other political proposals. The DEA carries out analyses and estimates of the development in the energy sector and represents Denmark in international forums.

The Danish Energy Regulatory Authority (DERA) controls prices and conditions in the energy sector. DERA’s purpose is to ensure an efficient and transparent energy market in Denmark. Transmission, storage and distribution undertakings and supply-committed undertakings are under the supervision of the DERA. Decisions of DERA may be appealed to the Energy Board of Appeal. Decisions by the Energy Board of Appeal cannot be brought before any other administrative body, but may be challenged before the courts.

Energinet.dk, 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.dk must ensure open and equal access to the transmission networks for all users. It also issues rules on gas transport and coordinates the general planning of emergency supply for the natural gas sector.

The city councils in the municipalities are responsible for the planning of local heat supply. In each municipality, the city council must carry out planning in cooperation with the supply undertakings and other stakeholders. The heat planning procedure ensures public participation, and as part of the heat supply planning, the city council may decide that connection to a collective heat supply system should be mandatory.

The Energy Supplies Complaints Board is a private board established by the energy industry and the Consumers’ Council. The Energy Supplies Complaints Board handles complaints about the purchase and delivery of energy from supply undertakings. As a principal rule, the board only accepts complaints from consumers. Decisions of the Board cannot be appealed to any administrative authority, but can be brought before the courts.

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4 www.efkm.dk.
5 www.ens.dk.
6 www.energitilsynet.dk.
7 www.ekn.dk.
8 Established by Act No. 1097 of 8 November 2011.
9 Act No. 1307 of 11 November 2014.
The main legislation for energy regulation is the Continental Shelf Act,\(^{10}\) the Act on Raw Materials,\(^{11}\) the Subsoil Act,\(^{12}\) the Pipeline Act,\(^{13}\) the Natural Gas Supply Act,\(^{14}\) the Heat Supply Act\(^{15}\) and the Electricity Supply Act.\(^{16}\)

### ii Regulated activities

A licence issued by the DEA is necessary for exploration, production, transmission, distribution and storage activities.\(^{17}\)

A permit is required for the establishment of plants and for expansion or changes to such plants causing increased pollution.\(^{18}\) Permits are issued by the relevant city council or regional council depending on the size of the plant. Permits for major plants require a prior public hearing, and for major plants there may be a duty to complete an environment impact assessment under the Planning Act.\(^{19}\) Offshore plants are primarily subject to approval under the Subsoil Act and Continental Shelf Act. Offshore installations are subject to approvals and permits issued by the DEA. These include operation permit, manning and organisation plan approval and approval for the contingency plan. To obtain an operation permit, there must be an evaluation of safety and health conditions for the installation and the operational conditions (health and safety review/safety case) and other relevant information regarding health and safety conditions (e.g., certificates). Offshore installations operating in Denmark must have a workplace assessment system.

### iii Ownership and market access restrictions

The Danish state has a general right to all hydrocarbons in the subsoil of the Danish territorial jurisdiction area. The state can grant licences for preliminary investigation, exploration and production of hydrocarbons. Licences are granted through tender procedures or under the ‘open door’ procedure.

The main part of the natural gas on the Danish market is produced in the Danish North Sea. Through the Danish North Sea Fund, the Danish state participates in concessions for exploration and production of hydrocarbons. The fund is administered by the Danish North Sea Partner, a unit under the Ministry. 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 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

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\(^{10}\) Act No. 1101 of 18 November 2005.
\(^{11}\) Act No. 127 of 26 January 2017.
\(^{12}\) See footnote 2, supra.
\(^{13}\) Act No. 277 of 25 March 2014.
\(^{14}\) Act No. 1331 of 25 November 2013.
\(^{15}\) See footnote 9, supra.
\(^{16}\) See footnote 3, supra.
\(^{17}\) See also Section III.iii, infra.
\(^{18}\) Act No. 1189 of 27 September 2016.
\(^{19}\) Act No. 1529 of 23 November 2015.
Denmark

pipeline network against payment. The physical planning of the system for supply of natural gas is governed by the Heat Supply Act. Establishment of new distribution network facilities for natural gas and major alterations to existing facilities requires approval from the relevant city council\textsuperscript{20} and, in certain cases, the DEA. A storage undertaking is obliged to place storage capacity at the disposal of Energinet.dk, but only to the extent necessary to enable Energinet.dk to maintain physical balance in the network and to ensure security of supply. A storage undertaking must grant access to the storage facilities on the basis of objective, transparent and non-discriminatory criteria. The Danish market for natural gas was fully liberalised on 1 January 2004, and since then customers have had a right to choose a natural gas supplier. Anybody may in principle establish a natural gas supply undertaking.

Electricity grid undertakings have a monopoly on the distribution in their areas and are governed by the Electricity Supply Act. The transmission system operator (Energinet.dk) 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.

\textbf{iv Transfers of control and assignments}

Natural gas and electricity licences, where applicable, can only be issued to applicants with the necessary expertise and economic capacity. The licence can neither directly nor indirectly be transferred to others without approval by the DEA. A gas distribution network or shares in companies that own distribution networks are generally only allowed to be transferred to the state. The state, on the other hand, has a duty to buy. The state must exercise its duty to buy within three months after the date of notification of the owner’s wish to dispose of the distribution network or the shares. If the parties cannot reach an agreement on the conditions of the transfer, the prices and terms of the transfer will be fixed by a valuation commission in accordance with the procedure that applies to compulsory sale to the state.\textsuperscript{21}

Since 1998, Danish competition legislation has been strongly influenced by EU competition law, but the Danish rules are generally stricter than those of the EU in terms of support for free competition.

\section*{III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES}

\textbf{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.dk, Denmark has secured ownership unbundling of the main transmission grid.

In the electricity and natural gas industries, there is a requirement for legal unbundling in relation to the parts of the value chain of monopolistic character. The Natural Gas Supply Act requires a company with a licence for transmission, distribution, storage, LNG business or universal service obligations to conduct only activities allowed under the licence.

\textsuperscript{20} There are 98 municipalities (city councils).

\textsuperscript{21} Act No. 1161 of 20 November 2008 on the Procedure for Compulsory Sale of Real Property.
As a general rule, the Electricity Supply Act does not allow grid and transmission licences to be issued to the same company. Undertakings producing electricity by means of waste incineration are not allowed to carry out other types of electricity production or trading activities. The requirement for unbundling of activities does, however, not preclude the use in combined waste incineration plants of other types of fuel (e.g., straw, chipped wood or natural gas) together with waste suitable for incineration.

The requirements are supplemented by demands for managerial unbundling in the Electricity Supply Act and in the Natural Gas Supply Act. To prevent conflicts of interest, executives and managers of a distribution undertaking must not directly or indirectly participate in the operation or management of an associated undertaking selling or producing natural gas or electricity, or participate in an associated undertaking that indirectly owns such an undertaking. Members of the board of directors of distribution undertakings must not directly or indirectly participate in the operation or management of associated undertakings selling or producing natural gas or electricity.

### ii Transmission/transportation and distribution access

Danish law allows full access on a non-discriminatory basis to the transmission and distribution systems in both the natural gas and electricity sectors.

**Natural gas**

The transmission network for natural gas is connected to the natural gas transmission networks in Germany and Sweden. The transmission network is connected to the distribution network to which the end-users are connected. There is a general right to use the transmission network against payment of applicable fees. Access can be denied if the transmission undertaking cannot meet the capacity requirements, cannot ensure the quality of the natural gas, cannot ensure security of supply, cannot ensure sufficient quantities of natural gas, or if a natural gas undertaking has severe economic and financial difficulties with fulfilling contracts (including take-or-pay commitments). Access can also be denied if a natural gas undertaking does not comply with the access requirements laid down by the transmission undertaking. Reasons must be given for denial of access, and a denial of access can be brought before the DERA.

**Electricity**

The transmission grid for electricity is the part of the electricity grid that transports electricity to local grid undertakings, which then distribute the electricity to end users. The transmission grid also transports electricity to and from other countries. The transmission grid is owned and operated by Energinet.dk, which is responsible for the security of supply and the overall balance and quality of the electricity supply system. Energinet.dk is also responsible for the overall planning and development of the transmission system. Energinet.dk 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.

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22 See footnote 8, supra.
Denmark

iii Terminalling, processing and treatment
The storage facilities for natural gas are currently situated at two locations in Denmark: Stenlille and Lille Torup. The two gas storage facilities are owned and run by Energinet.dk.

iv Rates
It is a general rule that access to transmission and distribution grids must be provided on the basis of objective, transparent and non-discriminatory criteria. When setting prices, grid undertakings must not discriminate between users. Transmission and grid undertakings must prepare a plan for internal supervision and describing the undertaking’s measures to prevent discriminatory practices. Prices must be based on the undertaking’s costs and a reasonable return on capital invested by the undertaking.

v Security and technology restrictions
Undertakings that sell oil in Denmark must keep oil reserves in storage ready for emergency use by the Danish state. Denmark’s obligations to maintain such oil storage follow from an EU directive and from rules laid down by the International Energy Authority. The Danish Act on Emergency Oil Supplies23 ensures emergency supply in the event of disruptions or threats in the oil sector, including keeping reserves of crude oil and petroleum products, and collecting data on the oil conditions in Denmark. The Danish emergency oil management system is primarily handled by the Danish Central Stockholding Entity, which is an independent organisation set up by the oil companies and appointed by the DEA.

IV ENERGY MARKETS

i Development of energy markets
Nord Pool Spot runs a power market in northern Europe and offers both day-ahead and intraday markets; 380 companies from 20 countries trade on the market. Nord Pool Spot is owned by the Nordic and Baltic transmission systems operators (in Denmark, Energinet.dk). In 2015 the group had a total turnover of 489TWh. The power price is determined by the balance between supply and demand. Factors such as the weather or power plants not producing to their full capacity may have an impact on how much power can be transported through the grid and may therefore influence the price of power.

ii Energy market rules and regulation
The Minister can decide that oil undertakings must submit information on the conditions of import, export, production, sale, storage and transport, and on other general matters. The Minister can stipulate that undertakings producing or importing oil must sell oil in accordance with international distribution schemes.

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

23 Act No. 354 of 24 April 2012 on Emergency Oil Supplies.
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.

### Contracts for sale of energy

Most power in the Nordic and Baltic region is traded on Nord Pool Spot. Natural gas, on the other hand, is still primarily traded through bilateral contracts, although an increasing quantity is traded at the market exchange Gaspoint Nordic. Danish energy legislation generally only regulates end-user contracts.

### Market developments

There are a large number of new energy policy initiatives seeking to accelerate the transition to green energy. The four critical focus areas are: energy efficiency, electrification, expansion of renewable energy and research, and development and demonstration.

## RENEWABLE ENERGY AND CONSERVATION

### Development of renewable energy

Denmark has a long tradition of active energy policy, initiated by the first oil crisis in 1973. When oil prices accelerated in 1973, Denmark was among the OECD countries most dependent on oil in its energy supply, with more than 90 per cent of all energy supply deriving from imported oil. Denmark launched an active energy policy to ensure the supply and enable Denmark to reduce its dependency on imported oil. In combination with oil and gas production from the North Sea, Denmark went from being a net importer of oil in 1973 to being more than self-sufficient in energy from 1997 and beyond.

In the Kyoto period 2008–2012, Denmark committed itself to a greenhouse gas reduction target of 21 per cent. Today, renewables account for more than 40 per cent of Danish electricity consumption and, through expanded offshore wind production and use of biomass, the government expects that renewables will reach almost 70 per cent of Danish electricity production in 2020. A new political agreement between the government and all the major opposition parties was reached in March 2012. The agreement covers the period 2012–2020 and sets out the following goals: more than 35 per cent renewable energy in final energy consumption, approximately 50 per cent of electricity consumption to be supplied by wind power, 7.6 per cent reduction in gross energy consumption in relation to the 2010 level and 35 per cent reduction in greenhouse gas emissions in relation to the 1990 level.

Energy taxes on electricity and oil were introduced in 1977, and since then taxes have been increased several times and have also been extended to coal and natural gas. In 1992, the taxes were supplemented by carbon taxes.
Other means of achieving renewable energy are heat-savings initiatives in buildings, use of renewable energy in buildings, municipal heat planning, energy-efficient electricity and district heat production, and use of renewable energy in electricity and district heat production, plus energy savings and use of renewable energy in industry and transportation.

Wind turbines have been supported politically for many years, including through state subsidies, feed-in tariffs, orders to the electricity utilities to build wind turbines, tenders for offshore wind farms and orders to the municipalities to allocate suitable areas for new onshore wind turbines. Approximately 40–45 per cent of electricity is currently produced by wind turbines (and this is expected to exceed 50 per cent in 2020).

In 2009, the Promotion of Renewable Energy Act24 was launched to promote the production of energy through the use of renewable energy sources, in accordance with climate, environment and macroeconomic considerations, to reduce dependence on fossil fuels, ensure security of supply and reduce carbon emissions and other greenhouse gases.

ii Energy efficiency and conservation

Denmark has long supported energy efficiency and conservation initiatives, which played an important role in the efforts to free Denmark from dependence on fossil fuels. In the 1976 Energy Plan, energy efficiency was one of two main targets. During the 1970s, a number of acts and initiatives were implemented to support energy efficiency, with a focus on three main areas:

a heat consumption in buildings;

b industrial and process – covering industrial and production-related consumption; and

c appliance and components – covering electrical appliances and components not directly related to industrial use.

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

a energy and carbon taxes on domestic and public sector energy consumption;

b carbon taxes on industrial consumption;

c carbon emission allowance trading scheme;

d voluntary agreements for industry;

e energy labelling for large and small buildings;

f energy labelling of appliances and lighting;

g norms for energy efficiency and voluntary agreements; and

h reduction of standby consumption.

iii Technological developments

The Danish strategy for energy-efficient technologies provides a framework for prioritisation and development of research and development efforts to achieve the greatest possible impact by public funds used in the field.

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24 Now Act No. 1288 of 27 October 2016 on the Promotion of Renewable Energy.
VI THE YEAR IN REVIEW

i New North Sea Agreement
On 23 March 2017, Maersk Oil and the Danish Underground Consortium entered into an agreement with the Danish government to secure future investments regarding exploration and production of oil and natural gas in the North Sea. The agreement aims to create incentives for new investments and applies only to new prospective investments. The main elements of the agreement are an accelerated depreciation – from the current 15 per cent to 20 per cent annually – and a larger deduction from the current 5 per cent to 6.5 per cent annually on all new investments.

ii Public service obligation (PSO) agreement
On 17 November 2016, the government agreed that the PSO tax will be phased out gradually between 2017 and 2022, providing long-term stability for investments in renewable energy. The PSO tax is a tariff added to consumers’ electricity bills, to support renewable energies. Beyond 2022, finance for renewable energy projects will be included in the Danish government’s budget, and will not form part of household costs.

iii Consolidation and new regulation of the natural gas sector
In September 2016, the government released an energy supply strategy, ‘Supply for the Future’. The strategy includes initiatives on consolidation and new regulation of the gas sector. This should make the sector more effective, and the government aims to realise an efficiency potential on 0.1 billion kroner in 2025 for the benefit of households and businesses. Furthermore, the initiatives include measures to increase competition in the retail market and economic regulation that focuses on effective operation of the gas sector.

iv DONG Energy’s initial public offering
On 9 June 2016, the initial public offering of state-owned DONG Energy became Europe’s biggest in 2016. DONG Energy sold 17.4 per cent of its shares at 235 kroner a piece, raising 17.1 billion kroner, according to a statement to the Copenhagen stock exchange. The Danish state will remain DONG’s biggest owner, with just over 50 per cent of the shares.

v Revision of the Electricity Supply Act
On 29 March 2017, the Minister proposed a bill including important parts of a new Electricity Supply Act. The Act opens possibilities for modernising the electricity supply sector. The new Electricity Supply Act was adopted on 2 June 2017 and will come into force in January 2018.

VII CONCLUSIONS AND OUTLOOK
As is the case for many other countries, Denmark’s energy policy was shaped after the oil crises of the 1970s. As Denmark’s own supply of oil and natural gas is diminishing, Denmark has continuously increased its focus on renewable energy, trying to ensure self-sufficiency. The regulation of the market is strongly influenced by EU legislation and international obligations.
Chapter 12

FRANCE

Fabrice Fages and Myria Saarinen

I OVERVIEW

In France, the energy market has undergone a progressive liberalisation as a result of the European plan to establish a unique energy market that would end national monopolies. This has naturally led to an important legislative and regulatory change, which was codified by an order dated 9 May 2011 and which created the legislative part of the Energy Code. This Code sets out provisions relating to electricity, gas, renewable energy, hydropower, oil and both heating and cooling networks.

This chapter will focus mainly on electricity and gas markets since they have been the main energy markets affected by such changes. It should, however, be underlined that the other sources of energy are also subject to specific regulation.

As a matter of history, after the Second World War, to rebuild the infrastructure and the network, the French authorities decided to grant a state monopoly to Electricité de France (EDF) and Gaz de France (GDF, today Engie) with regard to the production, transportation and distribution of electricity and gas respectively. This situation remained substantially unchanged for half a century until France had to implement into its national law two directives dated 1996 and 1998 adopted by the European Commission to promote an effective and efficient internal energy market, open to competition. These directives were progressively transposed into French law as of 2000 and initiated the beginning of the liberalisation, although initially only large industrial consumers could benefit from this system.

Further opening of the energy market occurred several years later with the transposition into French law of new directives dated 2003, which aimed to make this opening available to all professional consumers by 1 July 2004, and to all consumers, including residential or customers, by 1 July 2007.

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1 Fabrice Fages and Myria Saarinen are partners at Latham & Watkins AARPI. This chapter was written with the assistance of Julie Ladousse, an associate at the firm, and Augustin Destremau, law clerk.
3 Law No. 46-628 of 8 April 1946 concerning the nationalisation of electricity and gas, repealed by Law No. 2004-803.
Although significant progress had been made, the European Commission adopted the Third Energy Package to further liberalise the energy market, which included two new directives replacing the former electricity and gas directives. These directives were transposed into French law on 7 December 2010 by a new law commonly referred to as 'Law NOME', which led to the removal of several obstacles to the development of competition in the French electricity market. Greater price liberalisation for industrial and residential customers has been achieved, notably by requiring EDF to sell a substantial part of its existing nuclear facilities to alternative suppliers at a regulated price, from January 2011 to 2025, so as to allow alternative suppliers to compete fairly with the historical supplier. Finally, France launched an energy transition with the adoption of Law No. 2015-992 on 17 August 2015. This Law established new rules supporting renewable energy production and stated ambitious objectives that were specified by the multi-annual energy programming for the period 2016–2023.

II REGULATION

i The regulators

Compliance with the new energy market regulations is mainly controlled by the Commission of Regulation of Energy (CRE), the sectoral regulator, which was created by the Law dated 10 February 2000. 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:

a powers of decision, approval or authorisation (system operators, contributions to the public electricity sector, etc.);
b dispute settlement and sanctions relative to access to the electricity and gas networks;
c powers of proposal (tariffs for the use of public electricity grids, contributions to public electricity services, etc.);
d information and investigative powers with stakeholders;
e advisory powers (tariffs, regulated access to incumbent nuclear electricity, etc.); and
f additional powers (processing of tenders for electricity generation, etc.).

The CoRDiS committee, which is an independent body of the CRE, acts in matters where the CRE has competence with regard to sanctions, and settles disputes related to the access and use of public electricity grids and natural gas networks.

Further, an energy ombudsman has been put in place whose role is to provide consumers with all necessary information concerning their rights, current legislation and the means of dispute settlement available to them in the event of a dispute.

In addition, the French Competition Authority (FCA) has the power to prevent and sanction anticompetitive practices in any economic sector, including electricity and


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

7 Articles L131-1 to L135-16 of the French Energy Code.
gas. It must inform the CRE when seized of any matter that would fall under the CRE’s jurisdiction. The FCA must also notify the CRE of any abuse of a dominant position or any anticompetitive practice in the gas or electricity sector.8

Finally, the Higher Energy Council is a body established by the Ministry of Energy that is composed of several members including Members of Parliament. Its main purpose is to advise on national energy policy. The Council is consulted on regulatory acts relative to such policy and on electricity and gas market-related decisions.

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

There have now been greater strides towards liberalisation as production and supply are open to competition. Transmission and distribution are still, however, public service activities supervised by the CRE. Where, to guarantee this public service mandate, a legal and financial separation between such activities has taken place,9 transmission is performed by GRT (gas) and RTE (electricity), and distribution is performed by GRDF (gas) and ERDF (electricity) or local distribution companies.10

More generally, some activities, such as the exploitation of electricity production facilities, require an administrative authorisation when the installed power of the facility exceeds a certain threshold, with different thresholds for different types of facilities. This authorisation is delivered by the Minister of Energy according to specific considerations such as security, energy efficiency, technical and economic capacities of the applicant.11 Similarly, gas exploration also requires an administrative authorisation or a concession, which is granted subject to a public enquiry and a tender procedure.12

iii Ownership and market access restrictions
Although the French Energy Code does not provide for any restriction or requirement in relation to the acquisition of assets in the energy sector by foreign companies or individuals, it clearly states that the French state must hold at least 70 per cent of the capital and voting rights of EDF and one third of Engie13 (to protect the French national interest, the state may benefit from specific shares within the capital of Engie).14

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:15

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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.
12 Articles L131-1, L132-3 and L132-4 of the French Mining Code.
worldwide aggregate turnover of all the parties to the concentration exceeds €150 million;

b turnover in France of each or at least two parties concerned exceeds €50 million; and
c the transaction does not meet the EC Merger Regulation thresholds.

The examination process by the FCA is twofold. In Stage I (which takes up to 40 working days), the FCA has 25 working days to examine the transaction starting from the date when a complete notification is received. When remedies are proposed to the FCA, this period is extended by up to 15 working days. At the end of this period, the FCA can clear the transaction, with or without remedies or proceed to an in-depth investigation. In the absence of any decision, the transaction is tacitly cleared.

Stage II takes between 65 and 85 working days. If serious doubts remain as to the competitive impact of the transaction, the FCA proceeds with an in-depth investigation. During Stage II, if the transaction relates to a regulated area, the FCA may request a non-binding opinion from the relevant regulator (e.g., the CRE). At the end of Stage II, the FCA can either clear the transaction with or without remedies or prohibit the transaction.

The FCA’s authorisations for acquisitions may be subject to conditions.16 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.17

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Vertical integration is the process in which different aspects of the market are controlled by a common company or entity. Prior to the deregulation of the energy industry, French energy companies were largely vertically integrated, which created potential conflicts of interest and monopoly situations.

The European Commission issued Directives 2003/54/EC and 2003/55/EC principally to ensure efficient and non-discriminatory network access, ensure free choice of suppliers by consumers, and encourage investment. This legislation was transposed into the French system by a law dated 9 August 2004, which provided for a legal unbundling of regulated activities (distribution and transmission) from non-regulated activities (production and supply). After an inquiry launched in 2005 by the European Commission, however, serious shortcomings in the electricity and gas markets were identified, including an inadequate current level of unbundling between network and supply interests deemed to have negative

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16 See, for example, the decision of the FCA dated 7 February 2012: the FCA made its authorisation of the acquisition of Enerest by Electricité de Strasbourg conditional on a number of commitments designed to resolve competitions concerns, such as the commitment not to make offers for two energies that include at least one component at a regulated tariff. This commitment, the effectiveness of which is to be guaranteed by separating the sales teams responsible for electricity and gas at Electricité de Strasbourg, notably eliminates any risk of the company using its business of supplying energy at regulated tariffs as a tactic to win customers on the open market.

17 Article L151-3 of the French Monetary Code.
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 explained above, these Directives were transposed into French law so that the transmission and distribution system operators would be legally and fully unbundled companies. Accordingly, transmission and distribution system operators must be equipped with all the necessary human, technical, physical and financial resources to fulfil their obligations under French law and, in particular, they must own the assets necessary for their activity.

ii Transmission/transportation and distribution access

Non-discriminatory and fair access to transmission and distribution networks for gas and electricity are at the core of the free market approach. Any discrimination, prevention of new participants from entering the market, and restriction to fair competition in favour of the consumer, is subject to sanctions issued by the CoRDiS committee.

Among the measures guaranteeing such non-discriminatory and fair access, it should be noted that any refusal to enter into an agreement must be justified and notified to the applicant, as well as to the CRE, specifying that any refusal is justified by objective, transparent and non-discriminatory reasons. 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 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.
iv Rates
Access tariffs to networks aim at guaranteeing transparent and non-discriminatory access to public networks. These fees are calculated in a way that cover all costs supported by the system operators (costs arising from their public service duties, the research and development needed to increase the transmission capacity, and the grid connection).

The methodology used to establish access tariffs to the network is set up by the CRE. In addition to fixing the rates, the CRE grants appropriate incentives for transmission and distribution system operators over both the short and long term to increase efficiency, foster market integration and security of supply and support related research activities.26

v Security and technology restrictions
Security of electricity and gas supply is an essential public service obligation.27 The Ministers of Energy and Economy must ensure the fulfilment of this public service mission mainly by EDF, GDF, RTE, GRT, ERDF, GRDF and local distribution companies. In the event of a serious energy shortage, the government may subject energy resources to control and allocation.28 Such measures mainly concern production, imports, exports, storage, acquisition, and transportation. In the event of a serious energy market crisis, or threat to the safety or security of the networks and of people, the Minister of Energy may take protective measures to grant or suspend licences for the operation of power generating facilities.29 In times of war or serious international tension, the government may regulate or even suspend oil import or export completely.30

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

IV ENERGY MARKETS
i Development of energy markets
The sale of energy takes place within either the wholesale market or the retail market. The wholesale market is the market in which electricity and gas are traded (bought and sold) before delivery in the network to final customers (individuals or companies), whereas the retail market concerns the final clients who may freely choose their suppliers (eligible customers).31

The participants of the wholesale market are:

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

26 Articles L341-3 (electricity), L452-2 and L452-3 (gas) of the French Energy Code.
27 Articles L121-1 (electricity) and L121-32 (gas) of the French Energy Code.
28 Article L143-1 of the French Energy Code.
29 Article L143-4 of the French Energy Code.
30 Article L143-7 of the French Energy Code.
31 Article L331-1 of the French Energy Code.
As most of the activity in the wholesale gas market and wholesale electricity market takes place over the counter, through direct transactions or through intermediaries (brokers and trading platforms), the opening of these markets to competition has led to the emergence of organised markets, namely trading platforms (such as Epex Spot France or EEX Power Derivatives France).

**ii Energy market rules and regulation**

Even if the supply of energy is open to competition, it is still subject to certain requirements and monitoring.

First, the sale of electricity or gas is subject to governmental approval. Indeed, suppliers willing to purchase electricity or gas to sell them to consumers need an administrative authorisation that is delivered subject to their technical, economic and financial capacities, and according to their project’s compatibility with the security of supply obligation.

Second, each transaction performed on the French market that would involve the participation of a producer, broker or energy supplier, must be monitored by the CRE, regardless of the trading method (two-way trades, with or without a broker or transactions within organised markets).

Third, free competition is limited with respect to pricing practices since, in certain circumstances, ‘regulated tariffs’ may be chosen within the electricity market by customers having contracted for less than 36kVA. However, because of the European Commission’s unhappiness, especially with the electricity retail market and the dominant position exercised by EDF, Law 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 should bring more competition, with new participants entering the wholesale market.

Finally, the Contribution to the Public Electricity Service, which has been funded since 2016 by the domestic consumption tax on electricity for end users, has been created to compensate public service charges assigned mainly to EDF, such as support schemes for renewable energy or social electricity tariffs.

**iii Contracts for sale of energy**

The legal unbundling between the production and the distribution activities imposed by the energy market creates several inconveniences for the consumer who, as a result, gets an increasing number of contractors, the responsibilities of which are diminished.

To prevent this, the Law dated 7 December 2006, completed by the Law NOME, created a new section in the French Consumer Code entitled ‘electricity supply or natural gas contracts’, the provisions of which apply to contracts concluded by consumers and professionals for less than 36kVA (electricity) or less than 30,000kW (gas).

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33 Articles L333-1 (electricity), L443-1 and L443-2 (gas) of the French Energy Code.
35 Article L337-7 of the French Energy Code.
38 Articles L224-1 to L224-5 of the French Consumer Code.
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’. 39 This contract, which should at least last for one year, thus creates a tripartite relationship between the supplier, the distributor and the consumer, even though the supplier often remains the consumer’s main interlocutor.

The supplier must mention several specific provisions both in the offer and the contract. Failure to do so is subject to sanctions. 40 The consumer can rescind the energy supply contract at any time if it plans on changing supplier. Professionals are not entitled to ask the consumer for any other costs than those incurred by the rescission, provided that these costs were mentioned in the offer. 41

iv Market developments

Market developments have taken place in different areas, and in particular on the cost of electricity with the Law NOME and on renewable energies with the Law on energy transition. Moreover, the renewal procedure of hydraulic concessions has been launched and is ongoing, while the regime of hydraulic concessions has been reformed, notably regarding the procedure applicable to the granting of such concessions. 42

Finally, the implementation of legal frameworks for closed energy distribution systems and for the self-consumption of electricity might enhance the development of local energy markets for the upcoming years.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

In July 2007, the French government launched the Grenelle Environment Forum, a major national consultation that led to the emergence of priority targets in terms of controlling energy consumption and promoting renewable energies. This forum led to the enactment of two ‘Grenelle Laws’, on 3 August 2009 (Grenelle I) and 12 July 2010 (Grenelle II) respectively, 43 aiming at promoting environmental objectives such as the increase of the share of renewable energy to at least 23 per cent of final energy consumption before 2020, in accordance with European Union Directive 2009/28/EC. These laws were codified in a separate section dedicated to renewable energy in the Energy Code. More recently, Law No. 2015-992 of 17 August 2015 on energy transition and its several implementing decrees substantially modified the applicable legal framework on renewable energy.

To enhance the development of renewable energies, public authorities can use two economic instruments: (1) the purchase obligation, 44 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, 45 which

39 Article L224-8 of the French Consumer Code.
43 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.
provides that EDF is obliged to enter into a contract for the purchase of electricity – whose duration shall not exceed 20 years – with renewable energy producers, according to which an additional remuneration shall be paid to them.

ii Energy efficiency and conservation

To achieve a 20 per cent increase in energy efficiency, in accordance with the climate and energy package, on 25 October 2012 the European Union adopted Directive 2012/27/EU on energy efficiency. It lays down rules designed to remove barriers in the energy market and to overcome market failures that impede efficiency in the supply and use of energy, and provides for the establishment of indicative national energy-efficiency targets for 2020.

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

a the creation of an obligation for companies to be subject to an energy audit every four years; 46
b the submission by France of its report on its efficiency energy target to the European Commission on 24 April 2014; and
c the establishment of a requirement for public purchasers to buy products and services and to buy or rent buildings that have a high energy efficiency. 47

iii Technological developments

Directive 2012/27/EU also includes several provisions related to the development of smart grids and smart meters, the aim of which is to reduce bills by paying what was really consumed and by understanding consumption patterns better. The development of smart grids is based on the idea that it improves energy efficiency and better integrates renewable energy resources in the network.

The development of smart grids has also been decided in France. Indeed, a Decree dated 31 August 2010 provided that new connection points must be equipped with smart meters from 1 January 2012 and provided for a test run or pilot for such equipment.

Following the governmental announcement that 35 million smart meters will be provided to electricity customers throughout the country by 2020, the deployment started in December 2015.

VI THE YEAR IN REVIEW

2016 and the beginning of 2017 were characterised by several developments in the energy sector.

i The Conferences of the Parties to the United Nations Framework Convention on Climate Change (UNFCCC)

The Paris Climate Conference (COP21)

From 30 November to 12 December 2015, Paris hosted and presided over the 21st session of the Conference of the Parties to the UNFCCC, which resulted in the Paris Agreement whose aim is ‘to strengthen the global response to the threat of climate change’.

The Paris Agreement entered into force on 4 November 2016, after 55 countries that account for at least 55 per cent of global emissions had ratified it.

The Marrakech Climate Conference (COP22)
From 7 November to 18 November 2016, Marrakech hosted and presided over the 22nd session of the Conference of the Parties to the UNFCCC, which mainly led to discussions on the implementation methods of the Paris Agreement. The commitments of the signatory countries (such as reducing greenhouse gas emissions) will indeed only enter into force in 2020, and decisions in this respect will not be taken before 2018.

ii Creation of a legal framework for the self-consumption of electricity
The Order No. 2016-1019, dated 27 July 2016, created a legal framework that aims at fostering the development of self-consumption of electricity. This order, which was ratified by Law No. 2017-227 of 24 February 2017, notably provides that self-consumption will benefit from reduced access tariffs to electricity networks, and will be exempt from taxes such as the Contribution to the Public Electricity Service.

iii Creation of a legal framework for closed energy distribution system
A legal framework for closed energy distribution systems has been set up by Order No. 2016-1725 of 15 December 2016. The operation of these closed energy distribution systems, which will notably, but not only, be interesting for self-consumers of electricity, will be subject to the issuance of an administrative licence.

iv New legal framework for hydraulic concessions
The legal regime applicable to hydraulic concessions has been amended by Order No. 2016-518 dated 28 April 2016 and Decree No. 2016-530 dated 27 April 2016. These texts notably provide that such concessions can be granted to semi-public companies, and that the concessionaire is required to pay a royalty proportional to the revenues generated by the exploitation of the concession.48

v Multi-annual energy programming
Pursuant to Article 176 of the Law on energy transition, Decree No. 2016-1442, dated 27 October 2016, has set out medium-term objectives about the priorities of action of the public authorities for the period 2016–2023, including notably:

1. the reduction of final energy consumption by 12.6 per cent in 2023;
2. the increase of renewable energy production;
3. the establishment of a strategic plan by EDF on how to reduce the part of the nuclear industry to 50 per cent of electricity production by 2025 within a maximum period of six months; and
4. the prohibition of installation of any new coal plant that is not equipped with a system of gas capture or storage.

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vi High-energy efficiency requirement in public procurements and contracts

Decree No. 2016-412, dated 7 April 2016, created a requirement for public purchasers to buy products and services and to buy or rent buildings that have a high energy efficiency.49

vii Creation of an alternative competition procedure

Decree No. 2016-1129, dated 17 August 2016, created a new competitive procedure, namely, the competitive dialogue procedure,50 that exists alongside the classic tender procedure. This procedure, which resembles the competitive dialogue procedure for public procurement contracts, is specifically intended to foster the development of innovative renewable energies such as offshore wind farms, notably by allowing a reduction of the asked price of electricity, through extended deadlines and increased transparency.

viii Amendment of the schemes providing financial support to renewable energies

The regime, eligibility to and articulation of the two schemes providing financial support to renewable energies (see Section Vi, supra) has been substantially reformed by three Decrees: (1) 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; (2) Decree No. 2016-690 of 28 May 2016 setting out the terms and conditions of the assignment of the purchase obligation contract; (3) Decree No. 2016-682 of 27 May 2016 on the purchase obligation and on the supplementary remuneration.

ix Decree No. 2016-687 dated 27 May 2016

The installed power thresholds above which the installation of an electricity generating facility is subject to an administrative authorisation51 have been raised by Decree No. 2016-687 of 27 May 2016. This Decree notably provides that the threshold for electricity generating facilities using renewable energy, which previously ranged from 12–30MW, is now set at 50MW.52

VII CONCLUSIONS AND OUTLOOK

Since 2007, the liberalisation of the energy market and the energy transition continue together step by step. While historically France is strongly committed to a public energy service, a huge step towards liberalisation and energy transition has been achieved in the past few years, notably so with the end of regulated tariffs and the adoption of the Law on Energy Transition on 17 August 2015, which aims at developing the role of renewable energies.

Furthermore, the implementation of the newly elected President’s energy programme will have to be followed. Emmanuel Macron thus notably intends to maintain the objective of reducing the part of nuclear energy to 50 per cent of electricity production, to close all coal-fired power plants within five years, to fix a bottom carbon price for the European Union, to double the capacity of wind and solar energy production and to maintain the prohibition of shale gas exploration.

50 Articles R311-25-1 et seq. of the French Energy Code.
51 Articles L311-5 et seq. of the French Energy Code.
52 Articles R311-1 et seq. of the French Energy Code.
Finally, the amendment and the adoption by the European Parliament and Council of the European Commission’s Fourth Energy Package and its transposition and implementation by France will have to be closely monitored, as it may put into question the current French support schemes to renewable energies and the remaining gas and electricity regulated tariffs.
Chapter 13

GERMANY

Kai Pritzsche, Julia Sack, Henry Hoda and Ruth Losch

I OVERVIEW

The German energy sector continues to evolve dynamically. The government pursues the reform of the German energy market (the ‘energy transition’), meaning a shift of electricity generation to renewable energies, a substantial reduction of carbon dioxide emissions and a phase-out of nuclear energy. 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. While the cost increase for the support of renewables has already successfully been slowed down, the government has opted against the introduction of a capacity market and in favour of alternative capacity mechanisms in the form of several capacity reserves in order to ensure security of supply. At the same time, the large German energy companies are adapting their business models to the changing market conditions.

II REGULATION

i The regulators

The responsibility for the energy transition and all aspects related to it, including climate change, are concentrated at the Federal Ministry for Economic Affairs and Energy (BMWi). The main national regulatory authority is the Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway (BNetzA) under the authority of the BMWi. The 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. Since 2011, the BNetzA has also played a key role in planning and approving large energy network extension measures. At regional level, the regulatory authorities of the 16 German states are in charge of the regulation of the smaller networks, in particular distribution networks. The regulatory authorities monitor the compliance of network operators with applicable law, and determine the general market rules for transport of electricity and gas. Their duties include the supervision of non-discriminatory network access and determination of the grid operators’ individual revenue caps, and they also ensure that grid operators comply with unbundling rules and with their system security obligations.

The Federal Cartel Office (BKartA) has jurisdiction to apply competition law to the non-network-related parts of the energy supply chain. The BKartA is also in charge of merger control.

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Both the regulatory authorities and the BKartA have wide-ranging powers of enforcement, such as refusal of permits, issue of prohibition orders and imposition of fines. Since 2013, a market transparency unit at the BKartA has been overseeing and publishing fuel prices in order to increase transparency and competition in these markets. Since 2015, a parallel market transparency unit at the BNetzA has supervised the wholesale trade in electricity and gas markets.

Sources of law
The key source of legislation is the Energy Industry Act (EnWG), which was adopted in 2005 and substantially amended in summer 2016. A number of ordinances set out further details, such as the Incentive Regulation Ordinance and the Electricity and Gas Grid Fee Ordinances. As of 2013, a Federal Requirements Plan legally stipulates the economic necessity for certain grid expansion measures. According to the Grid Expansion Acceleration Act, the BNetzA has the competence to carry out the planning procedure for these measures. The Renewable Energies Act (EEG) sets out the priority network access and remuneration for the generation of electricity from renewable sources.

Another important source of law are the administrative decisions of the BNetzA, addressed to individual parties or to groups of network operators. BNetzA also issues general guidelines addressed to the public and interpreting energy sector legislation. The guidelines are not legally binding. However, market participants usually respect them as they form the basis of the BNetzA's decision-making.

ii Regulated activities

Network operation
Operators of distribution and transmission networks must obtain a grid operation permit confirming their personnel, technical and economic capability and reliability to ensure the long-term operation of the network. The permit has to be issued by the competent regulatory authorities of the federal states within six months after the authority has the complete application files at its disposal.

In addition, transmission system operators (TSOs) require certification by the BNetzA confirming their compliance with unbundling regulation. Before taking a final decision, the BNetzA has to submit its draft decision to the European Commission and must take utmost account of the European Commission’s statement. In one instance, the BNetzA rejected certification of an electricity TSO (TenneT TSO GmbH) owing to an alleged lack of sufficient financial means. In 2014, however, the BNetzA agreed to issue the certification subject to the condition that TenneT TSO GmbH undertakes to commission certain offshore grid connections in the North Sea. In another case, the BNetzA rejected the certification of Baltic Cable AB, operator of the Baltic Cable merchant electricity interconnector between Germany and Sweden.

When using public roads, network operators must enter into concession agreements with the municipality owning the roads. Such concession agreements have to be tendered by the municipalities every 20 years in a non-discriminatory procedure without the possibility of unduly favouring their own utilities. In 2017, new rules on the calculation of the grid purchase price and stricter obligations for bidders to file their complaints regarding the tendering process in a timely manner were introduced.
Generation and supply
The construction of power generation facilities requires a permit under the Federal Immission Control Act. The construction and operation of nuclear power plants requires a special permit under the Nuclear Energy Act. However, following the incident at the Fukushima Daiichi nuclear power plant in 2011, the German government decided to phase out nuclear energy by 2022. Hence, commercial nuclear power plants will no longer be authorised.

Besides, operators of power generation facilities with a capacity of 10MW or more have to inform the responsible TSO and the 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 the 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 final consumers must notify the regulatory authority of the commencement and of the discontinuance of their supply activities, including proof of sufficient resources and reliability.

Other than already mentioned, the supply or trading of energy does not require any specific licences under energy regulation provisions.

iii Ownership and market access restrictions
If a transmission system operator or owner is controlled by one or more persons from a country that is not a member of the European Union or of the European Economic Area, the grid operator will only be certified by the BNetzA if it complies with the unbundling rules and if the BMWi confirms that the certification does not endanger the security of the electricity and gas supply of Germany or of the EU.

Under general foreign investment rules, the BMWi may prohibit on the grounds of public order or national security the acquisition by a non-EU or non-EEA investor of a participation of 25 per cent or more in a German company or asset. However, the BMWi has not used these powers so far. In 2014, the BMWi cleared the acquisition of the oil and gas exploration and production division of RWE, RWE Dea AG, by LetterOne arguing that, albeit ultimately controlled by Russian investors, LetterOne is situated in the EU and that the acquisition does not pose a threat to national security.

Apart from the aforementioned restrictions and general unbundling regulation (see Section III.i, infra), there are no rules specifically aiming at a restriction of the ownership of new or existing energy assets.

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 the BNetzA of any intended transactions that may require a reassessment of their certification, particularly in the case of a planned takeover or participation by an investor from outside the EU or EEA.

Any transfer of control or decisive influence must be notified for merger clearance to the BKartA or to the European Commission if certain thresholds are exceeded. A merger
will be cleared if it does not significantly impede effective competition, in particular by creating or strengthening a dominant position. The BKartA decides within one month after notification or, if an in-depth investigation is initiated, within an additional four-month period. The European Commission has a maximum of 135 working days in which to carry out an in-depth investigation to review a merger (maximum of 160 working days if remedies are offered).

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

In implementing the EU’s Third Energy Package, since 2011 the EnWG has provided different unbundling regimes for TSOs and distribution system operators (DSOs).

TSOs

As of 3 September 2009, the German transmission networks were all owned by vertically integrated energy supply undertakings (VIUs); the TSOs could choose between three unbundling models: ownership unbundling, the independent system operator model and the independent transmission operator model.

Most of the TSOs have opted for the independent transmission operator model and some for ownership unbundling. The independent system operator model has not been applied so far. Following several competition law procedures initiated by the European Commission, and owing to the increased regulation of grid assets, three of the four major German VIUs (E.ON, RWE and Vattenfall) have (partially) divested their electricity and gas TSOs. This has resulted in foreign TSOs and financial investors, such as infrastructure funds, entering the German transmission market.

With respect to the ownership unbundling model, the BNetzA holds the view that a person controlling electricity or gas production, generation or supply activities may at the same time hold a minority participation in a TSO of up to 25 per cent, provided that this participation does not confer significant minority rights. This is evaluated on a case-by-case basis.

The European Commission has in the meantime recognised that a TSO may be certified as ownership unbundled despite having a shareholder with a participation in generation, production or supply activities if it can prove that no conflict of interest exists. This will be examined on a case-by-case basis, taking into account in particular the geographic location of the transmission activities and the generation, production or supply activities concerned, the value and the nature of the participations in these activities, as well as the size and market share of the generation, production or supply activities.

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. In 2013, the BNetzA initiated proceedings against several DSOs in order to investigate a suspected breach of their obligation to operate under their own brand. In the meantime, the DSOs have implemented unbundling-compliant brand policies.
At the level of the DSOs there remains a large degree of vertical integration. DSOs typically belong to municipal utilities or to one of the incumbent energy suppliers.

ii Transmission/transportation and distribution access

Connection to networks and network access is regulated. Network operators have to ensure a reasonable, non-discriminatory and transparent connection and access to their grids for all third parties, including extension of the network if required and reasonable (regulated third-party access). By way of exception, priority will be given to network connection and access of operators of renewable energy facilities.

Costs for network connection are in general borne by the network customer, except for renewable energy facilities whose connection costs are socialised.

Access to electricity networks is granted on the basis of 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. As of 1 January 2016, all network operators must grant network access on the basis of a model network access agreement developed by BNetzA.

Access to gas networks is based on capacity bookings in a two-contract entry-exit system: one contract is concluded between the grid customer and the grid operator for the feed-in of the gas, and a second contract is concluded between the grid customer and the grid operator for the offtake of the gas. Gas can be transported and traded without physical restrictions across networks, including on virtual trading points, within each of two gas market areas in Germany (GASPOOL and NetConnect Germany).

Network operators do not have exclusive rights to provide services within their network areas. Transmission and distribution networks are closely interlinked, and operators are obliged to cooperate. Contracts for network access and general terms and conditions are standardised and approved by the BNetzA. The BNetzA has the competence to set detailed rules on network access applicable to all network operators, for example in relation to balancing energy and capacity management.

Network operators may restrict network access to maintain system security. They must use non-discriminatory and market-based measures to prevent or eliminate bottlenecks. The increase in generation of electricity from renewable energy sources and the phase-out of nuclear energy is leading to a shift of generation to northern Germany, resulting in bottlenecks on the north-south transmission lines. Costs for re-dispatch measures of TSOs to relieve bottlenecks more than doubled since 2014 and amounted to €412 million in 2016. These costs 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. The BNetzA reviews the development plans and may request modifications. The necessity of all listed projects is then legally determined by the federal government. The BNetzA is responsible for the actual planning approval for projects that cross the borders between German states.
Rates

Since 2009, grid fees have been subject to revenue cap incentive regulation. Two years prior to the beginning of each five-year regulatory period, the competent regulatory authority determines a grid operator's allowed cost and asset base by analysing its costs of the preceding financial year (photo year). The cost and asset base in the photo year is the basis for the network operator's allowed revenues in the next regulatory period. The regulatory authority sets the grid operator's individual annual revenue cap for each year of the five-year regulatory period, taking into account individual and sector-specific efficiency targets and an allowed rate of return on equity set by the BNetzA. During the regulatory period, the annual revenue cap will in principle only be adjusted in the case of an adjustment of the consumer retail price index or a change of the grid operator's permanently non-controllable costs. As a result, the grid operator has an incentive to outperform its efficiency targets before the revenue cap is reset for the next regulatory period. Based on their fixed revenue caps, the grid operators charge the corresponding access fees to their grid customers.

The permitted rate of return on equity as set by the BNetzA for the current second regulatory period (gas: 2013–2017, electricity: 2014–2018) is 9.05 per cent before tax for new assets and 7.14 per cent before tax for old assets (commissioned before 2006). For the third regulatory period (gas: 2018–2022, electricity: 2019–2023), BNetzA has set the allowed rates of return on equity to 6.91 per cent before tax for new assets and to 5.12 per cent before tax for old assets.

In 2016, the Incentive Regulation Ordinance was amended mainly to improve investment conditions for DSOs. Capital costs for network investments made after the photo year are now recognised in DSOs' revenue caps without delay. Very efficient DSOs may receive an efficiency bonus.

Grid customers with atypical grid use or with continuous and very high consumption (at least 7,000 hours and more than 10GWh per year) have a right to individual network fees below the regulated tariffs. Such individually agreed fees have to be notified to the competent regulatory authority.

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 the BNetzA reviews whether the disruption or destruction of transmission assets in Germany could have a material impact on at least two EU Member States. The BNetzA can declare such assets to be critical European infrastructure. TSOs have to develop specific security plans for such assets, including access control, security of IT systems and emergency protocols. In 2015, an IT Security Act was adopted that shall tighten IT security requirements and extend their scope to all assets required for secure network operation.

ENERGY MARKETS

Development of energy markets

Gross energy consumption in 2016 decreased by 1.1 per cent compared to 2015; gross electricity consumption decreased by 1 per cent. In 2016, gross energy consumption was composed of oil (34 per cent), natural gas (22.7 per cent), hard coal (12.2 per cent), lignite (11.4 per cent), nuclear energy (6.9 per cent) and renewable energy sources (12.6 per cent). Gross electricity generation in 2016 was composed of lignite (23.1 per cent), hard coal
(17 per cent), nuclear energy (13.1 per cent), natural gas (12.1 per cent) and renewable energy sources (29.5 per cent), the latter mainly consisting of wind power (12.3 per cent), hydropower (3.3 per cent), biomass (7 per cent) and photovoltaic (5.9 per cent). These figures illustrate that despite an increased share of renewable energy sources, conventional energy sources are still the backbone of the German energy supply.

Germany still has a joint electricity market area with Austria. However, upon the European TSOs’ proposal for capacity calculation regions (CCRs), in November 2016 ACER determined the CCRs so as to include a bidding zone border between on the one hand Germany–Luxembourg and on the other hand Austria. Meanwhile, the Austrian TSO APG has challenged this decision before the European Court. Austrian stakeholders argue that the German–Austrian interconnector itself is not congested and that congestion within Germany and loop flows to neighbouring countries should be mitigated otherwise.

Germany has two separate dual-quality (high caloric and low caloric gas) gas market areas: NCG and GASPOOL. Within these gas market areas, gas can be traded without capacity restrictions at virtual trading hubs through matching buy and sell orders between two balancing groups. Owing to the decreasing production of low caloric gas in Germany and the Netherlands, until 2029 all grids and customer units will consecutively be transferred to comply with high caloric standards.

The European Energy Exchange AG (EEX) in Leipzig operates organised markets for trading in electricity, natural gas, oil, coal, carbon dioxide emission allowances and guarantees of origin. Electricity futures are offered for delivery in the market areas Germany–Austria, France, Belgium and the Netherlands. Gas futures and short-term gas contracts are traded for delivery in the two German market areas GASPOOL and NCG and in the Dutch Title Transfer Facility. The electricity spot market for Germany–Austria, France and Switzerland 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 – owing to currently low prices for carbon emission certificates – coal-fired power plants. The prices on the spot and forward markets are the benchmark for wholesale prices and over-the-counter trades.

The spot and futures markets are energy-only markets (i.e., there are no capacity payments). The increase in generation from renewable energies has led to a decrease of wholesale prices and has pushed conventional generation capacity out of the merit order, in particular flexible gas-fired power plants.

In order to guarantee security of supply, the Electricity Market Act of July 2016 implemented four capacity mechanisms in Germany. The ‘network reserve’ has existed in principle since 2013. It is composed of ‘system relevant’ power plants, mainly in Southern Germany, that would otherwise be decommissioned, providing additional redispatch potential if necessary. TSOs may also build ‘network stability plants’ themselves in the maximum amount of 2GW if the BNetzA approves their need. The last resort of TSOs to avoid energy shortages in times of extraordinary high demand and extraordinary low supply shall be provided by power plants outside the energy market being remunerated for the provision of capacity via a tendering process (capacity reserve). Until 2023, the function of the capacity reserve will mainly be served by lignite-fired power plants that are being
transferred to the ‘security standby mode’ before being decommissioned four years later. At present, only network reserve and the security standby mode are in operation as the other two reserves still lack the necessary state aid approval of the European Commission.

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 in order to prevent market manipulation.

Under the EU Regulation on wholesale energy market integrity and transparency (REMIT), market participants are required to publish inside information in an effective and timely manner. REMIT also prohibits market abuse in wholesale energy markets in the form of market manipulation and insider trading. Since 2015, market participants have to register with the BNetzA and report details of wholesale energy transactions executed at organised market places to the Agency for the Cooperation of Energy Regulators (ACER).

Since 2014, all EU-based entities that enter into derivatives transactions are required to report details of these transactions to a trade repository under the European Marketing Infrastructure Regulation (EMIR). There is also an obligation to report certain existing and historical derivatives transactions, although deadlines for this vary. Furthermore, EMIR established a central clearing obligation for certain over-the-counter derivatives and the application of risk mitigation techniques for non-centrally cleared over-the-counter derivatives.

iii Contracts for sale of energy

In principle, there are no regulatory limitations as to the entering of individual contracts for the sale of energy, both at wholesale and retail level. However, household customers have a right to be supplied at standard (but not regulated) tariffs by the local supplier with the most household customers within a network area (supplier of last resort). Energy supply contracts with household customers also have to comply with certain transparency and information requirements.

While there is no ex ante price regulation of wholesale or retail energy prices, regulated network charges, taxes and surcharges (such as the surcharge for renewable energies) meanwhile account for more than half of the final energy prices. Competition authorities may review energy prices (except the regulated components) and prohibit dominant suppliers from charging prices that unreasonably exceed costs or that are lower than on comparable markets.

In recent years, price increases for final customers based on the passing-on of input costs (e.g., increase in fuel cost for electricity generation) have frequently been annulled by the courts, arguing that these were not justified or that provisions in energy supply contracts enabling such price increases were not sufficiently transparent. Following landmark decisions of the European Court of Justice and the German Federal Court (BGH) in 2013 and 2014, according to which a standard clause for price adjustments that was widely used in supply agreements is invalid, network operators have to provide information on the scope, reasons and preconditions for the adjustment. In relation to oil price-indexed price adjustment clauses in gas supply agreements, in 2014 the BGH decided that such clauses do not per se constitute an unreasonable disadvantage for the customer if it is an entrepreneur. It is also
settled case law that customers cannot invoke the invalidity of a price adjustment if they have not objected to it within three years of receipt of the relevant invoice containing the price increase.

iv Market developments

The large utilities are increasingly looking for new business opportunities as conventional power generation facilities are driven out of the market by renewable energy sources. E.ON spun off its conventional generation and trading business into a new listed company (Uniper) in order to focus on renewable generation, energy grids and customer solutions. RWE transferred its renewables, grids and supply business to its listed subsidiary Innogy. Vattenfall divested its German lignite business to the Czech investor EPH in order to focus in Germany on district heating, supply and distribution grids. EnBW is also shifting its generation portfolio to renewables.

E.ON, RWE and Vattenfall brought an action before the Federal Constitutional Court against the decision of the German government to immediately shut down eight nuclear power plants following the nuclear incident at Fukushima in March 2011. The action proved to be only partially successful, though not on the financially central points. Further actions by E.ON, RWE and EnBW are pending, in particular regarding nuclear fuel tax. However, the outcome of these proceedings does not call into question Germany's decision to phase out nuclear energy by 2022.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

Reform of the EEG and Offshore Wind Farms Law

On 1 January 2017, a major reform of the EEG, the law governing the development of renewable energy sources, entered into force. The principles of priority network access and priority offtake of electricity from renewable energy sources have not been affected by the reform.

The main aim of the 2017 reform is to control the cost increase for electricity generation from renewable fuel sources. It is aiming to move away from 'produce-and-forget' guaranteed feed-in tariffs towards market-based mechanisms for their remuneration. Therefore, the EEG 2017 introduced auctions as the basic mechanism to determine the remuneration for electricity from onshore and offshore wind power, photovoltaic power and biomass, subject to a number of exemptions; for example, for smaller facilities, for which remuneration remains fixed by law. Auctions for other renewable energy sources, for example, geothermal energy, may be introduced at a later stage. The technology-specific auction volumes are limited to:

- **a** 2,800MW/year from 2017 to 2019 and 2,900MW/year as of 2020 for onshore wind;
- **b** 600MW/year for solar;
- **c** 150MW/year from 2017 to 2019 and 200MW/year as of 2020 for biomass; and
- **d** 6.5GW until 2020 and 15GW until 2030 for offshore wind.

In addition, BNetzA will carry out technology neutral auctions for onshore wind and solar power together in the amount of 400MW/year from 2018 to 2020. The first auction carried out for 1,500MW offshore wind power in March 2017 resulted in an average remuneration
of only 0.44 cents/kWh with most of the capacity being awarded for no subsidies at all. This has been a shock for the industry that will change future calculation and financing of renewables projects.

In addition to the EEG 2017, a new Offshore Wind Farms Law has been adopted that sets out rules for the planning, tendering and approval of offshore wind farms (OWFs). The main aim of the law is to better harmonise the construction of OWFs and their grid connections to the onshore grid. As a main feature, the new law introduces a central planning model in which the Federal Maritime and Hydrographic Agency instead of the developers identifies suitable areas for the construction of OWFs. The law applies to OWFs in the German exclusive economic zone and that will be commissioned from 1 January 2021.

State aid proceedings and support for energy-intensive industries
In November 2014, the European Commission closed its in-depth investigation to examine the compatibility of the EEG 2012 support scheme with EU state aid law. The Commission considered that the EEG 2012 constitutes state aid, but found it, in principle, to be in line with its Guidelines on State Aid for Environmental Protection. However, the Commission considered the reduction of the EEG surcharge for those companies in energy-intensive industries that do not fulfil certain criteria as set out by the Commission in its decision to constitute state aid incompatible with the internal market, and ordered Germany to recover such aid immediately. Meanwhile, Germany has appealed against the Commission’s decision before the General Court questioning the qualification of the EEG support scheme as state aid, but the General Court confirmed the Commission’s decision in May 2016. Germany’s appeal against this decision is currently pending before the European Court of Justice.

As regards the new EEG 2014, the Commission in July 2014 confirmed that it is compatible with EU state aid rules. In December 2016, the Commission also considered the EEG 2017 to be compatible with EU state aid law.

ii Energy efficiency and conservation
In its 2016 progress report on the status of the energy transition, the BMWi concluded that Germany is about to miss its goal to reduce gross energy consumption in 2020 by 20 per cent compared to 2008. Currently, Germany averages an annual reduction of 0.6 per cent although it should be 1.3 per cent. In 2014, the German government adopted a number of immediate and long-term measures to increase energy efficiency in its National Action Plan Energy Efficiency (NAPE). According to NAPE, the energy-saving potential in the building sector shall be better exploited, energy efficiency shall be promoted as a business model and the personal responsibility of households and industry for their energy efficiency shall be increased. In August 2016, the BMWi additionally published a green paper on energy efficiency that started a consultation process on the government’s strategy to reduce energy consumption.

As regards the reduction of greenhouse gas emissions, Germany could, based on current forecasts, also miss its target to reduce emissions in 2020 by 40 per cent compared to 1990. Following the 2015 Paris agreement to keep the global temperature rise this century well below 2 degrees Celsius above pre-industrial levels, the German government in 2016 adopted a national Climate Action Plan 2050 according to which Germany is to reduce its greenhouse gas emissions by at least 55 per cent compared to the 1990 level by 2030 and to at least 70 per cent by 2040.
iii Technological developments

Driven by the need to store the surplus electricity from renewable energy sources, the installation of power storage facilities, both at household and at commercial level, is developing very dynamically; however, from a low level. Storage facilities are based on a large variety of technologies, such as battery storage, power-to-gas, power-to-heat or power-to-liquid. Also, e-mobility increases the speed.

Another technological trend is virtual power plants, which are clusters of small distributed-generation plants, such as combined heat and power units, wind farms or photovoltaic installations dispatched by a central control entity. For new renewable energy installations, the EEG requires basically all generation facilities to be remotely controllable.

As part of the planned grid expansion measures new HVDC (high voltage direct current) technologies are researched and deployed, both offshore and onshore. Owing to local opposition against new transmission lines, underground HVDC cabling will play an important role to increase acceptance of the required grid expansion measures.

In relation to smart meters, the EU has set a non-binding target of rollout to 80 per cent of all consumers by 2020. In September 2016, the Act on the Operation of Measuring Points (MsbG) entered into force, which provides for the introduction of smart meters, including rules on data protection, data access, rollout and financing of the rollout. Due to the high standard on data protection, the certification of the central element smart meter gateway has been delayed. Thus, the rollout is not expected to start before the end of 2017. The MsbG establishes maximum price limits for the installation and service of the smart meters depending on the individual consumption. Provided the maximum price limits are met, from 2017 the installation of smart meters is mandatory for consumers with a consumption above 10,000kWh per year (as of 2020, more than 6,000kWh/year). The installation of smart meters for consumers with an annual consumption below 6,000kWh/year is optional.

In June 2016, a legislative package on hydraulic fracturing of conventional and unconventional gas (fracking) was adopted. This package permits fracking initially only for a few trial projects under very strict conditions, including an environmental impact assessment.

VI THE YEAR IN REVIEW

The fundamental reform of the EEG, introducing auctions as the basic mechanism to determine the remuneration level for the support of power from renewable sources, has already proved successful in countering a further cost increase. The increased share of intermittent renewable generation, however, puts further pressure on the viability of conventional generation facilities. This induced the large German utilities to accelerate the restructuring of their generation portfolios. Instead of introducing a capacity market, the legislator has opted for different reserve capacity mechanisms to ensure security of supply.

Regarding the financing of the phase-out of nuclear energy, the German operators of nuclear power plants now have legal certainty. Pursuant to a legislative package adopted in December 2016, the German state will take over responsibility for the storage of nuclear waste. This is financed by a fund into which plant operators will have to pay €23.6 billion. Plant operators remain responsible for the decommissioning and dismantling of their nuclear power plants, as well as for the packaging of the nuclear waste.

In terms of network regulation, the reform of the Incentive Regulation Ordinance has improved investment conditions for DSOs. However, the allowed rates of return for the third regulatory period will further decline compared to the second period.
With respect to the law on concession agreements for the use of public roads by network operators, it has been confirmed that municipalities must not unduly favour their own utilities in the tendering of concession agreements. Also, the conditions for the transfer of distribution grids following a change of the holder of the concession have been clarified.

VII CONCLUSIONS AND OUTLOOK

The reform process for the German energy markets continues. The 2017 reform of the EEG has been a decisive step towards a comprehensive market integration of renewable generation, and may even call into question the necessity for the further promotion of renewables in the long run.

In order to further decrease the reliance on conventional power sources, the government will need to formulate a coherent strategy for the integration of renewable energies into the heating and transport sector. The reform of the electricity market will have to take into account the development of the European energy market as it will be shaped by the EU clean energy package. At the same time, the large German utilities will continue to restructure their business models and to seek new business opportunities in order to adjust to the changing market conditions.

The market for power-to-X technologies and smart customer solutions will probably evolve further. On the other hand, it is expected that the implementation of the legislative package on fracking will limit the use of this technology in Germany.

The decision of the Federal Constitutional Court on the lawfulness of the immediate shut-down of eight nuclear power plants after the Fukushima nuclear accident may result in further compensation payments to plant operators, but will not call into question Germany’s decision to phase out nuclear energy by 2022.
I OVERVIEW

The Indian economy is undergoing large-scale transformation across various key sectors, and energy security has emerged as one of the key focus areas in unlocking the country’s potential for meaningful development. Along with key policy changes, the government is working towards improving the bankability of key energy assets by restructuring and improving the financial health as well as the operational efficiency of distribution companies, along with continuing its efforts to promote new areas of growth such as India’s offshore wind energy sector and the solar rooftop segment. The primary concerns for the country continue to be providing reliable, uninterrupted electricity to all and finding solutions to the unutilised capacity. While the majority of the contribution to India’s energy mix continues to come from conventional energy sources, the government remains keen on scaling up the Indian renewable energy market and has set a target of 175GW of renewable energy capacity to be installed by 2022. In the past year, India ratified the Paris Convention on Climate Change and aims to produce at least 40 per cent of its installed electricity capacity by 2030 from non-fossil fuels. Encouraged by the success of its initiatives in the renewable energy sector, and to ensure that commitments made to the international community are fulfilled, the government has considerably increased its renewable energy production targets, especially for the onshore wind energy and solar energy production.

II REGULATION

i The regulators

The power sector is governed by the federal government through, primarily, the Ministry of Power and the Ministry of New and Renewable Energy (the Renewable Energy Ministry). Currently, the Ministry of Power, the Renewable Energy Ministry and the Ministry of Coal are under the charge of a single minister to ensure an identity of objectives and synchronisation in policies. The Electricity Act 2003 (the Electricity Act) is the primary statute that governs generation, transmission, distribution and trading of electricity. The Electricity Act provides for the formulation of the National Electricity Policy 2005, the National Tariff Policy 2016 (the Tariff Policy), establishment of independent electricity regulatory commissions at the central level (the Central Electricity Regulatory Commission (CERC)) and state level (the state electricity regulatory commissions (SERCs)) and the setting up of the Appellate Tribunal for Electricity. The relevant SERCs exercise jurisdiction

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1 Neeraj Menon is a partner, Rashi Ahooja is a senior associate and Ankur Arora is an associate at Trilegal.
over intrastate electricity regulatory matters (including tariffs), whereas the CERC exercises jurisdiction over all interstate electricity regulatory issues (also including tariffs). The revised Tariff Policy was announced in 2016, with some of the key highlights being an increase in the solar renewable purchase obligation (RPO) to 8 per cent by 2022, exemption on the payment of interstate transmission charges for wind and solar power projects, applicability of RPOs on co-generation power plants, compulsory procurement by distribution companies of 100 per cent power from waste to energy plants in the respective state and development of intrastate transmission projects through a competitive bidding route for projects above a particular project cost threshold, to be decided by the SERCs. The government also proposed significant amendments to the Electricity Act, particularly in terms of enabling consumers to choose their electricity supplier by segregating the entities that distribute and supply power, stricter penalties for non-compliance with the RPOs and introducing a renewable generation obligation on thermal power producers, requiring them to set up or contribute towards renewable generation capacity. While the proposed amendments have not yet been finalised, the central government is exploring other initiatives with the state governments on measures to make the power sector more competitive.

The Department of Atomic Energy\(^2\) and the Atomic Energy Regulatory Board regulate nuclear energy in India. The government is also in the process of setting up a statutory, independent and autonomous Nuclear Safety Regulatory Authority to replace the Atomic Energy Regulatory Board.

In the past few years, the Ministry of Coal and the state-controlled Coal India Limited (CIL) have been at the receiving end of nationwide criticism for failure to supply the requisite quantity and grade of coal, leading to strong lobbying on the part of power producers for assured coal supplies by the government. In September 2014, the Supreme Court cancelled 204 out of 218 coal blocks allocated to various entities between 1993 and 2010 by holding the procedure of allocation to be illegal and arbitrary. However, with the enactment of the Coal Mines (Special Provisions) Ordinance 2014, and subsequently, the Coal Mines (Special Provisions) Act, 2015 (Coal Mines Act), there has been a push towards ensuring continuity in mining operations and transparency in allocation of coal blocks. In accordance with the Coal Mines Act, which now governs the coal block allocation process, the government has re-started auctioning the cancelled coal blocks and out of the re-auctioned blocks, certain blocks are now operational as well. Further, with the Coal Mines Act having lifted end-use restrictions on the coal mined from some of the re-allocated blocks to enable the sale of coal in the open market, the government is in the process of finalising a detailed mechanism for auctioning of commercial mining leases to both the government and private players. Last year, the Union Cabinet had approved a proposal for flexibility in utilisation of domestic coal with an aim to reduce the cost of power generation. The Central Electricity Authority has now devised a methodology for implementing the use of coal assigned to particular states in the power generating plants in such states, which will improve the efficiency of coal-based thermal power plants by reducing cost of coal transportation and allow coal swapping among plants.

The Ministry of Petroleum and Natural Gas (MoPNG) deals with issues relating to petroleum, natural gas, coal bed methane, shale gas and other petroleum products. Along with exploration and production, the MoPNG also monitors its supply, distribution, marketing and pricing. The Directorate General of Hydrocarbons (DGH), which is under

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\(^2\) Which is directly under the Prime Minister's charge.
the administrative control of the MoPNG, regulates the upstream segments for issues relating to exploration and production of oil and gas. The Petroleum and Natural Gas Regulatory Board (PNGRB) is the midstream and downstream regulator that regulates the refining, storage, transportation, distribution, marketing and sale of petroleum, petroleum products and natural gas.

ii Regulated activities

Electricity generation, including captive generation, is a delicensed activity. While generation activities can be freely undertaken without a licence, approvals and procedures under other laws for land acquisition, environmental, corporate and labour compliance must be adhered to.

Electricity distribution activities (except for distribution of electricity in rural areas) require a licence from the relevant SERC. Electricity trading is a distinct recognised activity for which a separate licence is required from the CERC or an SERC (for interstate and intrastate trading respectively). Licences are awarded by the CERC for interstate transmission activity by way of a competitive bidding procedure in accordance with CERC regulations. For intrastate transmission services, licences are awarded by the relevant SERC. The proposed amendments to the Electricity Act provide for disaggregation of distribution activities by requiring the supplier of electricity and distribution network provider to be separate entities so as to enable consumers to choose their supplier. Once these amendments come into force, supply of electricity will also require a licence from the relevant SERC, and the supply and distribution of electricity will be governed by separate operative codes to be issued by the relevant SERC.

Exploration of oil and gas are separately licensed activities. The DGH awarded licences through international competitive bidding for natural gas exploration blocks under the New Exploration Licensing Policy (NELP) rolled out in 1999. The production-sharing contract (PSC) under the NELP programme stipulated conditions regarding pricing and sharing of total product obtained with the government. The DGH has successfully carried out nine rounds of bidding under NELP, in which 254 oil and gas blocks have been awarded.

The MoPNG notified the New Domestic Natural Gas Pricing Guidelines 2014, which provide for the prices to be fixed on the basis of the annual average of the price of gas at specified international hubs, and require notification of the prices determined by the government on a biannual basis.

The Coal Bed Methane (CBM) Policy 1997 offered blocks for exploitation of CBM through biddable revenue-sharing based on production-linked payment. The Policy specified modalities regarding the commercial development of CBM, identification and allotment of blocks and fiscal incentives or provisions. DGH became the nodal agency for development of CBM in the country. In 2016, The Standing Committee on Petroleum and Natural Gas of parliament submitted a report on the production of CBM and recommended a revised CBM policy, which is expected to be issued later this year.

Recognising the constraints experienced in the present PSC format and differences in the fiscal and contractual regime for oil and gas and CBM, the government has framed the Hydrocarbon Exploration Licensing Policy (HELP), which provides for a uniform licensing system to cover all hydrocarbons, such as oil, gas, coal bed methane, etc., under a single licensing framework, allowing the possibility of exploring overlapping resources in a single block. Under HELP, both foreign and domestic companies can have a 100 per cent participating interest without the involvement of a government company in a joint venture.
Among the ostensible reasons for concluding the NELP is the fact that blocks that were bid for under numerous PSCs are mired in disputes over the inflating costs of production and deteriorating production of oil and gas. Through HELP, a revenue-sharing arrangement is proposed to be implemented, where bidders will be selected based on their upfront revenue-sharing commitment offered to the government, which will be payable from the first batch of production. The revenue-sharing model will not be subject to cost recovery and therefore aims at eliminating the often tedious process of cost scrutiny that the government was required to undertake under the previous regime. Although the move to a revenue-sharing model has largely been well received, a few industry participants are likely to get discouraged under the new model as the investment recovery periods for companies will increase. The HELP has also introduced an open acreage policy in India (OALP), which permits the licensee to exploit the full range of hydrocarbons accessible in a single block and allows companies to approach the government at any time, expressing their interest in bidding for one or more blocks, after which the government would invite competitive bids from others interested in the same blocks. However, for the OALP to be made operational, it is critical for the DGH to build a reliable national data repository of, among others, potential blocks for the exploration and production of various hydrocarbons.

The government has also introduced policy guidelines for exploration and exploitation of shale gas and oil by national oil companies, pursuant to which, the oil companies have started the first phase of assessment and have initiated exploration activities in 50 areas. While the potential shale gas reserves overshadow those of conventional gas, India has a long way to go in identifying shale gas-rich basins and acquiring the necessary technology and experience to extract shale gas, specifically in the absence of private participants.

Petroleum, natural gas and city gas distribution (CGD) networks can be developed either through an expression of interest to the PNGRB or under competitive bids invited by the PNGRB. Under the expression-of-interest route, the PNGRB must publicise upon receipt such an expression of interest, to receive proposals or comments from different entities, and may invite competitive bids or allow for the proposal (with or without modification).

iii Ownership and market access restrictions

Over the past decade, the government has progressively liberalised the energy sector, although government companies continue to be active players. Up to 100 per cent foreign direct investment is permissible in generation (except nuclear power), transmission, distribution of electricity and power trading, as well as in the oil and gas sector and up to 49 per cent in power exchanges without prior regulatory approval. Such investments are subject to sector-specific laws and policies.

A majority of generation, transmission and distribution capacities are with either public sector companies or with state electricity boards (SEBs), however, private sector participation is increasing, especially in generation and distribution. The interstate transmission system is mainly owned and operated by Power Grid Corporation of India Limited, a state-owned company, and the intrastate transmission system is owned and maintained by state utilities. However, the public–private partnership (PPP) structure is increasingly preferred by the government for setting up interstate and intrastate transmission networks. Electricity distribution is largely in the control of government distribution companies, with privatisation

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3 Investments of up to 49 per cent are permitted in petroleum refining undertaken by public sector entities.
being slow largely on account of the huge legacy liabilities of the state distribution companies. However, a few examples of privatisation in certain areas (such as Delhi, Orissa, Ahmedabad, Mumbai and Jamshedpur) have met with success.

In India, the ownership of all mineral resources, including oil and gas, vests with the government, and is administered through the MoPNG. The Gas Authority of India Limited and the Oil and Natural Gas Company are the largest owners of oil and gas pipelines in the country. Private players are increasingly entering the CGD space in urban areas.

iv Transfers of control and assignments
While there are no specific restrictions on transfer of control or assignment of a generating company, power purchase agreements issued pursuant to certain renewable energy policies and bidding documents for thermal and nuclear power procurement provide for shareholding restrictions for a certain period post-commercial operation. For instance, the Ministry of Power’s revised standard bidding documents for long-term (seven to 25 years) procurement of power from thermal power projects (Revised SBDs), provide for a lock-in period (though on a sliding scale) of up to 10 years following commercial operations.

Holders of licences for oil and gas exploration can transfer or assign all or part of their participating interest under the PSC, including any change in control of a party, with prior consent of the government.

Other than these sector specific restrictions, provisions of the Companies Act 2013, Competition Act 2002, and the Securities and Exchange Board of India (Substantial Acquisition of Shares and Takeovers) Regulations 1997 (applicable to listed companies) will apply with respect to change in shareholding through mergers and acquisitions.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES
i Vertical integration and unbundling
Under the Electricity Act, SEBs were required to be unbundled into separate generation, distribution and transmission companies and most states have now completed the process. Transportation, distribution and marketing activities in the oil and gas sector are yet to be unbundled. While the PNGRB had circulated a concept paper on unbundling of activities of transportation and marketing of natural gas, no policy decision has been taken on this aspect.

ii Transmission/transportation and distribution access
In the electricity sector, transmission licensees must provide non-discriminatory open access to its transmission system for use by other persons (including electricity distributors, traders and generating companies). Open access to distribution networks is also granted to bulk power consumers (i.e., consumers of above 1MW), to procure electricity at unregulated prices from entities other than the area distribution licensee. Separately, the government has the ability to issue directions to generators on operation of their power stations in extraordinary circumstances, a tool that more often than not has been used by state governments to restrict supply of power outside the state (in the event of a shortage).

The PNGRB prescribes an access code for common or contract carrier natural gas pipelines, regulations for capacity release for natural gas pipelines and requires natural gas transporters to declare capacity available for common carriage on a monthly basis.
iii Terminalling, processing and treatment

The PNGRB regulates the storage and treatment of oil and gas, including prescribing the eligibility conditions for registration of liquefied natural gas (LNG) terminals and prescribing the technical and safety standards for pipelines and CGD networks.

For imported LNG, the price under the term contracts and spot cargoes are mutually determined and are usually very high. Consequently, the MoPNG is currently exploring options such as price pooling to average out the prices and now that new pricing guidelines have been introduced, it is to be seen whether a separate price pooling mechanism will be adopted by the government.

iv Rates

Under the Electricity Act, transmission schemes are implemented either through the tariff-based competitive bidding process or under a cost-plus mechanism where a regulated tariff is determined by the relevant electricity commission. The CERC adopts a ‘point-of-connection’ method for calculating interstate transmission charges and losses, which aims at developing a uniform transmission charge-sharing mechanism among grid constituents. However, to help meet the proposed target of 175GW of renewable energy capacity by 2022, the government has, among other measures, exempted the payment of interstate transmission charges for wind and solar power projects under the new Tariff Policy. The tariff for electricity distribution, comprising wheeling charges and cost of supply, is levelled and determined on a cost-plus basis by the relevant SERC.

The PNGRB has enacted regulations for determination of transportation tariff for petroleum and petroleum products, natural gas pipelines and CGD network. The tariff for such pipelines is determined taking into consideration a reasonable rate of return on the normative level of capital employed plus a normative level of operating expenses in the relevant pipeline.

v Security and technology restrictions

With a sophisticated energy infrastructure and now smart grids being proposed, cybersecurity concerns are paramount. The Information Technology Act 2000 addresses hacking and security breaches of information technology infrastructure. The government issued a National Cyber Security Policy in 2013, which aims at creating a secure cyber ecosystem, encourages use of open standards to facilitate interoperability and data exchange, and provides for creating mechanisms for security-threat early warnings and vulnerability management.

Technology transfers into India are permitted in all sectors, including energy. All payments made for technology transfers into India are subject to Indian exchange control regulations. Export of technology transfers for specific sectors requires a licence under India’s Foreign Trade Policy.

IV ENERGY MARKETS

The National Electricity Policy 2005 envisions 85 per cent of power from new capacities being contracted through long-term power purchase agreements (PPAs) and the remaining 15 per cent power capacity through market mechanisms. It is also expected that more merchant capacity will be available in the next few years as the Revised SBDs provide for a quantum of installed capacity to be sold at market-determined prices.
The power market is dominated by long-term contracted power. For thermal power projects (coal and gas) and hydro projects, long-term power is procured through a negotiated route or pursuant to a competitive bidding route. The Ministry of Power has directed state governments and distribution companies to procure power under the competitive bidding route (except that mandatory competitive bidding for hydropower projects has now been postponed till the end of 2022). Bidding for long-term procurement from thermal power stations can be done on the basis of the Revised SBDs that provide for two modes of bidding and supply of electricity. Under the DLFOO model, a distribution licensee invites bids to procure a specified quantum of power, while also prescribing the type of fuel and technology that is to be used for the supply. Under the DBFOT model, a distribution licensee invites bids for setting up a project on the basis of the lowest tariff, while also specifying the fuel and location of the project (which is required to be arranged by the distribution licensees).

To specifically address stakeholder concerns on determination and impact of rising fuel import costs, the Revised SBDs provide for the cost of imported fuel to be benchmarked at actuals and linked to prevailing prices on international indices. In 2015, the government further amended the guidelines for procurement of power through the DBFOO route to revise the tenure to seven to 25 years and allowing the distribution licensees to deviate from the revised SBDs with the prior approval of the CERC or SERCs, allowing more flexibility for procurement of power.

While several states have commenced (and some have even concluded) the bidding process under the DBFOO model, the DBFOT model has met with severe criticism from market players, who have voiced concerns on the inequitable apportionment of risks. This has resulted in the Ministry of Power constituting a committee to review the DBFOT standard bidding documents, pursuant to which the further revised bidding documents for the DBFOT model are expected to be released by the ministry later this year.

While long-term procurement remains a top priority, the government is also determined to set up the short-term and medium-term markets for procurement of electricity. In January 2017, the government issued revised guidelines for procurement of electricity on medium term (one to five years) from power stations set up on a finance, own and operate basis. The revised guidelines mandate tariff determination through an open and transparent e-auction, with an overall aim of reducing power procurement costs. Similarly, guidelines for short-term (i.e., for a period of more than one day to one year) procurement of power by distribution licensees through a tariff-based bidding process have also been amended in 2016 to introduce the concept of reverse auction on an e-platform in the short-term supply of power.

In 2015, the Ministry of Power issued a notification introducing a targeted gas supply scheme focused on gas based thermal power plants with stranded capacity. The scheme envisaged facilitating the import of requisite quantities of gas with considerable incentives in the form of tax exemptions on the import and regasification of LNG as well as discounted gas transportation rates for financial year 2015–2016 and financial year 2016–2017. A target of 30 per cent plant load factor was set for the operational and stranded power plants, which was to be achieved towards the end of 2015–2016. Although the plant load factor remains around 30 per cent, the scheme has not been extended for the current financial year.

4 The DBFOO model refers to a project set up on a design-build-finance-own-operate basis.
5 The DBFOT model refers to a project set up on a design-build-finance-own-transfer basis.
On the distribution front, the major problems plaguing the power sector in India are the abysmal credit ratings of the state distribution companies and their persistent failure to honour payments to generators under PPAs or extensive delays in doing so. Distribution companies have borrowed heavily to finance losses in their businesses, and are facing major hurdles in repaying their debt. The government launched the Ujwal Discom Assurance Yojana (the UDAY scheme) in November 2015, with the objective of improving the operational and financial efficiency of state-owned distribution companies. One of the major features of the UDAY scheme involves requiring participating states to take over 75 per cent of the debt of distribution licensees by way of a grant over a period of two years and issue non-statutory liquidity ratio bonds, including state development loan bonds for subscription by pension funds, insurance companies and other institutional investors. Under the UDAY scheme, lenders and financial institutions will not levy prepayment charges on a distribution licensee’s debt, and will waive off unpaid overdue interest, including penal interest. For financing future losses and working capital of distribution companies, state governments will take over and fund future losses in a graded manner until financial year 2020-2021. The state governments have come forward in their support of the scheme and, at the time of writing, 27 states have signed up for the UDAY scheme, with almost all major distribution companies covered by UDAY. The state distribution companies participating in the scheme have reported significant interest cost savings and a sharp reduction in revenue losses.

For renewable energy projects, contracts are entered into with state utilities under specific state policies at preferential tariff or through competitive bidding depending on the state or central policy. Other modes of power sale include captive consumption and sale to consumers through open access. The CERC, through its Power Market Regulations 2010, seeks to promote and regulate interstate electricity transactions in various contracts (such as ancillary services market contracts and trading in renewable energy certificates (RECs)).

In December 2016, the Ministry of Power, in consultation with the Ministry of External Affairs, issued guidelines for cross-border trade of electricity with neighbouring countries like Bhutan, Nepal and Bangladesh to facilitate the cross-border trade with greater transparency, consistency and predictability. The tariff for the cross-border transaction is proposed to be determined through government-to-government negotiations, and then adopted by the relevant electricity regulatory commission. The guidelines also aim at evolving a dynamic and robust infrastructure along with reliable grid operation for cross-border transactions of electricity.

The REC is a market-based policy instrument introduced to increase and promote renewable energy capacity. Renewable energy producers who opt for the REC route are issued tradeable generation-based certificates that represent the renewable energy component of electricity generated, in addition to the average pooled cost of electricity from non-renewable sources of electricity of the past year. Generators who opt for the REC route cannot opt for the preferential feed-in tariff offered by the state distribution companies. These RECs can be bought by certain obligated entities (such as electricity distribution licensees and captive power consumers) to fulfil their RPOs.

In 2016, the government introduced HELP to revive the ailing gas market by providing for pricing freedom for gas discoveries in blocks that were yet to commence commercial production. HELP also removed restrictions on the companies on exploration by allowing them access to the national data repository maintained by the government that has the data and gives them the discretion to explore the areas for gas as per their choice. In addition to HELP, the New Domestic Gas Pricing Guidelines were introduced with the underlying
principle that producers in India should get a price similar to the rates prevalent in the international markets, which, in turn, is expected to increase investment in the sector and reduce the dependency on imports. However, the government recently issued a notification stating that the domestic gas pricing regulations will not be applicable on coal bed methane, and granted the coal bed methane producers marketing and pricing freedom to sell CBM at arm’s length price in the domestic market.

After the Supreme Court cancelled 204 out of 218 coal blocks in September 2014, the government has proceeded to auction these cancelled coal blocks through a transparent e-auction process, and 83 blocks have already been allocated out of which 31 coal blocks have been allocated through e-auction.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

The regulatory environment increasingly seeks to incentivise renewable energy, with favourable tariff regimes established by SERCs. The Electricity Act, the National Electricity Policy and the Tariff Policy encourage private sector participation in renewable energy through measures such as providing for feed-in tariffs, fixing minimum RPOs for distribution companies and captive power users and providing incentives such as accelerated depreciation schemes, excise duty exemptions and reduced customs duty on renewable energy equipment. In addition, a renewable energy project developer is also entitled to receive RECs if it does not opt for preferential feed-in tariffs. Several states have put in place specific policies to promote renewable energy development, however, incentives and policies are not always consistent between states and developers often shop around based on the policy that best suits their financial model and operational expertise. Consequently, the development of renewable energy in India is geographically skewed.

Onshore and offshore wind power

Wind energy accounts for a substantial portion of the installed renewable capacity in India. India added 5,400MW of wind power in 2016–2017, exceeding its actual target of 4,000MW. Wind power policies vary from state to state and policies in certain states are rated more highly for the incentives they provide and availability of a (more or less) single-window clearance mechanism. However, the incentives offered by the government have been reduced this year as the wind power projects can now only claim accelerated depreciation of up to 40 per cent (reduced from earlier limit of 80 per cent) and the generation-based incentives (i.e., a monetary entitlement per unit of electricity fed into the grid) that were previously given have been withdrawn from this financial year.

The central government issued new guidelines in 2016 for onshore wind power projects after a gap of around 20 years. The guidelines contain, inter alia, clear timelines for completion of project to prevent land squatting; provisions to ensure installation of international-quality wind turbines compliant with grid regulations; and provisions regarding environmental suitability of wind projects. These guidelines, issued by the central government, are in addition to the wind policies issued by the various state governments. The government also issued the National Offshore Wind Energy Policy in September 2015 with the aim of promoting the country’s offshore wind energy potential. The principal agency charged with the development of the sector is the National Institute of Wind Energy (NIWE). Under this policy, blocks are to be allocated through a competitive bidding route and developers are required to enter
into seabed lease agreements with NIWE. In additional to allocation of blocks, NIWE is also required to carry out the initial wind resource assessment and assist the project developers in obtaining clearances. Taking steps towards harnessing this enormous potential, the Environment Ministry has given its approval to a wind measurement project in the Gulf of Kutch, near the Gujarat coast, for setting up an offshore data collection platform for survey, investigation, exploration, data acquisition and other related technical studies in territorial waters. Unlike the procurement of solar power, wind power procurement was not done on competitive basis until 2016. The first ever tariff-based auction for long-term wind power contracts on an inter-state procurement basis was conducted this year, which has resulted in record low tariff of 3.46 rupees/kwh. Encouraged by its success, the government has issued draft guidelines for procurement of wind power through competitive bidding. To ensure investor confidence, draft guidelines have various payment security mechanisms, including issuance of letters of credit for unpaid bills, setting up a payment security fund by distribution companies in favour of the project developers and provisions for legally enforceable state government guarantees. However, the final guidelines are yet to be announced.

Solar energy

Solar plants can be set up under the Renewable Energy Ministry’s National Solar Mission (NSM, previously the Jawaharlal Nehru National Solar Mission), as well as under state policies. As is the case with wind energy projects, the accelerated depreciation limit has been reduced to 40 per cent on solar assets. Other incentives such as achievement-based incentives, subsidy programmes and tax benefits continue to be allowed on solar assets.

After successfully implementing both batches of Phase I, and Batch I, II and III of Phase II of the NSM, the Renewable Energy Ministry has issued final guidelines for Batch IV of Phase II of the NSM, which proposes to add capacity aggregating 5,000MW. In a departure from Batch II Phase II (but similar to Batch I Phase II and Batch III Phase II), solar power in Batch IV is proposed to be procured under the viability gap funding (VGF) scheme, where the tariff is predetermined and bidders are selected on the basis of the quantum of discount they are willing to accept on the VGF to be provided by the government. Giving a major push to the solar power development, especially the large scale photovoltaic (PV) projects, the government has increased the capacity of solar parks (involving projects of multiple developers) from the existing 20,000MW to 40,000MW.

The government recently issued revised draft guidelines for procurement of solar power through a competitive bidding route. With the aim of making projects under the NSM more bankable, under the revised draft guidelines, the government introduced the concepts of deemed generation payments (if the evacuation grid is unavailable for reasons not attributable to the solar power generator) and termination compensation. Similar to the draft wind power guidelines, these draft guidelines for solar projects also provide for payment security mechanisms, including issuance of letters of credit for unpaid bills, setting up a payment security fund by distribution companies in favour of the project developers and provisions for legally enforceable state government guarantees. The government’s decision to put forward these concepts is reassuring for the developer and lender community. However, the final guidelines have not yet been issued by the government and it therefore remains to be seen whether these provisions will be included when the final guidelines are issued.

On the domestic manufacturing front, the sector suffered a setback in 2016 when the World Trade Organization (WTO) ruled against the inclusion of certain domestic content requirements (DCR) in the tenders under the NSM. The guidelines under the NSM had
prescribed certain DCR to promote local manufacturing capability and attract efficient and advanced technology. In response, the United States raised a dispute at the WTO following failed consultations regarding the DCR for solar cells and modules (having once challenged the requirements under Phase I as well). It has claimed that the requirements (although for a portion of the total capacity) are in violation of India’s international trade obligations, as they discriminate against foreign suppliers. The WTO in its findings, stated that India’s DCR are trade-related investment measures, thereby violating the Trade Related Investment Measures Agreement and provisions of the General Agreement on Tariffs and Trade (GATT) by providing less favourable treatment within the meaning of GATT. India appealed the WTO’s decision before the WTO Appellate Body, which was rejected this year. Following the WTO ruling, there have been no fresh solar bids involving DCR. In another related development, the government has rejected a proposal to implement anti-dumping duties against imported solar cell technology. This decision of the Renewable Energy Ministry acknowledging that the current capacity of domestic manufacturing is inadequate to meet the targets for solar capacity addition, and focusing on growing the market first before promoting domestic manufacturing, has been hailed as highly pragmatic and investor-friendly.

To combat global warming and climate change, the International Solar Alliance (ISA), which is a partnership of more than 120 solar resource rich countries, was officially launched in 2015 with its headquarters in India. The objective of the ISA is to create a coalition for addressing the special energy needs and capacity building among the member countries in a collaborative manner. More than 20 countries, including India, have signed the Framework Agreement to see the ISA becoming an intergovernmental body under the UN charter.

In addition to setting up solar generation capacity through solar power plants and solar parks, various states are also looking to promote the setting up of both grid-connected and off-grid solar rooftop systems. The government launched a US$750 million subsidy scheme for rooftop solar projects to provide close to 30 per cent of the capital subsidy required. The government has already allocated around US$90 million in subsidies to various states in the country. In a bid to further encourage the use of solar rooftop systems, the government has recently exempted customs and excise duty on materials used in solar rooftop systems. Additionally, state governments are promoting the installation of such systems by introducing enabling legislation, such as net metering regulations. Solar Energy Corporation of India, which is a central government company under the administrative control of the Renewable Energy Ministry, issued a tender for 1,000MW capacity for the development of grid-connected rooftop solar capacity, utilising the rooftops of central government ministries and departments, reduced to 500MW after reassessment of the potential capacities of all the government ministries and departments. That said, the regulations for solar rooftop systems are not comprehensive, and there is ambiguity as to whether such systems will be treated as captive generating plants under the Electricity Act and rules, which are typically exempt from the payment of cross-subsidy surcharges, transmission or wheeling charges, or open access charges.

**Biopower and waste-to-energy projects**

The Renewable Energy Ministry has proposed to launch the National Bioenergy Mission (along the lines of NSM) to boost power generation from biomass by facilitating capital investments and reducing use of fossil fuels.

In the context of municipal waste-to-energy projects specifically, there is significant scope in Indian cities for business; however, several challenges are being faced by ongoing
projects. While there is opposition on account of environment and health hazards for the communities living in proximity to these projects, and low quality of waste because of lower calorific value, the government is trying to promote schemes to encourage cities and municipalities to take up waste-to-energy projects in PPP mode. Recently, India launched its largest waste-to-energy plant in Delhi, which will consume 2,000 metric tonnes of waste every day and shall generate 24MW of energy. The revised tariff policy mandates power distribution companies to buy 100 per cent of the electricity generated from the waste-to-energy plants in their respective states.

ii Energy efficiency and conservation

To institutionalise energy conservation efforts, the Energy Conservation Act 2001 was enacted and the Bureau of Energy Efficiency (BEE) was established under the Ministry of Power in 2002. Periodic energy audits have been made compulsory for power-intensive industries under the Energy Conservation Act.

The National Electricity Policy affords high priority to energy conservation and demand-side management through the BEE. To further enhance efficiency in thermal power projects, the Revised SBDs specify the station heat rate at which the power stations must be operated, failing which the developer is heavily penalised by a decrease in the fixed charge. Additionally, the CERC tariff regulations provide for operational norms such as reduction in heat rate for existing bigger units, linking of allowable heat rate to design heat rate, tightening of working capital norms, and norms on reduction in secondary fuel oil consumption.

iii Technological developments

The National Electricity Policy envisages special efforts being made for research, development demonstration and commercialisation of non-conventional energy systems. Further, it envisages the gradual introduction of efficient technologies (such as super-critical technology and integrated gasification combustion cycle) for generation of electricity. It also requires cost-effective technologies to be developed for high-voltage power flows over long distances with minimum possible transmission losses.

VI THE YEAR IN REVIEW

In the past year, the government has continued to introduce a spate of reforms across the energy spectrum, backed by swift executive action, which have enthused stakeholders in a hitherto stagnating market. The UDAY scheme appears to be a step in the right direction as it has managed to reduce the debt of various distribution companies and has been successful in enforcing stricter financial discipline, with the larger aim of aligning consumer tariffs with the cost of generating electricity. In the coal sector, although long overdue, the decision of the government to allow flexibility in utilisation of domestic coal and increasing the annual permissible amount of coal for sale to units in small, medium and other sectors by state nominated agencies has been received positively in the market. The decision to allow flexibility in the utilisation of domestic coal will allow coal-based thermal power producers the option of reducing costs and improving efficiency by allowing coal swapping among plants and reducing the cost of coal transportation.

In a landmark decision, this year, the Competition Commission of India (CCI) imposed a penalty of 5.91 billion rupees on Coal India Limited for abusing its dominant position, in relation to its fuel supply agreements with generation companies. CCI had originally imposed
a penalty of 17.73 billion rupees; however, the Competition Appellate Tribunal set it aside and asked the regulator to take a fresh look at its order. Although, the CCI has reduced the penalty, such imposition of penalty heralds a new approach of preventing monopolistic practices of government instrumentalities.

The Reserve Bank of India has also fine-tuned its scheme for long-term flexible finance structuring for infrastructure projects and debt-heavy power projects. Under the revised scheme, lenders are allowed to fix longer amortisation periods, say 25 years, which allow for refinancing to take place at five-year intervals. Similarly, providing further relief to these debt-heavy power projects, the government has approved a proposal where if an arbitral tribunal is passed against the government instrumentalities and the award is challenged in a court of law, government agencies would pay 75 per cent of the arbitral award amount to an escrow account against margin free bank guarantee. The proposal, if implemented as intended by the government, could substantially reduce the debt burden of these concessionaires or developers and make their balance sheets healthier.

In the transmission sector, giving a boost to large-scale transmission projects – which includes setting up the ‘green energy corridor’ to provide for additional large-scale renewable energy capacity – the government has launched the National Smart Grid Mission (NSGM), with a broad aim of planning, implementing and monitoring all the smart grid projects in the country. Through the NSGM, the government plans to develop smart microgrids by using state-of-the-art technology to monitor and control power flows. However, renewable energy project developers believe that the current grid infrastructure is inadequate to complement the rapid growth witnessed by the renewable sector.

In the nuclear power sector, India’s failed attempt to gain membership of the elite Nuclear Suppliers Group despite an unprecedented diplomatic push has been a major setback to India’s aim for energy security and combating climate change. India’s commitment to reduce its dependence on fossil fuels, and to ensuring that 40 per cent of the country’s energy requirements are met from non-fossil fuels, requires a significant ramp-up in nuclear power production. There were certain concerns of suppliers and manufactures of nuclear material and equipment who feared the possibility of exorbitant liability being passed on to them by an operator under the Civil Liability for Nuclear Damages Act 2010 in the event of a nuclear accident. The government of India has clarified that while the legislation would not be amended, it was not mandatory to include a civil liability clause in the contractual arrangements between the foreign supplier and the Indian operator. Critics are of the view that the government’s interpretation of the law is problematic in that liability will not be traced back to a supplier of nuclear equipment or material as they would rarely agree to a civil liability clause when it is not mandatory under Indian law. However, to allay the concerns of suppliers regarding their liability, the India Nuclear Insurance Pool, with a capacity of 15 billion rupees, was launched by Indian insurance companies. It provides coverage to operators and suppliers for any nuclear liability towards third parties.

At the international policy arena for energy sector, India has been successful in establishing the ISA, which is an Indian initiative and could help India in aligning its energy ambitions in the future. India has also joined the International Energy Agency this year as an associate member, which would help India to move to the centre stage of the global energy dialogue and to better represent the interests of the emerging markets.

One of the major developments of the past year came when the government announced the new Tariff Policy in January 2016. Under the revised Tariff Policy, solar RPO was fixed to 8 per cent by 2022 and the renewable generation obligation on thermal power plants were
introduced, which has been well received in the renewables market. While the introduction of the once promising system of RPOs and RECs resulted in a market where supply of RECs greatly outstripped demand on account of non-enforcement of RPOs, recent amendments by the CERC to the floor and ceiling price of solar RECs has resulted in a marked rise in the number of solar RECs traded on the market, albeit at the floor price. Further, the Supreme Court has made it mandatory for industries with captive power plants to procure a percentage of their energy from renewable sources and empowered the SERCs to impose penalties on units that failed to fulfil its obligations, which has further shored up the REC market.

The government has been striving for increase in production of renewable power through the use of advance technology by proposing installation of ‘ultra-mega solar power projects’, and through innovative solutions to capitalise on abundant solar energy by proposing solar parks along canal banks and solar power-driven agricultural pump sets and water pumping stations. The government has also proposed feeder separation to augment power supply to rural areas, and to strengthening transmission and distribution systems.

The tariffs determined by the competitive bidding process for the procurement of solar power have fallen steeply over the past year. India achieved its record-low tariff of US$ 4.9/kWh in the bid for a 750MW solar PV project at the Rewa Solar Park in Madhya Pradesh, which is one of the largest single-site solar projects in the world. Industry experts are attributing such a low tariff to the overall project design, with bidding documents that were largely seen as developer-friendly owing to provisions such as state guarantee, identified buyers and deemed generation benefits. The government has also given a massive thrust to increase the share of wind energy in the overall installed energy capacity of the country by introducing various policy initiatives in the past year in the wind energy sector that include the introduction of bidding in the wind energy sector; the Re-powering Policy; the Draft Wind-Solar Hybrid Policy; the New Guidelines for Development of Wind Power Projects, etc. Further, the promotion of solar rooftop projects by various state governments is a discernible trend, with a number of states issuing net metering regulations and upgrading local grids to match the growth of the solar rooftop sector.

As regards interstate scheduling and forecasting obligations for wind and solar plants, the CERC amended the Indian Electricity Grid Code and Deviation and Settlement Regulations, making scheduling mandatory for wind and solar plants with a capacity of over 50MW. The deviation settlement mechanism, which has replaced the unscheduled interchange mechanism, allows scheduling with a plus-or-minus 15 per cent range, with penalties payable by the generators for exceeding the permissible range, based on the tariff under their respective power purchase agreements. To complement the interstate regulations, several states have issued their draft intrastate scheduling and forecasting regulations and are expected to notify the final regulations by the end of this year.

On the natural gas front, welcome signs for beleaguered gas-based power plants include the significant fall in the price of gas following the bi-annual revision of gas prices under the New Domestic Gas Pricing Guidelines, and the diversion of gas from fertiliser plants to standard power stations in coastal states. In 2014, the government announced that it would lay an additional 15,000km of natural gas pipelines on a PPP basis; however, such proposal has not materialised due to lack of financial viability.

One key development revolves around the Supreme Court’s recent decision to deny compensatory tariffs to various power producers whose power plants are lying idle, underutilised or facing delays on account of a change in the Indonesian coal pricing regime. In 2014, the CERC and certain SERCs found that the difficulties faced by such power
producers were genuine, and sought to provide relief to these power producers in the form of a ‘compensatory tariff’, to compensate the losses suffered and additional costs incurred by them. However, the Appellate Tribunal for Electricity (APTEL) in its judgment in 2016 held that the CERC does not have jurisdiction when it comes to varying or modifying tariffs or granting compensatory tariffs in cases where a tariff has been determined through a tariff-based competitive bidding route. The APTEL did state, however, that the CERC would have the power to grant relief in the event that a force majeure or change in law were to be established. The Supreme Court has set aside the order of APTEL and held that the change in the Indonesian coal pricing regime is neither force majeure nor change in law as per the PPA. However, the Supreme Court held that the amendment to the New Coal Distribution Policy in 2013 would be considered as change in Indian law, and that the power projects that have been impacted by the shortfall in domestic coal supply due to such amendment may be compensated as per the change in law provisions in the PPA. In this regard, the Supreme Court has asked CERC to take a fresh look at the matter to determine the relief that should be granted due to the change in Indian law, if any.

In the oil and gas sector, the government has approved a policy for extension of production-sharing contracts for oil blocks granted prior to NELP to enable and facilitate investment to extract the remaining reserves by advanced technologies. This year, bidding for oil and gas blocks was conducted after a break of six years and contracts were awarded to the successful bidders under the Discovered Small Field Policy bid round – 2016. The selected bidders have been awarded the contract under the revenue sharing model, giving them pricing and marketing freedom. Further, the dispute between the government and the Reliance group (an oil and gas major) on the pricing of gas from the KG-D6 block that is currently under arbitration – specifically the discrepancy between the formula for determining the price of gas recommended by the Rangarajan Committee and the formula ultimately adopted by the government in the new pricing guidelines (which gives significantly lower prices) – will be crucial in determining key aspects such as pricing of gas in India, certainty of executive decisions (on key commercial aspects such as pricing) and the impact on investments in the oil and gas sector. While the government has, through HELP, introduced market and pricing freedom for gas discoveries, the benefit of this freedom will not be applicable to those blocks that are currently under arbitration – KG-D6 being one such block.

VII CONCLUSIONS AND OUTLOOK

The government has tackled policy reform in the energy sector with enthusiasm and aggression, bringing about significant key changes with the aim of increasing the bankability of power projects. The government’s policy reforms reveal a clarity of vision and a push for stability in the energy sector. This is apparent from the government’s aim of restructuring financially stressed distribution companies, bringing consistency in all the standard bidding documents for procurement of power, and introducing a new pricing regime for natural gas coupled with the shift to HELP. In respect of renewable energy, the new government is making significant strides by introducing key incentives for solar and wind power producers, a push for rooftop solar plants and ultra-mega solar power plants. The recent regulatory and policy changes made in the energy and infrastructure sector are indicative of the fact that the government is committed to greater transparency and openness in the sector, with most of the procurement moving towards a competitive bidding regime. The judicial authorities are also taking a serious look at irregularities and inconsistencies in government policies and
India

awards, which is evidenced by landmark judgments by the Supreme Court, including in the coal block deallocation cases, compensatory tariff cases and the CCI’s decision to levy a penalty on CIL.

However, there are persisting concerns, such as inadequate transmission infrastructure to support growth of renewable energy and lack of affordable financing. While the policy reforms have led to an initial spurt in capacity addition, achieving India’s aim of energy security is quite a way from being accomplished. That said, although the government seems to gaining some ground, it will require continuous and persistent reforms over the coming year to ensure that India achieves its ambitious targets in the energy sector.
I OVERVIEW

Indonesia is an archipelago of some 13,000 islands and 250 million people. It is the largest economy in South East Asia and a G20 member.

As a rapidly developing economy in transition and with the world’s fourth-largest population, Indonesia faces significant energy demands.

Currently, Indonesia has around 80.1 per cent electrification, but supply can be unreliable. It derives its energy mainly from fossil fuels (approximately 87 per cent). While rich in natural resources, growing industrial and residential consumption, as well as decreasing production, has resulted in Indonesia being a net importer of electricity and oil.2

i Governance framework

Indonesia is a presidential republic. The national People’s Consultative Assembly (MPR) consists of two houses: the People’s Representative Council (DPR) and the Regional Representative Council.

Indonesia has 34 provinces, subdivided into a total of 514 regencies and municipalities. Each sub-national government has its own executive (governors, regents and mayors) and legislature (regional DPR).

In 1999, Indonesia decentralised control to sub-national governments over their respective jurisdictions, except for foreign affairs, defence and security, judicial, monetary and financial, and religious matters.3 As such, there are both national and regional laws and regulations.

Indonesia has a civil law system, with the following hierarchy of laws:4

a the Constitution;5
b MPR decrees;
c laws or government regulations in lieu of law;6

1 Mochamad Kasmali is a partner at Soemadipradja & Taher. The author would like to thank Cameron Grant (foreign counsel), Anandianty Febrina and Jamal Soemadipradja (associates) for their assistance in updating this chapter.
2 In 2008, Indonesia left the Organization of the Petroleum Exporting Countries (OPEC) when it ceased to be a net exporter of oil.
3 Law No. 32 of 2004 (as amended by Law No. 8 of 2005, Law No. 12 of 2008 and Law No. 5 of 2014), as later revoked and replaced by Law No. 23 of 2014 on Regional Government (as further amended by Law No. 2 of 2015 and Law No. 9 of 2015).
4 Article 7(1) of Law No. 10 of 2004 on Lawmaking, as later revoked and replaced by Law No. 12 of 2011.
6 Government regulations in lieu of law are only enacted in emergencies.
d government regulations;
e presidential regulations;
f provincial regulations; and
g regency or municipality regulations.

II REGULATION

The Constitution establishes the framework for energy regulation and policy. Article 33(3) provides that the ‘earth and water and the natural resources contained within them are to be controlled by the State and used for the greatest possible prosperity of the people’. The Constitutional Court of Indonesia has actively applied Article 33(3) in a number of cases.

An earlier electricity law proposed to unbundle electricity into seven activities and remove the monopoly of the state electricity company (Perusahaan Listrik Negara, PLN) where competition was possible.7 In response to a challenge to this law, the Constitutional Court held that the concept of state control contemplates more than state ownership or regulatory power, extending to management of the relevant enterprise. On this basis, and because competition and unbundling were central to that electricity law, the Constitutional Court determined the entire law to be invalid.8

Indonesia’s energy policy is established under the Energy Law,9 which applies to both renewable and non-renewable energy.

Each energy sector is subject to different laws and regulations:

a Electricity: the Electricity Law,10 with regulations including:
  • the Electricity Business Regulation;11
  • the Electricity Supporting Business Regulation;12 and
  • the Electricity Business Licences Regulation.13

b Geothermal: the Geothermal Law,14 with regulations including the Geothermal Business Regulation.15

c Mining: the Mining Law,16 with regulations including the Mining Regulation.17

d Nuclear: the Nuclear Law,18 with regulations including the Nuclear Regulation.19

7 Law No. 20 of 2002 on Electricity.
9 Law No. 30 of 2007 on Energy.
10 Law No. 30 of 2009 on Electricity, replacing Law No. 15 of 1985 on Electricity.
12 Government Regulation No. 62 of 2012 on Electricity Supporting Businesses.
14 Law No. 27 of 2003 on Geothermal, as later revoked and replaced by Law No. 21 of 2014 on Geothermal.
15 Government Regulation No. 59 of 2007 on Geothermal Business Activities (as amended by Government Regulation No. 70 of 2010 and Government Regulation No. 75 of 2014).
16 Law No. 4 of 2009 on Mineral and Coal Mining.
18 Law No. 10 of 1997 on Nuclear Energy.
19 Government Regulation No. 2 of 2014 on Licensing of Nuclear Installations and the Utilisation of Nuclear Materials.
Oil and gas: the Oil and Gas Law,\textsuperscript{20} with regulations including:
- the Upstream Regulation,\textsuperscript{21} and
- the Downstream Regulation.\textsuperscript{22}

Other renewable energy sectors remain to be specifically regulated.

\textbf{i} \hspace{1em} \textbf{The regulators}

The Ministry of Energy and Mineral Resources (MEMR) has overall regulatory responsibility for energy and natural resources.\textsuperscript{23} The MEMR consists of four Directorates General, which are responsible for different sectors:
- electricity (DGE);\textsuperscript{24}
- minerals and coal (DGMC);\textsuperscript{25}
- new energy, renewable and energy conservation (DGNEREC);\textsuperscript{26} and
- oil and gas (DGOG).\textsuperscript{27}

Other energy regulators include:
- The National Energy Board (NEB): the Energy Law provides for the establishment of the NEB, which is responsible for formulating and implementing energy policies.
- Special Task Force for Upstream Oil and Gas (SKK Migas): SKK Migas advises the Minister of MEMR on tendering oil and gas blocks, executes production-sharing contracts (PSC) with successful entities and regulates PSC contractors.
- Oil and Gas Downstream Regulatory Agency (BPH Migas): BPH Migas’s responsibilities include licensing and regulating downstream oil and gas activities.
- National Nuclear Power Agency (BATAN): BATAN is responsible for research and development, exploration and exploitation of radioactive materials and management of radioactive waste.
- National Nuclear Power Supervisory Agency (BAPETEN): BAPETEN is responsible for regulating, licensing and supervising nuclear activities.

Indonesia also has a state electricity company, PLN, and a state oil and gas company, PT Pertamina (Persero).

\textbf{ii} \hspace{1em} \textbf{Regulated activities}

Business activities in Indonesia, including in the energy and natural resources sectors, require the relevant approvals or licences set out in the prevailing laws and regulations.

\textsuperscript{20} Law No. 22 of 2001 on Oil and Natural Gas.
\textsuperscript{21} Government Regulation No. 35 of 2004 on Oil and Gas Upstream Activities (as amended by Government Regulation No. 34 of 2005 and Government Regulation No. 55 of 2009).
\textsuperscript{22} Government Regulation No. 36 of 2004 on Oil and Gas Downstream Activities (as amended by Government Regulation No. 30 of 2009).
\textsuperscript{23} Presidential Regulation No. 24 of 2010 on the Positions, Duties and Functions of the State Ministries and Organisational Structure, Duties and Functions of Echelon I of the State Ministries, as amended by several Presidential Regulations, with the latest being Presidential Regulation No. 135 of 2014.
\textsuperscript{24} www.djk.esdm.go.id/.
\textsuperscript{25} www.minerba.esdm.go.id/.
\textsuperscript{26} www.ebtke.esdm.go.id/.
\textsuperscript{27} www.migas.esdm.go.id/.
Electricity

With appropriate approvals and licences, any entity (private companies, cooperatives, state-owned companies (BUMN) and region-owned companies (BUMD)) may generate electricity. Importantly, however, such electricity must be sold to PLN; transmitted, distributed and marketed to a specific area (e.g., within an industrial estate) as an integrated scheme; or used for the generator’s own purposes. Otherwise, PLN has priority with respect to the right to transmission, transportation and distribution of electricity.28

Relevant approvals include:29

a electricity supply:

- for the public interest (either for sale to PLN or as part of an integrated scheme) requires an electricity supply business licence; and
- for own use requires an electricity supply operating licence.

An application must be made to the relevant authority (DGE, governor, regent or mayor) and follow the procedures and fulfil the administrative, technical and environmental requirements under the Electricity Business Regulation and Electricity Business Licences Regulation. However, the process differs if the applicant is a foreign investment limited liability company (PMA company) or a domestic investment limited liability company (PMDN company). In accordance with the single-door licensing policy that was introduced in 2014, applications by PMA and PMDN companies must be made to the Indonesian Investment Coordinating Board (BKPM). If the application is successful, the Head of BKPM will then issue the electricity supply business licence on behalf of the Minister of MEMR;30 and

b electricity supporting business: this requires an electricity supporting business licence.

Again, an application must be made to the relevant authority (DGE, if the applicant is majority foreign-owned or relevant regent or mayor if majority Indonesian-owned) and follow the procedures and requirements under the Electricity Supporting Business Regulation and Electricity Business Licences Regulation.31 Again, the process differs if the applicant is a PMA or PMDN company, so that applications by such companies must be made to BKPM. If the application is successful, the Head of BKPM will then issue the electricity supporting business licence on behalf of the Minister of MEMR.32

Coal mining33

Under the Mining Law, to conduct coal mining an entity must hold either:

a a mining business licence (IUP), where an entity must:

- succeed in a public auction for the award of a mining area; and

28 Article 11(2) of the Electricity Law.
29 Articles 8–9 of the Electricity Law.
31 MEMR Regulation No. 35 of 2013 on Procedures for Electricity Business Licences (as amended by MEMR Regulation No. 12 of 2016).
33 The 2017 National Legislation Programme at DPR states that the Mining Law is one of the laws that will be amended. However, there is no indication when the new Mining Law will be enacted.
• obtain from the relevant authority (the Minister of MEMR or governor,\textsuperscript{34} depending on the location of the mining area) an IUP; or

\begin{itemize}
  \item a coal contract of work (CCoW): CCoWs were entered into between the government and companies under the previous mining law.\textsuperscript{35} They remain valid for 30 years after the commencement of production, but the Mining Law requires their provisions to be adjusted to comply with the Mining Law and following their expiry they must be converted into IUPs.
\end{itemize}

\textbf{Oil and gas}\textsuperscript{36}

To conduct upstream activities (namely, exploration and exploitation), an entity must:

\begin{itemize}
  \item succeed in a tender process held by DGOG for an oil and gas block; and
  \item enter into a PSC with SKK Migas.
\end{itemize}

The PSC is valid for 30 years and can be extended once for up to 20 years.

To conduct downstream activities, an entity must obtain from MEMR the relevant licence, such as:

\begin{itemize}
  \item a processing business licence;
  \item a transportation business licence (and a special right from BPH Migas to transport gas via a pipeline);
  \item a storage business licence; or
  \item a trading business licence.
\end{itemize}

\textbf{Renewable energy}

An entity is permitted to generate renewable electricity for sale to PLN.\textsuperscript{37} Under the Geothermal Law, geothermal resources can be utilised for:

\begin{itemize}
  \item an indirect purpose, which involves electricity generation. This will require a Geothermal Licence issued by BKPM;\textsuperscript{38} or
  \item a direct purpose, which does not involve electricity generation (e.g., an agribusiness or tourism purpose). This will require a direct utilisation licence issued by BKPM or the relevant governor, regent or mayor, as appropriate.
\end{itemize}

A Geothermal Licence is valid for up to 37 years, and can be extended for up to a further 20 years.

To explore, exploit and utilise geothermal resources for an indirect purpose an entity must:

\begin{itemize}
\end{itemize}

\textsuperscript{34} Law No. 23 of 2014 on Regional Government (as amended by Law No. 2 of 2015 and Law No. 9 of 2015), which revokes Law No. 32 of 2004 on Regional Government (and amendments thereto), removes the authority of a regent or mayor to issue an IUP or otherwise handle mining affairs and gives the authority to the relevant governor.

\textsuperscript{35} Law No. 11 of 1967 on the Basic Provisions of Mining, later revoked and replaced by the Mining Law.

\textsuperscript{36} As with the Mining Law, the Oil and Gas Law is also listed as one of the laws that will be amended in 2017. Again, there is no indication as to when the new Oil and Gas Law will be enacted.

\textsuperscript{37} MEMR Regulation No. 2 of 2006 on Renewable Energy Medium Scale Power Plant Businesses and MEMR Regulation No. 12 of 2017 on the Utilisation of Renewable Energy Sources for Electricity Supply.

\textsuperscript{38} MEMR Regulation No. 35 of 2014 on Delegation of Authority to Grant Electricity Business Licences in the Framework of Implementing a Single-Door Policy at BKPM, as amended by MEMR Regulation No. 14 of 2017.
Indonesia

a. succeed in a public auction for the award of a geothermal work area;
b. obtain a Geothermal Licence from the Minister of MEMR; and
c. obtain the relevant forest utilisation licence from the Minister of Forestry if the work area is located within a forestry area.

Further, to utilise generated geothermal electricity, an entity will also require the relevant electricity supply licence.

Approvals and licences required for other renewable energy sectors are still to be specifically regulated.

General

Energy and natural resources projects and proponents may also need to obtain appropriate approvals and licences in relation to:

a. land; for example, a right to own, right to build or right to use;
b. the environment: principally an environmental licence and environmental impact analysis approval or environmental management and monitoring efforts approval; and
c. forestry: principally a borrow-to-use forest area licence.

iii Ownership and market access restrictions

In accordance with Article 33(3) of the Constitution, and decisions of the Constitutional Court, Indonesia’s natural resources are state-owned.

Foreign ownership

Under the Investment Law, a foreign entity may directly invest in Indonesia by establishing a new PMA company, or purchasing shares in an existing limited liability company (provided that the line of business is open to foreign investment). Under the Company Law, the establishment of a company (including a PMA company) requires approval from the Ministry of Law and Human Rights (MoLHR), while foreign investment in a PMA company requires approval from BKPM.

The Investment Law provides that all business sectors are open to foreign investment, except those listed in the Presidential Regulation, commonly known as the Negative List. On 18 May 2016, the government issued a new Negative List by virtue of a presidential regulation. The new Negative List sets out significant changes to certain business sectors, to be more open to foreign investment, including allowing a number of major business lines, such as pellet biomass producers for the energy industry, to be open to 100 per cent foreign investment for the first time.

39 Law No. 25 of 2007 on Investment.
40 Law No. 40 of 2007 on Limited Liability Companies.
41 BKPM Regulation No. 14 of 2015 on Guidelines and Procedures for In-Principle Licences on the procedure and requirements for an investment application, as amended by BKPM Regulation No. 6 of 2016 and BKPM Regulation No. 8 of 2016.
42 The Negative List identifies the business sectors that are closed to foreign investments or are open subject to conditions.
43 Presidential Regulation No. 44 of 2016 on the List of Business Fields Closed to Investment and Business Fields Open to Investment with Conditions.
Indonesia

The new Negative List is just one of the government’s commitments to the ASEAN Economic Community to boost both foreign and domestic investment activities in the largest economy in the ASEAN region and, at the same time, it is expected to enhance business development growth among local micro, small and medium-sized enterprises and cooperatives.

Restrictions

Ownership restrictions in energy sectors include:

a  Electricity: a PMA company with 100 per cent foreign ownership may invest in power plants producing more than 10MW (including nuclear-resourced power plants) under a public–private partnership project during the concession period, subject to obtaining all required approvals and licences. Power plants of 1–10MW are open to up to 49 per cent foreign ownership, while power plants of less than 1MW are closed to foreign investment. However, geothermal-resourced power plants of less than or equal to 10MW are open to up to 67 per cent foreign ownership.

b  Coal mining: an IUP holder may be a PMA company that is 100 per cent foreign-owned. Under the Mining Law and Mining Regulation (as amended), after five years of commercial production, the foreign holdings must be progressively divested so that Indonesian investors own a minimum of 51 per cent after 10 years of commercial production. In addition, CCoW companies that have been in commercial production for 10 years would also be required to divest 51 per cent of their shares to an Indonesian party. An MEMR regulation further reinforces this restriction, but exempts special processing or refining IUP holders.44

c  Oil and gas: despite the general requirements of the Investment Law, under the Oil and Gas Law, a foreign oil and gas company that wins a tender for an oil and gas block does not need to establish a PMA company. Instead, the PSC is the basis for the foreign oil and gas company conducting its upstream activities as a permanent establishment business entity (BUT).

A BUT may be 100 per cent foreign-owned. Under the Upstream Regulation, however, after the first oil field development plan is approved by SKK Migas, the BUT must offer a 10 per cent participating interest to a BUMD in the region in which the oil and gas block is located. Otherwise the Negative List provides that offshore oil and gas drilling is open to 75 per cent foreign ownership, while onshore oil and gas drilling and upstream production are closed to foreign investment.

iv Transfers of control and assignments

As Indonesia’s natural resources are state-controlled, transfers of control and assignments must be of relevant approvals, licences, entities or shareholdings.

Any merger, acquisition or transfer of shares will require at the least BKPM approval (for a PMA company), MoLHR notification (for all companies) and probably approval from the relevant authority responsible for any energy approvals or licences.

Some specific approval processes include:

44 MEMR Regulation No. 27 of 2013 on Procedures for Divestment and Share Pricing and Changes to Capital Investment in Mineral and Coal Mining Businesses, as amended by MEMR Regulation No. 9 of 2017.
a. Coal mining: with MEMR approval, an IUP holder may transfer its IUP to another entity if it owns at least 51 per cent of that other entity. Any change to the capital investment of an IUP holder or CCoW company (including amendments to its investment or financing sources, status as a PMA company or a domestic investment company, shareholders, directors and commissioners or articles of association) requires approval from the Minister (via DGMC). Any change to a PMA company’s investment also requires DGMC and BKPM approval.

b. Oil and gas: during the first three years of exploration, the initial PSC contractor may only transfer its participating interest in a BUT to an affiliate, subject to DGOG approval. After those three years, the holder of a participating interest in a BUT may transfer all or part of its interest to any other party, subject to a favourable recommendation by SKK Migas and approval from DGOG. Such a recommendation and approval is not required for a transfer to another holder of a participating interest in the same oil and gas block. In the case of a proposed transfer to a non-affiliated party, DGOG may request that the participating interest be first offered to a BUMN.

c. Geothermal: a Geothermal Licence cannot be transferred to another entity. However, shares in the entity holding the Geothermal Licence may be transferred after the exploration phase is complete, subject to approval from the Minister of MEMR.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i. Vertical integration and unbundling

As indicated in Section II, supra, an earlier electricity law that sought to unbundle electricity activities was held invalid. As such, PLN retains an effective monopoly over electricity transmission/transportation and distribution.45

In contrast, the Oil and Gas Law unbundled oil and gas activities. Those undertaking upstream activities may not undertake downstream activities, including processing, transporting, storing and trading. DGOG and BPH Migas are responsible for determining how downstream activities are undertaken. DGOG is developing a national transmission and distribution network master plan.

ii. Transmission/transportation and distribution access

PLN’s transmission/transportation and distribution systems may be used by other electricity providers.46

In the case of oil and gas, BPH Migas will conduct a tender process to award a special right to transport gas through a pipeline in a given area. The holder of a Transportation Business Licence and a BPH Migas special right must provide third-party access to its transportation facilities and pipelines. DGOG may mediate any dispute between such operators.

45 Article 11(2) of the Electricity Law.
46 Articles 4 and 8 of MEMR Regulation No. 1 of 2015 on Cooperation of Electricity Supply and Joint Use of Electricity Grids.
iii Rates
BPH Migas has the authority to determine the rates for the transportation of gas via pipelines, which BPH Migas will evaluate from time to time. The most recent regulations were issued in 2013 (and amended in 2016).47 BPH Migas will consider the transportation business licence holder’s proposed fee in determining the rate.

iv Security and technology restrictions
The Minister of MEMR may by decree determine that certain energy and natural resource activities, assets or areas are vital national objects. An activity, asset or area is eligible to be a vital national object if:

a it relates to daily production needs; and

b any threat or disturbance to the activity would:
   • cause human or development disasters;
   • cause national transportation or communication disorder; or
   • disturb state administration.

Once declared a vital national object, an entity that operates it must ensure its security, but may request police assistance to provide additional security if a threat or disturbance is identified. In turn, the police may request military assistance in the event of a severe threat or disturbance.

IV ENERGY MARKETS

i Development of energy markets
All energy markets are highly regulated, with relevant tariffs determined and subsidised by the government.

In terms of electricity generation, the appointment of an independent power producer (IPP) commonly results from a competitive bidding process, although direct appointment and appointment by way of reference price is permitted with respect to renewable energy generation (i.e., solar, wind, hydro, biomass, biogas, urban waste-to energy and geothermal power), with respect to which the feed in tariff (FIT) payable by PLN is calculated by reference to the relevant local electricity generation supply cost, as compared with the national average generation supply cost, as approved by MEMR. Although the FIT varies based on the renewal energy project and the procurement scheme, the FIT is generally capped at 85 per cent of the local generation supply cost, so long as the local generation supply cost is above the national average generation supply cost. If, however, the local generation supply cost is equal to or below the national average generation supply cost, the FIT will equal the local generation supply cost.48 There is no transmission/transportation, distribution or retail competition.

47 BPH Migas Regulation No. 8 of 2013 on Tariff Determination for Gas Transportation via Pipelines, as amended by BPH Migas Regulation No. 14 of 2016.
48 MEMR Regulation No. 12 of 2017 on the Utilisation of Renewable Energy Sources for Electricity Supply.
The government intends to increase energy security by increasing domestic supply.\(^\text{49}\) In this context, large coal mining companies are subject to an annual domestic market obligation\(^\text{50}\).

Similarly, in relation to oil and gas, PSC contractors are required to sell 25 per cent of their production domestically\(^\text{51}\). Ultimately, all oil and the majority of gas are consumed domestically (with some gas exported to Singapore).

### ii Energy market rules and regulation

PLN’s electricity tariffs, which are regulated under the Tariff Regulation\(^\text{52}\), vary depending upon the consumption purpose (residential, industrial, etc.). There are additional regulations for renewable energy electricity tariffs\(^\text{53}\). MEMR determines the subsidised electricity price as part of the annual budget.

The DGMC sets the benchmark coal price from time to time, based on the Indonesian Coal Index, Newcastle Export Index and Newcastle Global Index. Coal mining companies must sell their coal at or above the benchmark price, which is designed to maintain state revenues from royalties and company tax.

BPH Migas determines the natural gas price for households and small consumers. DGOG determines the price for certain types of fuel oil. Once again, MEMR determines the subsidised fuel price as part of the annual process.

### iii Contracts for sale of energy

An entity that generates electricity (other than for its own purposes) to sell to PLN must do so as an IPP in accordance with a power purchase agreement (PPA). While PLN will propose a PPA’s terms and conditions\(^\text{54}\), these will, in practice, vary from project to project. As of 2017, all future PPAs (except for those concerning (1) wind and solar projects (i.e., intermittent renewable energy projects); (2) mini-hydro projects (i.e., up to 10MW); (3) biogas projects; and (4) urban waste-to-energy projects) must be premised on a build, own, operate and transfer (BOOT) basis\(^\text{55}\). Under PPAs executed on such a basis, the IPP would...

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\(^{49}\) Government Regulation No. 79 of 2014 on the National Energy Policy.

\(^{50}\) MEMR Regulation No. 34 of 2009 on Prioritising the Supply of Mineral and Coal Needs for Domestic Purposes.

\(^{51}\) Government Regulation No. 55 of 2009 on the Second Amendment to Government Regulation No. 35 of 2004 on Oil and Gas Upstream Activities.

\(^{52}\) MEMR Regulation No. 28 of 2016 as amended by MEMR Regulation No. 18 of 2017.

\(^{53}\) MEMR Regulation No. 1 of 2015 on Cooperation of Electricity Supply and Joint Use of Electricity Grids, MEMR Regulation No. 4 of 2012 on the Electricity Purchase Price by PT PLN (Persero) sourced from Small and Medium Renewable Energy Power Plants or Excess Electricity Power; MEMR Regulation No. 17 of 2014 on the Purchase of Electricity from Geothermal Power Plants and Geothermal Steam for Geothermal Power Plants by PT PLN (Persero), MEMR Regulation No. 44 of 2015 on the Purchase of Electricity by PT PLN (Persero) from City Waste Power Plants, MEMR Regulation No. 19 of 2015 on the Purchase of Electricity by PT PLN (Persero) from Hydropower Plants producing up to 10MW and MEMR Regulation No. 12 of 2017 on the Utilisation of Renewable Energy Sources for Electricity Supply.

\(^{54}\) Dr Ir Santosa Gotosusastro, ‘Experience and Management of Private Electricity: Independent Power Producers’ (PLN, 2010) and MEMR Regulation No. 10 of 2017 on the Basics of Electricity Sale and Purchase Agreements.

\(^{55}\) MEMR Regulation No. 10 of 2017 on the Basics of Electricity Sale and Purchase Agreements.
be required to transfer ownership of the project to PLN upon expiry of the PPA. Previously, it was common for geothermal and hydro power projects to be premised on a build, own and operate (BOO), but not transfer, basis.

In the case of oil and gas, exploration and exploitation is regulated by a PSC. The content of a PSC is regulated, including providing for the government’s production-sharing and the domestic market obligations. The PSC contractor will also be entitled to recover its investment or exploration costs at the production stage. While SKK Migas executes the PSC, it is subject to the Minister of MEMR’s approval.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

In January 2014, the DPR approved a new government regulation on energy policy (the New Energy Regulation), which contemplates abolishing electricity and fuel subsidies over the next decade, as well as encouraging increased use of renewable energy.

By 2025, the government aims to change its total energy use to:

a reduce oil fuel dependence from 42 per cent to less than 25 per cent; and
b increase renewable energy dependence from 6 per cent to at least 23 per cent.

Potential sources of renewable energy include biomass or waste, geothermal, hydroelectric, solar, wave or tidal, and wind energy. Indonesia is projected to hold 40 per cent of global geothermal reserves and the government aims to produce 6,500MW of geothermal energy by 2025. Since 2009, biomass/waste energy generation has also grown significantly.

Regulations specifically enable PLN to purchase renewable energy electricity, including geothermal electricity. There is also a regulation to involve PLN in supporting private infrastructure development of new and renewable energy plants, as well as income tax, value added tax and import duty relief for entities utilising new and renewable energy.

The government has been focusing on developing new and renewable energy, particularly geothermal energy through:

a exploration intensification and extensification
b regulating to facilitate regional development and investment; and
c the application of certain tax facilities.

56 Article 26, Upstream Regulations.
57 Government Regulation No. 79 of 2010 on Recoverable Operational Costs and Income Tax Treatment for the Upstream Oil and Gas Business Sector.
58 Government Regulation No. 79 of 2014 on National Energy Policy.
61 MEMR Regulation No. 12 of 2017 on the Utilisation of Renewable Energy Sources for Electricity Supply.
62 MEMR Regulation No. 17 of 2014 on the Purchase of Electricity from Geothermal Power Plants and Geothermal Steam for Geothermal Power Plants by PT PLN (Persero) and MEMR Regulation No. 12 of 2017 on the Utilisation of Renewable Energy Sources for Electricity Supply.
63 Presidential Regulation No. 4 of 2010 on Delegation to PT PLN (Persero) to Expedite the Development of Renewable Energy, Coal and Gas Power Plants (as amended by Presidential Regulation No. 48 of 2011 and Presidential Regulation No. 194 of 2014).
64 Minister of Finance Regulation No. 21/PMK.011/2010 of 2010 on the Granting of Tax and Customs Incentives for the Utilisation of Renewable Energy.
65 Law No. 18 of 2016 on the 2017 State Revenue and Expenditure Budget.
Under a recently introduced regulation that reinforces the authority of the central government over geothermal power for indirect utilisation, work areas for geothermal projects are awarded through public tender, which must take into account, among other things, the bidder’s technical and financial capabilities. Upon being awarded a work area, the winning bidder is subsequently required to make a deposit in an escrow account, to evidence a commitment to conduct exploration, after which deposit the winning bidder will be granted a geothermal permit for the relevant work area.\textsuperscript{66}

\textbf{ii Energy efficiency and conservation}

Regulations impose obligations on certain energy consumers to manage their energy usage, including by appointing an energy manager, formulating conservation programmes, conducting regular audits and reporting conservation to DGNEREC (among others).\textsuperscript{67}

MEMR has established a non-binding efficiency target to reduce electricity use by 20 per cent.\textsuperscript{68} It is contemplated that there will be incentives for entities that effectively manage or reduce their energy use, as well as penalties for those that do not.

The government’s efforts on energy efficiency are not a new phenomenon, as similar efforts were commenced in 1995 and further developed in 2005 through the National Energy Conservation Master Plan (RIKEN).\textsuperscript{69} RIKEN identified energy saving potential of 15–30 per cent in the industrial sector, 25 per cent in the commercial building sector and 10–30 per cent in the household sector.\textsuperscript{70} RIKEN has yet to be fully implemented.

Indonesia will need to enhance the use of renewable energy sources and reduce its dependency on oil and coal to expedite meeting energy-efficiency targets. Scaling up renewable energy production and applying advanced low-carbon technologies may improve energy security and would likely shift the economy to a more sustainable path.

\textbf{iii Carbon trading and tax}

As one of the world’s biggest emitters of greenhouse gases, Indonesia is planning to launch a voluntary carbon trading scheme, open to participation by other countries.\textsuperscript{71} Although the government has prioritised the implementation of this scheme, it remains difficult to predict whether businesses will participate.

While clear details of the scheme are yet to emerge, and no timetable has been set for its implementation, it is known that the scheme will involve the issuing of voluntary emission reduction certificates that domestic carbon emitters can use to offset their emissions.\textsuperscript{72} The government has pledged to reduce emissions to 26 per cent below business as usual levels by 2020, and by as much as 41 per cent, if it receives international funding.

To enhance the implementation of carbon trading, Indonesia intends to impose a carbon tax.\textsuperscript{73} A carbon tax charges emitters based on the amount of carbon they emit, with

\begin{enumerate}
\item Government Regulation No. 7 of 2017 on Geothermal Power for Indirect Utilisation.
\item Government Regulation No. 70 of 2009 on Energy Conservation; MEMR Regulation No. 14 of 2012 on Energy Management.
\item MEMR Regulation No. 13 of 2012 on Saving on Electricity Consumption.
\item http://prokum.esdm.go.id/Publikasi/Outlook%20Energi%202014.pdf.
\item www.reuters.com/article/2013/11/12/indonesia-carbon-climate-idUSL4N0IX4S920131112.
\end{enumerate}
the intention that emitters will substantially reduce their emissions. An amendment to the vehicle tax formula, to take into account carbon emissions, is expected to form part of the government’s carbon tax roadmap.\textsuperscript{74}

**VI  THE YEAR IN REVIEW**

**i  Summary of new regulations**

Laws, regulations and policies released in the past year include:

a. Government Regulation No. 1 of 2017 on the Fourth Amendment to Government Regulation No. 23 of 2010 on the Implementation of Mineral and Coal Mining Business Activities;

b. Government Regulation No. 7 of 2017 on Geothermal Power for Indirect Utilisation;

c. Presidential Regulation No. 22 of 2017 on the National Energy General Plan;

d. MEMR Regulation No. 1 of 2017 on the Parallel Operation of Electrical Power Plants with PT Perusahaan Listrik Negara (Persero) Electricity Networks;

e. MEMR Regulation No. 5 of 2017 on the Increase of Added Value of Minerals through Domestic Processing and Refining Activities;

f. MEMR Regulation No. 6 of 2017 on the Procedures and Requirements for the Granting of a Recommendation on the Implementation of the International Sale of Minerals from Processing and Refining, as amended by MEMR Regulation No. 35 of 2017;

g. MEMR Regulation No. 7 of 2017 on the Procedures for determining the Benchmark Selling Price of Metallic and Coal Minerals;

h. MEMR Regulation No. 8 of 2017 on Gross Split Production-Sharing Contracts;

i. MEMR Regulation No. 9 of 2017 on the Procedures for Share Divestment and the Mechanism to Determine the Price of Divestment Shares for Mineral and Coal Mining Businesses;

j. MEMR Regulation No. 10 of 2017 on the Basics of Electricity Sale and Purchase Agreements;

k. MEMR Regulation No. 11 of 2017 on the Utilisation of Gas for Electrical Power Plants;

l. MEMR Regulation No. 12 of 2017 on the Utilisation of Renewable Energy Sources for Electricity Supply;

m. MEMR Regulation No. 15 of 2017 on the Procedures for the Granting of Production Operation Special Mining Business Licences as a Continuation of the Operation of Contracts of Work and Coal Contracts of Work;

n. MEMR Regulation No. 19 of 2017 on the Utilisation of Coal for Power Plants and the Purchase of Excess Power;

o. MEMR Regulation No. 21 of 2017 on the Management of Drilling Waste and Drilling Dust for Geothermal Drilling;

p. MEMR Regulation No. 23 of 2017 on the Procedures for Reconciliation, Deposit and Reporting of Geothermal Production Bonus;

q. MEMR Regulation No. 24 of 2017 on the Mechanism to Determine Basic Costs for Electricity Generation Supply by PT Perusahaan Listrik Negara (Persero);

\textsuperscript{74}  www.kemenperin.go.id/artikel/16995/New-tax-rules-mulled-to-make-greener-cars-more-popular.
MEMR Regulation No. 26 of 2017 on the Mechanism to Determine Investment Costs for Upstream Oil and Gas Business Activities;

MEMR Regulation No. 27 of 2017 on Service Grade and Costs Relating to the Transmission of Electricity by PT Perusahaan Listrik Negara (Persero);

MEMR Regulation No. 28 of 2017 on Amendment to MEMR Regulation No. 5 of 2017 on the Increase of Added Value of Minerals Through Domestic Mineral Processing and Refining;

MEMR Regulation No. 29 of 2017 on Licensing for Oil and Gas Business Activities;

MEMR Regulation No. 34 of 2017 on Licensing in the Field of Mineral and Coal Mining; and

MEMR Decree No. 1415 K/20/MEM/2017 on the Approval of Business Plans for Electricity Supply by PT Perusahaan Listrik Negara (PERSERO) from 2017 until 2026.

ii Drafts of new laws and regulations

The DPR has approved 159 draft laws for incorporation into the National Legislative Program (Prolegnas) for 2015–2019. There are 49 draft laws prioritised to be passed this year, including proposed amendments to laws regulating the oil and gas, and coal and mineral mining industries. A new law to regulate the construction services industry was enacted on 12 January 2017 as Law No. 2 of 2017 on Construction Services.

The government also identified 196 draft government regulations and 91 draft presidential regulations prioritised to be issued in 2016. None of the draft regulations relevant to the energy sector have been issued, except for the draft government regulation on geothermal power for indirect utilisation, which was finally issued in 2017 as Government Regulation No. 7 of 2017.

iii Major changes in the mining industry

In the mining industry, major changes occurred during 2016 and 2017. First, the divestment obligation, the application of which depended on the mining activities engaged in by a PMA company (e.g., underground or open pit mining activities), has changed. Under the current regulatory regime, a PMA company that holds a production operation IUP is required to gradually divest after five years of commercial production, regardless of whether it engages in underground or open pit mining, or mining processing or refining activities, such that the maximum foreign ownership must eventually be reduced from 100 per cent to become:

- a 80 per cent after six years of commercial production;
- b 70 per cent after seven years of commercial production;
- c 63 per cent after eight years of commercial production;
- d 56 per cent after nine years of commercial production; and
- e 49 per cent after 10 years of commercial production.

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76 www.dpr.go.id/uu/prolegnas.

77 Presidential Decree No. 11 of 2016 on the Preparation of the Presidential Regulation Program of 2016; Presidential Decree No. 10 of 2016 on the Preparation of the Government Regulation Program of 2016.

78 MEMR Regulation No. 9 of 2017 on Procedures for Share Divestment and Mechanism to Determine Price of Divestment Shares for Mineral and Coal Mining Business Activities.
Secondly, the government has provided relief to production operation IUP holders, insofar as they may export certain copper, iron, ilmenite, lead, manganese, zinc and other scheduled ores and concentrates (exempted minerals) until 10 January 2022, subject to compliance with relevant regulations. CoW holders, however, may no longer export any exempted minerals unless they convert their CoW into a special IUP, subject to compliance with relevant regulations.

iv Gas industry development

Recently, the government has been keen to develop the gas industry. Certain industries (e.g., the fertiliser, petrochemicals, oleochemicals, steel, ceramics, glass and rubber glove industries) are able to request a special gas price, if the prevailing price is considered uneconomical and the contractor’s sale price exceeds US$6/mmbtu.79 If the request is approved by the Director General of DGOG, on behalf of the Minister of MEMR, the gas price for that specific industry would be reduced; the reduction would be borne by the state rather than the contractor.

In January 2017, the government introduced a gross-split mechanism to divide the state’s and the contractor’s oil and gas production, which replaces the cost recovery mechanism, under which the government was obliged to cover the contractor’s operational costs. The base split of gas production between government and contractor is 52 per cent and 48 per cent (while it is 57 per cent and 43 per cent for oil).

Several criteria are considered in determining profit sharing under the gross-split mechanism, including the size of the relevant oil and gas reserves, the location of the oil and gas project, field conditions, the level of exploitation difficulty in view of geological conditions and the technology that will be used in the working area.80 This gross-split mechanism will apply to any new PSC, while for existing PSCs, the contractor may propose that the government adopt the mechanism.

VII CONCLUSIONS AND OUTLOOK

Indonesia will continue to face the challenge of meeting growing energy demands. While other jurisdictions increasingly deregulate and privatise their energy markets, Indonesia retains a significant level of both state ownership and control. The constitutional and regulatory context explains this energy framework; however, the latter context is quickly evolving to prioritise renewable energy sources and energy efficiency. It remains to be seen whether the energy framework can align with market forces and address the ongoing issues from last year to ensure demand is met by sustainable supply.

79 MEMR Regulation No. 16 of 2016 on Procedures to Determine Specific Gas Price and Users.
80 MEMR Regulation No. 8 of 2017 on Gross Split Production-Sharing Contracts.
I INTRODUCTION

The Energy Regulation and Markets Review included a chapter on Iran for the first time in 2016, when the conclusion of the ‘Iran deal’ and the subsequent reopening of the country to foreign investors and companies promised a new period of potential transformation for its energy sector. Previously, and as a result of decades of isolation, the Iranian energy sector had not developed at the same pace and on an equal level with other jurisdictions. With the beginning of this new period, transformation did follow, albeit slowly and gradually. This chapter focuses and analyses recent changes and developments; looks ahead to expected trends, with a specific focus on the implications for foreign entities of entering the sector following the lifting of sanctions; provides an overview of the key entities in the Iranian energy sector; and looks ahead to the likely future developments in the Iranian energy sector. We provide a short summary of key aspects of the Iranian legal system to be aware of, and key considerations for operating or establishing an energy business in Iran.

II OVERVIEW

Iran’s energy sector has been affected and constrained by US sanctions since the 1979 Iranian Revolution, and UN sanctions since 2006. These have hampered development and progress for a country that was otherwise a key player in the energy sector. Economic sanctions affected this sector in another manner as well – they impelled Iran to develop a strong home-grown industry capable of developing and operating assets that were for the most part independent from foreign and global players.

As with other jurisdictions that have sought to transform a state-dominated energy sector into a modern industry capable of attracting significant private capital, Iran has had to deal with issues arising from that transformation, not least of which were the cross-subsidisation and artificially depressed energy prices. However, the prize is large. Both

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1 Munir Hassan is a partner at CMS Cameron McKenna Nabarro Olswang LLP and Shaghayegh Smousavi is a partner at CMS Pars.

2 Iran holds the world’s fourth-largest proved crude oil reserves (amounting to almost 10 per cent of the world’s reserves) and the world’s second-largest natural gas reserves. The country ranked ninth in total primary energy production and 10th in total primary energy consumption in 2014. See The US Energy Information Administration (EIA), Iran country profile, updated 19 June 2015: https://www.eia.gov/beta/international/analysis_includes/countries_long/Iran/iran.pdf.
the size of the Iranian energy sector and its influence in the region is expected to grow. Energy prices are significantly lower and energy consumption significantly higher than international and regional averages.

This, together with the relaxation of sanctions against Iran, has opened up opportunities in a potentially significant market for Western power and renewables companies in spite of the lingering effect of sanctions as well as those still in force, most notably those prohibiting US companies from engaging in transactions involving Iran.

III LIFTING OF SANCTIONS: KEY CONSIDERATIONS

On 14 July 2015, the Guardian Council of the Islamic Republic of Iran approved a multilateral nuclear agreement as consistent with the country’s Constitution and Islamic law. Pursuant to the agreement between Iran and the permanent members of the United Nations Security Council (China, France, Russia, the United Kingdom and the United States), plus Germany and the European Union (referred to as the E3+3) the International Atomic Energy Authority confirmed to the UN Security Council on 16 January 2016, formally known as Implementation Day, that Iran had complied with the programme set out in the Joint Comprehensive Plan of Action (JCPOA). In return, the E3+3 lifted the nuclear-related sanctions on the same day.

While the EU and UN nuclear-related economic and financial sanctions have been terminated, some sanctions will remain in place and are not affected by the nuclear deal, in particular sanctions related to human rights, proliferation and support for terrorism. The major sectors that will be affected by this initial phase of sanctions relief include the energy sector.

It remains important, particularly for companies with activities in the United States or the United Kingdom, to conduct due diligence and ensure compliance with the sanctions regimes before signing business contracts in or relating to Iran. A further risk for investors in the energy sector is the possibility that Iran violates its undertakings in the JCPOA. In such a case, the EU has reserved the right to reimpose sanctions on Iran – the ‘snapback’ provisions. Entities that have contracted with Iranian companies may, therefore, find themselves bound by contracts that they cannot perform.

It should also be noted that Iran, at 120th (2016–2017), ranks low on the World Bank’s Doing Business ranking of economies on their ease of doing business. Key challenges for Western companies, include being alive to the risks of bribery and corruption, as Iran scores high on the Corruption Perceptions Index. Inflation, price control and subsidies reduce proper price discovery and therefore reduce the prospect of merchant projects. A long-term lack of investment in infrastructure means that delays can arise from limitations imposed by wider infrastructure development needs. As with other similar jurisdictions, there remains a risk of bureaucratic delays and overlapping jurisdictions in consents and similar matters.

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3 The United States has eased sanctions on Iran in respect of the oil and shipping sector. However, the easing of these sanctions principally targets non-US persons conducting business with Iran and, save for limited exceptions, the general trade embargo remains in place for US companies. The US Treasury Department’s Office of Foreign Assets Control, through the issuing of General License H, authorises non-US entities to engage in business with Iran, subject to certain exemptions and restrictions including strict limitations on the extent of the involvement of the parent company.

4 Country profile by the Doing Business project: www.doingbusiness.org/data/exploreeconomies/iran.
As with other energy markets that have opened up in recent years, a common strategy for Western companies is to partner with a local (in this case Iranian) entity that can guide them through the domestic landscape (see Section IV, infra, on joint ventures with Iranian entities). However, initial experience has been that cultural and other barriers can make the process of effective partnering often difficult and, while it is important to know your counterparty well, reliable information on Iranian companies is not always straightforward to procure.

IV OVERVIEW OF THE OIL AND GAS SECTOR IN IRAN

Iran's oil and gas industry was looking for something close to US$200 billion during five years in investment to capitalise on the opportunities presented by the opening up of the sector following Implementation Day. The timing was perhaps unfortunate, with oil prices languishing without immediate evidence of an imminent recovery. Nevertheless, the costs of production in Iran were estimated to be significantly lower than the international average, and well below the low current oil price. In these circumstances, Iran has been pushing ahead with reforms to further open up its oil and gas sector to foreign investors.

On 1 October 2015, in response to criticisms of the previous buy-back contracts, the Iranian cabinet endorsed a new upstream oil and gas document known as the Iran Petroleum Contract (IPC). The purpose of the IPC is to facilitate foreign investment. The document consolidates the previous model agreements into one, and covers the exploration, appraisal and development phases.

The general terms and structure of the contractual framework of Iran’s upstream oil and gas was ratified in September 2016. This ratification finally took place with many amendments after political discussion. Nevertheless, and despite several attempts to finalise the terms of the IPC, no contract has yet been signed.

From the beginning, the nature of the IPC was a controversial issue. This is because Articles 77 and 125 of the Iranian Constitution require that international agreements have the parliament’s approval. However, it has been previously held that contracts in which one side is a government entity or company and the other side is a privately owned foreign company are not international agreements subject to Article 77. The criticisms also seem to rely on Article 45 of the Constitution, which requires state control of major industries and large mines (including oil and gas reservoirs). The IPC seeks to navigate the constitutional position by avoiding a production-sharing structure, and does not create ownership rights in reservoirs for foreigners. The contract is more akin to a risk service contract arrangement, with an exploration phase of four to six years, an appraisal phase of two years and a development phase of 20–25 years. The Oil Ministry supervises operations and the government-owned National Iranian Oil Company (NIOC) retains ownership of reservoirs, assets and extracted commodities. As NIOC remains responsible for the oil exploration and extraction, and all operations under the IPC are carried out on behalf of NIOC, all the assets, including equipment, wells etc., belong to NIOC.

6 'Iran’s Cabinet Approves IPC', NIOC, 6 August 2016.
7 See www.al-monitor.com/pulse/originals/2016/02/iran-new-oil-contract-ipc-petroleum. html#izz4A8gZjgLv.
In contrast to the previous buy-back approach, the IPC provides for a joint-venture model, among other things to allow collaboration and technology transfer, with decisions escalated to a committee comprising representatives of NIOC and the international oil and gas company (IOC). If oil is discovered and economical to extract then NIOC and IOC establish a joint operating company or joint venture to take implementation forward and develop, operate and produce from the field. Decisions would continue to be made through a joint committee. Further Iranian ownership participation in the company is also possible. This is a fundamental opportunity as foreign IOCs have not been able to be involved in oil production in Iran since the Revolution in 1979.

Nevertheless, the IPC seeks to attract IOCs from across the world – such as Total, Statoil, BP, Royal Dutch Shell, OMV, Wintershall, Repsol, Sinopec, as well as companies from Asia and the Middle East region – to its sector by providing attractive terms. These include a form of hedge against oil price volatility, with payments where there are significant changes in oil price, and providing some protection on risks relating to the ability to develop a field. This contrasts with the previous buy-back arrangements under which payments were linked to capital costs (typically providing a return of 15–17 per cent) and did not incentivise additional recovery in oil or account for changes in oil price. Among other things, the IPC also moves away from the previous approach under the buy-back arrangements that capped cost recovery and required the IOC to take all delay and cost-overrun risks. While costs will be recoverable under the IPC, costs and annual budgets are to be jointly agreed under a collaborative approach. The IOC would effectively take all exploration risks in the event that exploration and production targets are not met.

Also, notwithstanding ownership remaining with NIOC, the IPC could in some situations allow reserves to be booked, which is important for IOCs in terms of demonstrating their market value. The IOCs would take the risks on the costs of operation. As noted, there is also an emphasis on a collaborative approach in the IPC and a requirement on knowledge transfer into Iran.

Putting aside the single IPC-based agreement concluded with a local company, Iran’s Azadegan oil field will be the first field to be put out to tender using IPC in mid-2017.

V OVERVIEW OF THE POWER SECTOR IN IRAN

The Iran Electricity Regulatory Board (IERB) was established around the turn of the millennium. Its work is overseen by the Minister of Energy and it often works with external third-party consultants. It comprises an executive, called the Regulatory Board Secretariat, which runs a Logistics Unit, a Judicial Unit, a Market Process Planning and Scheduling Unit, and a Market Monitoring Analysis and Adjustment Unit. The Regulatory Board is responsible for monitoring, researching and supporting the electricity market, and suggesting regulations and electricity-related tariffs to the IERB. The IERB also has a role in maintaining an orderly functioning of the industry by managing relationships between industry participants. It is also empowered to manage claims arising between such entities. When making recommendations on regulatory changes and similar matters, the IERB may consult stakeholders and take into account comments and recommendations from industry.

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8 Iran’s Oil Ministry signed a US$2.2 billion worth agreement with Tadbiri Energy group, affiliated with the Execution of Imam Khomeini’s order company (EIKO), which was responsible for increasing the recovery rate of three fields (Yaran, Kupal and Marun).
Historically, Iran’s electricity market was a local, private and vertically integrated monopoly in Tehran, starting in 1905. An early Law of Iran Electricity Organisation was passed in January 1963, creating regional electricity companies, and followed by the establishment of the Ministry of Water and Electricity in 1964 (the Ministry of Energy since 1975), generally regulating the electricity sector. A year later, legislation was introduced that required all non-governmental electric companies to accept mandatory retail tariffs. As these tariffs proved to be below cost, a subsidy was required to maintain the companies as solvent and the companies in due course became Ministry subsidiaries.

The Generation and Transmission Company of Iran (Tavanir) was established in 1970, primarily to implement transmission and generation plans, and operate generation facilities and the transmission network. Today Tavanir has been restructured to be the holding company in charge of these activities.

Pursuant to the decision of the Iranian High Administrative Council, dated 18 December 2004, ‘all legal missions and activities regarding new energies (renewable) and all affairs regarding policymaking, planning supervision and supporting the relevant activities in the non-public sector shall be concentrated in the Ministry of Energy’.

The Iran Grid Management Company (IGMC) was formed in 2004, following the establishment of a wholesale electricity market for the trading of electricity by the IERB. The IGMC acts as the market and system operator.

A stumbling block to private sector participation has traditionally been Article 44 of the Iranian Constitution, which required all large-scale industries and power generation (among others listed) to be fully state-owned. In 2004, this article was amended to require the state to cede at least 20 per cent of control of power companies to private and ‘cooperative’ entities. This has led to a privatisation process in relation to this element of the generation sector (except in relation to ‘must run’ plant) and this privatisation process remains ongoing.

There is a wholesale electricity market in Iran (referred to as the IEM) comprising a day-ahead market for generators and retailers (typically the regional electricity companies) to buy and sell power. A power exchange and bilateral contracts sit alongside the market. Tavanir remains responsible for exporting power to neighbouring countries. However, as there is limited competition in the market, it functions as a fairly basic auction mechanism. Bids are submitted to offer power at specified prices. Purchasers of power specify quantities required. The market operator, IGMC, then clears the market. Generators are paid for capacity even if they are not successful in the bids to provide power to incentivise the provision of capacity to the market. The maximum bidding price is capped by regulation.

Private generators can contract to sell power bilaterally to purchasers via the power exchange or through futures contracts for power delivery. These prices are privately set and not subject to regulatory intervention. Power sold in the market is excluded from the day-ahead market. On a longer-term basis, generators and purchasers of power can also contract long-term power purchase agreements at negotiated price. Trades are then notified to the system operator, IGMC.

Despite considerable hydroelectric and renewables capacity, Iran remains significantly reliant on thermal and gas generation, with thermal power plants’ 11,353MW and gas

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10 Ibid.
11 For further information on the power sector, see www.igmc.ir.
12 For further information on the IEM and power exchange and trading arrangements, see www.igmc.ir.
plants’ 28,124MW accounting for 20.7 per cent and 36.8 per cent of the total installed capacity respectively by the end of the previous Iranian year (21 March 2017). Its power system and the use of energy in Iran are both notoriously inefficient, principally because of cross-subsidies, ageing infrastructure and lack of investment in advanced technologies. There is a plan to shift away from such implicit subsidies to ones that are targeted at the fuel poor. On technology and capital requirements, the focus remains on attracting foreign direct investment despite the imperfect sanctions position, volatility in the market, political uncertainties and the residual risk of a snapback occurring on sanctions.

Nevertheless, plans have been announced for 5 per cent to be renewable energy by 2020 (equating to about 2.5GW, down from 5GW announced in the Development Plan) with about 2GW expected to be wind power, and Iran has become an increasingly attractive market for foreign investment. Mindful of the need to compensate the holdback of the sanction years, the government has been pursuing a policy shift with a view to systematically incentivise the deployment of renewable energy, to establish a revised and more stable regulatory regime under the Renewable Energy and Energy Efficiency Organisation of Iran (SATBA (or SUNA)), and to offer feed-in tariffs that are nominally high when compared internationally.

Among the incentives is a purchase scheme for any electricity produced from renewable sources (solar, wind, biomass, geothermal, small hydropower plants, and more recently fuel cells and turbo-expanders) established by the Ministry of Energy for a recently increased period of 20 years.

According to last year’s resolution, based on the capacity of the power plants, the feed-in-tariffs vary between 3,400 and 4,200IRR/KWh in the wind sector, and 3,200 and 4,900IRR/KWh in the solar sector, taking into account the adjustment factor, namely inflation.

Under this scheme, more than €3 billion are to be invested in the renewable sector.

The success of the new tariff regime, which led to an almost seven-fold growth in development of renewable power plants in the past Iranian year alone (March 2016–March 2017) encouraged a continuance along the same path, with officials promising to keep the tariffs unchanged for the current year.

For the time being, the Iranian contractual practice is based on the existing power purchase agreement (PPA) model, a new and partially revised version of which is to be publically announced within the coming months. However, an additional tender-based system for large utility-scale renewable energy system projects is also under examination.

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15 An Act passed by parliament in December 2016 merged SUNA with the Iran Energy Efficiency Organisation (SUBA). According to the Act, all functions, obligations and authorities of SUNA, as well as its personnel, will be transferred to the new organisation called SATBA.

16 Prior to July 2015, contracts were limited to a five-year period and did not differentiate between technologies.

17 Statement by the president of OIETAI. Reported by IRNA: www.irna.ir/fa/News/82509590/.


Key points in the PPA include, among other points:

- While the PPA provides for a conditional purchase price, this price may be decreased if the project is delayed in commissioning;
- There should be the possibility of an increase in the purchase price if locally made equipment is used;
- The seller is responsible for any work concerning the design, construction, testing and commissioning of the grid connection facilities;
- The purchaser has no responsibility for connecting the plant to the grid – any expenditure in connection with these rests with the seller;
- The seller is responsible for obtaining all applicable permits at its cost. However, the purchaser has an obligation to assist the seller in obtaining the required permits;
- The purchaser should provide a revolving letter of credit from an Iranian bank, with a validity period not less than six months and a value equivalent to the amount to be paid by the purchaser. The expenses associated with the letter of credit shall be shared between the purchaser and the seller;
- The PPA is governed by Iranian law, with a dispute settlement mechanism requiring, first, negotiation, then referral of the dispute to an expert and, finally, to a court;
- Where changes in law provisions require an adjustment to the PPA terms and the changes are a result of new decrees and directives, any additional expenditure shall be compensated by the purchaser;
- There should be force majeure provisions allowing, upon the request of the seller, the performance to be suspended for a period of six months, without any payment. If not remedied within the period of six months, the purchaser may terminate the contract; and
- There should be termination rights in the event of certain circumstances arising, such as insolvency, assignment without consent by the seller or loss of required permits (subject to cure periods).

A key question for the success of the new tariff regime, in particular in respect of the large scale projects and bankability issues, in general, will be the availability of project finance. Linked to the bankability of the PPA, will be the question of availability of sovereign guarantees or another structure, such as a standing fund, as a backstop for payments over the long term.

VI LOOKING AHEAD: COMPETITION IN THE IRANIAN POWER AND OIL AND GAS SECTORS

Ultimately, whether competition is introduced into Iran’s energy sector will depend on the outcome of an ongoing debate between conservatives arguing for energy independence and self-sufficiency, and moderates (led by the recently re-elected President Hassan Rouhani and his administration since he first took office in 2013) looking at the best way to promote and advance the economy. With the energy industry having been in public hands during the era of sanctions, with significant involvement of the Islamic Revolutionary Guard Corps (IRGC), there are significant vested interests to overcome in the industry, and any opening up of the sector could be viewed with suspicion by the IRGC and Iran’s home-grown energy sector supply chain, particularly as the reforms promise to fundamentally redefine and rescope the role of NIOC and bring in substantial foreign investment and technology.
Introducing competition and tariff reform has a number of potential benefits for the energy sector in Iran. The purpose of such reforms is to ensure that the risks in the investments in the energy sector are allocated to the entity that can best manage them and also to force better investment decisions. Competition and liberalisation seeks to transfer greater performance risk to the private sector, harness the benefits of competition by introducing new technology and international best practice into the sector, and share financial gains with taxpayers and consumers.

Where the Iranian Ministry of Energy is also the regulator and direct investor in the power sector, the conflicts of interest can be significant. For effective regulation, a separation of key aspects of the state from the sector holds many benefits. However, Iran may wish to take a staged approach to liberalisation of the sector, to ensure that the process does not place undue upward pressure on energy prices (which can be politically difficult) or pressure on existing entities to reduce costs that create financial difficulties and unsettle the sector.

Competition will also require capacity-building in key institutions that will need to manage the capabilities and expertise in managing new market processes, as well as educating the full supply chain on the approach in Iran. Key elements that Iran may need to consider include establishing an independent transmission company and considering which entity should procure new power generation projects (as well as potentially other types of projects in the sector). A key goal is to make electricity a liquid commodity that can be traded in spot markets and wholesale markets. Where Tavanir is restructured, a regulated price control also needs to be established for the network and monopoly businesses, and the process for setting the initial tariffs involves considerations including ensuring adequate revenue, promoting efficiency and driving key policy objectives.

Iran does already have independent power projects and a number of power plants have been privatised or are scheduled to be privatised. For international investment, a sustainable PPA is offered by Iran designed to create a predictable revenue stream to raise financing and protect independent power projects from political risk. Also, perhaps most importantly, there has to be a clear ability for international investors to rely on the legal ‘sanctity’ of contract terms and pursue international arbitration. The existing Iranian PPA needs to be improved to provide a sustainable PPA framework and to be bankable according to international standard if international investments are to materialise. Further, while competitive procurement of new large-scale projects is usually the recommended approach, it is often the case that initial projects are not competitively procured and instead are procured on a negotiated basis.

Policy and sectoral changes in Iran will also create a question on how to deal with power purchase agreements held by existing power projects in Iran, which may not have contemplated significant market changes. As a basic principle, it will be important for Iran to honour existing contract terms and maintain confidence in the pipeline of projects. Any other approach would have an effect on market liquidity and could create above-market costs, as well as deter new entry and inhibit the gains associated with competition and market opening. They could also lead to claims and litigation. While it is worth making an effort to integrate independent power producers (IPPs), the magnitude of IPP contract terms affected can be a factor in the approach taken.

Iran is also looking to develop further its role as a major regional participant in the Middle East power market and this will be enhanced as it takes steps to implement arrangements drawing from international best practice and appropriate to the Iranian context.
ESTABLISHING AN ENERGY BUSINESS IN IRAN AND DISPUTE RESOLUTION

While it is beyond the scope of this chapter to detail the broader considerations on the appropriate form of investing or establishing a business in Iran, the recent opening up of the Iranian market means that this is a very relevant topic for entities wishing to become involved in the Iranian energy sector.

Investors, developers and supply chain entities looking to operate in the energy sector in Iran post-Implementation Day (see above) will need to decide on the form of their engagement and entry into Iran. Many entities will operate from overseas, some will consider opening up a branch office in Iran and, for more involved operations, an Iranian legal entity may need to be established or dealt with. Branch offices tend to be used typically for activities such as marketing, aftersales and certain service provision activities. However, engagement in direct commercial activities would affect the tax treatment of branch offices. Longer term and deeper operations would tend to be pursuant to the establishment of an Iranian companies such as a private joint-stock company or limited liability company. Alternatively, another route for engagement in Iranian projects is to set up a joint venture with a local entity. The joint venture could then participate in tender rounds, and this can also help on meeting local content requirements.

A foreign investment licence under the Foreign Investment Promotion and Protection Act (2002) permits the foreign investor to incorporate a company without restriction on the level of foreign ownership. It may be possible, following changes to regulations that came into effect in 2008, to incorporate a fully foreign-owned entity for specified activities.

A further useful consideration is to establish a business in a free trade zone (FTZ) such as Anzali, Aras, Arvand, Chabahar, Makoo, Kish or Qeshm. Existing and planned FTZs in Iran are subject to the Law on the Administration of Free Trade and Industrial Zones 1993. Each FTZ has an authority that manages the activities in the zone and issues permits. While FTZs look to streamline and ease the process of establishing a business in Iran and may impose attractive tariffs and customs duties to incentivise, as noted above the recent changes following the Foreign Investment Protection and Promotion Act (2002) make it viable for foreign entities to establish wholly-owned businesses generally in Iran. Iran’s 16 Special Economic Zones (SEZs) may also be a viable option for some foreign entities looking to establish themselves in Iran, and they provide many of the advantages associated FTZs. The FTZs are distinct from the SEZs, the difference is geographic: FTZs are established in border regions while SEZs can be set up anywhere on the mainland. In contrast to the FTZ, SEZs are considered as part of the mainland according to Iranian legal terms.

Furthermore, the law and regulations governing the FTZs are different from those applicable to SEZs. For instance, no visa is needed beforehand to enter into the FTZs (visas are issued on arrival), but in the SEZs, entrance of foreigners is subject to mainland regulations. In addition, in the FTZs, applying for investment is subject to the relevant FTZ regulations, whereas the law of the mainland remains applicable in the SEZs.

As such, it is important for entities looking to enter the energy sector in Iran to understand the broad framework of laws, regulations and industry frameworks currently

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20 See www.freezones.ir.
21 Ibid.
22 Ibid.
23 Ibid.
in effect in Iran. The Constitution of the Islamic Republic of Iran requires all laws and regulations to be based on Islamic criteria. Iran has two coexisting systems of law, namely the law of Islamic lawyers and codified law. It is beyond the scope of this chapter to provide a detailed overview of the Iranian legal system. We set out below some aspects of particular note in conducting transactions in the energy sector.

Iran has promoted foreign participation through the Foreign Investment Promotion and Protection Act (FIPPA), 2002. According to FIPPA, sectors including industry, mining, agriculture and services in greenfield and brownfield projects are open to investment in Iran subject to satisfaction of certain criteria. Foreign direct investment (FDI) may be admitted in fields where private sector activity is permitted. However, purely commercial activities are not considered to be foreign investment.

Therefore, foreign investors may choose the investment method in the project as FDI or foreign investment in all sectors within the framework of ‘civil participation’, buy-back and build-operate-transfer schemes.

A licence for foreign investment under FIPPA is issued by the Organization for Investment Economic and Technical Assistance of Iran (OIETAI). The licence provides for foreign investment to be treated on a par with Iranian investments, allows for disputes to be resolved outside Iran and repatriation of profits. It, generally, facilitates investment and secures against non-commercial risks including currency transfer, nationalisation, expropriation, government intervention and breach of contract by government. As to the major questions of expropriation and nationalisation of foreign investors’ assets, FIPPA recognises the right to receive immediately compensation based on the fair market value of the expropriated assets on the day before expropriation takes place. Besides, foreign investors have direct access to and possibility of withdrawal of export proceeds out of escrow accounts established in banks outside Iran. Foreign investors may export their goods and services without any commitment to reintroduce export proceeds to the country. Also, travel for foreign investors, directors, experts and their immediate family in relation to the investment covered by FIPPA is made easier by the grant of a three-year multi-entry visa, a residence permit, a work permit for each individual with a right of entry and a three-month residence permit on each occasion. Furthermore, all bilateral investment treaties concluded with other countries contain a provision whereby they are only applicable to investments for which the FIPPA licence is acquired.

According to statements from OIETAI officials, foreign investment applications are processed within 15 days, although, in practice, such a process can take up to 30 days to complete.

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24 Article 2 FIPPA.
25 Article 3 of Implementation Regulation of FIPPA.
26 Article 15 of Implementation Regulation of FIPPA.
27 Article 8 FIPPA.
28 Article 4 of Implementation Regulation of FIPPA.
29 Article 9 FIPPA.
30 Article 17 of Implementation Regulation of FIPPA.
31 Article 9 FIPPA.
32 Articles 13–18 FIPPA.
33 Articles 13–18 FIPPA.
34 Article 20 FIPPA and Article 35 Implementation Regulation of FIPPA.
35 Article 6 FIPPA.
The FIPPA licence validity can be extended upon request by the foreign investor (for example, if the foreign investor fails to bring in the investment capital within the determined period and needs an extension). Otherwise, the licence will be considered null and void. 36 In the renewable energy sector, applications for foreign investment licences are submitted to OIETAI, once the necessary permits have been obtained from SATBA.

In addition to the judiciary (court) system, the settlement of disputes through other methods such as arbitration has been recognised by the Iranian legislator and has developed significantly in recent years. This is aided by the considerable experience derived from the example of the Iran–United States Claims Tribunal and the work performed by different institutions providing specialised services in arbitration matters.

National arbitration in Iranian law is governed by the 2000 Civil Procedure Code (Articles 454–501). For international arbitration, a framework was established by the Iranian Law on International Commercial Arbitration of 1997. To complete the efforts in furthering the position of international arbitration under the Iranian legal system, Iran has ratified the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards of 1958.

There are two major arbitration bodies in Iran: the Tehran Regional Arbitration Centre, 2004, and the Arbitration Center of Iran Chamber, 2001. As is standard in international arbitration, there is no right of appeal against an award. A party may, however, apply to have an award set aside on certain grounds.

As far as arbitration of disputes relating to public and state property is concerned, particular attention should be given to cases where the subject matter concerns public and governmental property, or if a party is foreign, since the approval of the Consultative Assembly (the parliament) is also required in such cases. 37

VIII CONCLUSIONS AND OUTLOOK

The easing of sanctions marked the beginning of a new chapter in the Iranian energy sector, characterised by increased determination for progress and ambitious goals for development on the part of the Iranian government accompanied by higher, if still somewhat cautious, interest from the foreign investors’ side.

The impact on Iran’s economy has been notable and positive. With more than US$55 billion of assets unfrozen and made available, and around US$11 billion of FDI approved by the OIETAI, the highest level in almost two decades, raising production to pre-sanction levels of 3.85 million barrels per day and aggressively re-gaining its market share with approximately 2 million barrels per day of oil exports, the country has managed to bring down inflation to single digits (8 per cent in December 2016) from a peak of 45 per cent in 2013. 38

36 Article 32 of Implementation Regulation of FIPPA.
37 Article 139 of the Iranian Constitution provides that:

The settlement, of claims relating to public and state property or the referral thereof to arbitration is in every case dependent on the approval of the Council of Ministers, and the Assembly must be informed of these matters.

In cases where one party to the dispute is a foreigner, as well as in important cases that are purely domestic, the approval of the Assembly must also be obtained. Law will specify the important cases intended here.

38 See ‘Rouhani’s economic legacy’, Tehran Times, 14 May 2017. See also ‘Iran oil exports hit pre-sanctions high on run-up in condensate shipments’, Reuters, 3 October 2016.
The recent re-election of President Hassan Rouhani is a positive sign that the policy path already taken to incentivise foreign investment in the Iran energy sector will continue in the next four years. Despite the progress made, financial challenges still persist as valid concerns. It now remains to be seen whether the efforts initiated by the current administration aimed towards attracting large-scale foreign investment, while also localising know-how in the energy sector, will come to fruition in the coming year.

Nevertheless, the fact that Iran with its vast energy resources and all its potential remains a huge player in the energy sector is undeniable.
I OVERVIEW

Certain key historical and constitutional matters

Prior to 2003, when the government headed by Saddam Hussein was replaced, Iraq was governed by a socialist-leaning government with a very limited private sector in place. This has continued to be the case since the overthrow of the monarchy in 1958. A series of steps were taken by the various republican governments that nationalised the principal components of the economy, culminating in the 1972 nationalisation of the oil sector. Iraq had therefore become a centralised economy, with various ministries controlling most aspects of the economy.

Between 1980 and 1988, Iraq was involved in a war with the Islamic Republic of Iran, which was followed in 1990 by the invasion of Kuwait and the subsequent Gulf War I. Immediately after Kuwait was invaded, a series of UN Security Council resolutions imposed sanctions on Iraq, which were followed by a series of nationally imposed sanctions. These sanctions were widespread and extended into most imports, including key oil and gas and technological imports.

Following Iraq’s expulsion from Kuwait, the sanctions continued (until 2003), but more importantly, the central government lost effective political and security control over a significant portion of Iraq, to be referred to as the Kurdistan Region. In 2004, the Transitional Administrative Law (the Interim Constitution) recognised the boundaries of the Kurdistan Region, with the same boundaries adopted in the Permanent Constitution of 2005 (the Constitution). The Constitution was structured in a way that provided limited powers to the central government and shared certain powers between the central government and regional governments (the Constitution provides that other regions could be formed). All remaining powers are to be vested in the regional governments.

The matter of oil was hotly debated in the constitutional process, with a compromise reached that provided that the existing fields continue to be managed by the central government, and new fields are jointly managed with the revenues going to the central government. However, in the event of a dispute between the central government and the regional government over the development of new fields, the decision of the regional government would prevail. Issues relating to gas are treated in the same way. The Constitution further provided that Iraqi oil and gas is owned by the Iraqi people, and that the management of the oil fields is to be based on a federal oil and gas law that, to date (nine years after the Constitution was approved), has not been passed.

1 Salem Chalabi is a partner at Stephenson Harwood Middle East LLP.
There have been disputes between the Kurdistan Regional Government (KRG) and the central government on a number of oil and gas issues, in particular those relating to the development of new oil fields. The KRG has entered into production-sharing agreements with a substantial number of oil companies, agreements that the Iraqi Ministry of Oil (MOO) has been critical of. As a result of these disputes, the MOO has claimed on a number of occasions that the KRG has been selling its oil directly in the oil markets (through Turkey) and keeping the income from such oil sales. In response, the KRG has claimed that the central government has withheld amounts owing to it in the budget. Despite certain interim deals, the disagreements between the central government and the KRG continue at the time of writing. These continuing disagreements have led to various court and arbitration claims in various jurisdictions. These disputes have also involved the Republic of Turkey in connection with disputes relating to the Iraq-Turkey export pipeline, from which both Iraqi and Kurdish crude is exported to Ceyhan, Turkey.

In light of the constitutional separation of powers between the central government and the KRG, the electricity sector is effectively two separate sectors: one for the areas governed by the central government, and the other governed by the KRG. Each has developed in a different manner over the past few years.

ii Developments in 2014

The year 2014 saw two key developments: the takeover of certain parts of Iraq by the Islamic State and the drop in the price of oil.

In June 2014, the Islamic State took over significant areas in Western and Northern Iraq, such as the cities of Mosul, Tikrit and parts of the governorate of Tikrit. These areas were mainly governed by the central government, and therefore the central government was unable to continue providing electricity services to those areas that fell to the Islamic State. Simultaneously, in the governorate of Kirkuk, the Islamic State took over certain oil fields and was able to sell crude oil directly. Ultimately, troops belonging to the KRG were able to take back some of these fields, which are now under their control. Constitutionally, these fields are to be managed by the MOO (through North Oil Company) but, following certain negotiations, the KRG was unwilling to hand these back to the MOO, and is now operating the fields itself. This has increased tensions between the central government and the KRG.

As for the drop in oil prices, the impact has affected the Iraqi budget significantly, and therefore the MOO is considering amending the terms of its existing service contracts with the existing international oil companies. To that effect, it is looking at different alternatives to propose to the international oil companies. Moreover, parliament has asked the MOO to address the amendments of the technical services contracts.

iii Developments in 2015

The year 2015 saw several developments that affected the energy sector, in particular the continued drop in oil prices, which affected the Iraqi economy significantly. On the positive side, there were various offensives against the Islamic State that ended up with the recovery of certain towns and cities that had fallen to the Islamic State, including Tikrit and Al-Ramadi. These victories were coupled with an almost total destruction of the capacity of the Islamic State to produce oil from fields under its control.

In order to address significantly reduced oil revenues, the Iraqi government significantly reduced its expenditures, in particular its capital expenditure on infrastructure projects. The impact of such reduced infrastructure expenditures on the growth of the Iraqi economy has
not been positive as projects stalled, causing significant arrears to Iraqi companies and, more importantly, to international oil companies. The latter, accordingly, began to reduce their expenditures in the oil fields under the technical services agreement.

iv Developments in 2016

The year 2016 was a year in which the fiscal consolidation that commenced in 2015 became more entrenched, but was also a year in which Iraq engaged with the International Monetary Fund in a Stand-By Arrangement (SBA).

As oil prices dropped further in early 2016, the government decided to commence negotiations with the International Monetary Fund (IMF) for an SBA programme that would not only lead to loans from the IMF of US$5.4 billion over a three-year period, but also would unleash facilities from the international community for a total of approximately US$18.6 billion over a three-year period. The IMF programme is premised on three pillars:

a. the maintenance of sustainable debt over the next five years;

b. the repayment of arrears as well as the non-incursion of new arrears; and

c. the maintenance of decent levels of central bank reserves.

In order to achieve these goals, a principal condition precedent was that the MOO was required to become current on its arrears to the international oil companies by the end of 2016 (which it did). The IMF programme also required a restructuring of the Iraqi economy away from a state-controlled economy and also towards increasing non-oil revenues.

Throughout 2016, the government was able to stabilise its expenditures. However, it was also required to carry out an audit of all of its arrears, which it was able to do. These proved to be larger than expected and therefore Iraq’s investment expenditures, including those in the oil and electricity sectors, were required to be reduced.

At the same time, the MOO began to consider some new large-scale investment projects, including the Basra-to-Aqaba pipeline (the Najaf-to-Aqaba portion was awarded on a build–own–operate–transfer basis in March 2017). Moreover, there have been proposals relating to the refinancing of some large infrastructure projects, in particular, the Karbala refinery.

II THE IRAQI ELECTRICITY SECTOR

i The Ministry of Electricity – Baghdad

The Iraqi Ministry of Electricity’s (MOE’s) role in the electricity sector is, to say the least, all encompassing, with it being the principal policy maker, power producer, service provider, regulator and operator. As with most other ministries in Iraq, the MOE is beset with bureaucracy and corruption, and therefore is not conducive towards structural innovation and reform. The senior staff of the MOE are, by contrast, technically trained to a good standard and have significant knowledge of technical developments in the electricity sector.
The legislative basis for the MOE is currently vague, which has made it difficult to clarify its powers. Accordingly, the MOE’s powers are somewhat broad in the power sector. In recent years, however, it (together with the various arms of the executive branch) has prepared two drafts of an MOE law. In late 2016, the draft law was passed. The following is a brief summary:

a. The MOE is designed to organise the electricity sector in Iraq, including the introduction of the private sector into the generation and distribution sectors. In connection therewith, one of the goals of the law is to transfer the electricity sector from a purely public enterprise to a mixed or private sector enterprise.

b. It is also designed to make the electricity sector less centralised (with everything controlled by the office of the Minister of Electricity), by among other things encouraging the role of the provincial governments.

c. It is designed to encourage renewable energy.

Administratively, the MOE is currently divided into various central departments (generation, transmission, distribution, etc.) and various regional departments (e.g., south generation). The passing of the law, which has not yet been implemented, has at the time of writing not amended too much administratively within the MOE. In an effort to carry out the above, the electricity law keeps more or less the same central departments within the ministry (generation, transmission, distribution, etc.) but then plans to convert the regional departments into public companies. In total, there will be 10 such separate public companies (mirroring the existing departments now). The idea is that assets of each of the departments would be transferred to the relevant public company. Ultimately, the law proposes that these companies would be converted into publicly owned companies (listed on the Iraq Stock Exchange).

The law also contemplates opening private investment opportunities in the electricity sector. These include the introduction of private companies in the electricity distribution sector, which will charge tariffs. This could be a problem for such companies and for the MOE. In early 2015, the MOE announced the introduction of higher tariffs to be paid by the consumers. (Currently, only a small percentage of consumers pay what they actually consume in electricity, principally because of meters that are old and have been tampered with, corruption in the collection of electricity bills (which are manually collected) and rewiring of home electricity lines.) The introduction of higher tariffs caused public uproar as the public at large felt that the new tariffs would be unduly burdensome at a time of economic hardship, an uproar that was picked up on by powerful political actors who ended up opposing the new tariff. The MOE was therefore forced to withdraw this proposal. Later in the year, as part of Iraq’s entry into the IMF SBA, the Iraqi cabinet voted on a resolution that reintroduced higher tariffs. These new higher tariffs were structured to be less strenuous on the poorer elements in Iraqi society. Transferring this task to the private sector may work better, as the private sector may prove less responsive to political pressures; but at a time in which electricity shortages and cuts are the norm, the public at large may not favour such a move. In 2016, the MOE embarked on a pilot programme in a neighbourhood in Baghdad.

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2 The Ministry of Electricity (MOE) was established during the time of the Coalition Provisional Authority (2003–2004). Prior to that, the various components of the MOE, which were organised as state owned enterprises, were part of the Ministry of Industry and Minerals. Once the MOE was established, such state-owned enterprises were de facto converted into directorates of the MOE.
to privatise distribution and collection of electricity tariffs. This programme was followed by a wider plan, announced in the form of a ‘request for information’, for privatising the collection of electricity tariffs throughout the country. By early 2017, the tariff collection programme was introduced into several areas, although there have been demonstrations against the introduction of the programme in cities such as Basra.

The law has the right intentions, but it suffers from some of the same legislative basis that makes it difficult for the private sector to flourish in Iraq. Or rather, although the draft law itself may have the right incentives, there are a large number of legal and regulatory hindrances that make it difficult for the private sector to carry out business in Iraq. For example, there is a law in Iraq (Law No. 56 of 1977) that provides that the government or any governmental entity need not obtain judicial decisions prior to attaching private assets if they are seeking to recover their debts. Coupled with the fact that Iraq is not party to the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards, such laws make it very hard for international financial institutions and investors to feel comfortable doing business in Iraq generally.3

ii The private sector in the Iraqi electricity sector
There were significant developments in the private sector entering the electricity business in 2014. First, however, by way of background, there are a few matters to keep in mind:

a The Iraqi transmission and distribution network is owned completely at this stage by the MOE. There is no direct private ownership interest in the transmission and distribution sector. The MOE, in conjunction with the World Bank, has indicated that it intends to privatise these two sectors, although no concrete steps have been taken in connection with it. Accordingly, other than as mentioned above with respect to the attempted privatisation of the collection of electricity tariffs, the only private sector involvement in transmission and distribution has been in the fulfilment, construction and implementation of MOE procurements orders.

b In 2010–2011, the MOE conducted a tender for four independent power producer (IPP) projects in the generation sector, using GE Frame 9E turbines that had been recently acquired by the MOE (and which it was to sell to the winning bidders). The total of these projects combined was 2,750MW. However, owing to certain structural difficulties, in particular to do with the supply of fuels (the MOE did not want to assume the risks of supply and requested that the developers enter into separate supply agreements with the MOO), there was little or no international interest in these tenders. Accordingly, only local companies bid (with some international participation in the consortia) and, with one exception, these bidders had no experience of the IPP sector. Shortly after the bids were analysed by the MOE’s IPP team, a new minister was appointed who was not in favour of these projects. He therefore cancelled the tendering process, and ran tenders to award these as engineering, procurement and construction contracts.

In late 2013, the Iraqi cabinet instructed the MOE to commence negotiations with three independent Iraqi companies to develop independent power plants in Iraq. In February 2014,

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3 Recently, in an effort to ensure a more advantageous dispute resolution venue for international investors, Iraq joined the International Centre for the Settlement of Investment Disputes, which is a part of the World Bank.
the Iraqi cabinet passed resolution 90 of 2014, authorising the MOE to enter into power purchase agreements with these three companies, pursuant to which these companies were to develop up to 9,000MW. Some of the locations were allocated in the cabinet resolution. In particular, one of the developers was to develop a 3,000MW power plant in the Al-Rumailah area of the Basra Governorate, while another developer was to develop a 1,500MW power plant in the Besmaya area south of Baghdad (adjacent to a new real estate development project), subsequently extended to 3,000MW. In April 2014, two of the developers entered into heads of terms with the MOE and the National Investment Commission to develop combined cycle plants, which were followed in June 2014 with the execution by the MOE of power purchase contracts with these two developers.

In late 2015, two further projects were entered into with one developer. These projects, one of which is in Al-Rumailah and the other in Shatt Al-Basra, are somewhat uniquely structured. They involve the expansion of open cycle power plants to combined cycle power plants, with ownership of the open cycle power plants remaining in the hands of the MOE and ownership of the steam turbine portion of the plant remaining in the hands of the developer, with the developer operating the whole plant. This structure has many of the characteristics of a build-operate-transfer structure. Although negotiations have been completed with respect to these two projects, at the time of writing, there are various practical and technical matters that are still being discussed.

In late 2016, a fourth developer, Raban Al-Safina, entered into a power purchase contract to develop a 750MW combined cycle plant in the Maysan Governorate in Southern Iraq. At the time of writing, the developer has not yet identified the equipment to be used in this plant or the principal construction contractor.

From a regulatory perspective, key issues facing these projects include the following:

a. There have been difficulties in transferring the land to the projects. Again, by way of background, the vast majority of land in Iraq is owned by the Iraqi Ministry of Finance (MOF), which has been somewhat reluctant to transfer land (even by way of lease) to developers of various projects, including electricity projects. Other government entities have followed the lead of the MOF. This matter has proved to be a hindrance to private investment in Iraq in general.

b. Although a grid code has been developed by the MOE, which the companies have been willing to comply with, in practice this has not been tested by the private sector and it seems certain integrating difficulties are being experienced at the early stages of these projects.

c. The companies have covenanted to comply with the environmental laws and regulations in Iraq, which have generally been developed by the Ministry of the Environment. The process will entail the projects having to obtain environmental licences from the Ministry of the Environment, which grants these after conducting an examination similar to a Phase I environmental impact study. However, the Ministry of Environment is not very experienced in the electricity sector and has not developed specific regulations for this sector. In practice, therefore, at this stage, environmental compliance is still untested and, since the financing of these projects are not contingent on international project finance, one is not sure whether these projects would comply with the World Bank Group Environmental, Health and Safety Guidelines.

d. Learning from the experience of 2011, the MOE has assumed the obligation of providing fuels to these companies. The MOE is looking at ways of securing these fuels, including the natural gas that Iraq lacks. Although both the MOO and the MOE
are experienced with respect to the laying out of pipelines (and have processes for usage of the land on which the pipelines may be located), difficulties could arise in particular due to the security situation in certain parts of Iraq. Certain difficulties have also arisen with respect to the supply of water, in particular with respect to the needs of steam turbines (in the combined cycle power plants).

e The cabinet further approved the issuance by the Ministry of Finance of payment guarantees to the developers, which are the international norms for such power purchase contracts. These payment guarantees have been issued and, to date, they have been accepted by the lenders to these projects.

f The tariffs were agreed between the cabinet and the developers, and therefore were not left for market forces. These tariffs were not divided into capacity charges and output related charges, but one tariff was agreed for the production of each of the simple cycle and the steam turbines productions. These tariffs have since become the benchmark, although there are new tenders in various stages of development that could impact these benchmarks.

g As the first two projects are groundbreaking projects, the licensing processes have not been tested out and are not fully clear. The National Investment Commission established a ‘one-stop shop’ mechanism to assist in moving matters forward, but this has not been successful. As a result, there have been substantial delays in every single step. Indeed, Iraqi bureaucracy is stultifying. For example, in discussing with international oil companies the difficulties that they face, near the top of the list is always the matter of obtaining visas. Whereas in most developed countries, the process for obtaining visas is a relatively simple process, the Iraqi Ministry of Interior intentionally makes things difficult, ostensibly for security reasons.

The Iraqi MOE has also announced a number of new investment projects in the generation sector, including a tender for a 750MW plant in the City of Al-Samawa, 300km south of Baghdad. The structure for the project was amended by the MOE, and currently the MOE is considering various new alternatives to the project. There is a pipeline of other projects that have been announced by the MOE, including conversions of existing simple cycle generation plants into combined cycle generation plants.

As these new projects move forward and perhaps get implemented, Iraq would be faced with a significant portion of its power generation sector in private hands, and with the MOE paying significant sums for electricity under the various power purchase contracts. At this stage, the focus is on moving forward with the transmission and distribution side of the electricity sector.

There is significant potential for investment in the transmission and distribution side of the electricity sector; yet, at this stage, there is no regulatory framework for this. Accordingly, the MOE continues taking steps to improve its transmission grid, which it owns. The plans to privatise this sector have not been adopted, despite proposals introduced by international experts. As for the distribution sector, Iraq is still reliant on old technology, with little introduction of more modern technologies such as smart meters. Having stated this, in 2013, the MOE launched a pilot project for smart meters; but this was a pilot project that was not very clearly part of a structured plan.

At a time when Iraq is facing serious budgetary difficulties, the MOE tried unsuccessfully to launch tariff increases but had to withdraw them owing to political pressures. This leaves Iraq collecting very low levels of income from its electricity generation (with significant
subsidies going to loss-making state-owned enterprises belonging to the Ministry of Industry and Minerals). As Iraq is embarking on stand-by arrangements with the IMF, the issue of electricity tariffs and their collection will need to be addressed, as non-oil revenue will need to increase.

Coupled with this, the lack of natural gas and, due to the mature state of the refineries, limited availability of refined products, Iraq imports refined products and increasingly uses other less efficient products (such as heavy fuel oil) to fuel its generators. The imports of products such as diesel (which fuels a large number of small production generators) ends up exacting even more pressure on the state budget. Electricity, therefore, continues to be a major drain on the state budget.

iii The Ministry of Electricity – Kurdistan

The evolution of the electricity sector in the Kurdistan Region has been somewhat different. As it became apparent that the central government’s generation capacity was not going to meet sufficient demand in the areas under central government control, the KRG decided to develop its own generating capacity and, realising it had limited funding to do so, requested that the private sector do so. In addition, the KRG took over the existing grid and began to develop it. In doing so, it relied on the existing central government grid code and practices.

In 2007, the KRG entered into its first power purchase agreement with Mass Global, a private sector company owned by a reputable Kurdish businessman for the development of a 500MW plant in Erbil, which is the capital of the Kurdistan Region. Although this power purchase agreement was designed on a similar basis to international standards, its terms were more favourable to the developer. As the power plant was implemented quickly, the KRG entered into two other power purchase agreements, each for 500MW, with the same company to develop generation plants in the other two major Kurdish cities – Suleymaniyah and Dohuk. As these plants were also set up quickly, it became apparent that demand had increased and therefore the capacities of each of these plants was significantly increased. At the time of writing, the International Finance Corporation acquired from Mass Global a portion of the project company operating the Suleymaniyah power plant. In addition, the KRG entered into power purchase contracts with other developers more recently.

The critical issue for the development of these plants was that the KRG assumed responsibility for bringing natural gas to these plants, and it did so from one of the undeveloped natural gas fields in the Kurdistan Region, the Khor Mor field. Lacking money, it entered into development arrangements with a Sharjah-based company, Dana Gas, in order to develop the fields. Dana Gas carried out the development and was able to supply, through self-funded pipelines, the natural gas to the various power plants. This was one of the success stories of the KRG, in that not only were untapped gas deposits utilised but they were done so to bring power to the Kurdistan Region, which currently has 24 hours of electricity a day. However, a dispute arose between Dana Gas and the KRG, which went to arbitration, and in November 2015, Dana Gas was victorious in the arbitration and was awarded approximately US$2 billion in damages. In addition, due to the budgetary difficulties faced by the KRG, owing to its dispute with the central government (over the division of oil revenues) and lower oil revenues in general, the KRG has begun to default on certain financial obligations. It is unclear how that will impact on its obligations under the power purchase contracts, as well as its ongoing relationship with the gas suppliers.
III THE IRAQI OIL SECTOR

i Energy markets

Development of power markets and contracts for sale of power

At the time of writing, with limited exceptions discussed below, electricity in Iraq is provided by two types of providers – the MOE and private unregulated owners of generators scattered across the country. The MOE’s supply was discussed above and, owing to the fact that it cannot supply electricity 24 hours a day across the country, there are thousands of private owners of generators who have developed their own neighbourhood grids. These private owners of generators are unregulated and therefore they do not comply with any of the government-imposed regulations. Owing to the general security breakdown in the country, and coupled with the fact that the central government has not been in a position to provide electricity 24 hours a day (especially in the hot summer months), the government has allowed these private generator owners to carry out their unregulated neighbourhood activities. Generally, there is no uniform pricing mechanism for these private owners, but through conversations with these private participants, it seems that after covering their costs (maintenance and diesel costs), they are making profit margins of 30–40 per cent. The suppliers of diesel are also making similar profit margins, as the risks of supply are significant.

In addition to the above, there is effectively a third limited producer of electricity in federal Iraq: the international oil companies who are producing electricity for their own use. Since these fields have not developed completely, electricity production has not reached its capacity. Under the technical services agreements between the international oil companies with the companies belonging to the MOO, the plants are owned by these government-owned companies (such as the South Oil Company), with the power produced only being used in the relevant oil fields. Although this is not necessarily ideal or efficient, the grid between oil fields is not well developed or integrated, and therefore electricity production is limited to the individual field where such generation plants are located. Again under the relevant technical services agreements, the government counterparty is required to provide electricity or to reimburse the international oil companies for the costs of electricity production. The costs have been relatively high because the international oil companies have been using smaller diesel generators. The regulatory framework for this electricity generation has been very limited, and the MOE is not involved in these activities as its grid is not used. The only regulations applicable are environmental, but these are not applied uniformly.

The only other electricity producer in the federal region is a Turkish company called Karkey Karadniz, which operates power barges moored in or around the Basra region in Southern Iraq. These barges are supplying a total of 450MW, mainly to the populations in Southern Iraq. The barges are tied to the grid through high voltage substations in three separate areas, and they are operating on heavy fuel oil, which the MOE is committed to supplying. This company has entered into power purchase contracts with the MOE (the first one being in 2010). Initially the tariffs were extremely high, but as the company was able to recover its capital expenditures and expand its fleet (the initial production was 110MW), tariffs were reduced but were principally based on negotiations rather than other market sources.

As for the main power suppliers who have entered into power purchase contracts with the MOE, as indicated above, these companies (who have not yet commenced production at the time of writing) are not allowed to sell their production other than to the MOE (as buyer under the power purchase contracts). As generation capacity increases over the next few
years, it is anticipated that this may change. In the Kurdistan Region, the matter is slightly different. As other private plants have emerged, the KRG is only committing to purchasing a minimum percentage of generated electricity, and the developers are allowed to supply power to third parties, including the international oil companies developing the fields in the Kurdistan Region. The problems with this are mainly related to the grid, as it is still relatively undeveloped and there are technical difficulties in the private sector development.

**Market developments**

There have been a number of announcements of projects in Iraq, but whether these will reach implementation and commercial operation is unclear. In addition, there have been a number of developments that could influence the power market in Iraq, detailed below.

**Budgetary impacts**

The reduction in the price of crude oil has caused a major budgetary problem in Iraq, and therefore certain existing obligations of the state may be delayed or amended. For example, there has been speculation that the structure and terms of the technical services agreements between the international oil companies and the MOO may be amended. Moreover, the delays in the development of the oil fields may cause the collection and treatment of the associated gas from the oil fields to be delayed. At the time of writing, however, and based on discussions with personnel from the MOO, the South Gas project with Shell Oil (to gather and treat the associated gas from several giant oil fields) is still on track.

**Security situation**

The deterioration in the security situation, especially in the western desert areas of Iraq, has caused delays in the development of some of the gas fields in the areas, such as Akkaz. Moreover, the strategic pipeline project to Jordan has also been delayed owing to the fact that there are large tracts of land not under government control.

**Additional borrowing**

In light of the budgetary constraints in 2015 and 2016, Iraq may begin entering into loans and other types of borrowing in the international financial markets. In addition, various ministries including the MOE may enter into vendor financing agreements for the supply of equipment, in particular for the transmission grid. At the same time, owing to the difficult environment in Iraq (legal, regulatory and security), traditional project finance may not be available and accordingly non-traditional forms of financing would be required to be made available (or more aggressive lenders, such as Chinese financial institutions).

**IV RENEWABLE ENERGY**

The Iraqi renewable energy sector is still in its infancy, without any significant renewable energy projects in place. At the time of writing, the MOE intends to enter into agreements with two sets of developers for a total of 100MW. The basis of these new contracts are still being negotiated.
V CONCLUSIONS AND OUTLOOK

The Iraqi electricity sector has significant opportunities. However, there are current obstacles – legal, regulatory and security (as well as the lack of natural gas and refined products) – that can delay the development of the electricity sector in Iraq. Coupled with the above is the significant corruption that exists, which makes it reasonable to conclude that development would be slow.
I OVERVIEW

In recent years, Italy’s gross domestic product has increased by about 0.8 per cent, and the demand for electricity and gas has followed the same trend.

In particular, with regards to the electricity market, we have witnessed an increase in both demand (by almost 1.5 per cent) and net imports, an increase that has been largely possible thanks to the support of the thermoelectric sector, whose electricity production has risen by nearly 9 per cent.\footnote{Andreina Degli Esposti is a founding partner of Studio Legale Villata, Degli Esposti e Associati.}

An important part of electricity consumption is also covered by renewable energy sources. In 2016, the Energy Services Manager (GSE) received €15.9 billion for the incentivisation of green energy. Furthermore, Italy reached the target set by the European Union on the percentage of final electricity consumption generated from renewable sources (17.1 per cent), surpassing this goal in 2015 (17.5 per cent) and again in 2016 (17.6 per cent).\footnote{AEEGSI, 2015 Annual Report. Please note that the AEEGSI Annual Report for 2016 – which provides important information concerning the energy market – has not yet been published. As reported by the Authority, the forthcoming Annual Report is expected for June 2017. For this reason, the present work will not deal with corporate operations (e.g., mergers and acquisitions) that took place in the market in the past year.}

The amount of electricity purchased on the Day-Ahead Market (MGP), as well as on the stock exchange, has also increased.

The number of sellers in the end-user market has been expanding since 2008. As in the past, the safeguarded service has declined in terms of both the power supply and the number of customers served, to the advantage of the free market. The switching activity in recent years has also been lively.

Like the electricity market, the gross domestic consumption of natural gas is on the rise, as well as the net imports.

However, the downward trend of the production of natural gas still continues. Therefore, since the increase in imports was higher than the consumption, the level of dependence on imports from abroad is growing.

Once again, as has been the case for many years, the number of companies that have operated in the wholesale market has continued to grow.

\footnote{GSE, 2016 Annual Report.}
The only market other than those managed by the Energy Market Manager (GME), which is actually used by operators, and on which a significant and consistently growing liquidity is registered, is the natural-gas balancing platform division (PB-GAS), dedicated to daily balancing.

Despite the modest growth in sales on the final market, the number of active vendors in this segment of the industry has recorded a significant increase.

Looking exclusively at the sales on the free market, the sectoral volumes have shown a marked rise in domestic electricity consumption. On the other hand, very marked losses in terms of both customers and volumes⁴ have been recorded on the safeguarded market.

II REGULATION

i The regulators

The energy market is regulated by the entities given below.

The Ministry of Economic Development (MISE)

Organised in four different departments, MISE is responsible for all the authorisation procedures of state competence and for the enforcement of all statutes and regulations concerning the energy sector. Within the Energy Department of the above-mentioned Ministry, a very important role in the energy sector is performed by the Commission on Hydrocarbon and Mineral Resources, which carries out an advisory function for all activities connected with the research, production and exploitation of hydrocarbons.

The Regulatory Authority for Electricity Gas and Water (AEEGSI)

Law No. 481 of 14 November 1995 set up the AEEGSI to protect the interests of consumers, promote completion and ensure efficient and profitable nationwide services with satisfactory quality levels for users.

Aside from its main regulatory functions (it defines the tariff-system for the use of infrastructure, ensures free access to the gas and electricity grid and promotes investments through incentives), the AEEGSI also plays an inspective role (it is granted the power to impose administrative sanctions in case of non-compliance with its provisions, aimed at ensuring the transparency of service conditions and promoting the rational use of energy).

To fulfil these activities, the AEEGSI is supported by the Antitrust Authority to ensure the implementation of the rules on free competition in the energy market.⁵

Furthermore, the AEEGSI plays an advisory role to the parliament and may issue proposals and reports (see the report published annually about the state and the activity of the energy supply sector).⁶

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⁴ AEEGSI, 2015 Annual Report. Please note that the AEEGSI Annual Report for 2016 has not yet been published.


The Compensation Fund for the electricity sector (CCSE)
The CCSE is a non-economic public body established through Provision No. 941, approved by the Interdepartmental Committee on Prices on 1 September 1961. It collects certain tariff components payed by the industry operators, which are then stored in management accounts in favour of the businesses.\(^7\)

Energy Services Manager (GSE)
The GSE is a public limited company, established by Legislative Decree No. 79 of 16 March 1999, with the function of promoting renewable energy sources in Italy, mainly through the distribution of economic incentives and information campaigns aimed at spreading the culture of environmental protection in the energy field.\(^8\)

Energy Market Manager (GME)
The company GME, wholly owned by the GSE, was established by Legislative Decree No. 79 of 16 March 1999. It is responsible for organising and managing the electricity, natural gas and environment markets, respecting neutrality, transparency, objectivity and competition criteria.\(^9\)

ii Regulated activities
With regards to the electricity market, its deregulation arose after the approval of Legislative Decree No. 79 of 16 March 1999, which established that the production, importation, exportation, purchase and sale of electricity are completely free.

The transmission and dispatching of electricity, however, continue to be under the monopoly of the state. More specifically, while a single operator (Terna SpA) runs long-distance energy transmission, the distribution of electricity to consumers was deregulated and carried out by several operators. Regardless, the distribution was given under concession to a single operator (a natural monopoly).\(^10\)

As for the gas market, deregulation was achieved as a result of Legislative Decree No. 164 of 23 May 2000 (Letta Decree), which recognised that no licence is generally required for the production, import and sale of natural gas. Storage, transport and distribution activities are operated under a concession regime.

The development and construction of new facilities (e.g., transmission lines, power plants and gas storage facilities) require prior authorisation under state and regional legislation, in order to ensure compliance with, inter alia, health and safety standards, environmental protection and existing infrastructure.\(^11\)

iii Ownership and market access restrictions
There are no restrictions on ownership of new and existing assets, service providers or licence holders. The only ones are those – in relation to mergers and acquisitions – that antitrust authorities may impose on operators in order to comply with competition rules.

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\(^7\) E Picozza, S Sambri, op. cit., p. 155.
\(^8\) E Picozza, S Sambri, op. cit., p. 165.
\(^9\) E Picozza, S Sambri, op. cit., p. 176.
\(^10\) Legislative Decree No. 79 of 16 March 1999.
\(^11\) Legislative Decree No. 164 of 23 May 2000.
iv Transfers of control and assignments

By Decree-Law No. 21 of 15 March 2012, Italy issued an innovative framework describing the intervention powers reserved to the state in the case of corporate transactions involving businesses operating in the energy sector.

Specifically, the Decree establishes that any decision, act or measure taken by a company owning one or more national interest energy networks (i.e., any changes in the ownership, control, use or availability of energy assets, the merger or demerger of the company, the transfer abroad of its registered office, the change in the company objects, the dissolution of the company and the transfer of whole or parts of the company) must be notified within 10 days to the Presidency of the Council of Ministers.

Within 15 days from the notification, the government may veto the aforementioned decisions, acts and measures, if they constitute an exceptional threat of serious prejudice to national interests. Once this period has passed, the operation can be carried out.

Finally, in the event of purchases of shares of the aforementioned companies by a non-EU person or body, the condition of reciprocity is to be respected.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

The unbundling obligations on vertically integrated energy operators represent one of the main regulatory instruments adopted by Italy in order to impose impartiality and neutrality in the management and development of the energy infrastructure network, which is a natural monopoly market system (the ‘essential facility’).

With regard to the electricity transmission grid, there was a first phase, in which an independent system operator managed the network,\(^{12}\) and then there was a second phase, consisting of the ownership unbundling (OU) through a preliminary privatisation procedure of the vertically integrated Enel Terna SpA.\(^{13}\) Legislative Decree No. 93/2011 has imposed the independence of the transmission system operator in terms of its organisation and decision-making powers from other activities (generation, distribution and sales).\(^{14}\)

With reference to the gas transportation pipeline, in 2012 the vertically integrated company ENI SpA adopted an independent transmission operator model: it owned the gas network while keeping control of the service provider company (Eni Snam Rete Gas SpA).\(^{15}\) In 2013, the said model was replaced by an OU system, as certified by the AEEGSI via Resolution No. 515/2013.\(^{16}\)

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12 Legislative Decree No. 79/99 provided that the integrated company (Enel Terna SpA) continued to be the owner of the network, while its management was entrusted to a public company owned by the Ministry of Economy (GRTN SpA).

13 Decree-Law No. 239/2004 and the Decree of the President of the Council of Ministers of 11 May 2004 placed the shares of Enel Terna SpA on the market, banning Enel SpA from holding more than 5 per cent of capital. They have furthermore entrusted both the management and the ownership of the network to a private company (Terna SpA).

14 The transmission system operator Terna SpA was declared compliant with the OU model on 5 April 2013 (see AEEGSI Resolution No. 142/2013/R/eel).

15 See AEEGSI certification No. 403/2012.

16 The transfer of Eni Snam’s shares began with the entry in force of Decree-Law No. 1/2012 and the subsequent Decree of the President of the Council of Ministers on 25 May 2012. This operation was then completed in 2013, when the Deposits and Loans Fund (Cassa Depositi e Prestiti) purchased 30 per cent of
The electricity and gas distribution is regulated as a territorial monopoly, meaning that a public tender for the concession of the distribution service to a single operator in each minimum geographical area must be held.

However, in the electricity sector, such tenders shall start no earlier than 2030, because of the legislation aimed at restricting the service to the current operators (Enel Distribuzione and other companies), on the basis of the concessions issued by 31 March 2001 by the Ministry of Economic Development (MISE), which are valid until 31 December 2030.\(^{17}\)

In the gas sector, the Letta Decree (Legislative Decree No. 164/2000) gave local authorities the power to award the service through public tenders for a maximum of 12 years after the ending of the transitional period, during which the current concessions shall remain in force.\(^{18}\)

By Resolution No. 296/2015/R/com, the AEEGSI has eventually imposed upon electricity and gas distribution network providers both the functional separation (unbundling) and the separation between brand and communication policy (debranding), as well as the integrated information system for the provision of commercially sensitive information.

**ii Transmission/transportation and distribution access**

All network operators must ensure that any interested service provider has access to the transmission and distribution networks of gas and electricity. At the same time, the third-party access (TPA) must not affect the continuity and safety of the transmission and distribution service.

In this context, AEEGSI has the task to identify the most suitable criteria in order to guarantee freedom and equal terms of access to the network for all applicants. The same regulation obliges network managers to adopt codes of good practice in compliance with the abovementioned criteria.

With reference to the electricity sector, the AEEGSI issued the ‘integrated text of active connections – technical and economic conditions for the connection to electricity grids with the obligation to connect third parties’,\(^{19}\) which is valid for both the transmission and distribution networks.

Moreover, pursuant to the Decree of the President of the Council of Ministers dated 11 May 2004, on 1 November 2005 the Terna Grid Code came into force, with prior approval by both the AEEGSI and the MISE.\(^{20}\)

Furthermore, the AEEGSI has established an alternative disputes resolution (ADR) procedure by Resolution ARG/elt 123/08, which provides that the Authority shall decide on disputes over rights of access to the network. This ADR system is currently regulated by Resolution 188/2012/e/com.

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17 See Legislative Decree No. 79/99 (Bersani Decree).
18 At present, many municipalities have not published any tender notice yet, because Law No. 21/2016 has eventually postponed the terms for said publication.
19 See AEEGSI Resolution No. 99/2008.
20 See AEEGSI Resolution No. 79/2005.
With reference to the gas sector, the AEEGSI has approved the Snam Network Code\textsuperscript{21} and the Network Type Code\textsuperscript{22} as a reference model applicable to all operators of distribution networks.

Finally, it is also noteworthy that Law No. 239/2004 has exempted from TPA all private operators that promote investments on the network, in order to enable them to carry out trading activities through the infrastructure use (the ‘merchant lines’).

The Ministerial Decree dated 21 October 2005 sets forth the competitive criteria for the granting of the exemption, which are evaluated by the MISE. However, the European Commission carries out the final assessment.

### Rates

In accordance with a pro-competition regulatory strategy, the AEEGSI predetermines the rates for transmission/transportation and distribution of electricity and gas through a pricing mechanism based on a balance between the several interests at stake (network maintenance, promotion of investments, safety and efficiency of the network, environmental protection and accessible costs for the customers).

With respect to the electricity market, on 23 December 2015 the AEEGSI adopted the ‘Pricing Regulation on transmission, distribution and metering of the electric power, for the period 2016–2023’ (Deliberation No. 654/2015/R/eel).

As regards the gas market, through Deliberation No. 514/2013/R/gas on 14 November 2013, the Authority issued the ‘Pricing criteria for the rates of transportation and dispatching of natural gas for the period 2014–2017’ (RTTG).\textsuperscript{23}

However, in 2014, the Regional Administrative Court (TAR) of Milan partially voided the RTTG, in so far as it did not comply with Article 38.2\textsuperscript{bis} of Decree-Law No. 83/2012.\textsuperscript{24} In 2015, the Council of State upheld the TAR judgment.\textsuperscript{25} Therefore, the AEEGSI has commenced the proceeding aimed at modifying the regulation in compliance with the Council of State’s ruling.\textsuperscript{26} The 2016 pricing proposals regarding the tariffs for gas transportation and dispatching and the metering service were temporarily approved on 11 December 2015.\textsuperscript{27}

Furthermore the Authority approved the tariff regulation\textsuperscript{28} for the gas distribution service, whose validity was extended until the end of 2019.\textsuperscript{29} The distribution and metering tariff is aimed at guaranteeing the coverage of distribution service costs (VRD). In particular, the VRD covers:

\begin{itemize}
\item[a] the centralised investments in fixed assets;
\item[b] the amounts invested in each distribution area; and
\item[c] the operating costs related to distribution.
\end{itemize}

\textsuperscript{21} See AEEGSI Resolution No. 75/2003.
\textsuperscript{22} See AEEGSI Resolution No. 108/2006, as amended by Resolution No. 53/2010.
\textsuperscript{23} See AEEGSI Deliberation No. 814/2016/R/com on 29 December 2016.
\textsuperscript{24} Pursuant to Art. 38.2\textsuperscript{bis} of Law Decree No. 83/2012, the Authority should have adjusted the tariffs of natural gas transportation in favour of those operators with the highest natural gas consumption.
\textsuperscript{25} See the Council of State’s Decision No. 3735, dated 28 July 2015.
\textsuperscript{26} See AEEGSI Deliberation No. 429/2015/R/gas, dated 3 September 2015.
\textsuperscript{27} See AEEGSI Deliberation No. 606/2015/R/gas, dated 11 December 2015.
\textsuperscript{28} See AEEGSI Resolution ARG/gas 159/08.
\textsuperscript{29} See AEEGSI Deliberation No. 573/2013/R/gas, updated by Deliberation No. 774/2016/R/gas.
Furthermore, Law No. 290/2003 introduced a price cap incentive. This mechanism has imposed a profit restriction based on the harmonised rate of growth of consumer prices for a certain number of years. Within the boundaries of this restriction, each operator is free to determine the rate.

### Security and technology restrictions

Legislative Decree No. 61/2011 sets forth the criteria for the identification of European critical infrastructure. In the energy sector, such infrastructure are then concretely identified by the MISE.

A fundamental element for the security of electrical infrastructure is to ensure the continuity of the service, measured by the 'energy not supplied' indicator.

The regulation of the quality of the natural gas transportation service in terms of security, continuity and commercial quality in the period 2014–2017 is governed by Resolution No. 602/2013/R/gas.

Furthermore, Part I of the Consolidated Law on ‘Regulation of the quality and the tariffs of distribution and gas metering services over the period of 2014–2019’ regulates certain activities relevant to the safety of the gas distribution service. Such regulation is intended to minimise the risk of explosions and fires caused by the gas distributed, and therefore its ultimate goal is to protect people and property from damages due to accidents caused by gas.

In addition, by Resolution No. 255/2015/R/eel of 29 May 2015, the AEEGSI has taken the first steps for the regulation of the cyber security of the 'smart grid' (intelligent distribution network). The AEEGSI is participating in a workgroup organised by the Council of European Energy Regulators, specifically set up in order to better identify the boundaries of this topic and the role played by the regulators. At the moment, there is no specific regulation, and other institutions are responsible for the cybersecurity of the country.

### IV ENERGY MARKETS

#### i Development of energy markets

As previously mentioned, the GME manages the Italian energy market (the Italian Power Exchange, or IPEX) on which electricity is sold and bought wholesale.

More specifically, the GME organises and manages:

- the Forward Electricity Market;
- the Daily Products Market in which continuous negotiations take place;
- the MGP, organised in the form of auctions; and
- the Intraday Market, with auctions, divided into five sessions.

On behalf of the Italian grid operator (Terna SpA), the GSE also manages both the Ancillary Services Market through which it collects offers and communicates the results, as well as

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30 See AEEGSI Resolution No. 574/2013/R/gas.
31 In particular, the Committee for the Security of the Italian Republic cooperates with the Ministries, the Agency for the Digital Agenda, the Presidency of the Council of Ministers and other authorities with safeguarding functions (i.e., the Data Protection Authority and the Communications Authority).
a platform registering the transactions carried out over the counter. On this platform, the parties that have concluded contracts outside the IPEX register their trade obligations and set forth the relevant electricity input and output plans, committing to perform these contracts.32

With the entry into force of Law No. 99 of 23 July 2009 (laying down provisions for the development and internationalisation of companies, as well as relating to energy), the GME was entrusted with the organisation and economic management of the natural gas market on an exclusive basis. The GME gas markets include:

- the natural-gas trading platform (P-GAS);
- the natural-gas market (MGAS); and
- the natural-gas balancing platform (PB-GAS).

### ii Energy market rules and regulation


The gas markets are regulated by the Decree of the Ministry of Economic Development approved on 6 March 2013 (as subsequently amended by the Ministerial Decrees approved on 21 May 2014, 9 June 2015, 25 February 2016 and 11 May 2016).

The electricity markets, M-GAS, P-GAS and PB-GAS each have their own market and technical rules. The market rules include the criteria and procedures for the admission of new participants, the trading and settlement rules, as well as the sanctions and sanctioning procedures in the event of a breach of market rules. The GME is generally responsible for the oversight of market operations, as well as for the enforcement of market rules.33

### iii Contracts for sale of energy

Regarding the market at wholesale level, bilateral contracts for the sale of electricity and gas – which must be in compliance with the technical requirements provided by the GME – are not subject to restrictions.

At the retail level, since 2007 (for electricity) and 2003 (for gas), all customers can freely enter into contracts for the purchase of gas or power from sellers that meet certain minimum requirements.

Given that the power and gas sellers must comply with certain specific rules on transparency and fairness of information to customers, under the supervision of the AEEGSI, each user is essentially free to choose the energy seller that applies the best contractual and tariff conditions in relation to its individual case (the ‘free market’).

However, to date, until 1 January 2018 (see below), consumers also have the possibility to avail themselves of the safeguarded market for the supply of electricity and gas. This market guarantees the application of the prices laid down by the AEEGSI, which updates the reference values used to calculate the rates applied to residential and non-residential consumers each trimester.

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32 See Article 5 of Legislative Decree No. 79 of 16 March 1999.
33 See the Decrees of the Ministry of the Economic Development approved on 19 December 2003 and 6 March 2013.
Market developments

Government Bill No. AS 2085 (which is still in the process of approval) provides for the elimination of the safeguarded service and the full liberalisation of the electricity and gas markets at the retail level, starting from 1 January 2018.

At the same time, when the full liberalisation process is completed, according to a recent proposal operators of the energy market will compete through tender rules for the acquisition of customers that have not yet completed the switching to the free market (at the time of writing this rule is still under discussion in parliament).

To facilitate the transition from the aforementioned safeguarded service to the free market, the AEEGSI has set up a transitional regime pursuant to which, from 1 January 2017, users can enter into a contract for the supply of electricity and gas with a maximum duration of 12 months. Although based on the free market, this contract provides for contractual conditions imposed by AEEGSI for all operators. The economic conditions are very similar to those of the safeguarded service, but with an additional one-time bonus, differing from supplier to supplier.34

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

In Italy, there are multiple incentive mechanisms for renewable energy plants, such as monetary economic instruments (e.g., the feed-in tariff35 and the feed-in-premium36) and quantitative economic instruments (Green Certificates, albeit now abolished).37

With regard to the construction of installations for the production of electricity from renewable sources, Legislative Decree No. 387/2003 has introduced a new simplified authorisation procedure, namely, the single authorisation issued by regions or provinces to modify town-planning regulations.

In addition to the authorisation regulated by Decree No. 387/2003, Decree No. 28/2011 has introduced the simplified authorisation procedure, which replaces the declaration of commencement of activity. Moreover, with reference to particular types of installations that do not require any building permit, the law requires a simple notice to the Public Administration.

Finally, the electricity generated from renewable energy sources is granted priority access to the transmission and distribution grid. The connection fees for renewable energy are

34 See AEEGSI Resolution No. 369/2016, as amended by the Resolution No. 541/2016.
35 For example: (1) the all-encompassing incentive tariffs Cip 6/92 (feed-in tariff), applicable to the electricity fed into the grid by plants powered by renewable and assimilated sources; and (2) the inclusive fixed tariff established under the Law No. 244/07.
36 Such as feed-in premium tariffs applicable to the electricity produced by both photovoltaic plants that came into operation until 26 August 2012, and to solar thermal plants.
37 Since 2015, the Green Certificate mechanism currently conceived is no longer to be applied. From 1 January 2016, the producers eligible to benefit from this mechanism have received a ‘replacement’ incentive provided by the GSE referred to net production of their plants, up to the end of the period indicated by the law.
Italy

lower than those applied to conventional production plants, and the producer of renewable energy may also decide to build all the facilities for the connection to the network by himself or herself, without having to pay any costs.38

ii Energy efficiency and conservation

The Italian efficiency incentive system comprises a variety of mechanisms.

In particular:

a in the energy saving sector, the ‘White Certificates’ certify the achievement of energy savings through energy efficiency initiatives and projects;

b the Ministerial Decree of 16 February 2016 has provided funds for energy redevelopment interventions, such as thermal insulation of matt surfaces, window replacement or the installation of condensation heat generators in lieu of traditional air-conditioning systems;

c Law No. 232/2016 has extended the duration of tax deductions for energy redevelopment projects up to 31 December 2017. Through this incentive mechanism, building owners can deduct 65 per cent of the expenses, whereas apartment owners can deduct 70 per cent;

d Legislative Decree No. 20/2007 has implemented European Directive 2004/08/EC on cogeneration. Said Decree has introduced the CAR qualification,39 which is awarded by the GSE if energy production reaches at least 50MWh/year. This qualification gives access to the White Certificates, under the terms and conditions established by the Ministerial Decree dated 5 September 2011.

iii Technological developments

Following the smart grid pilot projects carried out by several operators in Italy since 2011,40 the MISE recently established a state aid programme aimed at supporting investments for the construction of intelligent electricity distribution networks.41 Regulation (EU) No. 651/2014 of 17 June 2014 has laid down the rules for specific regional aid programmes.

The aforementioned ministerial decree provides the legal framework for all national or regional administrations that intend to make public investment tenders, in order to promote the upgrading and optimisation of the electrical network in the assisted areas of the country.

As for second generation smart metering (2G) (i.e., the systems that enable the remote reading and control of electricity, gas and water meters), in the electricity sector the AEEGSI has recently approved the recognition of costs for low voltage electricity metering, in addition to commissioning provisions42 and functional specifications.43

In the gas sector, the AEEGSI has finally updated the commissioning requirements of smart gas meters up to 2018.44

38 See Resolution AEEGSI No. 281/2005.
39 ‘Cogenerazione ad Alto Rendimento’ (high-yield cogeneration).
41 The Ministerial Decree issued on 19 October 2016 has allocated €321,620,225 for the promotion of smart grids in Basilicata, Calabria, Campania, Puglia and Sicily.
42 See AEEGSI Resolution No. 646/2016/R/EEL.
43 See AEEGSI Resolution No. 7/2016/R/EEL.
44 See AEEGSI Resolution No. 554/2015/R/gas.
VI  THE YEAR IN REVIEW

The key developments in legislation in the energy sector in 2016 and 2017 include:

a  MISE Decree dated 13 March 2017, amending the rules of the natural gas market;

b  MISE Decree dated 14 February 2017, which defines natural gas storage for the period 2017–2018;

c  MISE Decree dated 29 December 2016, which allows a 30 per cent reduction in electricity expenses for economically disadvantaged consumers;

d  Law No. 232 of 11 December 2016, which has extended the duration of tax deductions for energy redevelopment projects up to 31 December 2017 (see the paragraph on energy efficiency and conservation);

e  MISE Decree dated 19 October 2016, establishing a state aid programme aimed at supporting investments for the construction of intelligent electricity distribution networks (see the paragraph on technological developments); and

f  MISE Decree dated 23 June 2016, regarding the incentives for the production of electricity from renewable source plants other than photovoltaic ones.

VII  CONCLUSIONS AND OUTLOOK

In conclusion, to look at the development prospects of the energy market, it is necessary to refer to AEEGSI Resolution No. 3 dated 15 January 2015.

This resolution establishes the strategic framework of the principal operations that have to be carried out in the electricity, gas and water services sectors over the period 2015–2018, in both an Italian and European context.

These are the strategic guidelines to be pursued in the electricity and gas sectors:

a  the creation of more secure, efficient and integrated electricity markets;

b  an increase in funds and flexibility of the gas market from a European-wide approach; a revision of the gas payment structure and of the management of gas services according to market rules; and a greater flexibility and efficiency of the balancing system;

c  increased responsibility of network operators for targeted development of national and local infrastructures. To reach this purpose, it is necessary to regulate cross-border infrastructures at a European level and to selectively manage infrastructural investments; and

d  the creation of more competitive retail markets, thanks to a more informed and active demand; the non-discriminatory access to energy withdrawal data and the development of measuring instruments; the supply of energy services by the various players in the market; the elimination of tariff barriers to energy efficiency and to the management of electricity consumption; an increased competition in the market; and a greater responsibility of distributors and sellers in the case of arrears.

The aforementioned resolution also comprises strategic guidelines concerning:

a  the regulation of the water sector (i.e., the stability and clarity of the regulatory framework in order to encourage investments in infrastructure);

b  the enforcement of the aims set by AEEGSI (i.e., the reorganisation and the development of support tools for final consumers); and

c  accountability, simplification and transparency (i.e., new accountability measures for stakeholders).
I OVERVIEW

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

Given the high level of public interest attached to the provision of electric utilities, certain market entry regulations have long been in place. However because of the Great East Japan earthquake and the subsequent accident at the Fukushima Daiichi nuclear power plant, government energy policy is currently in the midst of vast and rapid structural change. As of 31 March 2017, all nuclear power plants, except for three, are currently under suspension in Japan and over recent years other measures to secure alternative resources (including increasing the supply of renewable energy sources and traditional thermal power), conserve existing energy supplies and increase local energy production have been discussed concurrently with a review of the current industry regulations. As a result, the current legislation is in a transitional phase. There are three headline changes affecting the regulation of electricity markets. Firstly, under the Electricity System Reform programme, entry into the electricity retail business was fully liberalised as of 1 April 2016. In preparation for this, a new regulatory authority for monitoring the new liberalised market was established in 2015. Secondly, the legal unbundling of the electric power transmission function and sector from the existing dominant power suppliers will be implemented in 2020. In addition to these two changes, feed-in tariffs (FITs) were introduced in 2012 and the renewable energy market has been rapidly expanded since then. In response to rapid expansion of the renewables market, the FIT system has been continuously revised to address several problems.

The gas industry in Japan can be divided into the following two major enterprises: the town gas industry, which is the primary source of natural gas to consumer residences through piping; and the liquefied petroleum gas (LPG) industry, which provides LPG via cylinders to consumers in areas where piped gas is not yet available. Significant reform liberalising the town gas retail business was implemented on 1 April 2017. As a result, subcategories of the town gas-related business was reorganised and entry into the retail gas business has been relaxed (i.e., only registration is required). Entry into the LPG industry requires registration with the relevant authority, and the prices for the provision of LPG may be freely set by the provider.

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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 Ministry jurisdiction over various matters including comprehensive policies in relation to energy and mineral resources and the securing of the stable and efficient provision of gas, electric power and heating to Japan. In addition to these matters, comprehensive policies in relation to energy and mineral resources and the securing of the stable supply of energy are handled by the Ministry’s Agency for Natural Resources and Energy, and the monitoring of the liberalised electricity markets, as well as compliance with a code of conduct for network sectors, is handled by the recently established Electricity and Gas Market Surveillance Commission.

The Organization for Cross-regional Coordination of Transmission Operators (OCCTO) is not a governmental organisation but is an independent organisation constituted by all of the electricity business entities pursuant to the Electricity Business Act (EBA). The OCCTO’s remit is to monitor the electricity supply–demand balance and frequency, and order electricity business entities to supply electricity to other electricity business entities. The OCCTO has the power to instruct or recommend electricity business entities to ensure stable electricity supply subject to Article 28-40, Item 6 of the EBA.

Other governmental agencies regulate certain aspects of the energy industry in Japan, including the Ministry of Environment, the Nuclear Regulation Authority and relevant local governments.

Main sources of law and regulation

The EBA is the main source of legislation regulating businesses involved in the generation, transmission and distribution, and sale of electric power. In addition to this, the Electricity Business Act Enforcement Orders and the Ordinance for Enforcement of the Electricity Business Act further provide detailed regulations for the enforcement and governance of the system provided under the EBA. A number of relevant orders and ordinances ruling the generation, transmission and sale of electricity have also been enacted.

As for nuclear power, regulation is provided in the Atomic Energy Fundamental Act, the Act on Compensation for Nuclear Damage and other specialised legislation.

The Gas Business Act (GBA) is the primary source of legislation regulating businesses involving town gas. In addition to this, the Gas Business Act Enforcement Orders and the Ordinance for Enforcement of the Gas Business Act further provide detailed regulations for the enforcement and government of the system provided under the GBA.

The primary source of legislation regulating businesses involving LPG is the Act Concerning the Securing of Safety and the Optimisation of Transaction of Liquefied Petroleum Gas (the LP Gas Act). In addition to this, the LP Gas Act Enforcement Orders and the Ordinance for Enforcement of the LP Gas Act further provide detailed regulations for the enforcement and government of the system provided under the LP Gas Act.
Regulated activities

Electricity

After the Fukushima incident, the Japanese government decided to undertake significant reform of the energy regulation system. The regulations for electricity businesses are also undergoing substantial changes at the moment. Prior to the new EBA (which came into effect on 1 April 2016), licences for electricity businesses were required when the intended activities fell within one of five categories, and only 10 prominent regional companies (which used to be categorised as general electricity utilities) were allowed to supply electricity to general consumers and businesses (low-voltage electricity) in their respective markets. However, the amendment to the EBA to liberalise the entire retail electricity market has streamlined regulated electricity business into three simple categories (i.e., electricity retail businesses, generation businesses and transmission and distribution businesses) to adjust to the liberalised retail market and promote a level playing field for competition between the general electricity utilities and other electricity business entities.

Electricity retail business

A company running an electricity retail business (the sale of electricity to general and large-scale consumers and businesses) is required to be registered by the METI. For a company to be registered as a retail company, it is first required to become a member of the OCCTO. Then an application document must be filed to the METI. The METI and the Electricity and Gas Market Surveillance Commission will then examine the application. An application for the register will be accepted unless the business entity’s activities are found to fall under certain negative requirements, including a lack of ability to procure electricity to respond to the maximum demand of its customers and being unable to properly operate an electricity retail business. In anticipation of the market liberalisation, many retail entities have entered this new market with various types of electricity price plans. As of 30 March 2017, 389 entities are registered as retail companies.

Electricity generation business

Companies that generate and supply electricity in excess of 10,000kW to retail companies are required to file with the METI to commence their generation business. They are also required to apply for membership of the OCCTO before filing. Under the old regulation structure of the EBA, independent power producers did not need approval or to file for the commencement of their generation business (provided they filed the price and met the other required terms of the supply of electricity), but under the new EBA, generation business entities are required to file their generation business and are also subject to certain obligations. For example, generation companies are required to submit a plan stating the amount of electricity generation that can be produced by a unit of the facilities they possess. Additionally, by a standard contract with general transmission companies, generation business entities are required to report their estimation of supply for the next 30 minutes.

Electricity transmission and distribution business

The electricity wheeling service industry is classified into three subcategories: general transmission, transmission and specific transmission by the amended EBA; and each is
covered by a different regulatory scheme. Entry to this area has not been liberalised even following the amendment of the EBA because these businesses are responsible for ensuring that all consumers have sufficient access to electricity.

Of the different companies in the three categories, the most prominent are general transmission companies. General transmission companies are business entities providing electricity wheeling services through their own transmission lines throughout their service area. Those intending to engage in the general transmission business are required to obtain approval from the METI in advance. The company must submit a business plan to the METI, which must be satisfied that the plan is feasible. Its facilities also need to be capable of covering the electricity demand. To gain approval, the company must submit a 10-year plan, as do companies in the other two categories above.

A transmission company supplies the electricity to general transmission companies throughout its own grid. Those intending to engage in the wheeling industry are also required to obtain approval from the METI.

In contrast to these two, specific transmission companies, which transmit electricity to a specific point, are only required to notify the METI.

**OCCTO**

These three types of electricity business entities are all under an obligation to be a member of the OCCTO to allow the OCCTO to monitor and coordinate the whole electricity market. Members of the OCCTO have to provide information about the amount of electricity produced by their facilities, etc. on a continuous basis. The OCCTO can instruct its members to maintain a balance of electricity supply and demand in the market to ensure the stable supply of electricity to consumers.

**Gas**

*Town gas businesses*

In line with the Electricity System Reform, the amendment to the GBA, which came into effect on 1 April 2017, significantly changed the town gas regulation, which is called the Gas System Reform. This amendment implements full liberalisation of entry into the gas retail business, which 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 fall under certain negative requirements, including the lack of ability to procure gas to respond to the demand of its customers and being unable to properly operate a gas retail business. In principle, the entire application and registration process will require around one month to complete.
As of 31 March 2017, the number of town gas retail business operators was 45. It should be noted that regional monopolies have been recognised in relation to town gas retail business operators and, accordingly, the percentage of operators for the service areas in large metropolitan areas is understandably high. The share of the largest operator, Tokyo Gas (service area: Kanto region with Tokyo as its main focus), currently accounts for about 38 per cent of the market whereas the combined share of the three major corporations (Tokyo Gas, Osaka Gas and Tohou Gas) providing service areas in large metropolitan areas accounts for about 73 per cent (based on sales volume as of March 2016). The Gas System Reform aims to change the situation by furthering competition in the town gas retail business under the relaxed requirements for entry into the gas retail business.

Town gas generation business
Before 1 April 2017, a town gas generation business was not required to obtain a registration or licence, or file other documents with the METI. However, after 1 April 2017, companies that generate town gas are required to file with the METI.

Town gas transportation business
Under the new regulation, a town gas transportation business is categorised into two subcategories under the new GBA: general gas transportation business and specific gas transportation business. A general gas transportation business is a business that transports gas through its gas pipeline throughout its service areas. In order to operate a general gas transportation business, approval from the METI is required and the business is subject to certain regulations and controls by the METI as explained below. On the other hand, a specific gas transportation business is a business that transports gas through its gas pipeline to a specific point. Only notification to the METI is required in order to operate a specific gas transportation business.

The purpose of this two-tier regulation is to expand the gas pipeline network, which is established on an area basis (especially in urban areas) by separating the gas between the various networks. General gas transportation business operators now have to make their gas pipelines readily available due to strict regulations imposed by the METI, while specific gas transportation business operators may operate their businesses without strict control by the METI.

Sellers of LPG
The LP Gas Act stipulates that necessary registration for the sale of LPG must be obtained from the METI when intending to establish sales offices catering to two or more prefectures and from the prefectural governor when catering to only one prefecture.

Registration involves the necessary submission of application forms in which statutorily required data, such as details of the sales office, gas storage facilities and other necessary information, are described. Applicants will be registered with the corresponding authority (either the METI or the prefectural governor) as long as there are no applicable statutory grounds for denial of the application.

Registrations will require 30 days to process or 15 days if the registration is applied for via the relevant authority’s electronic information processing system.

As of March 2016, the number of business operators that had obtained the necessary registrations and were currently engaged in the sale of LPG is 20,522. Entry barriers to this section of the industry are low and a large number of small and medium-sized businesses
have been entering into the LPG industry in which even retail rates are not regulated. While all-electric technology products were widely spread by the electric power companies to replace the use of gas, this figure is still less than half of when LPG sales were at their peak (54,000 operators in 1967).

iii Ownership and market access restrictions

The only existing restrictions on foreign investment in the electric power industry or the gas industry are those imposed by the general laws regulating the entry of foreign investment in Japan stipulated in the Foreign Exchange and Foreign Trade Act. For example, if a foreign investor were to obtain 10 per cent or more of the shares of an electric power or gas utility (including both town gas and LP gas), intend to set up a branch for the conduct of electric power or gas business or otherwise engage in any such activities, the Foreign Exchange and Foreign Trade Act requires that the relevant authorities be notified in advance of such activities. Furthermore, in the event of the performance of any such activities requiring advance notification of the relevant authorities, a follow-up report after the performance must also be submitted accordingly. Both prior notification and follow-up reports must be submitted to the Bank of Japan, which in turn will facilitate the submission of the notifications and reports to the Minister of Finance or other relevant minister in charge. The relevant authorities have the power to provide a recommendation or an order to suspend such foreign investment, if it hinders national security, public order or public safety.

iv Transfers of control and assignments

Electricity

The prior approval of the METI is necessary in the event of a transfer of the whole business of a general transmission company or in the event of a merger or demerger whereby the surviving entity completely absorbs any such business. The criteria for granting such an approval are the same as those for the original grant of approval to operate such businesses. A merger or demerger of other types of electricity business entities obliges them to notify the METI. Notification to the METI is also required upon the handover of any equipment or facilities to retail companies, power suppliers and any types of transmission companies.

Gas

The transfer or acquisition of all or part of a general gas transportation business requires authorisation from the METI before it can be effective, as does the merger or demerger of any entity that is a general gas transportation business operator whereby all or part of the business is succeeded by the surviving company. The criteria for the grant of the required authorisation are the same as those for the original grant of approval to operate such businesses. Only post facto notification is required for transfer of the business or merger or demerger of the town gas-related business (i.e., town gas retail business, town gas generation business and specific gas transportation business).

In the case of LPG businesses, however, in the event of any transfer of the business in its entirety or of any merger or demerger whereby the surviving entity completely absorbs the business, the succeeding entity is only required to notify whichever is relevant of the METI or the prefectural governor.
III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Electric power

*Integrated system for the production and transmission of electric power*

In Japan, following the end of World War II and up until 1995, the production and transmission of electric power, as well as its assorted related retail operations, were run as a single integrated utility by 10 electric power companies, each with a regional monopoly over the 10 main regions of Japan.

However, amid the institutional reform post-1995, Japan realised the liberalisation of its electric power generation and retail sectors. That being said, the electric power transmission sector is still very much dominated by the aforementioned 10 power companies (former general electricity utilities).

Because the electric power distribution grid is public infrastructure, measures have been implemented to prevent general electricity utilities from abusing their dominant market positions and to ensure the transparency of the electric power industry. Specifically, anti-trust measures that have been implemented include, the compulsory notification of electric power transmission details; the requirement of equal treatment of consumers; and the compulsory separation of the electric power transmission division accounts of general electric power business operators from their other divisions.

*Government policy on separation and unbundling of electric power transmission sectors*

As part of the Electricity System Reform, the amendment to the EBA passed in 2015, which aims for the legal unbundling of the transmission sector to ensure the neutrality of all entities engaged in electricity-related business. No electricity company can run an electricity retail business or generation business with a transmission business in the same entity after April 2020, unless otherwise permitted by the METI. That means that the 10 former general electricity utilities, except for Okinawa Electric Power Company, must split those departments to an affiliate or others by that date.

*Obligations undertaken by general transmission companies*

Because transmission facilities and the business conducted with them are mostly owned by the former 10 general electricity companies, to secure the effective liberalisation of other sectors, these companies are required to provide neutral treatment to retail companies. General transmission companies are not allowed to refuse to execute a grid connection contract without reasonable grounds. The EBA provides that the electricity supply-demand balance and frequency must always be maintained within a certain threshold. General transmission companies must also provide final assurances to each consumer to deliver electricity where consumers do not have a contract with any of the retail companies. General transmission companies are also responsible for the delivery of electricity to consumers on Japan’s remote islands.

*Cybersecurity*

As most activities involved in the electricity business are controlled by information technology, it is urgent for businesses in the sector to establish a reliable cybersecurity system. The Basic Act on Cybersecurity stipulates that Critical Infrastructure Information (CII) operators shall make an effort to assure cybersecurity voluntarily and proactively. Because there is no regulation that clearly stipulates the concrete actions a CII should take with regard to IT
protection, a strategy for cybersecurity committee established by the Cabinet has announced that the security criterion for CII operators will be clarified. It is clear that electricity business entities, especially general transmission companies, fall within the definition of CII operators, and will almost certainly be required to adapt their processes in line with any changes to the security requirements.

ii Gas

**Terminalling, processing and treatment**

After importation, LNG meant for the town gas industry is converted into gas and sent through pipelines or transported by tanker lorries, and stored in gas storage facilities for supply to consumers. The facilities for processing, transportation and storage are mainly owned by the gas utility business operators, who supply the gas to consumers.

Pipelines that are used for gas transportation and gas holders that are used for storage of gas are regulated by the GBA and the technical standards for gas facilities prescribed by ministerial order. Likewise, tanker lorries are regulated by the High-Pressure Gas Safety Act and the Safety Regulations for General High-Pressure Gas.

The transportation and storage of LPG are regulated by the LP Gas Act and the High-Pressure Gas Safety Act. More particularly, whereas storage and transportation at distribution and wholesale levels are regulated by the High-Pressure Gas Safety Act, the storage and transportation supply level to general end-users are regulated by the LP Gas Act.

**Government policy on separation and unbundling of town gas transportation sectors**

As part of the Gas System Reform, as in the case of the Electric System Reform, for a town gas-related business, the legal unbundling of the transportation sector is scheduled for April 2022 to ensure the neutrality of all entities engaged in a gas-related business. This reform is expected to apply to three major players: Tokyo Gas, Osaka Gas and Tohou Gas. By April 2022, these companies will have to separate those sectors and transfer them to an affiliate or other entity.

**Obligations undertaken by general transmission companies**

Since gas pipelines are dominantly owned and operated by a few operators, such as the three major players, in order to secure the effective liberalisation of other sectors, general gas transportation business operators are prohibited from refusing to execute a transportation contract without reasonable grounds. Also, the terms and conditions of such contracts and amendments are required to be approved by the METI in advance.

IV ENERGY MARKETS

i Japan Electric Power Exchange

The Japan Electric Power Exchange (JEPX) exists for the benefit of all electric power-related transactions. It was founded on 28 November 2003 as a market for the commodity trading of electric power and serves as an intermediary for electric power spot trading, forward transactions and other similar transactions. (It is possible to undertake both buy and sell orders through the JEPX.) To participate in electric power commodity trading on the JEPX, membership as a trade affiliate is necessary. As of 3 April 2017, 124 companies were trade affiliates of the JEPX. As of 1 April 2017, JEPX has the spot market opening 365 days and
established a market in which members can trade electricity until one hour prior to its actual use. This market enables electricity business entities to adjust the amount of electricity they provide until the last minute.

The JEPX is managed by a general incorporated association comprising electric power companies and other such entities. It is a private exchange that operates and is regulated by its own market rules.

ii Terms and conditions of supply

Electricity

As explained above, the amendment to the EBA that came into effect on 1 April 2016 liberalised entry into the electricity retail business, but provides a provisional measure that requires former general electric utilities (utilities allowed to retail electricity at low voltage market before the liberalisation) to continue to provide the existing terms and conditions until 2020 at earliest in order not to let the electricity price raise unreasonably. Additionally, all retail companies are subject to regulations in certain codes of conduct such as to deliver explanations and documents in relation to certain matters, for their supply to customers.

Gas

Obligation to supply

Similarly to the electricity sector, on 1 April 2017, entry into the town gas retail business was fully liberalised. However, certain town gas retail business operators specified by the METI shall continue to supply gas under the terms and conditions approved by the METI. Further, gas retail companies are also subject to regulations on certain codes of conduct such as to deliver explanations and documents regarding the terms of certain matters for their supply to customers.

No such obligations are imposed on LPG business operators.

iii Market developments

Electricity

The Amendment to the Commodity Futures Act that took effect in 2016 provides that electricity becomes subject to commodity futures trading, which enables market participants to avoid the risk of volatility. The Tokyo Commodity Exchange, Inc. aims to launch an electricity future market by March 2018 according to its midterm management plan announced in March 2017.

An infrastructure fund market that enables the listing of funds that invest in certain infrastructure such as electric generation facilities, established by the Tokyo Stock Exchange, Inc. in April 2015, has developed over the past two years. Following the first listing of an infrastructure fund in June 2016, two additional infrastructure funds were listed on the market. The three infrastructure funds invest in solar power facilities. The market provides opportunities for a broad range of investors, including retail investors, to invest in infrastructure-related investments and adds an option for developers who, in particular, develop large-size power facilities.
Gas
With respect to gas, no particularly noteworthy market developments are currently anticipated or under consideration.

V RENEWABLE ENERGY AND CONSERVATION

i Electricity

The Renewable Electric Energy Act
Japan has recently been subject to huge developments in the area of renewable energy. The Act on Special Measures concerning the Procurement of Renewable Electric Energy by Operators of Electric Utilities (the Renewable Electric Energy Act) was enacted with the objective of introducing FITs (a system whereby the total volume of electricity should be purchased at a fixed price and a fixed term). The Renewable Energy Act became effective on 1 July 2012, and the FIT scheme was amended on 1 April 2017. The major requirements for a generator to sell electricity at the fixed price under the FIT scheme can be summarised as follows:

a Execute an interconnection agreement with one of the general transmission companies or one of the specific transmission companies for its renewable energy generation facility.

b Obtain certification by the METI for its plan on the generation business relating to the renewable energy generation facility in accordance with the requirements under the Renewable Energy Act. Renewable electric energy, which is subject to the FIT scheme, is currently limited to certain renewable energy sources: solar, wind, water (currently statutorily limited only to small and medium hydroelectric generators with an output of less than 30,000kW), geothermal and biomass.

c Execute a power purchase agreement with one of the general transmission companies and the specific transmission companies for a renewable energy generation facility with the above certification. Such transmission companies are obliged to accept an offer by a generator to execute such a power purchase agreement, unless it falls into certain exceptions.

Sales prices and contract terms
Set out below are the changes in sales prices and contract terms granted by the FIT scheme in recent years. In relation to solar power, as a reflection of the sudden drop in price of solar panels, the sales price is falling (as per our further notes below). In comparison, measures have been taken to establish favourable pricing and to support investment in respect of offshore wind power and existing headrace tunnel-type medium and small-scale hydroelectric power generators. A bid system, which was newly adopted by the recent amendment, is currently only applicable to facilities with solar power of 2MW or more.
<table>
<thead>
<tr>
<th>Electricity generated</th>
<th>Sales price (excluding tax)</th>
<th>Contract term</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
<td>2014</td>
</tr>
<tr>
<td>Solar power</td>
<td></td>
<td></td>
</tr>
<tr>
<td>&lt; 10kWh</td>
<td>¥38</td>
<td>¥37</td>
</tr>
<tr>
<td>≥ 10kWh &lt; 2,000kWh</td>
<td>¥36</td>
<td>¥32</td>
</tr>
<tr>
<td>≥ 2,000kWh</td>
<td>¥36</td>
<td>¥32</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wind power</td>
<td></td>
<td></td>
</tr>
<tr>
<td>&lt; 20kWh</td>
<td>¥55</td>
<td>¥55</td>
</tr>
<tr>
<td>≥ 20kWh</td>
<td>¥22</td>
<td>¥22</td>
</tr>
<tr>
<td>Offshore wind power*</td>
<td></td>
<td>¥36</td>
</tr>
<tr>
<td>Geothermal power</td>
<td></td>
<td></td>
</tr>
<tr>
<td>&lt; 15,000kWh</td>
<td>¥40</td>
<td>¥40</td>
</tr>
<tr>
<td>≥ 15,000kWh</td>
<td>¥26</td>
<td>¥26</td>
</tr>
<tr>
<td>Hydroelectric power</td>
<td></td>
<td></td>
</tr>
<tr>
<td>&lt; 2000kWh</td>
<td>¥34</td>
<td>¥34</td>
</tr>
<tr>
<td>≥ 2000kWh &lt; 1,000kWh</td>
<td>¥29</td>
<td>¥29</td>
</tr>
<tr>
<td>≥ 1,000kWh &lt; 5,000kWh</td>
<td>¥24</td>
<td>¥24</td>
</tr>
<tr>
<td>≥ 5,000kWh &lt; 30,000kWh</td>
<td>¥24</td>
<td>¥24</td>
</tr>
<tr>
<td>Existing headrace tunnel-type medium and small-scale hydroelectric power**</td>
<td></td>
<td></td>
</tr>
<tr>
<td>&lt; 200kWh</td>
<td>¥25</td>
<td>¥25</td>
</tr>
<tr>
<td>≥ 200kWh &lt; 1000kWh</td>
<td>¥21</td>
<td>¥21</td>
</tr>
<tr>
<td>≥ 1,000kWh &lt; 5,000kWh</td>
<td>¥14</td>
<td>¥14</td>
</tr>
<tr>
<td>≥ 5,000kWh &lt; 30,000kWh</td>
<td>¥14</td>
<td>¥14</td>
</tr>
<tr>
<td>Biomass power</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>¥13 to ¥39 depending on material used</td>
<td>¥13 to ¥39 depending on material used</td>
</tr>
</tbody>
</table>

* Offshore wind power: generators that require a vessel for access for construction and operational maintenance.
** Existing headrace tunnel-type medium and small-scale hydroelectric power: generators that utilise existing headrace tunnels with renewable electric power equipment and hydraulic steel pipes.
Increase in renewable electric energy generation and associated problems

Following the introduction of FITs, renewable source energy generation – solar power generation in particular – is increasing rapidly. Set out below are recent data on electricity generated by renewable source energy generation facilities and purchased by business operators (million kWh).

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar power (&lt; 10kWh)</td>
<td>485,686.0</td>
<td>578,017.8</td>
<td>514,854.4</td>
<td>647,426.3</td>
</tr>
<tr>
<td>Solar power (≥ 10kWh)</td>
<td>425,466.9</td>
<td>1,317,731.0</td>
<td>1,860,298.5</td>
<td>3,048,280.8</td>
</tr>
<tr>
<td>Wind power</td>
<td>489,638.3</td>
<td>492,082.3</td>
<td>349,975.4</td>
<td>493,690.3</td>
</tr>
<tr>
<td>Hydroelectric power</td>
<td>93,552.6</td>
<td>107,277.2</td>
<td>112,223.6</td>
<td>174,341.6</td>
</tr>
<tr>
<td>Geothermal power</td>
<td>570.9</td>
<td>608.1</td>
<td>3,931.7</td>
<td>6,870.5</td>
</tr>
<tr>
<td>Biomass power</td>
<td>316,940.0</td>
<td>364,438.0</td>
<td>383,095.3</td>
<td>611,217.6</td>
</tr>
<tr>
<td>Total</td>
<td>1,811,854.7</td>
<td>2,860,154.4</td>
<td>3,224,378.9</td>
<td>4,981,827.4</td>
</tr>
</tbody>
</table>

On the other hand, problematic businesses, such as those that utilised favourable pricing to obtain facility certification from the METI but delayed commencement of work and attempted to obtain fraudulent profits, had been frequently reported. In response, the METI has placed conditions on certified solar power facilities since 2014, requiring them to secure the land title and procure the solar modules. In addition, the Renewable Energy Act was amended on 1 April 2017 and as a result the certification for a plan for a generation business relating to a renewable energy generation facility will only be granted by the METI where the renewable energy generation facility reaches the stage of certain development, including the execution of an interconnection agreement with certain transmission companies and when there is the prospect of obtaining the necessary land titles.

Further, a rapid increase in renewable energy generation has caused a lack of capacity in transmission lines in some areas. Currently, new solar and wind-power projects held in certain areas are subject to unlimited restrictions on the output from renewable energy generation facilities that satisfy certain requirements, including that they expect an oversupply of electricity. Although transmission companies have recently embraced policies to expand the capacity of transmission lines, this issue is still yet to be fully resolved.

ii Gas

In terms of gas-related renewable energy, biogas has been generating a lot of attention in recent years. Biogas is a flammable gas produced by the fermentation of organic waste such as raw sewage, food waste and livestock excretions, a feature that allows it to be harvested at sewage treatment plants, food factories and other such locations. Major town gas utilities such as Tokyo Gas and Osaka Gas have in recent years established guidelines for and promoted the purchase of biogas. Additionally, several local governments began to produce biogas in a sewage facility or refuse disposal facility.

VI THE YEAR IN REVIEW

The electric power industry regulations have, following the events at Fukushima in 2011, already witnessed great reforms. First, the electric system reform started, including full
Japan

liberalisation of entry into the electricity retail business, and the following phase of the reform, including legal unbundling of the electric power transmission function and sector from the existing dominant power suppliers, will be implemented in 2020. Second, the introduction of FITs has encouraged the emergence of new entrants to the renewable energy industry and the renewable energy market has been expanded, but the FIT system is being revised to address several problems, including a newly adopted bid pricing system for solar power generation of a certain size, the first of which is expected to occur this year.

As explained above, the gas system was reformed along the same lines as the electric system reform, and from April 2017 the full liberalisation of entry into the gas retail business was implemented and new regulations for gas transportation businesses (especially general gas transportation businesses) have been imposed to make gas pipelines available to gas retail business operators. Furthermore, from 1 April 2022, the gas transportation (pipeline) business sector of three major companies (Tokyo Gas, Osaka Gas, and Tohou Gas) will be unbundled.

VII CONCLUSIONS AND OUTLOOK

The events at Fukushima in 2011 served as the main catalyst for the reforms that the electric power industry has recently been facing. The full extent of these reforms and their effects, however, remain to be seen. As of April 2017, all 48 nuclear power stations in Japan except three are stopping operations. In the meantime, the Nuclear Regulation Authority issued new nuclear power station safety standards in July 2013 and currently 17 nuclear power stations are in the process of review for restart under the new safety standards (nine stations have already passed). However, it is still unclear when and how many nuclear power stations will restart operations.

Under these circumstances, Japan will become increasing reliant on its remaining sources of energy, that is, oil and LNG. These traditional sources of fuel are regarded as more stable and reliable; however, because they are ultimately non-renewable resources, this in and of itself introduces an entirely different set of issues. At the end of the day, Japan’s energy requirements may push it in the direction of renewable energy such as those discussed above. The output of such energy sources is, however, substantially smaller compared with nuclear energy, not to mention inherently unstable and less reliable. Accordingly, Japan’s demand for alternative and reliable sources of energy may even result in renewed interest in the gas industry, which in turn will surely lead to further developments in this field.

With all facets of the energy industry shifting so rapidly at the moment, the only thing that can be said with any certainty is that change is imminent. Exactly how and what form this change will take remains to be seen, and it is certainly worth keeping a close eye on Japan in the years to come.
I OVERVIEW

Korea relies on over 97 per cent of its primary energy sources from overseas acquisition, and fossil fuels, such as petroleum, gas and coal account for 85 per cent of these sources. Therefore, there are policy needs in the short term to take measures against fluctuations in the supply and demand for energy based on global factors, and in the long term to take measures against the depletion of fossil fuels. The 2011 Fukushima nuclear power plant accident in Japan has served as a warning to carefully consider the use of nuclear energy policy and the new energy environment, and the effects of climate change, has increased the use and interest in new and renewable energy.

Under the current environment and policy needs, Korea has designated the Energy Act and Framework Act on Low Carbon and Green Growth (the Framework Act) as its basic laws. These energy laws were prepared with the intention of achieving certain policy goals such as having a steady supply of energy, eco-friendliness, market principles and energy security, and these goals are being implemented in line with the changes to the energy market and environment through the enactment and amendment of individual laws.

The energy policy framework is not likely to change fundamentally under the new Moon Jae-in government, which has been in place since 10 May 2017. However, the new government is expected to re-examine the nuclear power policy, and may halt construction of any new nuclear power plant. Under the new government, it is also expected that the safety of energy facilities, in particular nuclear power plants, will be strengthened by preparing for natural disasters and enhancing cybersecurity. The new government will promote the development of new and renewable energy.

II REGULATION

i The regulators

Regulators

The Ministry of Trade, Industry and Energy (MOTIE) is in charge of all regulations regarding individual energy resources (e.g., electricity, petroleum and gas). In particular, the MOTIE carries out duties regarding entry regulations for individual energy resources with respect to licences, reporting and registration. Among the individual energy resources, with respect
to electricity, the Electricity Regulatory Commission is an affiliated organisation within the MOTIE that was formed to, *inter alia*, decide on granting approval and licences for electric utility businesses, electric business acquisitions and other matters.

The Korea Power Exchange (KPX) is in charge of duties regarding establishing or managing the electricity market, and duties regarding transactions involving electricity, etc.

Further, the Prime Minister’s Office is in charge of matters related to the Framework Act, which is a basic law regarding the macroscopic energy policy, and the Energy Commission, which is an affiliated organisation within the MOTIE, was formed to, *inter alia*, deliberate over matters regarding important energy policies and plans. The Ministry of Environment and the Ministry of Foreign Affairs are also involved in energy-related policies such as establishing emissions-trading systems, clean energy and climate change, as well as joining international treaties.

**Main sources of law and regulation**

The Framework Act, which was enacted in January 2010, is a general law regarding energy policies. In the past the Energy Act was the general law regarding energy policies, but after the enactment of the Framework Act, several of its provisions were transferred to the Framework Act. The Framework Act establishes or promotes comprehensive government energy policies and national strategies, including solutions to climate change and energy issues, expansion of growth and development, strengthening the competitiveness of companies, efficient use of land and creation of a pleasant environment (Articles 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:

- **Electricity**: the Electric Utility Act (EUA), as amended in 2017, 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.

- **Petroleum and gas**: the Petroleum and Petroleum Substitute Fuel Business Act (PBA), as amended in 2015, and the Urban Gas Business Act (UGBA), as amended in 2016, 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.

- **Nuclear energy**: the Nuclear Energy Promotion Act regulates the research, development, production and use of nuclear energy; the Nuclear Safety Act regulates the safety of nuclear energy; and the Nuclear Damage Compensation Act regulates matters regarding damage compensation arising in relation to nuclear energy.

- **New and renewable energy**: the Act on the Promotion of the Development, Use and Diffusion of New and Renewable Energy (the New and Renewable Energy Act), as amended in 2015, acts as the basic law regarding the development of technology for new and renewable energy as well as the use and dissemination of new and renewable energy.
Regulated activities

Electricity

Under the EUA, electric utility businesses are categorised into five types of business, the definitions of which are as follows:

a. Electricity generation business: a business, the main purpose of which is to generate and supply electricity to operators of the electricity sales business via the electric utility market.2

b. Electric transmission business: a business, the main purpose of which is to set up and operate electric installations necessary to transmit electricity produced at power stations to operators of the electricity distribution business.3

c. Electric distribution business: a business, the main purpose of which is to establish and operate electricity installations necessary to distribute electricity transmitted from power stations to consumers of electricity.4

d. Electric sales business: a business, the main purpose of which is to deliver electricity to consumers.5

e. District electric business: a business, the main purpose of which is to generate electricity with electric generating units of up to 35,000kW to meet the demand of a specific supply district, and to supply the produced electricity to consumers of electricity in that specific supply district, not via any electric utility market.6

The Korea Electric Power Corporation (KEPCO) had a monopoly on the production and supply of electricity in Korea until the late 1990s, and was entirely responsible for generation, transmission, distribution and sales. Currently, KEPCO is still responsible for transmission, distribution and sales of electricity, KEPCO’s subsidiaries and various private companies are competing in the electricity generation business.

According to Article 7 of the EUA, any person who intends to operate an electric utility business must obtain a licence, based on the business type, from the Minister of the MOTIE (the Minister); the Minister’s approval is required when the person intends to modify important matters relating to the licence, such as the business district or specific supply district, supply voltage and, in the case of electricity generation businesses and district electric businesses, the place of electric installations, equipment capacity and the type of motive power.7 To obtain a licence, the following documents must be submitted to the Minister:8

a. an application for a licence;

b. a business plan;

c. the articles of incorporation, a profit and loss statement and balance sheet (the articles of incorporation are only required in the case of an entity that is being established); and

d. the shareholder’s registry (unless the applicant’s power capacity is 3,000kW or less; if the applicant is a new entity whose financial capability cannot be assessed, the largest shareholder of the entity will be constructively deemed as the applicant).

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2 Article 2(iii) of the EUA.
3 Article 2(v) of the EUA.
4 Article 2(vii) of the EUA.
5 Article 2(ix) of the EUA.
6 Article 2(xi) of the EUA; Article 1-2 of the Enforcement Decree of the EUA.
7 Article 7(1) of the EUA; Article 5(1) of the Enforcement Rule of the EUA.
8 Article 7(1) of the EUA; Article 4(1) of the Enforcement Rule of the EUA.
The Minister will grant electricity utility licence after an application has undergone deliberation by the Electricity Regulatory Commission. The criteria for issuing the licence as provided by Article 7(5) of the EUA are:

- *a* to have the financial and technological capability necessary to operate the electric utility business in the optimal manner;
- *b* to be able to carry out the electric utility business as planned;
- *c* all or a part of two or more business zones for operators of the electric distribution business or specific supply districts for operators of the district electric business must not overlap;
- *d* in the case of district electric businesses, to meet at least 50 per cent of the electricity demand of a specific supply district and not to constitute any obstacle to the supply of electricity by another operator to consumers residing in the neighbouring area because of that business;
- *e* power plants and power generation fuel must not be concentrated in certain areas to disrupt the power system; and
- *f* to conform with the standards set by the Enforcement Decree of the EUA on the basis of public necessity.

An operator of the electric utility business must set up the electric installations necessary to operate the electric utility and start up the business within the preparation period determined by the Minister.\(^9\)

From 22 June 2017, the EUA will require that the Minister take into consideration the economic efficiency of electric installations, and their impact on the environment and public safety, when establishing a basic plan for electrical supply.\(^10\)

**Petroleum**

Article 2 of the PBA defines the term ‘petroleum’ as ‘crude oil, natural gas (including liquefied natural gas)’ and ‘petroleum products’ as ‘gasoline, kerosene, diesel, fuel oil, lubricating oil, hydrocarbon oil and petroleum gas (including liquefied petroleum gas)’\(^11\) and categorises petroleum businesses into three types of business: petroleum refinery businesses,\(^12\) petroleum export and import businesses\(^13\) and petroleum sales businesses.\(^14\)

Anyone who intends to operate a petroleum refinery business must register his or her business with the Minister by submitting an application for registration and a business plan to the Korea Petroleum Quality and Distribution Authority, which was established pursuant to Article 25-2 of the PBA.\(^15\) In connection with petroleum refinery businesses, anyone who intends to operate a business for manufacturing asphalt, base oil and lubricant must report the business to the Minister.\(^16\)

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9. Article 9(1) of the EUA.
10. Article 3(2) of the EUA.
11. Article 2(i) and (ii) of the PBA.
12. Article 2(iv) of the PBA.
13. Article 2(v) of the PBA.
14. Article 2(vi) of the PBA.
15. Article 5(1) of the PBA; Article 4(1) of the Enforcement Rule of the PBA.
16. Article 5(2) of the PBA; Article 8(1) of the Enforcement Decree of the PBA.
Also, anyone who intends to operate a petroleum export and import business must register his or her business with the Minister 30 days prior to the expected date of the initial customs clearance, by submitting an application for registration, a business plan and import agent agreement to the Korea Petroleum Quality and Distribution Authority.\textsuperscript{17} Such a registration, however, is not required for a person who is already registered as an operator of a petroleum refinery business, and for the import and export of certain petroleum products such as asphalt, lubricant and base oil.\textsuperscript{18} To qualify for the registration of a petroleum export and import business, an applicant must be equipped with a storage facility capable of storing the greater of the quantity of 15 days’ worth of planned domestic petroleum sales or 2,500kL.\textsuperscript{19} The previous storage capacity requirement of the greater of the quantity of 30 days’ worth of planned domestic petroleum sales or 5,000kL has been relaxed to the current requirement since December 2016 to induce price cuts by lowering entry barriers to the petroleum export and import business, thus promoting price competition among petroleum products both domestic and foreign.

Petroleum sales businesses are classified into (1) general agents and solvent agents; (2) gas stations; (3) solvent vendors; (4) manufacture and sales businesses of petroleum by-products; (5) secondary fuel oil vendors; and (6) general vendors, aviation fuel sales business and special vendors. While (1) to (5) need to be registered with the head of the local government,\textsuperscript{20} petroleum sales businesses that fall under (6) need to be reported to the head of the local government.\textsuperscript{21}

To facilitate integrated controls and regulations of liquefied petroleum gas businesses, the PBA excludes liquefied petroleum export and import business from petroleum export and import business.\textsuperscript{22} To further protect consumers of petroleum products, the PBA prohibits the sale of petroleum and petroleum alternative fuels whose volumes have been improperly increased by artificial heating, and punishes violations.\textsuperscript{23} In addition, the PBA adds the Customs Office as an agency from which the Minister of the MOTIE may request tax information for efficient supervision and monitoring of conducts that may disrupt sound distribution of petroleum products in the market or violate prohibition against manufacturing of fake petroleum products.\textsuperscript{24}

**Urban gas**

The UGBA defines the term ‘urban gas’ as natural gas (including liquefied gas), petroleum gas, by-products from naphtha cracking and biogas,\textsuperscript{25} and synthetic natural gas (SNG).\textsuperscript{26} Under the UGBA, urban gas businesses are categorised into five types of businesses: gas wholesale business, general urban gas business, urban gas recharging business, by-products from naphtha cracking and biogas manufacturing business, and SNG manufacturing business.\textsuperscript{27}

\textsuperscript{17} Article 9(1) of the PBA; Article 8(1) of the Enforcement Rule of the PBA.
\textsuperscript{18} Article 9(1) of the PBA; Article 10(2) of the Enforcement Decree of the PBA.
\textsuperscript{19} Article 12(1) of the Enforcement Decree of the PBA.
\textsuperscript{20} Article 10(1) of the PBA; Article 12(1) to (6) of the Enforcement Rule of the PBA.
\textsuperscript{21} Article 10(2) of the PBA; Article 12(7) of the Enforcement Rule of the PBA.
\textsuperscript{22} Article 9(1) of the PBA.
\textsuperscript{23} Article 39(1)(iii) of the PBA.
\textsuperscript{24} Article 41-3 of the PBA.
\textsuperscript{25} Article 2(i) of the UGBA; Articles 1-2 of the Enforcement Decree of the UGBA.
\textsuperscript{26} Article 2(i) of the UGBA.
\textsuperscript{27} Article 2(i-2) of the UGBA.
Besides the above, recently, there has been very active development of shale gas. To allow private businesses to flexibly take appropriate measures and seek new business opportunities in response to the changes in the international energy market, such as the expansion of the Northeast Asia LNG purchase market, a reporting system was implemented for businesses that carry natural gas in and out, and the sale of natural gas abroad for self-consumption by a direct importer (which imported the natural gas) is permitted.

According to the UGBA, the definition of each urban-gas business is as follows:

\( a \) Gas wholesale business: a business by which urban gas is supplied by a person, other than an operator of general urban gas businesses or by-products from naphtha cracking and biogas manufacturing businesses, to general urban gas business operators, urban gas recharging business operators or large users.

\( b \) General urban gas business: a business that supplies urban gas supplied by gas wholesale business operators, or petroleum gas, by-products from naphtha cracking or biogas produced by the general urban gas business operator itself, to users through pipelines according to the general demand.

\( c \) Urban gas recharging business: a business that supplies urban gas supplied by gas wholesale business operators, or by-products from naphtha cracking or biogas produced by the urban gas recharging business operator itself, by recharging the gas in a container, storage tank or tank fixed to a vehicle.

\( d \) By-products from naphtha cracking and biogas manufacturing business: a business that manufactures by-products from naphtha cracking and biogas itself for self-consumption or supplies to gas wholesale dealers or general urban gas businesses (except for a business that manufactures naphtha by-products with manufacturing permit as required under Article 4 of the High Pressure Gas Safety Control Act, and supplies by-product gas through dedicated piping directly to such facilities designated under the MOTIE Ordinance).

\( e \) SNG manufacturing business: a business that manufactures SNG itself for self-consumption, supplies to gas wholesale dealers or supplies to a party that holds the majority of the shares of the applicable SNG manufacturing business for the parties' self-consumption.

\( f \) Natural gas export and import business: a business exporting or importing natural gas.

\( g \) Business that carries natural gas in and out: a business pursuant to Article 154 of the Customs Act that carries natural gas in or out from the storage facility in the bonded area.

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28 Article 2(ix-2) and (ix-3); Article 10-2(3) of the UGBA.
29 Article 10-6 of the UGBA.
30 Article 2(iii) of the UGBA.
31 Article 2(iv) of the UGBA.
32 Article 2(iv-2) of the UGBA.
33 Article 2(iv-3) and Article 8-3 of the UGBA.
34 Article 2(iv-4) of the UGBA.
35 Article 2(vii) of the UGBA.
36 Article 2(ix-2) of the UGBA.
Under the UGBA, a person who intends to operate a gas wholesale business must obtain a licence from the Minister of the MOTIE 37 and a person who intends to operate general urban gas business must obtain a licence from the head of the local government. 38 A licence for the gas wholesale business and general urban gas business will only be granted if applications meet the following requirements:39 (1) the relevant urban gas business is of an economic scale appropriate for the public interest and general demand; (2) the relevant applicant has financial resources and technical capability necessary to properly conduct such an urban gas business; and (3) the relevant applicant has the capability of establishing and maintaining appropriate supply facilities for the stable supply of urban gas. A person who intends to operate an urban gas recharging business and by-products from naphtha cracking and biogas manufacturing business must obtain a licence from the head of the local government for each place of business. 40 A person who intends to operate an SNG manufacturing business must obtain a licence from the Minister for each place of business. 41

Anyone who intends to operate a natural gas export and import business must register his or her business with the Minister 30 days prior to the expected date of the initial customs clearance, by submitting an application for registration and a business plan (including current status or construction plan of the storage facility of natural gas and a supply plan for the five years following the year of the import of natural gas). 42 If a natural gas export and import business operator who is an urban gas business operator intends to conclude a natural gas import, export or transportation agreement, he or she must obtain approval from the Minister after meeting the urban gas requirements in relation to demand and supply, and appropriateness of price. 43 Anyone who intends to operate a business that carries natural gas in and out must report the business to the Minister. 44

On the other hand, the UGBA includes provisions to improve regulations on natural gas export and import business operators, and to strengthen safety requirements. In addition, to flexibly respond to natural gas supply and demand situations at home and abroad, the UGBA exempts natural gas import agreements that meet certain criteria from the requirement to obtain pre-approval from the Minister. With respect to these natural gas import agreements, the importers are required to report to the Minister only after concluding the agreements. 45 The UGBA strengthens safety requirements by stipulating that, in cases where liquefied petroleum gas facilities are changed into urban gas facilities, urban gas operators and gas users must implement certain safety measures such as demolition of liquefied petroleum gas containers and ancillary equipment. The UGBA imposes penalties for violations of the safety requirements, and even gas users who fail to comply with the safety requirements will be subject to penalties. 46 The UGBA also requires that safety measures for gas plumbing and gas use facilities be implemented in the case of an extension or alteration to a building

37 Article 3(1) of the UGBA.
38 Article 3(2) of the UGBA.
39 Article 3(7) of the UGBA.
40 Article 3(3) of the UGBA and Article 3(4) of the UGBA.
41 Article 3(5) of the UGBA.
42 Article 10-2(1) of the UGBA; Article 10-6 of the Enforcement Rule of the UGBA.
43 Article 10-5(1) of the UGBA.
44 Article 10-2(3) of the UGBA.
45 Article 10-5(2) of the UGBA.
46 Article 28-2 and 54(6) of the UGBA.
where urban gas pipelines are installed. The UGBA also newly introduces penalty provisions against those parties that cause damage, or inflict harm to the functionality of, urban gas pipelines.

**New and renewable energy**

The New and Renewable Energy Act authorises the Minister of the MOTIE to establish a basic plan to promote use, dissemination and technological development of new and renewable energy every five years after consultation with the head of the relevant central administrative agency and deliberation by the New and Renewable Energy Policy Council. Also, to achieve the goals set out in the basic plan, plans for implementation must be established and carried out for each type of new and renewable energy every year.

The New and Renewable Energy Act provides that tradable renewable energy certificates (REC) will be issued to new and renewable energy suppliers. On the other hand, in cases where new and renewable energy suppliers receive support from the MOTIE in an amount equal to the balance between the trading price of the electric power supplied by new and renewable energy sources and the standard price announced by the MOTIE, RECs will be issued to the state. The MOTIE may trade the certificates issued to the state in the market to keep the balance of demand and supply and to stabilise prices. In addition, the New and Renewable Energy Act abolishes the renewable energy installation specialist system and the renewable energy building certification system, which have been found to be ineffective, and integrates the renewable energy facility certification system into the Korean Industrial Standards certification system under the Industrial Standardisation Act.

To ensure the adequate quality of new and renewable energy fuels, the New and Renewable Energy Act authorises the Minister of the MOTIE to announce quality standards for new and renewable energy fuels, and requires that new and renewable energy suppliers must pass a quality inspection for new and renewable energy fuels by a designated quality inspection agency. The New and Renewable Energy Act also introduces renewable fuel standards that require petroleum refinery operators and petroleum exporters to mix more than a certain percentage of new and renewable energy fuel in fuel for transport. Violations of these requirements may be punished by civil fines. Moreover, the New and Renewable Energy Act requires a new and renewable energy facility certification holder to take out an insurance policy against damage to be suffered by a third party. Under the New and Renewable Energy Act, new and renewable energy suppliers may join a mutual aid association for the purpose of developing new and renewable energy technology and facilitating new and renewable energy business operations.

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47 Article 28-3 of the UGBA.  
48 Article 48(4) and (8) of the UGBA.  
49 Article 5(1) and (2) of the New and Renewable Energy Act.  
50 Article 6(1) of the New and Renewable Energy Act.  
51 Article 12-7 of the New and Renewable Energy Act.  
52 Article 13 of the New and Renewable Energy Act.  
56 Article 30-2 of the New and Renewable Energy Act.
iii Ownership and market access restrictions

Article 96 of the EUA provides that a foreign-capital invested company under the Foreign Investment Promotion Act may not obtain a licence for an electricity generation business under Article 7(1) of the EUA (this restriction is limited to the operation of atomic power stations) or approval for a plan for the manufacture and supply of fuel for atomic power generation under Article 28 of the EUA. There is no other restriction on foreign-capital invested companies with respect to the operation of electric utility businesses. The PBA and UGBA do not contain any provisions limiting foreign-capital invested companies’ operation of the relevant businesses.

iv Transfers of control and assignments

With respect to an electric utility business, if a person intends to acquire all or part of an electric utility business from its operator or to divide or merge an electric utility company or to acquire more than a certain percentage of shares in an electric utility company (except for those with power capacity less than 20,000kW) to ensure management control, it must obtain approval from the Minister.57 There are no particular restrictions on the acquisition, division or merger of petroleum businesses and urban gas businesses.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Electric power

In Korea, KEPCO, which was established pursuant to the Act on the Korea Electric Power Corporation, initially had a monopoly on the production and supply of electricity as the Korean government decided that, to protect the public interest, it would be appropriate for a public corporation to conduct the business of generating and distributing electricity. The supply of electric power, however, became unstable from the late 1980s because of a rapid increase in the demand for electricity, so the Korean government enacted the Act on the Promotion of the Reorganisation of Electric Power Industry in 2000 and privatised the electricity generation business by dividing KEPCO’s electricity generation business into six subsidiaries. As of January 2017, the number of private companies participating in the electricity market increased to 1,421. Other electric utility businesses (i.e., electricity transmission business, electricity distribution business and electricity sales business) are still wholly operated by KEPCO.

Urban gas

The UGBA has various provisions that regulate the proper management of the supply and consumption of urban gas, which is public property. A general urban gas business operator and gas wholesale business operator must prepare and submit to the head of the local government a gas supply plan for five years.

57 Article 10(1) of the EUA.
ii Transmission/transportation and distribution access

*Electric power*

According to the EUA, only members of the KPX are entitled to carry out electric utility transactions at the electric utility market and, other than a consumer who uses 30,000kVA or more, no consumer may purchase electricity directly from the electric utility market. Accordingly, electricity produced by electricity generation business operators must be supplied to electricity consumers by operators of electric transmission, distribution and sales businesses. The EUA further provides that no operator of the electricity generation business and electric sales business may refuse to supply electricity without just cause as prescribed by the Enforcement Decree of the EUA and the operator of an electric utility business must maintain the quality of service that it provides. Moreover, operators of electric transmission businesses, electric distribution businesses and district electric businesses must be equipped with and maintain and manage installations meeting the standards determined and publicly notified by the Minister so as to smoothly transmit or distribute electricity regardless of changes in the supply and demand of electricity.

*Petroleum*

The PBA has various provisions that regulate the management of the quality of petroleum products and prevent the distribution of pseudo-petroleum products.

In the event that a petroleum refinery business operator, petroleum export and import business operator or a registered petroleum sales business operator intends to sell or deliver certain petroleum products (e.g., petrol for vehicles, kerosene, light oil, petroleum by-products), the operator must have the petroleum products inspected by a quality inspection institution appointed by the Minister. Any operator will be prohibited from selling or delivering petroleum products that have failed the quality inspection. According to Article 29(1) of the PBA, no one may engage in manufacturing, importing, storing, transporting or keeping pseudo-petroleum products.

Meanwhile, to promote the expansion of the exporting of petroleum products, Article 29(2)(v-2) of the PBA stipulates that the blending of petroleum products at the general bonded area for the purpose of export only, as well as storing and transporting such mixtures, will not be viewed as the manufacturing of fake petroleum products.

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58 Article 44 of the EUA.
59 Article 32 of the EUA; Article 20 of the Enforcement Decree of the EUA.
60 Article 14 of the EUA.
61 Article 18(1) of the EUA.
62 Article 27 of the EUA.
63 Products manufactured by a method of mixing petroleum products with other petroleum products or petrochemicals; Article 2(x) of the PBA.
64 Article 25(1) of the PBA; Article 28(1) of the Enforcement Rule of the PBA.
65 Article 27 of the PBA.
66 Article 29(2)(v-2) of the PBA.
Urban gas
No gas wholesale business operators shall refuse to supply natural gas, or have the supply thereof interrupted, to general urban gas business operators, urban gas charging business operators or bulk buyers without justifiable cause.67 Each urban gas business operator must have the urban gas that it supplies inspected by an urban gas quality inspection institution to confirm that the gas fulfills the required quality standards.68

iii Rates
Electric power
An operator of an electric sales business must prepare terms and conditions concerning electric utility charges and other conditions of supply (i.e., supply districts, type of supply and supply voltage and frequency), and obtain approval from the Minister.69 Further, an operator of the electric sales business must specify the details of the utility charges based on items in electric utility bills charged to consumers of electricity.70 An operator of the electric transmission business or electric distribution business must set charges for the use of electric installations and other matters concerning the conditions of their use.71

Petroleum
A petroleum refinery business operator, petroleum export and import business operator and petroleum sales business operator must report their sale prices of petroleum products to the Minister.72

Urban gas
A general urban gas business can have a party that is requesting a change in the contract regarding the supply of urban gas or supply of gas pay for all or a portion of the installation costs of the gas supply equipment or facilities (Article 19-2). Also, where it is difficult to supply urban gas for any of the reasons stipulated under Article 19, the national and local government can pay for all or a portion of the installation costs (Article 19-3). Gas wholesale business operators must obtain the approval of the Minister of the MOTIE in determining the rate. When a determined rate is changed, the same approval is required (Article 20(1)).

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67 Article 19 of the UGBA.
68 Article 25-2(1) of the UGBA.
69 Article 16(1) of the EUA; Article 16(1) of the Enforcement Rule the EUA.
70 Article 17 of the EUA.
71 Article 15(1) of the EUA.
72 Article 38-2(1) of the PBA.
Security and technology restrictions

Electric power

Where an operator of an electric utility business intends to perform the works for setting up or altering electric installations for the electric utility, he or she must obtain approval for the plan for the works from the Minister, and undergo periodic inspections conducted by the Minister.

New and renewable energy

If the Minister of the MOTIE deems it necessary for the promotion of the use and supply of new and renewable energy or to increase the vitality of the new and renewable energy business, it may make it mandatory for a party that holds over 500,000 kilowatts of generating units (excluding equipment for new and renewable energy), the Korea Water Resources Corporation and the Korea District Heating Corporation to use new and renewable energy with respect to a determined generation quantity per year within the scope of 10 per cent of the total power production amount for supply energy. Where the Minister of the MOTIE deems that the above party with the obligation to supply did not fulfil its obligation by not using sufficient new and renewable energy in supplying its energy, the Minister may impose an administrative fine.

ENERGY MARKETS

Development of energy markets

Electricity

As previously described, transactions regarding electricity take place at the KPX pursuant to the EUA, which was established as an independent legal entity on 2 April 2001. Specifically, transactions occur between the over 1400 electricity generation business operators and a sales business operator 24 hours a day and 365 days a year, based on prices that change every hour.

Gas

Gas is divided into the wholesale sector and retail sector. The Korea Gas Corporation is in charge of business in the wholesale sector, and regional urban gas companies are in charge of business in the retail sector. Specifically, through the main line operated by the wholesaler operator (i.e., the Korea Gas Corporation), gas is supplied to the general urban gas companies, and urban gas companies supply consumers through the pipes that are operated regionally. Because of the public nature of the gas business, the central government oversees and supervises each of the duties of the wholesaler operator and local governments oversee and supervise each of the duties of retail operators.

73 Article 61(1) of the EUA.
74 Article 65 of the EUA.
75 Article 12-5(1) and (2) of the New and Renewable Energy Act; Article 18-3 of the Enforcement Decree thereof.
76 Article 12-6(1) of the New and Renewable Energy Act.
ii Energy market rules and regulation

Electricity

Electricity is regulated through the EUA. Electricity transactions must occur through the KPX and users of electricity cannot directly purchase electricity from the power market (EUA, Article 31). Electricity transactions are regulated by the power market operating regulations as determined by the KPX pursuant to Article 43 of the EUA and, pursuant to Article 53 of the EUA, the Electricity Commission, which is a part of the Ministry of Trade, Industry and Energy (MOTIE), regulates the above.

Gas

Gas is regulated pursuant to the UGBA. With respect to the importing (wholesale) of gas, aside from the direct importing system for self-consumption, it is exclusively imported by the Korea Gas Corporation (KOGAS). Urban gas businesses purchase urban gas from KOGAS and sell it to consumers. Recently, however, signs of changes in the effective monopoly of KOGAS over the gas market (including LNG and LPG) are visible. The government is attempting to amend the Enforcement Decree of the UGBA, which will enable direct importers of LNG to sell it to each other (up to 10 per cent of the direct import volume) without going through KOGAS. The completion of additional LNG storage facilities of private companies will also open up competition for the domestic LNG market.

iii Contracts for sale of energy

Electricity

The price on the electricity market is determined based on the electricity demand price predicted by the KPX a day in advance and the supply bid price of the electricity generation business operators. The electricity charge (the sales price of businesses that sell electricity), however, is approved by the government pursuant to laws such as the EUA, as opposed to supply and demand, because of its public nature. After a large-scale power outage in Korea on 15 September 2011, electricity costs were increased a total of four times until November 2013. The main reason for the increase was the need to align costs with actual usage. In particular, in November 2013 electricity costs increased by an average of 5.4 per cent and, included in this, the industrial electricity cost increased by 6.4 per cent. Since that time, there has been no further increase or decrease in electricity rates. According to the Second Basic Energy Plan confirmed in January 2014, besides classifying electricity rates based on use (e.g., industrial, general and housing), as was done in the past, seasonal or time differential pricing has also been introduced.

Starting from 2016, the MOTIE is domestically promoting energy storage systems (ESS) by increasingly procuring ESS to maintain power quality; providing an incentive to attach ESS to solar installations over a certain size; and allowing ESS to be used as emergency power. The MOTIE also supports the overseas expansion of customised ESS, taking into account country-specific power market status. In 2017, KEPCO has 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. Under the amended rules, starting from
May 2017, 50 per cent of the reduced electricity bill will be discounted where the renewable energy self-consumption rate is 20 per cent or more, and the ESS discount period will be extended for one more year until 2020.

In addition, under the new Moon Jae-in government’s energy resources policy, businesses related to mid-to-large size lithium secondary batteries for electric vehicles, energy storage, carbon capture and storage, and transmission and distribution equipment are expected to expand.

**Gas**
The transacting price in the wholesale sector is determined based on the contracts executed between the Korea Gas Corporation and urban gas companies. Since the Korea Gas Corporation imports all of its gas, it is directly or indirectly regulated by the government regarding the import volume and conditions. With respect to the issue of whether to strengthen or relax regulations on importing gas, there are differences in views between the government (which favours relaxation) and the National Assembly (which favours strengthening). In the retail sector, approval of the charge is required from local governments.

**iv Market developments**
The UGBA permits the sale of direct imports for self-consumption (currently for generating power SK and for manufacturing steel POSCO abroad (Article 10-6(1)). The MOTIE released the Natural Gas Industry Development Strategy in December 2015, which aims to ensure a fair gas market system by promoting regulatory improvements, and to increase efficiency in the domestic natural gas market by promoting imports of natural gas for self-consumption.

**V RENEWABLE ENERGY AND CONSERVATION**

**i Development of renewable energy**
The Act on Promotion of Alternative Energy was enacted in the 1980s, and the government later established its comprehensive support policy, the Basic Plan for Technical Development for Alternative Energy (1988–2001). Also, to achieve its efficient promotion, the government established the Alternative Energy Business Department within the Korea Energy Management Corporation as the organisation in charge of the development of new and renewable energy.

In the 1990s, to prepare for the Climate Change Convention, the comprehensive technology development plan for energy and the environment, the Energy Technology Development 10-Year Plan (1997–2006), was established to establish a system to promote technological development of not only new and renewable energy, but also to help saving energy, and develop clean energy and resource technology.

As 2000 approached, there was a new understanding of the importance of new and renewable energy and, to strengthen policies regarding technical development and its increased use, the Act on Promotion of Alternative Energy was amended to become the Act on Promotion of Development, Use and Diffusion of Alternative Energy. This Act served to form the basis for business promotion regarding feed-in tariffs (FITs) for new and renewable energy direct output, an obligation for public institutions to use new and renewable energy and new and renewable energy equipment certification procedures, etc., which made it possible to create an early market for new and renewable energy.
The Basic Plan for Development and Use of New and Renewable Energy (2003–2012) was established and implemented for the further promotion of new and renewable energy development and dissemination, and the relevant law was again amended in 2004.

Korea applied FITs from 2002, but in 2012 they were replaced by the Renewable Portfolio Standard (RPS), which obligates certain operators of energy businesses to supply certain amount of new and renewable energy. In March 2014, according to the RPS, KEPCO and its six subsidiaries will invest a total of 42.5 trillion won by 2020 to increase the supply of ESS using wind or solar power and other new technologies from the current 0.8GW to 12.3GW. The government is, however, considering re-implementing the FIT system, particularly for small to medium-sized companies.

Meanwhile, starting from 2017, the Korean government is increasing the RPS quota from the previous 3.5 per cent to 4 per cent. It is expected that the RPS quota will increase by 0.5 to 1 per cent per year and reach 10 per cent in 2024. The solar and non-solar market has been integrated since March 2016, and the separate RPS quota for solar energy has been abolished. The separate RPS quota for solar energy was introduced to protect the solar market in the face of other renewable energy sources, the generation cost of which is lower than solar energy, but it has turned out to be an obstacle to the solar industry.

On the other hand, in January 2017, in order to increase the efficiency of new and renewable energy businesses, the MOTIE introduced the ‘20-year-fixed price contract system’, which requires power companies to conclude a 20-year long-term contract with wind and solar energy sales companies at a fixed price calculated as the sum of the REC and the System Marginal Cost. This system is expected to ensure the profit stability of new and renewable energy companies and minimise their cost of supply.

The government also aims to adopt international standards and certification systems for new and renewable energy-related businesses. In that regard, the government has joined the IEC System for Certification to Standards Relating to Equipment for Use in Renewable Energy Applications and will actively support the export of new and renewable energy facilities to the global markets if they meet certain conditions according to international standards.

Also, new systems have been put in place such as the 1 Million Green Homes Project, where the goal is to build 1 million units of new and renewable energy housing by 2020. Further, under the new and renewable energy financial support plan, the new and renewable energy equipment industry is being fostered by reducing initial investment costs and assisting in economic feasibility based on long-term low-interest financial support to consumers that install equipment to use new and renewable energy and manufacturers of equipment that use new and renewable energy.

To promote the growth of Korea’s new and renewable energy industry, the government established the Fourth Basic Plan for New and Renewable Energy in September 2014, which aims to expand the renewable energy share of total energy generation by up to 11 per cent by 2035 and to switch from government-led energy policy to consumer-centric policy by promoting pilot projects in which residents will participate. The government will also support overseas expansion of renewable energy companies by facilitating loans for small and medium-sized companies expanding their business overseas. In June 2014, the MOTIE announced the Renewal Energy Revitalisation Plan, which included protection of the solar market by expanding the solar supply obligations from 1.2GW to 1.5GW.
With regard to new and renewable energy, the new Moon Jae-in government has promised to:

- expand new and renewable energy capacity by 20 per cent by 2030;
- promote KEPCO’s large-scale renewable energy projects;
- increase the minimum RPS requirements;
- promote eco-friendly energy self-reliant cities;
- expand new and renewable energy projects involving public participation such as household solar power;
- apply FIT to small-scale new and renewable energy facilities;
- create environment-friendly energy funds; and
- support demand resources market, solar rental business and other related business models.

Under the new government’s initiatives, new and renewable energy facilities are expected to increase.

ii Energy efficiency and conservation

In 1995, the government established the use of demand management investment plans for energy suppliers pursuant to Article 12 of the Energy Use Rationalisation Act (Article 9 in the current version of the Act) and these plans have been in use since 1996 by companies such as KEPCO, the Korea Gas Corporation and the Korea District Heating Corporation. Meanwhile, because of the restructuring and privatisation of the electricity industry, and based on the amendments to the EUA, the government established the groundwork formation plan for the electricity industry in December 2000, which, with the government funds for this groundwork, separately promotes demand-side management businesses.

Under the electricity demand management policy, which was established to achieve a stable supply and demand of electricity and efficient electricity use, the representative businesses are divided into load management businesses, which reduces the maximum electricity demand, and energy-efficiency businesses, which reduces electricity consumption through high-efficiency devices. In terms of gas and heating, for the management of a stable supply and demand, emphasis is put on the dissemination of gas cooling and cogeneration facilities and efforts are being made to obtain greater energy efficiency compared with individual heating systems through regional heating and cooling businesses.

According to the Sixth Electricity Supply and Demand Basic Plan, which was announced by the MOTIE in February 2013, the government has strengthened measures to manage demand by companies, such as the demand adjustment programme of advance notice (where financial incentives are offered to customers who reduce their demands at peak times by observing contract terms and conditions during the KEPCO-announced summer and winter peak periods) and load reduction by adjusting vacation or maintenance schedules, as well as using smart meters to manage the electricity-saving system and intelligent demand. Subsequently, in July 2015, the MOTIE released the Seventh Electricity Supply and Demand Basic Plan and announced that it would actively consider the temperature fluctuation and demand trends in developed countries for precise power-demand forecasting. For efficient supply and demand management, the MOTIE is adopting innovative technological solutions, including the negawatt market, ESS and energy management systems (EMS). Through these policy improvements, the MOTIE will be able to provide electricity without resorting to mandatory power-saving for industries or limiting air-conditioning temperatures, except in
exceptional cases. At the plenary session of the National Assembly in July 2016, the MOTIE announced that it would release the Eighth Electricity Supply and Demand Basic Plan in July 2017. In the Eighth Electricity Supply and Demand Basic Plan, the government is expected to significantly raise the target of 11 per cent of new and renewable energy ratio set in the Seventh Electricity Supply and Demand Basic Plan.

iii Technological developments

The fourth industrial revolution is transforming the energy sector, among others, and the energy 4.0 era is emerging that fuses energy and related fields and promotes the digitisation of energy. Faced with this new development, the government will establish and implement plans to build an ICT-based energy infrastructure that effectively links distributed energy supply, flexible and intelligent consumer demand responses, and distribution grids. According to Article 5 of the Smart Grid Construction and Utilisation Promotion Act, the MOTIE is expected to release the Second Smart Grid Basic Plan for the next five years by July 2017. The Second Smart Grid Basic Plan aims at transitioning to a private-led industrial mature stage. More specifically, it focuses on creating new business through the convergence of industries, such as IT and telecommunications, and fostering industries linking power networks and new energy business, such as AMI and ESS. In particular, the MOTIE announced that it would set up government-wide institutional support for private investment.

In the market, industries relating to smart factories or power plants, smart home appliances, eco-friendly energy towns and zero energy buildings are expected to grow. In particular, investment is expected to increase in connection with the construction of smart grid and ‘internet of things’ dedicated infrastructure.

In addition, the new government’s policy initiative to promote green cars will expand the supply of green cars by building electric vehicle charging infrastructure, reducing the green car toll by 50 per cent and completing highway charging facilities. The policy initiative is expected to increase investment in green cars.

VI THE YEAR IN REVIEW

Two key subjects in 2016 were the fourth industrial revolution and climate change.

With respect to climate change issues, Korea signed a universal climate deal, the Paris Agreement, adopted at the Paris climate conference (COP21) in December 2015 to replace the 1997 Kyoto Protocol on climate change. The National Assembly ratified the Paris Agreement in November 2016. Pursuant to the Paris Agreement, the government is obligated to cut greenhouse gas emissions by 37 per cent compared to its emissions forecast by 2030. In addition, in order to meet another goal of the Paris Agreement to limit the global average temperature to 1.5°C, the government should establish a carbon emission reduction target and a long-term low carbon development strategy by 2020. In that regard, the government held a cabinet meeting on 6 December 2016 and confirmed the First Basic Plan for Response to Climate Change, and the Basic Roadmap for 2030 National Greenhouse Gas Reduction, a detailed plan to achieve the 2030 greenhouse gas reduction target (37 per cent reduction in 2030 emission estimates) proposed by Korea in the Paris Agreement. In the process of implementing the Paris Agreement, there may be conflicts between existing market participants and government regulators. In order to mitigate such conflicts and to create new
markets by establishing new energy regulations, the Moon Jae-in government aims to reduce greenhouse gas emissions by creating a wood industry complex through the expansion of forest investment, and invigorating forest carbon management and trading.

The new energy industry, which is strongly driven by the government, is expected to become the catalyst for the fourth industrial revolution. In particular, the emergence of ESS, renewable energy and ICT convergence technologies is triggering a fundamental paradigm shift in traditional energy systems. On the other hand, there is criticism that the government may restrict the creative initiatives of the market participants by limiting or micromanaging the roles of public and private enterprises in the new energy industry.

**VII CONCLUSIONS AND OUTLOOK**

The Fukushima nuclear power plant accident in Japan on 11 March 2011 and the large-scale power outage on 15 September 2011 in Korea have had a significant effect on Korea’s energy policies and laws. Because of the Fukushima nuclear accident, the likelihood is high that nuclear energy, which accounted for about 12 per cent of the country’s energy mix, will be reduced in the future and the reduced amount would be replaced with new and renewable energy. The power outage was the combined result of factors such as the failure to predict electricity demand, the price of electricity, which fell short of the production cost, and structural deficiencies in the industry, and this is likely to cause policy-oriented changes to the electricity industry, such as an increase in electricity rates.

As Korea signed the Paris Agreement, it is bound by obligations to reduce greenhouse gas emissions. These obligations are expected to produce further promotion of the sectors that develop and implement new, clean and renewable energy sources.

2017 will be an important year to determine the future of national energy policy as there are a number of challenges to the national energy policy that will be addressed in 2017, such as the 3rd Energy Basic Plan, the 8th Electricity Supply Plan, the Basic Plan for Emissions Trading Scheme and the Basic Plan for Climate Change.

In particular, the new Moon Jae-in government, which has been in place since 10 May 2017, aims at suspending all new nuclear power plants, immediately shutting down nuclear power plants that have reached their design life, strengthening emission standards and emission charges for factory facilities as countermeasures against fine dust and strictly controlling fine dust concentrate discharge areas such as industrial complexes, thermal power plants, airports and harbours. It is also expected that the new government will promote green cars, invigorate the new and renewable energy industry and build additional new and renewable energy generation facilities.
Overview

Lebanon has been plagued by a chronic electricity crisis since the end of the 1975–1990 Civil War, with successive governments failing to make large investments to regain a sustainable position in the ailing sector and its outdated infrastructure. Most Lebanese regions experience 10 to 12 hours of electricity rationing a day, and these power cuts increase dramatically in the event of malfunctions in any of the aging plants. It is common for residents to pay additional costs for external generators to compensate for frequent power cuts. The electricity sector in Lebanon has long suffered from the lack of a global strategy aimed at revitalising it by addressing the needs with respect to infrastructure, generation capacity, operation and maintenance. The large influx of Syrian refugees over recent years has exacerbated the electricity crisis.

The energy sector in Lebanon is mostly controlled by the government and other public sector institutions, namely the state-owned Electricité Du Liban (EDL) founded in 1964. EDL is an autonomous institution operating under the umbrella of the Ministry of Energy and Water (MOEW), and is the sole producer and supplier of electricity. Generation of electricity in Lebanon is mainly produced through thermal power plants constituting 80 per cent of the total generation capacity, while hydroelectric power plants provide around 10 per cent of such capacity. Also, and until 2010, additional electricity was purchased from neighbouring countries.

The year 2010 was a turning point with respect to the electricity sector as it witnessed the approval by the Lebanese government of a Policy Paper for the Electricity Sector initiated by the MOEW (the Policy Paper). The Policy Paper comprised a comprehensive plan and a realistic implementation programme for the radical rehabilitation and development of the electricity sector to respond to the economic and social needs and aspirations of Lebanon. It covers three distinct strategic areas: infrastructure, supply and demand, and legal framework. The electricity sector requires drastic reform of the wider energy sector. The Policy Paper dedicated specific provisions to address renewable energy and energy efficiency, Lebanon being one of the wealthiest countries in terms of renewable energy resources, notably, solar and wind. Accordingly, and with the support of the Lebanese Centre for Energy conservation (LCEC), the MOEW began implementing solar and wind energy projects.

While the MOEW initiatives and action plans provide for a series of solutions as part of a national energy strategy, the Lebanese electricity sector still requires long-term reform.

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1 Souraya Machnouk is a partner and Hachem El Housseini, Rana Kateb and Chadi Stephan are senior associates at Abou Jaoude & Associates Law Firm.
The first attempt to organise hydrocarbon resources in Lebanon in line with international standards took place in August 2010, with the enactment of the Offshore Petroleum Resources Law (OPRL); this law established the Lebanese Petroleum Administration (LPA), which, together with the Lebanese Council of Ministers and the MOEW, participates in the regulation of the oil and gas sector.

In 2012, the Council of Ministers approved the launching of the first offshore licensing round for hydrocarbon exploration. In 2017, two long-awaited decrees were finally published in the Official Gazette, governing respectively:

- the delineation of the Lebanese maritime waters into 10 distinct blocs; and
- the tender protocol for the award of exploration and production agreements.

Regarding onshore hydrocarbon resources, a draft law is still being discussed at the level of parliamentary commissions. A draft hydrocarbon policy is currently being developed by the LPA, and will ultimately be subject to the approval of the Council of Ministers.

II REGULATION

i The regulators

The MOEW was established by virtue of Law No. 20 of 1966, and later reorganised by virtue of Law No. 247 of 2000, and is vested with the following powers, among others:

- Setting the general policy for the sector, as well as the general master plan, and the discussion of directive studies and putting them in their final version and submitting them to the Council of Ministers for ratification.2
- Proposing the comprehensive rules for the organisation of the services related to the electrical energy production, transmission, distribution and the supervision of execution.3
- Proposing draft laws and decrees related to the electricity sector.4
- Proposing general safety conditions, environmental conditions and technical specifications applicable to the electrical installations and equipment, provided that the same are issued by virtue of a decree taken by the Council of Ministers upon the competent minister’s proposal after consulting the competent authorities.5
- Entering into the necessary contacts with other countries aimed at establishing electrical interconnections and exchanging electrical energy, and the ratification of the necessary contracts after the parliament’s approval.6
- Taking all available measures, including the provision of distribution networks according to the laws and contracts ratified by the government to remedy any defects in any of the electricity sector’s activities that may have a negative effect on this sector’s interests or on the consumers’ rights and interests.7

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2 Article 6 of Law No. 462 of 2002.
3 Article 6 of Law No. 462 of 2002.
4 Article 6 of Law No. 462 of 2002.
5 Article 6 of Law No. 462 of 2002.
6 Article 6 of Law No. 462 of 2002.
7 Article 6 of Law No. 462 of 2002.
The OPRL has vested various prerogatives related to hydrocarbon resources in the Council of Ministers, the MOEW and the LPA. Most of the decisions taken by the MOEW are subject to the approval of the Council of Ministers and such decisions are considerably influenced by the LPA’s technical advice and recommendations.

The Council of Ministers approves the state’s petroleum policy and all decrees related to petroleum activities. The Council of Ministers also approves all exploration and production agreements, appoints the LPA’s board, approves petroleum licences and decides on extending the duration of the exploration or production periods after consulting with the LPA.

The MOEW is responsible, inter alia, for signing exploration and production agreements (following authorisation of the Council of Ministers), implementing the OPRL, supervising petroleum activities and protecting the environment from hydrocarbon-related pollution.

The LPA is an independent, technical, regulatory and advisory public entity in charge of managing the petroleum sector, under the supervisory authority of the MOEW. The LPA’s prerogatives encompass the preparation of strategic, economic, financial, technical, geological and environmental plans so as to ensure a prudent and efficient management of Lebanon’s upcoming hydrocarbon wealth. The LPA’s goal is to ensure a successful, transparent and sustainable development process for all petroleum activities, in concert with various governmental bodies, international organisations and civil society.

The main sources of law and regulation governing hydrocarbons are:

- the OPRL dated 24 August 2010;
- Decree No. 9438 dated 4 December 2012, appointing the LPA;
- Law No. 163 dated 18 August 2011, identifying and delineating the marine zones of Lebanon;
- Decree No. 6433 dated 1 October 2011, governing and delineating the Lebanese Exclusive Economic Zone;
- Council of Minister Decision No. 41 dated 27 December 2012, opening the first offshore licensing round for hydrocarbon exploitation;
- Decree No. 9882 dated 16 February 2013, on the pre-qualification of companies;
- Decree No. 42 dated 19 January 2017, on the delineation of maritime blocs; and
- 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.

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 over 90 per cent of the Lebanese electricity sector (including the Kadisha concession in North Lebanon, which is owned by EDL), with a standing monopoly despite the enactment of Law No. 462 in September 2002 (Law 462) providing, inter alia, for the privatisation of electricity production and distribution activities. Some private companies hold a concession to generate or distribute electrical power. EDL’s capacity

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8 Article 1 of Decree No. 16878 of 1964.
to generate electricity stands at approximately 1,800MW, leaving a gap with the actual market demand that is currently filled by unregulated private generators, mainly in residential and commercial sectors.

Other participants in the sector include hydroelectric power plants owned by the Litani River Authority, concessions for hydroelectric power plants such as Nahr Ibrahim and Al Bared, and distribution concessions in Zahle, Jbeil, Aley and Bhamdoun.

In order to ensure equality and competition, Law 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, some of its provisions related to (1) the privatization process and (2) the formation of the NRESO are not yet implemented for various reasons, mostly political.9

The licence is an official document issued by the NRESO to joint-stock companies that are granted a concession for a maximum duration of 50 years to (1) establish, equip, develop, appropriate, operate, manage or market equipment within the scope of public services in the fields of production, transportation and distribution of power exceeding 10MW, or (2) use the aforementioned equipment by virtue of a financing leasing contract.10 Since the NRESO has not been established yet, the Lebanese Parliament enacted several laws granting the authority to the Council of Ministers to issue the licences and permits for a specific period of time until the establishment of the NRESO.

The OPRL subjects the performance of ‘petroleum activities’ to a licence; the term ‘petroleum activities’ encompasses planning, preparation, installation and implementation of activities associated with a subsea reservoir, such as reconnaissance, exploration, production and exploitation, laying of pipelines, development of facilities, production and transportation. The OPRL singles out the following licences:

- a Reconnaissance licence: The general conditions and scope of this licence and the corresponding fees are determined by the Council of Ministers by decree upon the proposal of the MOEW based on the opinion of the LPA. This non-exclusive licence is granted by virtue of a MOEW resolution, based on the opinion of the LPA, for a period not exceeding three years.

- b Construction, placement and operation of transportation or storage facilities: the Council of Ministers may grant such a licence if the corresponding works are required as part of the approved plan for development and production.

- c Production licence: The general conditions and scope of this licence and the corresponding fees are determined by the Council of Ministers by decree upon the proposal of the MOEW based on the opinion of the LPA. This licence is granted by virtue of a MOEW resolution based on the opinion of the LPA.

- d The OPRL also provides that the Council of Ministers awards exclusive authorisations to carry out petroleum activities in a specific bloc by virtue of an exploration and production agreement, setting out the right-holders’ authority to explore, develop and produce oil and gas offshore.11

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9 Article 19 of Law No. 462 of 2002.
10 Article 1 of Law No. 462 of 2002.
11 As per the specific provisions of the draft EPA enacted by virtue of Decree No. 43 dated 19 January 2017.
iii Ownership and market access restrictions

There are no major ownership and market access restrictions in the energy sector. However, it should be noted that there is a market monopoly by EDL, which controls approximately 90 per cent of the electricity generating capacity in Lebanon, save for the few above-mentioned concessions.

Lebanon recently witnessed several instances where private sector companies were granted the right to generate electricity. Most notably, two power ships owned by a Turkish private company have been leased by the Lebanese government since 2013 in order to compensate for the shortage in the electric supply resulting from the lack of proper maintenance of existing plants. The two power barges are anchored at a specially constructed dock off the coast of Beirut, and have a total output of 370MW, with an output to the national grid of an extra two hours’ electricity a day.

Furthermore, and according to the above-mentioned Policy Paper for the Electricity Sector (see Section I, supra), a project under preparation aims to grant private sector companies the right to build wind farms for the purpose of producing electricity and connecting to the EDL grid for distribution.

The transportation of electrical energy remains exclusive to EDL, but it is possible, through a decree taken by the Council of Ministers upon the proposal of the Minister of Energy and Water, to ratify contracts with the private sector for the management, operation, development or equipment of the transmission’s activities.

The OPRL and Decree No. 43 of 19 January 2017 regulate the terms of exploration and production agreements to be entered into between the Lebanese state and a consortium of at least three right holders. The various right holders form an unincorporated joint venture in which each of them has an indivisible interest. However, the OPRL and Decree No. 43 unequivocally provide that the Republic of Lebanon has title to all petroleum resources in the seabed of Lebanese waters and the exclusive right to their management.

There are no specific restrictions on the award of licences pursuant to the OPRL, except for qualification requirements with which any prospected licensee is required to comply.

iv Transfers of control and assignments

Licensees and permit holders are not allowed to waive or assign their participating interest or permits to any other party, unless they have obtained the prior approval of the NRESO’s (currently the Council of Ministers) and provided that the transfer or assignment conforms with Law 462 and the regulations issued for its implementation.12

The OPRL provides that the interest of a right holder in an exploration and production agreement is a ‘non-transferable participation interest’. The OPRL further provides that:13

a the rights and obligations pertaining to a petroleum right may not be transferred or assigned in whole or in part except to a company qualified according to the provisions of the OPRL, and only after obtaining the approval of the Council of Ministers;

b the same shall apply to the direct assignment of any right in a company that enjoys a petroleum right, including, inter alia, the transfer of shares or other rights that may grant the holder thereof decisive control over said company; and

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12 Article 23 of Law No. 462 of 2002.
13 Article 70 of the OPRL entitled ‘Transfer or Assignment of a Petroleum Right’.
no ownership or usage right in any facility upon which a petroleum activity depends shall be transferred, except after approval by the Council of Ministers.

Finally, the OPRL\textsuperscript{14} provides that the conditions for the sale or transfer of any interest in petroleum shall be set out in a Decree taken by the Council of Ministers.

\section*{III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES}

\subsection*{i Vertical integration and unbundling}

As stated above, the Lebanese electricity sector is monopolised by EDL, who currently controls over 90 per cent of the sector (including the Kadisha concession in North Lebanon). Moreover, the sector includes hydroelectric power plants owned by the Litani River Authority; concessions for hydroelectric power plants such as Nahri Ibrahim and Al Bared; and distribution concessions in Zahle, Jbeil, Aley, and Bhamdoun, each of which serves a particular geographical area.

According to the 2010 Policy Paper for the Electricity Sector, this structure should be subject to several changes that are aimed at a partial liberalisation of the electricity sector in Lebanon. After the Paper was announced, investors became interested in the electricity sector, and in engaging in the production and distribution of electricity according to the regulations in force. An important focal point is the collaboration between the public and private sectors since 2012, which consists in outsourcing to private sector companies some of EDL’s activities related to the design, implementation, operation and maintenance of a distribution network with the customers and metering services. This is encouraging for the private investors to invest increasingly in the Lebanese electricity sector.

In relation to natural gas, there is no market regulation yet; the only relevant instrument issued so far is Law No. 549 dated 20 November 2003 governing the design, financing, development and reconstruction of two refineries; building a terminal for the import and export of LNG; building facilities for the storage of LNG; and establishing networks for its sale and distribution.

Currently, no LNG terminals or facilities have been erected. Accordingly, there is no effective market for LNG sale or distribution.

\subsection*{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.\textsuperscript{15}

In relation to natural gas, these issues have not been addressed yet.

\textsuperscript{14} Article 40 of the OPRL entitled ‘Sale of Petroleum’.

\textsuperscript{15} Article 5 of Law No. 462 of 2002.
iii Rates
The rates of the distribution and sale of electricity for all voltage levels are set by EDL according to its investment and financing needs in order to develop its activity.\(^\text{16}\)

In relation to natural gas, these issues have not been addressed yet.

iv Security and technology restrictions
The MOEW is entitled to take any measures, including those aimed at ensuring that the distributions are executed according to the laws and contracts ratified by the government, in order to remedy any defects in the electricity sector’s activities that may negatively impact this sector’s interests or on the consumers’ rights and interests. The MOEW may also propose general safety conditions, environmental conditions and technical specifications with respect to electrical installations and equipment, provided that they are issued by virtue of a decree taken by the Council of Ministers upon the competent minister’s proposal after consulting the competent authorities.\(^\text{17}\)

Similar considerations to those outlined above govern petroleum activities. Chapter 9 of the OPRL, entitled ‘Health, Safety and the Environment’, outlines the safety and security obligations imposed in conjunction with petroleum activities. These include ensuring the highest levels of safety, having in place a ‘health, safety and emergency response plan’ and efficient emergency preparedness. The competent authorities also have the right to request that the right holder place a determined facility at their disposal and facilitate any specific measures for the purpose of protecting health, safety, security or the environment.

In addition, it should be noted that the Israel Boycott Act enacted by the Lebanese parliament on 23 June 1955 prohibits, under penalty of criminal sanctions, any natural or moral person from conducting, directly or through an intermediary, any agreement with or in the interest of bodies or persons residing in Israel.

The Council of Ministers may, pursuant to a recommendation of the Boycott Bureau (a stand-alone body operating at the Lebanese Ministry of Economy and Trade), enlist any company breaching the provisions of the Israel Boycott Act on a blacklist and prohibit any dealings with such company.

IV ENERGY MARKETS
i Development of energy markets
Law 462 was expected to liberalise the sale and distribution of electricity in Lebanon and create a competitive free market for electricity, as it also organises the privatisation process, which has not kicked off yet despite a legal framework being in place (Privatisation Law No. 228 of 31 May 2000). The NRESO, that was supposed to play a leading role in regulating the electricity sector, has not been established yet. The Policy Paper for the Electricity Sector provides for (1) the implementation of a programme to cover the traditional power supply infrastructure whereby international private companies have carried out the rehabilitation of existing power plants and construction of new plants, and (2) a promising renewable energy programme under which qualified developers will build and operate solar or wind power stations and sell the power generated to EDL, which retains the exclusive right of

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

\(^\text{17}\) Article 6 of Law No. 462 of 2002.
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 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 produce, transmit and distribute electricity for end users in Lebanon. However, and as stated above, other parties play a partial role in the sector, such as the concessions for hydroelectric power plants of Nahr Ibrahim and Al Bared and the distribution concessions in Zahle, Jbeil, Aley and Bhamdoun.

It is important to mention that, up until the full liberalisation of the electricity sector in Lebanon, the tariffs and rates are set by EDL even for the above-mentioned concessions. As for any electricity production activities carried out by the private sector, the transmission of such produced electricity remains the sole right of EDL.

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

iii Contracts for sale of energy

Electricity producers and distributors are permitted to have individual contracts for the sale of electric power to EDL, since the latter possesses the sole right to transmit the electricity. Hence, electricity producers are required to connect their production to EDL’s grid in order for it to reach the end users, while the rates and other charges are mandated by the government.

In relation to natural gas, the corresponding guidelines are yet to be developed.

iv Market developments

The full implementation of Law 462 would be considered a huge step forward in the liberalisation and encouragement of private investments in the energy sector. However, such 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. If the private sector is to participate in the erection of new facilities together with the Lebanese government, this will require the prior enactment of the Public-Private Partnership Law.

A draft law is currently being discussed at the level of parliamentary commissions to provide for several amendments to Law 462, such as:

- provisions for feed-in tariffs for cogeneration;
- organisation of a transitional period until EDL is corporatised;
- the introduction of IPPs to build and operate new combined cycle gas turbine units;
- the financing of future plan expansions; and
- the introduction of renewable energies.

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.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

There is an obvious trend to increase the inclusion of the production of renewable energy as part of the implementation of the national electricity strategy. The MOEW encourages public, private and individual initiatives to adopt the utilisation of renewable energies to reach the 12 per cent target in the generation of electricity by 2020. In an initiative launched in partnership with the MOEW, the UNDP established the Country Energy Efficiency and Renewable Energy Demonstration Project for the Recovery of Lebanon (CEDRO) in 2007, with an initial budget funded by the government of Spain to enhance the national energy strategy by contributing in achieving renewable energy projects.

Also, the LCEC18 works closely with the MOEW by setting action plans and national strategies in terms of energy efficiency and renewable energy. In an effort to reach the 12 per cent objective, the LCEC has set two consecutive four-year action plans, known overall as the National Energy Efficiency Action Plan (NEEAP).19 The 2011–2015 NEEAP comprises 14 initiatives of which seven were dedicated to renewable energy. The 2016–2020 NEEAP includes 26 initiatives, setting targets and strategies for the achievement of the energy-saving targets. The LCEC, with support from the MOEW, has further put in place the National Renewable Energy Plan (NREAP) 2016–2020, a follow-up report to the 2011–2015 NEEAP specifically dedicated to renewable energy strategies and their implementation.

Lebanon has already witnessed the implementation of projects using renewable sources that are connected to the grid via EDL.

a Wind energy: Lebanon constitutes a viable country for energy wind production. In 2013, as part of the implementation of the national strategy for renewable energy development leading to achieving the 500MW wind generation target by 2020, the MOEW launched a tender to private corporations to build the first wind power farm in Lebanon with a capacity of 50–100MW. The electricity generated by the wind farm will be sold to EDL via off-take 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, comes as part of the NEEAP to install 200MW of solar farms by 2020. The first phase of the project has been achieved, connecting an extra 1MW of electricity to the grid. Also, the MOEW plans to install around 30MW of solar farms for the public sector between 2016 and 2020. The development of PV farms is becoming more appealing, especially with the decrease in related solar installations’ prices.

c Water energy: while 75 per cent of Lebanon’s market demand was covered by electricity generated from hydroelectric sources in the 1970s, the production of hydroelectric power was seriously affected during the civil war and afterwards. Opportunities in the

18 The Lebanese Center for Energy Conservation (LCEC) is an independent governmental organisation operating under the supervision of the Lebanese Ministry of Energy and Water.
19 The National Energy Efficiency Action Plan is a national action plan developed based on the requirements of the League of the Arab States and according to the format used by the European Union.
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, which will include the hydroelectric power plant supplying the grid with approximately 100MW of hydroelectricity.

Bioenergy (including waste to energy): 23 bioenergy streams have been identified as potential resources for energy production. All action plans stated in the National Bioenergy Strategy for Lebanon set in 2012 by the MOEW along with the UNDP as part of the CEDRO project have been reinstated in the NREAP 2016–2020, as the Ministry recognises that the future of bioenergy is promising. On-ground surveys and assessments have been carried out to identify the most efficient and promising biomass streams. As for waste to energy, the process for producing electricity was launched in 2015 through the establishment of a 7MW plant in the Naameh landfill to produce electricity.

ii Technological developments

The LCEC has drafted an energy conservation law, the Renewable Energy and Energy Conservation Law, which sets the legal framework for the implementation of the NREAP and addresses the production by the private sector of electricity from renewable energies, the management of energy supply and demand and the computation of renewable energy tariffs. The proposed law also covers topics related to energy efficiency in connection with the electricity grid. It provides for mandatory audits and certifications while catering for incentives to promote green solutions.

Notwithstanding the above, a series of initiatives are being carried out with respect to the development of smart technologies that would have an estimated impact on energy demand management. The launching by EDL of the advanced metering infrastructure, comprising the installation by three private distribution service providers of smart meters over the Lebanese territory, is expected to provide energy efficiency in terms of monitoring and synchronisation of wide area networks. A pilot project is currently being carried out to test the responsiveness of the Lebanese network.

VI THE YEAR IN REVIEW

There is a growing national momentum to develop action plans and strategies for the electricity sector, and to encourage all related initiatives. The political commitment in a country like Lebanon plays a crucial role in achieving the goals of the 2016–2020 NREAP. The involvement of the private sector in the various tenders relating to energy and electricity projects is increasing, especially in light of the incentives proposed by the Central Bank of Lebanon and private financial institutions to finance such projects.

20 The construction of the 300-foot high Janna Dam was suspended in May 2016, only to resume later despite local ecological and environmental warnings and concerns.
A 10-year reform plan proposed by the incumbent Minister of Energy and Water based on the 2010 Policy Paper was approved by the Council of Ministers on 28 March 2017. The first phase of the plan involves the lease of two additional power barges from the Turkish company that already operates two smaller ships in Lebanon, and the activation of the two recently overhauled power plants of Zouk Mikael and Jiyyeh, with the aim of increasing electricity supply to 21 hours a day this year. The main idea behind the leasing of the barges is to give the MOEW more time to build new power plants that can provide all of Lebanon with 24 hours of electricity in the future. The two additional floating power plants will reportedly generate up to 890MW at a cost of US$340 million a year. The plan also envisions the construction of solar power plants in several areas in the country.

The plan has been met with skepticism and controversy, with challengers alleging its high-cost factor, lack of transparency and the expectancy that it will result in a significant increase in electricity tariffs.

The issuance in early 2017 of the decree on the delineation of maritime blocs and the decree on the tender protocol and the model exploration and production agreement has paved the way for the closing of the prequalification process; the grouping of the qualified companies in consortia; and, finally, following approval by the Council of Ministers, the execution of the corresponding exploration and production agreement between the winning consortia and the Lebanese state for one or more of the maritime blocs.

On 26 January 2017, the MOEW announced that five out of the 10 maritime blocks were open for bids. Prequalified companies should submit their bids by 15 September 2017. The aim of the Lebanese government is to have one or more exploration and production agreement signed by the end of 2017.

VII CONCLUSIONS AND OUTLOOK

While the Lebanese energy and electricity sector is currently witnessing drastic progress, it is essential to ensure a full correlation between the development of the legal framework and the privatisation process set out by Law 462. The restrictions imposed by Law 462 should be lifted so as to offer a more flexible legal framework, allowing the private sector to invest in energy production and distribution at fair yet competitive rates to third parties. Additionally, the introduction of legal reforms for alternative technologies and renewable energy activities should be envisaged to fill a considerable gap towards a sustainable national energy strategy.

After a long stalemate (between 2013 and 2017), Lebanon is steadily heading towards becoming a hydrocarbon state, provided extractable discoveries are made in the near future. A successful first licensing round will be a decisive step.

Lebanon’s key challenge is to ensure that the process is managed with a sound governance system and utmost transparency. The Lebanese government’s recent request to join the Extractive Industries Transparency Initiative is a key indicator in this direction, and a message of confidence to both the applicant companies and the Lebanese civil society.
I OVERVIEW

The first Malaysian legislation governing the supply of electricity in the country was enacted in 1949, and predates legislation governing the mining, extraction, refining and supply of hydrocarbons, which has been Malaysia’s primary source of energy since the 1950s. Every five years since 1966, the Malaysian government, via the Economic Planning Unit of the Prime Minister’s Department of Malaysia (EPU), sets out the development plans for the country in the Malaysia Plan, which lays out the country’s economic policies and presents a general guide for regulators, legislators and investors alike about the direction and focus the country is expected to take over the next five years.

The export of hydrocarbons has historically been a major contributor to Malaysia’s economy accounting for up to 20 per cent of the national gross domestic product in recent years. In 1994, crude oil (52.2 per cent) and natural gas (45.1 per cent) together comprised an overwhelming 97.3 per cent of energy production in Malaysia, which at the time amounted to a total of 62,874 ktoe. Up until 2010, the country’s reliance on natural gas as an energy source has been steadily increasing, and at the end of 2010 natural gas accounted for 71,543 ktoe of the 106,794 ktoe total energy produced nationwide. Since then, the increasing local demand for energy supply and rapidly diminishing hydrocarbon resources has instigated a gradual but sure shift in energy sector policies of recent years, as the industry strives to reduce its dependency on fossil fuels and develop its renewable energy market infrastructure, beginning with the implementation of the National Depletion Policy in 1980 in order to conserve the main energy resources (namely, crude oil and gas) of the country. According to the Eighth Malaysia Plan (2001–2005), the Malaysian government aimed to have five per cent of the total energy supply in the country produced from renewable energy resources. Unfortunately, renewable energy sources only accounted for about 1.28 per cent of the total energy produced in Malaysia by the end of 2005, possibly due to the lack of financial and legislative support as well as the limitations in existing technology and infrastructure of the

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1 Fariz Abdul Aziz is an energy partner and Karyn Khor is a legal associate at Skrine.
2 PricewaterhouseCoopers, ‘The Malaysian Oil & Gas Industry: Challenging times, but fundamentals intact’ (May 2016).
3 Ibid. at footnote 2.
4 Ibid. at footnote 2.
5 Ibid. at footnote 2.
time. As of 2014, the country’s energy production of 98.236 ktoe comprised 64.2 per cent natural gas, 30.1 per cent crude oil, 1.7 per cent coal and 4 per cent renewable resources such as biodiesel, hydropower, solar energy, biomass and biogas. 6

II REGULATION

The energy sector in Malaysia was formerly a state monopoly, where the national electric utility company, Tenaga Nasional Berhad (TNB) held the exclusive rights to generate, transmit and distribute electricity in Peninsular Malaysia and Sabah. However, a nationwide blackout that resulted in losses of an estimated 218 million ringgit in the manufacturing sector alone, 7 set off a chain of events that culminated in the privatisation of the energy distribution sector and the entry of independent power producers (IPPs) into the energy market, as well as the emergence of the first power purchase agreements (PPAs). The PPA dictates the terms upon which the IPPs would sell the electricity that they generate to TNB, who is the exclusive owner and operator of Malaysia’s electricity distribution network.

i The regulators

The energy market in Malaysia and its participants are subject to a host of legislation governing the supply of electricity generally and the mining of energy resources. More recently, new legislation has been introduced to account for the growing renewable energy sector. The laws that are relevant to the energy sector in Peninsular Malaysia and Sabah 8 are as follows:

a. Electricity Supply Act (ESA) 1990;
b. Gas Supply Act 1993;
c. Renewable Energy Act 2011;
d. Environmental Quality Act 1974;
e. Occupational Safety and Health Act 1994;
f. Factories and Machinery Act 1967;
g. Petroleum Development Act 1974;
h. Petroleum (Safety Measures) Act 1984; and
i. Petroleum and Electricity Control of Supplies Act 1974.

The legislation listed above also require compliance with the regulations, orders, rules and other sub-legislation made thereunder. Some of the more relevant ones are listed below:

b. Electricity Regulations 1994;
c. Licensee Supply Regulations 1990;
d. Gas Supply Regulations 1997;
e. Renewable Energy (Feed-In Approval and Feed-in Tariff) Rules 2011;
g. Renewable Energy (Technical and Operational Requirements) Rules 2011; and

6 Ibid. at footnote 2.
8 On 1 September 1990, legislative powers in respect of energy laws in the state of Sarawak were delegated to the local state authority.
The sub-legislation deals in much greater detail with the practicalities of complying with the laws, and include regulations on, \textit{inter alia}, safety, licensing, management of supply, transport and transmission, technical and operational requirements and exemptions. The laws may also empower the relevant ministers or regulatory authorities to make further guidelines or directives in respect of their regulatory sphere.

There are multiple regulatory authorities in Malaysia overseeing the various segments of the energy sector. Today, the Energy Commission of Malaysia (the Commission) is the primary regulator of the energy and gas supply in Peninsular Malaysia and Sabah.\footnote{The regulation of energy and electricity in the state of Sarawak is under the purview of Sarawak Energy Berhad (SEB), known as the Sarawak Electricity Supply Corporation (SESCO) prior to privatisation. Additionally, Sarawak has its own state laws for environmental protection and occupational health and safety; with the exception of the laws relating to petroleum, which fall within the jurisdiction of the Malaysian federal government, the other federal laws have limited or no application in the state of Sarawak. The Gas Supply Act 1993 was only recently amended (in 2016) to apply to the state of Sarawak.} The Commission shall have all functions imposed on it under the energy supply laws and shall also have, \textit{inter alia}, the following functions:\footnote{Section 14, Commission Act 2001.}

\begin{enumerate}[a]
\item to advise the Minister of Energy, Green Technology and Water (Minister) on all matters concerning national policy objectives for energy supply activities;
\item 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;
\item 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;
\item to promote the use of renewable energy and the conservation of non-renewable energy; and
\item to promote research into, and the development and the use of, new techniques relating to:
\begin{itemize}
\item the generation, production, transmission, distribution, supply and use of electricity; and
\item the supply of gas through pipelines and the use of gas supplied through pipelines.
\end{itemize}
\end{enumerate}

The Commission reports to the Malaysian Ministry of Energy, Green Technology and Water (KeTTHA) and is responsible for the oversight of all elements of the industry from tariffs and licensing to consumer safety. The Commission works in close cooperation with the Sustainable Energy Development Authority of Malaysia (SEDA), which is a statutory body formed under the Sustainable Energy Development Authority Act 2011 to administer and manage the implementation of the feed-in tariff mechanism under the Renewable Energy Act 2011 (see below). A company seeking to participate in the extraction of oil and gas in Malaysia will generally do so by entering into production-sharing contracts, joint operating
agreements or farm-out agreements with Petroliam Nasional Berhad (PETRONAS), and a PETRONAS licence is required in order to operate a business of processing or refining of petroleum and marketing or distributing petroleum or petrochemical products.

ii Regulated activities

Supply of electricity

The construction, operation, management and use of electrical installations, plants and equipment designed for the supply or use of electricity requires a licence from the Commission. There are two main types of licence issued under the ESA (ESA Licences):

a licences for ‘private installations’, meaning any installation operated by a licensee or owner solely for the supply of energy to and use on the licensee’s or owner’s own property or premises, or, in the case of a consumer, taking electricity from a public installation or supply authority, for use only on the licensee’s or owner’s property or premises; and

b licences for ‘public installations’, meaning an installation operated by a licensee for the sale and supply of electricity to any person other than the licensee.

The ESA provides that 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 his or her 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 Single Buyers Rule Guidelines and the guidelines and directives of the Grid Code Operator. The Commission may attach other terms and conditions to the licence as they see fit.

A person seeking a licence under the ESA must apply via the Commission’s online application system. Although neither the ESA nor the rules and regulations issued thereunder expressly imposes any ownership or equity limitations on the applicant, such limitations are usually set out in the terms and conditions of the licences and other regulatory approvals or, alternatively, they may be contained in the provisions of the PPAs signed between the IPPs and TNB.

Since the early 1990s, the Commission has awarded power plant projects to companies based on a competitive bidding system, although the absolute discretion regarding who to grant these projects to lies with the Malaysian government; to date, there have been three recorded instances where a power plant project has been awarded by direct negotiation with the company involved, as opposed to a bidding process. The Commission has stressed that direct awards of power plant projects are the exception and not the rule.

The present benchmark tariff for competitive pricing of electricity is the rate paid to the 1,000MW gas-fired power plant, located in Prai, Penang. This was also the first power plant project ever awarded through tender in the country, won by TNB in 2012 at a tariff of 0.347 ringgit per kWh.

11 Section 2, Petroleum Development Act 1974.
12 Section 6, Petroleum Development Act 1974.
13 Section 9, Electricity Supply Act 1990.
14 Section 9(4), Electricity Supply Act 1990.
Prior to 2015, no PPAs had ever been granted to a foreign company (i.e., a company owned and controlled by non-Malaysians). Government policies required an IPP operator to have no more than 49 per cent of its equity in the hands of non-Malaysian entities. At the end of 2015, the government made an exception for the acquisition of 1Malaysia Development Bhd’s power assets by China General Nuclear for 9.83 billion ringgit, making it the largest acquisition by value in the history of Malaysia’s energy industry and the first – and so far, the only – instance where the Malaysian government has made an exception to the foreign equity rule and allowed a non-Malaysian entity to acquire 100 per cent of the equity in an IPP.\footnote{Elffie Chew, ‘Malaysia’s 1MDB Sells Power Unit in Step to Wind Down Operations’, \textit{Bloomberg} (23 November 2015).}

The Commission may issue a provisional licence in restricted circumstances. A company that has obtained a Feed-in Tariff Approval from SEDA (see below) for any of the following types of public renewable energy installations may apply to the Commission for a provisional licence:

\begin{itemize}
  \item[a] biogas installations;
  \item[b] biomass installations;
  \item[c] solar photovoltaic installations; and
  \item[d] small hydropower installations.
\end{itemize}

This is typically done to facilitate the development of the renewable energy project and to enable them to apply for financial incentives and programmes prior to the construction and operation of the facilities, and is intended to ease the entry of new participants to the renewable energy market. The Commission has stated that any company that requires a bank 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.\footnote{Commission Guidelines on Application for a Provisional Licence.}

\textbf{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 Renewable Energy Act 2011 (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:

\begin{itemize}
  \item[a] the connection to supply-line connection points for the distribution of renewable energy generated by renewable energy installations that are owned by feed-in approval holders;
  \item[b] the priority of purchase and distribution by the distribution licensee (meaning the holder of a ESA licence)s for renewable energy generated and sold by feed-in approval holders; and
  \item[c] the feed-in tariff to be paid by distribution licensees to feed-in approval holders for such renewable energy.
\end{itemize}

In order to be eligible to participate in the feed-in tariff system, the applicant must propose to generate renewable energy from a renewable energy installation with an installed capacity of not more than 30MW, or such higher installed capacity as may be approved by the Minister.
In addition, Rule 3 of the Renewable Energy (Feed-In Approval and Feed-In Tariff Rate) Rules 2011 provides that where the producer is a corporate body, it is subject to the following requirements and provisos:

\( a \) 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;\(^{18} \) and
\( c \) if the company is already a holder of a ESA licence, or if it is an associate of an existing ESA licence holder, then that company is prohibited from making any application for a feed-in approval relating to a renewable energy installation proposed to be connected to the electricity distribution network of the ESA licence holder.\(^{19} \)

The application may be made by the company or its authorised representative, and it should be submitted either manually to SEDA, or online via SEDA’s online application portal. The application should include supporting information regarding the renewable energy installation, including:

\( a \) a description of the installation including the type of renewable energy resource to be used;
\( b \) the proposed location of the installation;
\( c \) the proposed installed capacity of the installation;
\( d \) the proposed feed-in tariff commencement date; and
\( e \) the name of the ESA licence holder whose electricity distribution network is proposed to be connected to the renewable energy installation, including the location, details and specifications of the proposed connection.

The other pre-requisites for SEDA approval may vary according to the source of the renewable energy (solar, biomass, hydroelectricity, etc) and the output of the renewable energy installation. SEDA has a number of guidelines and documents on its website detailing the application processes, tests and checks to be carried out and technical requirements for each particular type of renewable energy installation. For instance, corporate applicants must have a minimum paid-up capital of 20,000 ringgit or equivalent if they intend to develop renewable energy installations with a rated kWp or net export capacity of up to 72kWp or kW. If the installation’s net export capacity exceeds 72kWp, then this minimum paid-up capital is increased to 50,000 ringgit or its equivalent.\(^{20} \) Additionally, SEDA may require the applicant to conduct tests and checks, including a Connection Confirmation Check or Power System Study conducted in accordance with the Renewable Energy (Technical and Operational Requirements) Rules 2011.

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.\(^{21} \) SEDA will not approve

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\(^{18} \) 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’.

\(^{19} \) Rule 3 of the Renewable Energy (Feed-in Approval and Feed-in Tariff Rate) Rules 2011.

\(^{20} \) Guidelines and Determinations of the Sustainable Energy Development Authority of Malaysia dated 5 February 2016.

\(^{21} \) Rule 19 of the Renewable Energy (Feed-in Approval and Feed-in Tariff Rate) Rules 2011.
such 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 (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 varies according to the type of renewable resource used, and the capacity of the renewable energy installation. Similar to PPAs, REPPAs may contain restrictions on foreign participation, foreign control or transfer/assignment that are more stringent than those prescribed under the renewable energy laws, although these will generally be reflective of the existing government policies on foreign investment in the Malaysian energy sector.

It should be noted that Feed-in Tariff approvals are subject to a quota. Presently, successful applications will be placed in a queue and subject to a ballot process until the quota is exhausted.22

**The supply of gas via pipelines (for private gas utilities and supply of gas to consumers)**

The Gas Supply Act 1993 (GSA) applies to the delivery of gas to consumers via pipelines, downstream from the connection flange of the loading arm at the regasification terminal, or the last flange of the gas processing plant or onshore gas terminal.23 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 their own premises, for example restaurants; and
- **b** gas utility licence – allowing licence holders to supply gas via pipeline to third parties for use.

However, as part of the Tenth Malaysia Plan and the country’s New Energy Policy, the Malaysian government has recently opened up the gas supply market in order to manage the growing demand for energy and gas in Malaysia and encourage economic growth. In 2016, the GSA was amended to provide more opportunities for third parties to have access to and manage gas distribution networks that they do not operate. Interested parties may now apply to the Commission for any of the following licences:

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

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22 Ibid. at footnote 22.
23 Section 1(3), Gas Supply Act 1993.
In order to obtain a licence under the GSA, the applicant:\(^{24}\)

\(a\) must be a Malaysian-incorporated company or, if incorporated outside Malaysia, must be approved by the Commission;

\(b\) must meet the minimum paid-up capital stipulated by the Commission (this ranges from 1 million ringgit to 5 million ringgit and depends on the type of licence being applied for);

\(c\) must not already hold any other GSA licences, and the applicant’s directors must not hold any directorships in other GSA licence holders;

\(d\) must have sufficient financial capability;

\(e\) must have sufficient relevant technical capability; and

\(f\) must comply with such other additional requirements as may be set by the Commission from time to time.

Presently, licences shall not be granted to any person who is not incorporated in Malaysia, or who does not have a place of business in Malaysia (except for a licence for import of gas into a regasification terminal).\(^{25}\) Licences granted under the GSA are not transferrable or assignable without the written consent of the Commission or the Minister.\(^{26}\) The Commission has stated that the third-party access system will be implemented on 16 January 2017, and there will be a 12-month grace period for existing players to obtain the necessary licences in order to comply with the GSA.\(^{27}\)

An application to the Commission for a licence for the distribution, retail or use of gas must include details regarding the area of supply; the site location plan and piping layout; the technical specifications of the piping system; and any other information that the Commission may request in order to enable it to organise and supervise the gas distribution network in the country.\(^{28}\)

**Other licences, certifications and approvals**

The above licences relate to the construction of power plants and power installations, supply, sale, distribution and transmission of energy. Any person interested in entering the energy market in Malaysia should also be mindful that other ancillary licences and certifications may be required in the process of obtaining the above-mentioned licences and approvals from the Commission. Approvals from the Department of Environment of Malaysia or the Malaysian Department of Occupational Health and Safety would also be relevant to an IPP. As a condition of the ESA licences or PPAs, a licence holder would generally also be required to employ certain technically skilled and qualified persons, and potential applicants should bear in mind that although the Malaysian government has been gradually liberalising professional services in Malaysia – including engineering and construction services – the relevant laws continue to prescribe minimum qualification requirements that are favourable to Malaysians or require local participation (e.g., a minimum period of residency in Malaysia, or a minimum percentage of Malaysian or Bumiputera\(^{29}\) equity in an applicant company).

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29 The term ‘Bumiputra’ or ‘Bumiputera’ is used to describe Malays and the indigenous peoples of Malaysia.
variety of other laws, such as the Factories and Machinery Act 1967 and the Petroleum (Safety Measures) Act 1984, also contain provisions addressing licences, approvals, certifications and registrations relating to safety, transportation and other ancillary matters that are ancillary, but nonetheless essential, to any party interested in entering the Malaysian energy market.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

The electricity transmission network in Peninsular Malaysia, known as the National Grid, is owned and operated by the national energy company, TNB. IPPs sell the electricity generated to TNB at a pre-determined tariff. Likewise, the electrical grid that supplies power in Sabah is operated by Sabah Electricity Sdn Bhd, a company owned partly by TNB and partly by the Sabah State government; whereas the grid in Sarawak is owned by Sarawak Energy Berhad, which is fully owned by the Sarawak state government. These companies collectively have a monopoly on the ownership and operation of Malaysia's power grids, and are responsible for their construction, operation and maintenance. Since the privatisation of power production in the early 1990s, the upstream market for the generation of electricity remains highly competitive with a mix of local and foreign power producers and a competitive bidding system for power plant projects.

Regarding gas, as at the beginning of 2017, only two companies have been granted a gas utility licence by the Commission: Gas Malaysia Sdn Bhd, a PETRONAS-associated company that operates and maintains the Peninsular Gas Utilisation pipeline system in Peninsular Malaysia; and Sabah Energy Corporation Sdn Bhd, which operates and maintains the gas distribution pipelines in Sabah. However, as stated above, recent amendments to the GSA are expected to facilitate the entry of new market players into an industry that is presently dominated both on the upstream and downstream level by state-controlled enterprises comprising a duopoly market in Peninsular Malaysia and a monopoly in Sabah.

ii Transmission/transportation and distribution access

The ESA provides that, save in very limited circumstances, an ESA licence holder has a duty to supply electricity to the premises to which his or her licence relates upon receiving a notice of request from the owner or occupier of those premises. The amended GSA imposes a similar duty on the holder of a gas retail licence to supply gas to (1) a consumer's premises; and (2) any regasification, transportation or distribution licensee, upon receiving notice of a request from them.

32 Section 24 and Section 25, Electricity Supply Act 1990.
iii Rates

The Commission is empowered to determine the tariffs for both electricity and gas under the ESA and GSA, and to issue guidelines of tariffs and charges including the methodology, principles or categories of tariffs and charges, and the duration for the imposition and review of said tariffs and charges.

Electricity prices are set by TNB under the regulation of the Malaysian government, via the Commission. Similarly, the tariffs for gas supply are set by Gas Malaysia Sdn Bhd, after approval of the rates by the Commission.

iv Security and technology restrictions

In the case of a lock-out, strike, or other emergency, or if he decides that public interest so requires, the reigning monarch of Malaysia, the Yang di-Pertuan Agong, may authorise the Commission to suspend the ESA licence or take temporary possession of any power installation or gas pipeline, and operate it in a manner that the Commission sees fit, or he may order that the licence and use of the installation or pipeline be withdrawn either partially or completely.

As to information security, both the ESA and GSA have similar information security provisions, requiring an ESA licence holder and GSA licence holder respectively to be responsible for the preservation of confidentiality, integrity and availability of its information, information systems and supporting network infrastructure pertaining to its duties and other matters as provided under the relevant Act. He or she would also be required to take all necessary measures to protect the relevant information from unauthorised access, intrusion or removal or any risk thereof, and in the event he or she becomes aware of any incident that may interfere or affect the performance of his or her activities under the licence, he or she is obliged under the ESA to inform the Commission immediately.34

IV RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

Since the implementation of the Tenth Malaysia Plan, the government – via the Commission, KeTTHA, and SEDA – have implemented a range of programmes and projects to educate the Malaysian public and encourage electricity efficiency and energy conservation. Energy laws and regulations are reflective of this; for example, the Efficient Management of Electrical Energy Regulations 2008 authorises the Commission to require operators and owners of installations that consume 3 million kWh or more over a six-month period to engage a registered energy manager to analyse the total consumption of electrical energy, advise on the development and implementation of measures to ensure efficient management of energy and monitor the effectiveness of the implemented measures.35 The introduction of the feed-in tariff mechanism under the REA and the implementation of the Solid Waste and Public Cleansing Management Act (2007) were similarly enacted in aim of growing and developing the country’s green energy industry while creating jobs and improving the quality of life of Malaysians generally.

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Malaysia
There are currently a number of fiscal incentives in place that are specifically targeted
at potential entrants to the renewable energy market in Malaysia. For example, KeTTHA
has approved a budget of 5 billion ringgit to help fund new energy efficiency projects in
Malaysia for the period 2018–2022.36 As of 1 September 2016, there have been a total of
509 applications processed, of which 243 projects were approved.37 Following the spirit of
the Eleventh Malaysia Plan, SEDA – with the blessing of the EPU – 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.38
The Malaysian Investment Development Authority (MIDA) offers tax incentives
for green technology projects and services. Subject to any other conditions imposed by
MIDA, a Malaysian company that undertakes a green technology project may be eligible for
Investment Tax Allowance of 100 per cent of the qualifying capital expenditure incurred in
a green technology project from the year of assessment 2013 until year of assessment 2020.
Similarly, a Malaysian company that provides green technology services is eligible for an
income tax exemption of 100 per cent of their statutory income from the year of assessment
2013 until year of assessment 2020.39
ii

Technological developments

A vital part of the Malaysian government’s drive towards energy efficiency involves
monitoring and educating consumers so as to improve management on the demand-side. In
2011, the Sustainability Achieved via Energy Efficiency programme was launched, whereby a
total of 44.3 million ringgit was allocated as rebates for the purchase of new energy efficient
refrigerators and air conditioners for domestic use, as well as chillers for industries. The total
energy saved as a result of this initiative was 306.9GWh.40
In 2014, TNB, along with the government, launched a 1,000-unit smart meter,
two-year pilot smart grid project in Melaka and Putrajaya.41 The project was funded by the
government and is targeted at reducing energy consumption by encouraging Malaysians to
be engaged with their energy management. There has been no news on a nationwide rollout
to date, although this may be on the cards if the pilot project proves successful and any
technological or operational kinks have been ironed out.
The Malaysian government has also taken a ‘lead by example’ approach when it comes
to renewable energy. Starting in 2013, the Ministry of Finance issued Government Green
Procurement Guidelines, through which the government will actively acquire products and
services that are environmentally friendly, and leverage its purchasing power to encourage

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Mohd Khalemi, ‘Green Tech Financing Scheme to Continue With RM5bil Funding | Green Technology
Financing Scheme (GTFS)’, KeTTHA, 2 March 2017.
More information is available on SEDA’s website at www.seda.gov.my/?omaneg=00010100000001010101
000100001000000000000000000000&s=5400.
Malaysia Investment Development Authority, ‘Application for Incentive and/or Expatriate Posts for Green
Technology’.
Economic Planning Unit, Prime Minister’s Department, Malaysia, ‘Eleventh Malaysia Plan Strategy Paper:
World Class Energy Sector Volume 6, 2015.

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industries and private enterprises to do likewise.\textsuperscript{42} Since its pilot in July 2013, five selected ministries have procured green products and services worth 352 million ringgit as of April 2015.\textsuperscript{43}

\section*{V THE YEAR IN REVIEW}

\textit{a} In July 2016, construction began on the Jimah East 2,000MW coal-fired power plant in Port Dickson, Negeri Sembilan. TNB is working on the power plant project jointly with Mitsui & Co Ltd and Chugoku Electric Power. The power plant is expected to begin commercial operations in 2019\textsuperscript{44} and TNB projects that it will increase TNB’s generation capacity to 25,198MW by the end of 2020.\textsuperscript{45}

\textit{b} On 9 September 2016, the Gas Supply (Amendment) Act 2016 came into force, introducing the concept of third party access to the Malaysian gas supply market.

\textit{c} On 1 November 2016, the Malaysian government rolled out a Net Energy Metering Scheme for 500MW capacity in Peninsular Malaysia and Sabah. Under the scheme, excess solar power or other renewable energy from private generators operated by consumers (e.g., solar panel installations on rooftops of buildings and car garages) will be fed back into the power grid and those consumers will be able to offset the cost of power drawn from their utilities.\textsuperscript{46}

\textit{d} PETRONAS has confirmed that it is on track to complete its Refinery and Petrochemical Integrated Development (RAPID) project on schedule, in partnership with Saudi Aramco. Production is targeted to commence in 2019 and the refinery will help supply the growing need for petroleum and petrochemical products in Asia Pacific.\textsuperscript{47}

\textit{e} On 23 January 2017, PETRONAS announced that the LNG Train 9 in Bintulu, Sarawak moved to commercial operations phase as of 1 January 2017. PETRONAS reported that the facility ‘will boost the production capacity of the PETRONAS LNG Complex by 3.6 million tonnes per annum to approximately 30 million tonnes per annum and will strengthen PETRONAS’ position as a leading player in the global LNG business’.\textsuperscript{48}

\section*{VI CONCLUSIONS AND OUTLOOK}

The 2016 amendments to the GSA, which allow third parties access to gas facilities that they do not themselves own or operate, have opened up new possibilities and points of entry into the gas supply market. This is in line with the government’s policies in the Ninth, Tenth and Eleventh Malaysia Plan, which, in relation to the energy sector, focuses on two

\begin{itemize}
\item At the time of writing, the GGP (Version 2014) is available at www.scpmalaysia.gov.my/images/GGP%20GUIDELINES%20-%20FINALL%20-%20NAIM%20-%200808014.pdf.
\item Eleventh Malaysia Plan (2016–2020), pp. 6–16.
\item ‘Construction Begins on 2,000MW Jimah East Power Project in Malaysia’, Energy Business Review 26 July 2016.
\item ‘PETRONAS says its Refinery and Petrochemical Integrated Development (RAPID) project remains on track after Aramco’s snub’, The Star Online 27 January 2017.
\end{itemize}
main principles: firstly, to continue to stress on ‘pursuing green growth for sustainability and resilience’ and reduce the country’s dependence on fossil fuels and encourage the use of clean, renewable energy; and secondly, meeting the growing local demand for energy resulting from socio-economic growth and expansion. Meanwhile, the global slowdown in oil and gas may be the catalyst the country needs to boost investment and development in its renewable energy sectors. SEDA and KeTTHA are presently developing a Renewable Energy Transition Roadmap 2050, which is intended to map out a smooth transition for Malaysia from its fuel-based electricity generation to renewable energy resources. The roadmap is expected to be complete by the end of 2017.\textsuperscript{49} Shifting the country’s dependence from fossil fuels to renewable resources to meet its growing energy demands has been a primary concern and focus of government policy for a good part of the past two decades, and likely will continue to be in the near future.

Chapter 23

MEXICO

Juan Carlos Serra Campillo and Jorge Eduardo Escobedo Montaño

I OVERVIEW

i Oil and gas

Before the 2013 amendments to Mexico’s Federal Constitution, the Mexican energy industry was completely closed to private investment, all activities related to oil were reserved to the government and were carried out and performed only by the government-owned oil and gas company Petróleos Mexicanos (Pemex) and its subsidiaries. Private companies’ participation in the hydrocarbons industry was limited to service agreements with Pemex.

On 20 December 2013, Articles 25, 27, and 28 of the Federal Constitution were amended and 21 transitional articles were approved by the Mexican Congress, allowing Mexico to award allocations to government-owned production companies, or exploration and extraction agreements to private natural or legal persons.

On 12 August 2014, 21 secondary laws were issued and published in the Official Federal Gazette, and 22 regulations were published on 31 October 2014. As a result of those amendments, an entirely new environment in the energy industry arose.

The new energy legal framework allows the participation of private companies in hydrocarbon projects, subject to their having obtained the required permits from the new government regulatory bodies.

Although private companies may engage in any activity related to the hydrocarbon industry, Pemex through its new government-owned subsidiaries will continue to participate in all upstream, downstream and midstream activities. These subsidiaries are (1) Pemex Exploration and Production; (2) Pemex Drilling and Services; (3) Pemex Cogeneration and Services; (4) Pemex Ethylene; (5) Pemex Fertilizers; (6) Pemex Logistics; and (7) Pemex Industrial Transformation.

The opening up of the exploration and extraction business area is evidenced in the upstream sector, where new private companies have been participating in:

- the seven calls to tender that have been issued by the National Hydrocarbons Commission (CNH); and
- the two farm-out procedures also called by CNH.

Currently, 38 exploration and extraction agreements have been awarded to private companies for onshore and offshore oil and gas fields and although their commercial exploitation will

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2 www.diputados.gob.mx.
not commence immediately, these new contracts represent important investment in Mexico for the coming years. Furthermore, one farm-out contract for exploration and extraction activities in ultra-deep waters has been awarded to a major international company that will partner with Pemex. Also, another project was recently announced by Pemex and CNH for exploration and extraction activities in shallow waters. More blocks are expected to be farmed out by Pemex throughout 2017; the development of those areas, in cooperation with Pemex, will be opened up to private companies through participation in a tender process overseen by CNH.

ii Electricity
The Mexican legal framework governing the electricity market has changed from being restricted to unrestricted, with the market now fully open to private investment, in generation and trading, with the possibility of joint ventures or public–private partnerships between the Mexican government (through the government-owned production company Federal Electricity Commission (CFE)) and private companies. The first government auction for long-term supply and purchase contracts was initiated last year by the new regulatory body, the National Energy Control Centre (CENACE). The auction’s main purpose was to purchase and sell power, cumulative electric power and clean-energy certificates. The auction, which was concluded in 2016, resulted in 11 agreements to purchase electricity from private companies. Additionally, the second electric auction called by CENACE, which was also concluded in 2016, resulted in numerous agreements to develop solar and wind electric projects throughout the Mexican territory. Currently, CENACE is preparing the auction guidelines to call for a third tender procedure.

II REGULATION
i The regulators
Different governmental regulatory bodies have responsibility for upstream, downstream and midstream activities in the hydrocarbon industry, and other government bodies have responsibility for electricity industry activities. These regulatory bodies are as follows.

Ministry of Energy (SENER)
SENER is in charge of Mexican energy policy and issues directives on, among other things, oil and gas matters. SENER selects contractual areas for oil and gas activities that will be put out to tender by CNH, and determines the model contract to be used in each tender and for each contractual area. It also issues permits for treating and refining oil, processing natural gas and exporting and importing hydrocarbon and oil products.

SENER is in charge of issuing the policies and guidelines that establish the electricity market and the conduct of the electricity industry in general, such as the Wholesale Electricity Market Guidelines (the Guidelines) (see Section IV.ii, infra).

CNH
The following are among the main responsibilities of CNH:

\( a \) to regulate and supervise exploration and extraction of hydrocarbons;
CNH has issued seven calls to tender for the award of exploration and extraction contracts in shallow and deep waters, and for some onshore blocks. Bidding guidelines and model contracts for each type of tender are prepared by SENER with technical assistance from CNH. Additionally, CNH has called two tender procedures for some blocks farmed out by Pemex, which were awarded in round zero.

**Energy Regulatory Commission (CRE)**

At present, and because of the amendments made to the Federal Constitution, CRE has taken on an important role in matters related to electricity, natural gas, hydrocarbons, oil products and petrochemicals.

CRE issues regulations and permits regarding the transportation and storage of hydrocarbons and oil products; transportation by pipelines and storage of petrochemicals; distribution of natural gas and oil products; regasification, liquefaction, compression and decompression of natural gas; trade and public sale of natural gas and oil products, and distribution of petrol and fuels for aircraft.

None of the activities referred to above may be carried out without prior authorisation and a permit from CRE.

In addition, CRE is in charge of issuing all permits related to electricity generation, and the qualified supply and small-scale distribution of electric power, among other things. Furthermore, it issues administrative regulations and methodologies to determine fees in connection with those activities.

**Industrial Safety and Environmental Protection Agency (ASEA)**

The main purpose of this regulatory entity, which is controlled by the Ministry of Environment and Natural Resources, is safeguarding people, the environment and industrial hydrocarbon facilities, including the safe decommissioning and disposal of facilities.

ASEA’s areas of control and supervision include activities related to oil and gas, natural gas, oil products and petrochemicals.

**Mexican Petroleum Fund**

The Mexican Petroleum Fund is in charge of obtaining, managing, investing and supplying revenues from allocations, as well as hydrocarbon exploration and extraction contracts, net of taxes.

The fund is a government trust created by the Ministry of Finance and Public Credit, as trustor, and Mexico’s central bank, the Bank of Mexico, as trustee, and is managed by three government representatives and four independent members.

One of the main purposes of the fund is to pay the compensation obtained from exploration and extraction activities to private companies and investors, according to the model contract and the terms and conditions set therein.
**CENACE**

CENACE is an impartial body responsible for the planning and operational control of the National Electricity System, as well as operating the wholesale electricity market and ensuring open access to the national transmission network and general distribution network.

**Natural Gas National Centre (CENAGAS)**

CENAGAS is an impartial body responsible for the management of the National Natural Gas Storage and Transportation System. Its purpose is to guarantee the efficient supply of natural gas throughout the country.

**ii Regulated activities**

Exploration and extraction activities will be carried out by means of contracts awarded by CNH through bidding procedures in which determined oil and gas fields are tendered. If a company is awarded a contract for a determined field, it enters into the specific type of contract to be used for that field (e.g., licence, production-sharing contract, income sharing, and services).³

Oil and gas downstream and midstream activities will be carried out through permits issued by SENER and CRE, as follows:

- **SENER**: for hydrocarbons, petrol and fuel import and export activities; treatment and refining of oil; and, process of natural gas; and
- **CRE**: transportation, storage, distribution, commercialisation and public dispensing of petrol.

Permits required for electricity industry activities are issued by CRE and CENACE, as follows:

- **CRE**: permits related to the generation, independent production, small-scale production, and the supply of electricity; and
- **CENACE**: permit to connect to the national distribution and transmission network.

Furthermore, for the development of new facilities, there may be additional requirements or federal, local or municipal permits needed, depending on the location, among them: (1) a construction permit; (2) a land-use licence; (3) an environmental impact assessment; (4) social impact studies; (5) a civil protection programme; (6) an air emissions environmental licence; and (7) an operational licence.

To develop energy projects, surface rights must be secured and, therefore, agreements with landowners must be executed. If a project is to be developed on agrarian or ejido land, certain requirements must be met in accordance with specific agrarian legislation and regulations.

**iii Ownership and market access restrictions**

Underground hydrocarbons are considered to be the sole property of the Mexican state and therefore, no private company may own them. Once hydrocarbons are extracted from the

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underground, they may be transferred to an exploration or extraction contractor depending on the contractual scheme applicable for the specific area from which the hydrocarbons were extracted (e.g., under licence contracts).

If an exploration or extraction of hydrocarbons contract is awarded to a foreign entity, one of the conditions of the agreement is Mexican residency for tax purposes, for which typically a Mexican entity is incorporated according to Mexican law and prior to formalisation of the exploration or extraction contract.

The requirement to get oil-related interests is by means of being awarded and exploration or extraction contract.

iv Transfers of control and assignments
Following CNH public tender procedures for the award of agreements for the exploration and extraction of hydrocarbons in shallow water, model agreements concluded in relation to upstream activities give the possibility of conducting the sale, assignment, transmission or any disposition of all or any part of the rights and obligations that derive from the agreements. Prior written authorisation is required from CNH, which will take into consideration the prequalification criteria that was considered for the original contractor.

Also, through entering into exploration or extraction agreements, the contractor is bound not to undergo, directly or indirectly, a change of control during the term of the agreements, without prior consent from CNH. The contractor also agrees to inform CNH of any changes in its capital structure, unless it is listed on the Mexican Stock Exchange.

With regard to other activities in the production chain (midstream and downstream), the new legal framework allows for the assignment of permissions granted by both SENER and CRE, provided that the licensees have obtained the prior corresponding approvals in such instances, and for which the following conditions must be met:

a the permit shall be in full force and effect;

b the transferor has fulfilled all its obligations; and

c the transferee meets all the requirements to be a permit holder and agrees to comply with the obligations under the permit that is the subject of the assignment.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling
Before the Energy Reform, Pemex, through its subsidiary body Pemex Gas and Basic Petrochemicals, owned the infrastructure that formed the integrated national natural gas storage and distribution system. Following the energy reform the newly created body CENAGAS owns and controls the system and as an independent administrator and manager is responsible for developing all related activities for the storage and distribution of natural gas.

SENER with the support of CENAGAS has issued a five-year plan to expand the national natural gas storage and transportation system. The plan includes more than 5,150 kilometres of gas pipeline and aims to:

a expand the system by 85 per cent by 2018;

b develop strategic social and commercial pipelines; and

c increase import capacity from 5 to 9Bcf.
According to the applicable legal provisions, participants in the natural gas industry may hold different permits for activities related to the transportation, distribution, storage, and commercialisation of natural gas if they meet the necessary requirements issued by CRE.

According to the Electric Industry Law (the Electricity Law), the public transmission and distribution of electricity are services provided by the government. The Federal Electric Commission (CFE), which before the energy reform was the sole actor in this industry, owns and participates throughout the chain of production by means of different subsidiaries created for this purpose.

Pursuant to the Electricity Law, activities related to the chain of production in electricity matters are carried out independently by these subsidiaries of CFE under conditions of strict legal separation between them.

### ii  Transmission/transportation and distribution access

Licensees that provide transportation and distribution services to third parties through pipelines, and that provide the storage of hydrocarbons, petroleum and petrochemicals, are obliged to provide open access to their facilities and services, with no discriminatory preferences, and subject to availability of capacity in their systems, according to the regulations issued by CRE.

Additionally, permit holders who have reserved capacity contracts and fail to exploit them or make them effective will be required to make them public and available in return for the authorised fees set by CRE.

In the electricity industry, distributed generation shall guarantee open access to the general distribution network, as well as access to the markets in which the power will be sold.

Additionally, CENACE, as manager of the electricity distribution and transmission system, must guarantee open access to the national network.

### iii  Rates

Fees related to the transportation and distribution of natural gas are determined by CRE by means of methodologies devised for those purposes. The fees are subsequently approved by CRE. Regulatory considerations related to fees will apply except for the activities related to public sale of liquefied petroleum gas, petrol and diesel.

Furthermore, terms and conditions for transmission, transportation and distribution activities are subject to prior approval by CRE. The terms and conditions will be part of the permit issue by CRE related to the above-mentioned activities. Terms and conditions reflect the common international practices for which they are being approved and must procure the competitive development of the markets while ensuring both the quality of services and that they are provided in an efficient, continuous and safe manner. Finally, as terms and conditions are part of the permit, when rendering their services permit holders may not agree conditions different from those approved.

Rates related to the selling of oil products have been liberalised by CRE, which has implemented, for such purposes, a liberalisation strategy that aims to set maximum selling prices by dividing the country into five different regions.

### iv  Security and technology restrictions

Although energy infrastructure has always been considered of strategic importance for the country’s development, and thus the focus of very tight coordination between the federal,
local and municipal authorities to protect and safeguard it, this coordination has not been affected by regulatory policies. All energy matters come under federal jurisdiction and there is no conflict, therefore, as to which authorities must attend to security and law enforcement.

Notwithstanding the above, for the past years there have been problems with criminal organisations, mostly in matters related to the illegal extraction and commercialisation of oil products from oil pipelines. As a consequence, new laws have been enacted by the Federal Congress to increase the criminal sanctions for those who participate at any point in the chain of illegal commercialisation of oil products.

Prior to the Mexican energy reform, all hydrocarbon and electricity infrastructure was solely owned by CFE and Pemex, and those government-owned companies, in coordination with the federal government, were in charge of securing all related infrastructure.

The law does not provide specific requirements for permit holders or exploration or extraction contractors in relation to security matters.

IV ENERGY MARKETS

i Development of energy markets

Certain energy-market activities, such as exploration or extraction of hydrocarbons, are subject to bidding procedures and may only be conducted following a bidding procedure and the award of a contract that allows private or government-owned companies to operate within a determined area or block.

Although CRE has already issued permits regarding the sale of oil products and some private companies have begun setting service stations throughout the country, the market, as it exists at present, is still dominated by Pemex franchises. This selling scheme has applied in Mexico for years, with Pemex as the sole participant in the exploration, extraction, refining, supply and distribution chain.

On the basis that the new legal framework for energy allows private participation throughout the productive chain, CRE has already issued permits for the commercialisation and public sale of oil products. As of 1 April 2016, imports of oil products and fuels into Mexico are permitted, and a new market related to these activities will emerge in the coming years.

Although the natural gas market is more organised and there are a vast number of private companies carrying on storage, distribution and sales of natural gas, it is important to bear in mind that first-hand sales of these products were also carried out previously exclusively by Pemex.

Organised electricity markets have just begun to emerge, with private participants starting to move into those areas of business permitted by law that, prior to the energy reform, were completely closed to private companies and foreign investment. Nevertheless, rules have already been set by SENER and calls to tender have been issued by CENACE for auction procedures to purchase and sell electric energy.

ii Energy market rules and regulation

Different regulations apply in the electricity and gas markets. For electricity markets, the main regulations are (1) the Electricity Law and its regulations; and (2) the Wholesale Electricity Market Guidelines (the Guidelines) issued by SENER.
The electricity market is regulated by CENACE. Pursuant to the Guidelines, individuals or companies that conclude contracts with this government body – as generators or commercial suppliers, among others – will be able to make transactions related to the purchase and sale of electric energy.

In the natural gas industry, CRE has issued a number of administrative rules with a view to regulating the market and the selling of natural gas products. Additional rules have also been issued by CRE in order to regulate downstream and midstream activities, mainly, for oil products (gasolines and diesel).

### iii Contracts for sale of energy

Market participants are permitted to enter into individual contracts for the sale of natural gas as long as the terms and conditions of such contracts comply with the requirements established in the corresponding legal provisions (i.e., terms and conditions, and fees related to natural gas, which must have the prior approval of CRE).

Consideration has to be given to the details of each particular power-related operation, such as the means by which power will be delivered to the purchaser, because, as has been mentioned, interconnection to the National Electricity System requires a permit from CENACE.

In some cases, permits will be required for sellers (e.g., for the commercialisation of natural gas, or electricity generation permits) or for buyers (e.g., for storage of natural gas), therefore it is always advisable to review any energy contract prior to concluding it.

### iv Market developments

The government’s strategy is to attract as many potential investors as it can to participate in all energy activities, including those related to hydrocarbons and electricity. This strategy is being coordinated by SENER and the Ministry of Finance and Public Credit, with CNH and CENACE preparing and carrying out all hydrocarbon bidding procedures and electric power auctions.

The main developments in Mexico’s energy markets concern oil and gas, as well as electricity. Seven tender procedures have been conducted by CNH resulting in the award of 38 exploration and extraction contracts, representing estimated investments of US$22.3 billion.

Additionally, CENACE has already concluded two electric auctions, following which approximately 33 companies have been awarded contracts.

### V RENEWABLE ENERGY AND CONSERVATION

#### i Development of renewable energy

The most significant development related to renewable energies is the issuance of the Energy Transition Law published in the Mexican Official Gazette on 24 December 2015. The main purpose of this law is to promote the sustainable use of energy and set obligations related to clean energies and the reduction of polluted emissions.

Some of the most relevant aspects of the Energy Transition Law include:

- to facilitate the gradual increase of clean energies in the electricity industry;

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4 www.diputados.gob.mx/LeyesBiblio/pdf/LTE.pdf.
b. to establish mechanisms promoting clean energies and to reduce air emissions; and
c. support for the objectives of the General Law on Climate Change.

The referred law provides that SENER must have as its main goal a minimum participation of clean energies for electricity generation of 25 per cent for 2018, 30 per cent for 2021 and 35 per cent for 2024.

As noted above, following the two auctions by CENACE of long-term supply and purchase contracts, several contracts related to electric power and clean-energy certificates have been awarded.

According to SENER, of the planned 2,085MW increase in Mexico’s electricity generating capacity 1,691MW will be related to solar energy projects, which will represent investments of at least US$2.6 billion.

Through the Energy Transition and Sustainable Use of Energy Fund, created to use and apply new technologies related to sustainable energy, new projects have been funded, including the solar-energy electricity-generation system installed in the state of Aguascalientes using 1,021 solar panels to supply energy for new electric vehicles that serve as public taxis in the city of Aguascalientes. This programme will help reduce CO2 emissions by 255 tonnes per year.5

ii Energy efficiency and conservation

The most significant change has been regarding the previously mentioned Energy Transition Law. This piece of legislation replaced the Development of Renewable Energy and Energy Transition Financing Law.

The current policies being implemented aim to attract investments to develop sustainable projects in Mexico and increase electricity generation by means of renewable energies.

According to SENER’s Renewable Energy Prospects 2015–2029, Mexico has a proven and probable generation potential of 100,278GW per year. Solar potential is considered as being practically unlimited in terms of national energy consumption.

All policies related to renewable energies are aligned with the purposes and goals of the National Energy Strategy 2014–2028 published by SENER.

iii Technological developments

The development of renewable energy projects continues to be promoted by the Mexican government. Additionally, private companies have shown increased interest in investing in projects within different Mexico states.

In Mexico, there is an important research network dedicated to renewable energy that includes both public and private sector participation: this consultative council on renewable energy has been established by SENER to analyse and promote new projects.

Additionally, the Electrical Research Institute (IIE) has also promoted several projects aimed at encouraging and supporting technological innovation in the electricity sector, including among energy sector suppliers and users, through applied research, technological development and specialised services.

5 www.sener.gob.mx.
The IIE offers technological support to investors and evaluates the performance of photovoltaic and concentrated solar radiation conversion systems for industrial electricity generators. It also studies the generation of hydrogen using renewables, and its conversion to electricity through the use of fuel cells.

VI THE YEAR IN REVIEW

The year 2016 was an important one for Mexico regarding the energy industry. One major tender procedure for the awarding of 10 exploration and extraction contracts in deep waters was concluded, with eight contracts awarded to international companies. One farm-out contract for a major block in ultra-deep waters of the Mexican Gulf was also concluded, resulting in one contract to exploit jointly with Pemex – the block known as Trion. Additionally, three calls for tenders were announced and are currently being conducted by CNH.

Many permits related to downstream and upstream activities, mostly regarding selling, commercialisation and storage of oil products and natural gas have been granted by CRE so national and international companies may carry out such activities throughout the territory. Mexico has been able to attract private companies not just to participate in the above-mentioned tender procedures, but also to invest in infrastructure for midstream and downstream activities.

In the electricity industry during 2016, the two long-term electric auctions were conducted by CENACE and several contracts were awarded for the purchase of electric power and clean-energy certificates.

During 2016, CRE issued a vast number of administrative regulations in connection with the oil, gas and electricity industries, which together comprise the new legal framework for energy applicable to those industries in Mexico, and which will provide investors with legal certainty in connection with their activities in the country.

VII CONCLUSIONS AND OUTLOOK

As will be evident from this chapter, Mexico has great potential for investment in the oil, gas and electricity industries on account of having a considerable availability of resources.

The new Mexican energy legal framework was almost completed during 2016. The coming years will be important years for the industry in Mexico, since the hydrocarbon contracts awarded to private companies will be implemented and additional tender and auction procedures will be called, resulting in more contracts.

Additionally, the electricity contracts that have already been awarded will also be implemented in the coming years.

Important challenges may yet lie ahead for the full implementation of the energy legal framework, such as securing the surface rights needed to develop onshore fields for exploration and extraction of hydrocarbons, or to develop new infrastructure such as gas and oil pipelines. Nonetheless, Mexico is now prepared to welcome foreign investments and companies to implement one of its most significant constitutional reforms.
Chapter 24

MOZAMBIQUE

Fabrícia de Almeida Henriques and Paula Duarte Rocha

I OVERVIEW

Mozambique is a rapidly developing country with great potential for the production and export of hydrocarbons and the generation of electrical power.

However, legislation in energy matters is only now trying to keep up with the pace of the growing complexity of the energy investments being made in the country, and the aspiration of establishing specific incentives for the generation of renewable electricity and for off-grid power initiatives in non-urban and ‘peri-urban’ communities. The framework of the electricity sector, the Electricity Act, for instance, is over 15 years old. A regulatory overhaul in the electricity sector is said to be in the pipeline and the new legislative framework for oil, approved by Law No. 21/2014 of 18 August, has, after several years in the pipeline, finally been enacted.

Other legislation recently enacted in the oil and gas sector, includes, notably, Decree No. 45/2012 of 28 December, relating to the production, import, loading, storage, handling, distribution, sale, transport, export and re-export of petroleum products (the Petroleum Products Regulation), and Decree-Law No. 2/2014, relating to the specific legal and contractual regime applicable to projects in the Rovuma Basin.

The electricity sector is a concession-based system with limited competition, in which one company, state-owned Electricidade de Moçambique, EP (EdM) is the national transmission grid operator, and also holds concessions for generation, transmission, distribution and supply of electricity. Other notable concessionaires include Hidroeléctrica de Cahora Bassa SA, which produces most of the energy consumed in Mozambique, and MoTraCo SA, a joint venture between the Mozambican, South African and Malawian governments, which transmits power from South Africa to the Mozal aluminium smelter.

The oil and gas sector also has a concession system, where operating risks from the exploration of hydrocarbons are mostly borne by private investors. Empresa Nacional de Hidrocarbonetos EP (ENH) operates mainly in the upstream sector and holds participations in all oil and gas fields concessions in Mozambique. Recent years have witnessed very significant discoveries of natural gas, which have attracted several oil and gas market participants to the country and transformed the upstream industry.

\[^1\] Fabrícia de Almeida Henriques and Paula Duarte Rocha are partners at Henriques, Rocha & Associados, member of MLGTS Legal Circle as Mozambique Legal Circle.

\[^2\] Law No. 21/97 of 1 October.
In the petroleum products sector, there have been recent legislative attempts at creating an unbundled and competitive market. State-owned company Petróleos de Moçambique SA (Petromoc) is active in the midstream and downstream sector, storing and selling petroleum derivatives such as fuels, oils and lubricants.

The latest and most detailed instrument of government policy for the energy sector is contained in Resolution No. 10/2009, of 4 June (the Energy Strategy), in which one can find the main policy goals defined by the Mozambican government in this matter, notably:

a to provide greater access to electricity and fuels to rural and peri-urban areas;

b to discourage the non-sustainable use of lumber as a source of energy;

c to stimulate the sustainable production of biofuels;

d to diversify energy sources;

e to implement a cost-based tariff system, one that includes environmental externalities; and

f to engage in international cooperation, especially with the Southern African Development Community (SADC).

Other important policy resolutions for the government can be found in (1) Resolution No. 27/2009 of 8 June, which adopted the Strategy for the Concession of Areas for Petroleum Operations; (2) Resolution No. 62/2009, of 14 October, which adopted the Policy for the Development of New and Renewable Energies; and (3) Resolution No. 64/2009, of 2 November, relating to the Strategy for the Natural Gas Market in Mozambique.

II REGULATION

i The regulators

The most relevant administrative entities regulating the Mozambican energy industry are:

a the Council of Ministers, for all sectors of the energy industry;

b the Ministry of Natural Resources and Energy, for all sectors of the energy industry;

c the National Electricity Council (CNELEC), for the electricity sector; and

d the National Petroleum Institute (INP), for the oil and gas sector.

The Council of Ministers represents the executive branch of government in Mozambique and, as such, the Constitution and main legislative diplomas in this sector grant it substantial powers in this field. Pursuant to the terms of the Constitution, the Council of Ministers may propose or enact legislation and promote and regulate economic activity. Making use of these powers, the Council of Ministers has adopted the vast majority of energy legislation in Mozambique.

In addition to the powers of legislation and regulation, the Council of Ministers has regulatory powers set out in the law, such as the granting of concessions (after the applicable tender offer) for electricity projects with nominal installed capacity of over 100MVA, according to the terms of Decree No. 8/2000 of 20 April (the Energy Concessions Regulation).

The Ministry of Natural Resources and Energy, as part of the central government, also has important powers in what the energy sector in Mozambique is concerned, defined in Presidential Decree No. 21/2005, of 31 March, such as in adopting regulations in the energy sector and licensing the activities of storage, distribution, supply and sale of natural gas and petroleum products, as well as the granting of concessions of electricity projects with nominal installed capacity between 1MVA and 100MVA. More importantly, the Ministry of
Natural Resources and Energy is the entity that instructs and (in tandem with the Council of Ministers) decides on concession requests for electricity and oil and gas projects, and monitors the activities of the concessionaires.

CNELEC is the regulatory body for the electricity sector and its powers, mainly set out in the Electricity Act and Decree No. 25/2000 of 3 October, include:

- promotion of compliance with legislation in the electricity sector;
- issuance of opinions on a variety of issues, such as expropriation proposals for electric facilities' projects, new concessions and tariffs;
- performing studies on different aspects of the electricity sectors; and
- participation and supervision of public tenders for electricity concessions.

CNELEC also has mediation and arbitration functions for disputes arising between concessionaires and their respective consumers.

Finally, the INP has its powers set out in Decree No. 25/2004 of 20 August, categorised as:

- management of National Petroleum Database;
- research activities;
- powers relating to petroleum development, production and transport activities;
- powers relating to the safekeeping of operators interests; and
- general powers of administration, monitoring and regulation.

The INP also has powers to license as well as inspect any facilities relating to petroleum operations.

As for the applicable sources of law, the main framework legislation both in the electricity and in the oil and gas sectors is enacted in the form of law of the Mozambican parliament (the Electricity Act and Law No. 21/2014 of 18 August, the Petroleum Act). This legislation is implemented largely in the form of Decrees adopted by the Council of Ministers. Finally, the Ministry of Natural Resources and Energy may also issue orders.

ii Regulated activities

All activities in the electricity value chain (generation, transmission, distribution and supply) and most activities in the oil and gas value chain (prospection, research and production and transport of oil and natural gas, as well as the distribution and supply of natural gas) are subject to a regulatory approval by the Ministry of Natural Resources and Energy, the Council of Ministers or local authorities, depending on what is established in the applicable law, in the form of a concession agreement. Activities in the petroleum products value chain (production, storage, transport, distribution and sale, as well as the operation of unloading terminals and oil pipelines) are subject to licensing by the Ministry of Natural Resources and Energy in accordance with the terms of the Petroleum Products Regulation.

Energy facilities across all sectors are also subject to licensing, pursuant to the terms of the relevant legislation.

Concessions in the electricity sector are subject to tender offers, in accordance with the Energy Concessions Regulation. Tenders must follow the guidelines set out in the terms of reference and are directed to the relevant competent authority (i.e., the Council of Ministers).
Ministers, the Ministry of Natural Resources and Energy or local authorities). Tenders must also specify the technical and financial details of the project and provide sufficient evidence of the appropriate qualifications of the applicant. Hydroelectric projects require additional information on the characteristics of the hydroelectric use of the water resources; energy generation and transport concessions are also subject to additional requirements.

After the tender has been requested, CNELEC issues an opinion on the subject; projects that imply the acquisition of land-use rights must also be preceded by a public consultation. After these steps have been undertaken, a decision by the relevant regulatory authority must be issued within 15 days. The effectiveness of this decision may be subject to conditions, such as expropriation or the granting of land-use rights.

A favourable decision by the authority will determine the entering of a concession agreement, where terms such as duration, applicable taxes and tariffs, conflict resolution mechanisms, guarantees, reversion and applicable law must be included. The concession agreement must also include a draft of the agreement to be signed by the National Transmission Network operator.

Electricity facilities are also subject to the granting of establishment and operation licences by the Ministry of Natural Resources and Energy prior to the start of operations. For the establishment licence, technical features of the facilities must be presented with the application, which must be decided within 15 days, except if additional documents or information are requested by the Ministry of Natural Resources and Energy. If granted, the publication of an edict in the Official Gazette will ensue and the project for the construction of the facility may begin. At the end of construction, a site visit accompanied by a favourable opinion from the competent inspector is required for an operation licence to be issued.

Concessions pertaining to hydrocarbons prospection, research and extraction or construction and operation of pipelines are also subject to tender offers, according to the terms of Decree No. 34/2015 of 31 December (the Petroleum Operations Regulation). Exceptions are made for tender offers in which no bidder has been chosen, termination of concession, or unitisation purposes, among others. In such cases, the Decree stipulates that a concession agreement may be attributed via a direct or simultaneous negotiation with applicants.

In the sale and distribution of natural gas, the competent authority to grant a concession depends on the area for distribution or sale awarded pursuant to the terms of Decree No. 44/2005 of 29 November through a tender offer. As in oil and gas upstream concessions, the procedure for the awarding of a concession is also not regulated in the diploma.

Licensing of oil or gas facilities must include an establishment licence, requested from the INP, which has 10 days to make its decision upon receipt of the necessary information and documents, as well as the opinion of various regulatory entities such as for health, environment, labour and civil protection. The operation licence is then granted after construction, and a site visit made by a committee, which will confirm whether the facility conforms to the project, any regulatory conditions and applicable technical norms.

Finally, licensing of activities relating to petroleum products and the corresponding facilities is subject to the approval of the Ministry of Natural Resources and Energy, except for licensing of fuel stations for resale and sale to end users, which is carried out by the local

4 Such procedure simplified by the provisions of Decree No. 10/2016 of 25 April.
5 A ‘model’ or ‘draft’ concession agreement for research and exploration of oil was implemented by Resolution of the Council of Ministers No. 25/2016 of 3 October.
authorities and by the provincial directorates of the Ministry of Natural Resources and Energy, respectively. Licence requests must be accompanied by several elements of identification, as well as the main technical characteristics of the facilities at which the activities will be undertaken; different activities entail specific documentation or information, which must be presented with the request. The licensing entity must decide within a period of 30 days from receipt of the request, and is bound by certain criteria to overrule it, such as the occurrence of anticompetitive effects stemming from the granting of the licence. Licences may be subject to conditions to be defined by the relevant licensing entity.

Before the start of operations of any of the aforementioned activities in the petroleum products fuel chain, licences must be registered after a mandatory site visit, to be carried out by a commission that includes representatives of various regulatory authorities, including the licensing entity.

iii Ownership and market access restrictions

In the electricity sector, there are no obvious limitations on the ownership of both new and existing assets and companies in this business sector, nor direct restrictions on asset ownership save for the general merger and takeover control provisions introduced in Law No. 10/2013, enacted on 20 March 2013 (the Competition Act), the scope of which is the protection of competition in the undertaking of economic activities. Preference, however, is given to applicants for oil or natural gas concessions that are Mozambican nationals or are associated with Mozambican nationals if two or more applicants are on equal footing.

In the petroleum products sector, however, several restrictions of this nature exist, set out in the Petroleum Products Regulation, the most relevant being:

a. the prohibition of the mingling of distribution and retail activities, except when it relates to liquid petroleum gas (LPG) or compressed natural gas and for training purposes (undertaken in fuel stations);

b. licensed entities may be entitled to hold more than one licence in the value chain, as long as no anticompetitive effects stem from this situation; and

c. only Mozambican nationals and Mozambican companies may hold licences for petroleum products (there appears to be no restrictions for Mozambican companies held by foreign equity holders, however).

There are no restrictions on the provision of regulated services (i.e., supply of electricity and natural gas) and no restrictions on the ownership of assets or licensed activities other than those set out in the previous paragraph.

iv Transfers of control and assignments

Transfer of interests in electricity concessions, of assets encompassed by an electricity concession and of establishment licences of electricity facilities are subject to regulatory approval by the regulatory authority that granted the concession or the licence, according to the terms of the applicable Mozambican law. Transfer of operation licences of electrical facilities is not possible under Mozambican law and, as such, should the licensee change, a new licence will have to be issued pursuant to the terms of Decree No. 48/2007 of 22 October.

The procedure for the transfer of concession rights or assets encompassed by the concession itself is not clear in either the Electricity Act or the Electricity Concessions Regulation, but will likely depend on a request submitted to the relevant regulatory authority and, if land-use rights are transferred, a public consultation, the same as with the granting of
a new concession. In respect of establishment licences, the transfer will be subject to a request to the Ministry of Natural Resources and Energy. No express standards for reviews or decision-making guidelines are established in these procedures for the regulatory authorities, but such authorities in Mozambique are, according to the Constitution, bound by principles of equality, impartiality, ethics and justice.

With regards to the transfer of interests in oil or natural gas concessions, the new legislation makes direct and indirect transfers of the concession subject to prior governmental approval, along with other forms of assignment of participation interests, directly or indirectly, in concession agreements, including the transfer of shares or other forms of participation of the holder of concession rights.

As for the petroleum products sector, transfer of facilities in the corresponding value chain is subject to prior authorisation from the Minister of Natural Resources and Energy, who is bound to grant it if the licensee does not obtain, after the transaction, more than a 30 per cent market share of the relevant petroleum products market.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Shortly after the independence of the Republic of Mozambique from Portugal in 1975, EdM was granted, by Decree Law No. 38/77, a quasi-monopoly in the generation, transmission and distribution of energy, with the exception of off-grid generation and other existing concessionaires (notably the Cahora Bassa dam, albeit not in operation at the time). The result was a fully integrated vertical system in the electricity sector until the adoption of the Electricity Act. Nowadays, the sector is still bundled to some degree, as EdM still holds a single concession for distribution and sale of electricity. It is the main transmission concessionaire, as well as the national transmission grid operator, through the provision set out in Decree No. 43/2005 of 29 November, as unbundling requirements in this sector do not exist under Mozambican law.

With regards to oil and natural gas, there is also no formal bundling or concentration of the upstream industry, notwithstanding the fact that ENH is a party to all concessions in the upstream sector.

Recent efforts towards the implementation of networks for distribution and sale of natural gas have been made, and the law determines that concessions must be unbundled. Concessions for suppliers of natural gas are further subject to an exclusivity period, after which third parties may sell natural gas to end-consumers.

ii Transmission/transportation and distribution access

Operators of storage, transport, transmission and distribution networks are obliged to provide access to these networks and to practise non-discriminatory treatment of third parties.

In the electricity sector, the Electricity Act provides for the mandatory granting of access to third parties to electrical networks. Decree No. 42/2005 of 29 November (the National Transmission System Regulation) establishes that transmission concessionaires must enter into agreements for the transmission of electricity to any generation and distribution concessionaire, and to any final consumer that requires connection to the grid. Likewise, distribution concessionaires must guarantee the supply of electrical energy to all consumers who have the capacity to ensure payment for their respective connections. Connection may be refused only in certain cases; for example, where the supply is in medium or low voltage
and the requested capacity may cause damage to the distribution grid, or if the applicant is declared insolvent or bankrupt. Distributors also have the obligation to install new lines whenever so required (as long as a minimum consumption per 100 metres of new distribution lines is assured). Access to transmission and distribution grids must be made in a non-discriminatory fashion regarding quality of service and agreed-upon tariffs.

Pipelines and petroleum product facilities must also transport, store, unload or handle hydrocarbons or fuels from third parties without discrimination, as long as there is available capacity and no insurmountable technical issues exist. Furthermore, capacity must be increased if such an operation does not affect the integrity of the facilities and as long as those third parties provide the necessary funding. Access to natural gas distribution networks, on the other hand, is subject to rules for negotiated access to be enacted by the Minister of Natural Resources and Energy. In any case, all activities must be conducted with transparency and without discrimination against third parties.

Network providers in distribution and transmission of energy, as well as distributors of natural gas, are granted rights over a predetermined area. The law is not clear, however, on whether the rights are exclusive.

Finally, competition concerns have definitely played a role in the rules concerning third-party access to energy networks. Council of Ministers’ resolutions regarding energy policy mention tackling competition issues, which necessarily implies dissipating the negative effects of ‘bottlenecks’ for consumers by giving suppliers ease of access to electricity and natural gas networks. A general provision on the matter has been implemented by the Competition Act regarding the abuse of a dominant position.6

iii  Terminalling, processing and treatment

Storage, processing and treatment of oil and natural gas, as well as the storage of petroleum products, are subject to licensing of the activity and registration of the respective facilities (see Section II.ii, supra). There does not appear to be any specific regulation on liquefied natural gas facilities.

iv  Rates

As a general rule, rates for transport and distribution of energy are mostly determined by bilateral contracts rather than regulated tariffs (which are only set for the sale of electricity, natural gas and fuels to the end-consumer). There are, however, standards that some concessionaires must consider when setting the fees for the rendering of their services.

Nonetheless, the Electricity Act in the electrical sector establishes a ‘transit tariff’ for third-party use of transmission and distribution facilities, which is not regulated. The National Transmission System Regulation determines that contracts entered into with transmission concessionnaires must set rates that:

a assure non-discriminatory treatment of consumers;
b assure the coverage of costs consistent with ‘standard costs’;

6 Article 19(3)(b) of the Competition Act establishes that the following is considered an abuse of a dominant position: the refusal by a company to grant to any other company, for adequate compensation, access to a network or other essential infrastructure that the first company controls as long as the other company cannot, for legal or practical reasons, operate as a competitor of the company that controls the assets at issue. This provision is not applicable if the company that controls the assets at issue demonstrates that such access is impossible under reasonable conditions.
c stimulate new investment in the expansion of electrical systems;
d induce the use of electrical systems; and
e minimise the costs for expansion or use of electrical systems.

As for distribution, rates are fixed with generation and energy supply concessionaires. For the latter, a tariff for use of the distribution system must be set.

Oil and gas pipelines are subject to tariffs set in the relevant concession agreement and are based on the following principles:
a the tariff is to contemplate total reserved capacity for the infrastructure;
b the tariff shall include the cost of capital and operational costs;
c the tariff shall take profitability into account, which must not exceed the designated rate of return.

Petroleum product storage facilities are subject to ‘non-discriminatory’ and ‘commercially acceptable’ terms in the setting of use rates. In oil re-exporting services (in bunkers), rates must be fair, competitive and non-discriminatory, taking into account the prices charged in other terminals in Southern Africa.

Natural gas distribution network rates are set by concessionaires, subject to the rules of negotiated access set by the Minister of Energy.

v Security and technology restrictions

Energy legislation in Mozambique takes into account several security policy concerns, such as:
a fuel supply security and safety;
b theft of energy and theft and vandalism of power lines; and
c energy supply and network security.

As regards supply security and safety of hydrocarbon fuels supply (e.g., petrol), the Petroleum Products Regulation addresses safety concerns regarding petroleum product facilities by imposing several obligations on their respective owners, such as:
a the obligation of distributors to keep a permanent deposit of 6 per cent (or 3 per cent, in the case of LPG) of the fuels acquired for sale in the previous 12 months, as well as ‘operational reserves’ of the aforementioned fuels;
b the mandatory decommissioning of redundant petroleum product facilities;
c specialised works on petroleum products’ facilities being conducted or supervised by licensed oil technicians;
d the obligation to be subject to a five-year inspection obligation on petroleum product facilities; and
e the prohibition on causing or allowing oil or petroleum product spills.

The Energy Strategy expressly issues recommendations for tackling the problem of theft and vandalism in the electricity networks, notably by advocating greater involvement of local communities in distribution and transmission power lines projects. Notwithstanding the foregoing, the Electricity Act establishes the theft of electricity or power lines as a crime.

Security of electricity supply is also a relevant concern in energy policy and the National Transmission System Regulation provides relevant rules on this subject. First, capacity of transmission and distribution networks must be adequate in relation to expected
consumer demand. Solely regarding the distribution grid, the National Transmission System Regulation obliges distribution concessionaires to ensure service quality and supply of energy through the grid may only be interrupted under certain conditions. Finally the operator of the National Transmission System, as the coordinator of the electricity grids in Mozambique, has the obligation regarding the overall management of the system’s quality, security and continuity of supply.

IV ENERGY MARKETS

i Energy market rules and regulation
There are no organised markets for the sale of energy commodities in Mozambique. The import and export of electricity is subject to a concession, to be granted according to the terms of concessions for the generation, distribution or transmission of electricity (see Section II.ii, supra).

With regards to petroleum products, imports of LPG, gasoline, jet fuel and diesel are aggregated through IMOPETRO, a company under both state and private ownership, and customers of this entity must be holders of generation or distribution licences. In exceptional cases (e.g., to ‘defend the country’s economic interests’) imports may be made through a duly licensed distributor and only if and when local production does not meet demand.

ii Contracts for sale of energy
The sale of electricity and natural gas in Mozambique takes place exclusively through bilateral agreements between generators and suppliers.

iii Market developments
As mentioned above, the electricity market is expected to undergo a regulatory overhaul, and statutes for petroleum operations and the fiscal treatment thereof were approved by parliament in August 2014. These statutes define new rules regarding state participation in oil and gas projects, introduce local content obligations and introduce changes to royalties and taxes payable for the production of oil and gas. One change worth noticing in particular is the government’s obligation to ‘allocate’ to the Mozambican market a quota of at least 25 per cent of the oil or gas, or both, produced and sold in Mozambique.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy
Mozambique has seen timid, yet steady, development in renewable energies, notably solar energy. In this regard, it is worth noting that a few solar power plant projects are under development and construction and that, also, a solar panel factory sponsored by the Mozambican Electricity Fund is currently operating in the city of Matola, next to Maputo.

The Council of Ministers enacted the Policy for the Development of New and Renewable Energies. Its main objective is to promote greater access to clean energy through the equitable, efficient, sustainable and culturally sensitive use of new and renewable energy.

Additionally, the Regulation that Establishes the Tariff Regime for New and Renewable Energies was approved by Decree No. 58/2014 of 17 October. This statute sets out feed-in
tariffs remunerating the electricity generated by: (1) biomass power plants; (2) wind farms; (3) mini-hydro power plants; and (4) photovoltaic power plants with an installed capacity of up to 10MW and that comply with eligibility requirements defined in the diploma.

**ii Energy efficiency and conservation**

The aforementioned Renewable Energy Development Policy also approaches energy-efficiency issues but, as in the area of renewable energy, no rules or policies have yet been enacted to promote it.

**iii Technological developments**

Encouragement of greater technological developments in the field of renewable energies has recently taken place through the creation of a laboratory for photovoltaic energy, the first in the field of renewable energies in Mozambique.

**VI THE YEAR IN REVIEW**

Key events in the energy sector in 2016 for Mozambique included:

a the enactment of a model concession agreement for upstream activities in the oil and gas sector;

b BP and the promoters of the Area 4 Rovuma Basin entering into a long-term agreement for the purchase and sale, respectively, of LNG;

c the inauguration of a floating power plant in the North of Mozambique;

d the launching of project BRILHO by the Mozambican government, a project designed to develop rural communities through improved cook stoves, electrification through mini-grids and installation of solar household systems; and

e although not directly related to the energy sector, the country’s government deficit woes, resulting in the provisional suspension of foreign assistance from international institutions, have affected the economy as a whole.

**VII CONCLUSIONS AND OUTLOOK**

The Mozambican energy sector faces a multitude of challenges, outlined throughout this chapter:

a the country’s infrastructure is not sufficient to meet demand, which is reflected in the fact that large areas of the country are without electricity or natural gas, and electrical power distribution networks are outdated;

b because of the inefficient power purchase arrangement with South African utility company Eskom, Mozambique still has to ‘import’ electrical energy from its own hydroelectric power plant in Cahora Bassa; and

c Mozambique’s oil and gas findings require a stable governance structure, and experienced participants in the oil and gas industry, for commercial development of the findings to begin. The enactment of the new Petroleum Act and the approval of corresponding regulations (including regulations specific to projects located in the Rovuma Basin) may aid the achievement of this goal.

These problems are being tackled, but most are very capital-intensive. Electrification of rural areas, promoted by the Mozambican Electricity Fund by way of small distribution networks,
off-grid projects and small renewable energy generation, and the various electricity generation projects that are being planned for this decade, are both examples of how the country is dealing with some of these issues.

Once these obstacles are finally overcome, Mozambique, with its abundant natural resources and strategic geographical position in the region, will doubtless stand poised to become one of the key players in the sub-Saharan Africa energy market.
Chapter 25

NETHERLANDS

Roland de Vlam and Max Oosterhuis

I OVERVIEW

The Netherlands has a large and strong energy industry that generates an annual output of around €40 billion; more than 7 per cent of the Dutch GDP and more than 100,000 employment years. The Netherlands has an innovative and powerful gas industry, while Dutch seaports have a strong position in the transhipment of fossil fuels and related industrial activities (refining, chemicals, electricity generation). The Netherlands also has specific strengths in the area of sustainable energy technology, with an above-average share, measured by turnover, in the European market in the biochain, offshore wind and solar PV sectors. This is partly thanks to the presence of traditionally strong adjacent markets such as the semiconductor industry (solar PV), the agricultural sector (biochain) and the offshore sector (wind power). Additionally, the Netherlands has a number of strong industrial clusters, such as Energy Valley in Groningen and the Port of Rotterdam.

Following the discovery in the early 1960s of the Groningen field in the north of the Netherlands – one of the largest reservoirs in continental Europe – the Netherlands has grown to be a significant gas country in Europe and the biggest gas producer within the European Union. Broadly, 25 per cent of all European natural gas reserves are located in the Netherlands, accounting at the end of 2014 for 0.4 per cent of the global natural gas reserves in the world.

The system by which the Dutch gas sector is organised is often referred to as the ‘Gas Building’. The Gas Building was erected following the discovery of the Groningen field and the full appreciation of its magnitude. A field lifetime production licence for the Groningen field was granted to Nederlandse Aardolie Maatschappij (NAM), a 50/50 joint venture between Shell and ExxonMobil, subject to the condition that NAM entered into a general partnership (the Maatschap Groningen) with the state-owned participating company, currently named Energie Beheer Nederland (EBN). In this partnership, the State took a 40 per cent financial share and NAM 60 per cent, although the voting rights remained 50/50. The Maatschap Groningen entered into a gas sales agreement with NV Nederlandse Gasunie (Gasunie), a joint venture of Shell and ExxonMobil (25 per cent each) and the Dutch State (10 per cent + 40 per cent via EBN) for the entire gas production from the Groningen field. Gasunie, and upon the unbundling in 2005: GasTerra, was made responsible for the marketing and distribution of the gas with priority for gas produced from small fields. This ensured the maximum coordination of production and marketing of the Groningen gas and gas produced

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1 Roland de Vlam is counsel and Max Oosterhuis is a partner at Loyens & Loeff NV. The authors wish to thank Yu An Chan for her work on this chapter.
from small fields. This public/private system of central marketing has been applied ever since to gas production in the Netherlands. EBN takes a 40 per cent stake in the proceeds and producers are entitled – not obligated – to sell the produced gas to GasTerra.

The Dutch market for power generation is fully liberalised. The power generation market is dominated by four foreign energy companies: Essent (owned by RWE); Nuon (owned by Vattenfall); E.ON; and Engie. Other large-scale generators are EPZ, EDF/PZEM NV and new entrants CCI and GSO Capital. Decentralised generation (mainly cogeneration) and imports are other important power sources.

The market for supply of gas and electricity has been fully liberalised since 2004. All customers are entitled to choose their supplier. There are currently over 50 active suppliers of electricity and gas in the Netherlands.

Transmission and distribution of power and gas are subject to strict regulation. The national high-pressure gas transmission system is owned and operated by GTS, a 100 per cent state-owned company. The gas transmission system is interconnected with Germany and Belgium and via the BBL interconnector (Bacton-Balgzand Line) with the United Kingdom.

The national high-voltage (100kV and higher) transmission system is operated by TenneT, also a 100 per cent state-owned company. Seven interconnectors link the national power transmission system to Germany (three), Belgium (two), the United Kingdom (BritNed) and Norway (NorNed). New interconnection capacity is scheduled to become available between the Netherlands and Germany (Wesel, 2017) and between the Netherlands and Denmark (Cobra Cable, 2019). In addition, two connections with Norway are in the planning stage. TenneT is also the owner of a large part of the German transmission system, formerly owned by Transpower.

Regional gas and electricity systems are operated by nine regional system operators that are owned (directly or indirectly) by regional and local authorities (provinces and municipalities). Third-party access to the systems is regulated in the Electricity Act 1998 and the Gas Act.

Heat distribution to small-scale consumers is regulated by the Heat Act, which entered into force on 1 January 2014 but is to be overhauled already 2017–2018 (see Section I.i, infra).

I Legislation
The Mining Act provides the legislative framework for the licence regime and state participation in the exploration and production of minerals and geothermal heat, and for underground storage of minerals and CO2 onshore in the Netherlands, and offshore in the Dutch part of the continental shelf underlying the North Sea. The Mining Act applies to minerals to the extent that these occur at a depth of more than 100 metres. In December 2016, the Mining Act was amended, among other things, to implement the EU Offshore Safety Directive as well as to regulate the evidentiary presumption in relation to damages to gas extraction in Groningen because of earthquakes (subsequently amending the provisions on damages and liability in the Dutch Civil Code). Not all parts of the approved bill entered into force directly.

Dutch midstream and downstream energy legislation implements the EU Directives regarding the internal energy markets (the EU Third Package), as laid down in the Electricity Act 1998 and the Gas Act and secondary legislation including the relevant governmental decrees and ministerial orders.
In addition, detailed regulations are elaborated in network codes determined by the Dutch regulator (the Authority for Consumers and Markets (ACM)). These Codes provide secondary legislation on tariffs, technical conditions and procedures with respect to *inter alia* system access, system operation and measuring services.

In previous contributions, we have reported on a complete overhaul of the Electricity Act 1998 and the Gas Act with the submission of a bill under the project name STROOM. However, this STROOM bill was rejected by the Senate in December 2015 on the controversial ownership unbundling provisions (see Section Vi, *infra*). A new legislative proposal to amend the Electricity Act 1998 and the Gas Act with the objective of facilitating the national energy transition was submitted to parliament on 8 December 2016. At the time of writing, parliamentary debate had been put on hold pending the formation of a new government.

The Heat Act entered into force on 1 January 2014. The objective of the Heat Act was to offer protection to small-scale captive consumers connected to a heat distribution system. It regulates the price of heat supply by means of a price cap equivalent to the reference price of individual gas-fired heating. The Act has been heavily criticised by end users, suppliers and even the ACM. A complete revision of the Heat Act commenced in 2016. Earlier, on 2 April 2015, the Minister of Economic Affairs (MEA) published his ‘Heat Vision’, announcing this review to include research into the possibility of a new market model and regulation of the whole heat chain from supply to end user. The Heat Vision letter was followed by a letter from the MEA of 17 February 2016 providing the outlines for the new policy to be laid down in a completely revised Heat Act. A draft bill for this act was published for public consultation in July 2016. The draft bill proposes several amendments to resolve major bottlenecks in the current Heat Act, such as the applicability of the law to parties other than energy companies such as associations of home owners. Other amendments regard the heat tariff methodology, compensation for disruptions and third-party access for heat producers (not suppliers). As is the case with the new legislation for electricity and gas, preparation of the new Heat Act has been suspended pending coalition negotiations following the 2017 elections.

II REGULATION

i The regulators

The Mining Act assigns principal regulatory powers in upstream oil and gas, apart from those involving the environment and spatial planning in general,2 to the MEA and the State Supervision of Mines (SSM). The Mining Act provides that the Competition Act also applies to offshore mining activities; as such, the regulatory powers of the ACM pursuant to the Competition Act indirectly extend to the offshore industry as well. The SSM falls under the competence of the MEA. Two statutorily established advisory bodies – the Mining Council and the Technical Committee on Soil Movement (TCB) – complete the main structure of decision-making, supervisory, enforcement and advisory bodies in upstream oil and gas.

The ACM is the designated regulator pursuant to the Electricity Act 1998, the Gas Act and the Heat Act. The ACM is assigned with supervision of compliance with these acts as well as the EU Regulations 714/2009, 713/2009 and 1227/2011. With respect to supervision of

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2 Licence holders are subject to various requirements in respect of, *inter alia*, waste water discharges. Compliance with these requirements is monitored by the SSM and enforced by the MEA.
transmission and distribution, the ACM has been designated to determine the Tariff Code and the Technical Codes, the tariff methodology and (maximum) tariff decisions. Further, the ACM is assigned the task of dispute resolution between system operators and customers. The ACM has considerable powers to sanction infringements of the Acts, including the possibility to impose orders subject to a penalty or administrative fines.

Certain regulatory powers in the Electricity Act 1998 and the Gas Act are assigned to the MEA, including the power to adopt secondary legislation by Ministerial Decree and consent. The MEA must publish an Energy Report at least every four years, giving guidance on decisions to be taken by the Dutch government with respect to a reliable, sustainable and affordable energy supply including the governmental view on energy in the long run. The Energy Report 2015 was published in January 2016 and has its main focus on energy transition. This is one of the key policy objectives of the Dutch government (and of the MEA in particular).

Furthermore, the MEA is charged with the general supervision with respect to the transmission and distribution systems. The designation of a network operator is subject to the MEA’s consent. In events of non-performance, the MEA may decide to appoint a silent trustee or to rescind the designation of that system operator and have it replaced by a different system operator.

ii Regulated activities

With respect to mining, licences are required for exploration and production activities, for (underground) gas storage activities and for (underground) CO2 storage activities. They should be applied for with the MEA under the Mining Act. Applicants must demonstrate the financial and technical capability to execute the relevant mining activities. The licensee is responsible for the prudent development of minerals and the removal, upon depletion, of the mining works. In the event of multiple applicants for an exploration licence for one area, the licence is awarded to the joint applicants and one of the applicants is designated as ‘operator’. Liquefied natural gas (LNG) facilities are regulated under the Gas Act. The same applies for underground gas storage in as far as the services are technically or economically necessary for efficient access to the system for the supply of end consumers.

No licences are required for power generation in the Netherlands under the Electricity Act 1998. A specific licensing regime applies to offshore wind power generation, pursuant to the Offshore Wind Energy Act (OWEA), which entered into force on 1 July 2015 (see Section V, infra). Applicants must present a full financing, technical and economic plan for the realisation of an offshore wind farm, and licences are awarded only to the winner of the related subsidy tender.

The market for supply of gas and electricity has been fully liberalised since 2004. All customers are eligible to choose their supplier. No specific licensing is required for supply of gas or electricity except for the supply to small-scale end users. Small-scale end users are defined in the Electricity Act 1998 and the Gas Act as users with a connection of maximum 3x80A (electricity) and 40m3/h (gas). Licensees are obliged to offer reasonable prices and conditions.

The ACM prescribes a ‘model contract’ consisting of several fixed, standardised, pre-determined components, which must be sent to consumers in a single package. All model contracts contain the same information in the exact same order. The General Conditions to the contract must be in accordance with the model conditions of the Dutch energy industry.
association, Energie-Nederland. Prices can only be adjusted twice per year, on 1 January and 1 July. Price adjustments must be announced at least one week in advance. Contracts are to be terminated at all times, with a notice of 30 days at the most.

No licences are required for trading in gas or power. Nevertheless, traders must register and apply for certain acknowledgments from the relevant TSO: GTS or TenneT. Market parties are subject to balancing regulations, including programme responsibility. Programme responsibility of small-scale end users is attributed by law to supply companies that have been acknowledged by TenneT (power) or GTS (gas).

iii Ownership and market access restrictions

The Mining Act does not contain (foreign) ownership constraints. Licence applications can only be denied if the applicant fails to demonstrate its technical and financial capabilities. There are no restrictions applicable with respect to ownership of mining works or installations.

There are no restrictions in respect of (foreign) ownership of power generation facilities. As stated above, the central power generation park is in foreign hands with RWE, Vattenfall, Engie and Uniper as the ultimate owners of those facilities.

With respect to power and gas (distribution) systems, the Electricity Act 1998 and Gas Act provide that ownership of transmission and distribution systems and the shares in the system operators are held by the state, provinces or municipalities. Pursuant to the Independent Grid Management Act, which amended the Electricity Act 1998 and the Gas Act in 2008, private ownership of transmission or distribution systems is prohibited. Furthermore, the Electricity Act 1998 and the Gas Act provide for a mandatory ‘ownership unbundling’ of system operation activities. As a result, system operators may not form or be part of a company group that includes production, trade or supply of electricity or gas. As these restrictions apply not only to TSOs but also to distribution system operators (DSOs), this group prohibition is more restrictive than the unbundling provisions in the European Directives.

iv Transfers of control and assignments

Transfer of a mining licence is subject to ministerial consent. Consent can only be withheld on grounds of technical and financial capability. The consent requirement does not apply in the event of a change of control in the licence holder. However, the MEA may withdraw a licence on the grounds of a lack of technical or financial capability of the licence holder; as such a change of control may be subject to an ex post regulatory review, in particular a change of control of the operator. There are no approval requirements with respect to the transfer of mining works or installations.

The Electricity Act 1998 provides for a notification obligation with respect to the change of control in generation facilities with a nominal minimum capacity of 250MW, and the MEA may withhold its consent or attach conditions to its consent to such a change based on public safety or security of supply considerations. A similar provision has been included in the Gas Act with respect to LNG installations and LNG companies. Transactions in violation of these provisions can be declared null and void by court, on the basis of these provisions.
Both provisions in the Gas Act and the Electricity Act 1998 refer to further rules set out in the ministerial regulation on the notification of change of control regarding the Electricity Act and the Gas Act.3

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

As mentioned above, the Electricity Act 1998 and the Gas Act provide for ownership unbundling of system operation activities. As a result, system operators may not form or be part of a company group that includes production, trade or supply of electricity or gas.

This group prohibition has been the subject of court proceedings between three (formerly) integrated energy companies, Essent, Eneco and Delta, and the Dutch state.

On 26 June 2015, the Netherlands Supreme Court (the Supreme Court) ruled that the ‘unbundling’ provisions laid down in the Electricity Act 1998 and the Gas Act are not in conflict with European Union law.4 The Supreme Court’s judgment followed the judgment of the EU Court of Justice (ECJ) of 22 October 2013 in which the ECJ considered (in short) the restrictions on the free movement of capital affecting undertakings active in the electricity and natural gas markets to be compatible with EU law.5

On 1 November 2016, the court of appeal of Amsterdam rendered its judgment that the unbundling of Eneco is not in violation of the European Convention on Human Rights. In the case of Delta, the court considers that since Delta is a (70 per cent) co-owner of a nuclear power plant (together with EPZ) that is not easily saleable due to the current low electricity pricing, this may result in a disproportionate burden for Delta. In an interlocutory decision, the court orders both the Dutch state and Delta to give a more detailed explanation regarding this matter before the court can render a final judgment.6 Following ACM’s administrative enforcement orders obliging both companies to execute the unbundling plan by 31 January (Eneco) and 30 June 2017 (Delta), Eneco and its network operator Stedin effectuated their ownership unbundling on 30 March 2017. On 31 March 2017, it was announced that Stedin acquired the shares in Enduris, the network operator of Delta, the latter being rebranded PZEM following the sale of its B2C and telecom businesses to EQT in December 2016. PZEM remains a shareholder in EPZ and EdF’s partner in the Sloe power plant.

ii Transmission/transportation and distribution access

System operators have been designated exclusively for the construction, maintenance and operation of systems in their respective designated regions. With respect to the connection to the system, the system operator is designated exclusively for the operation and construction of electricity connections up to 10MVA and gas connections up to 40m³/h. This exclusivity does not exist for larger connections (larger than 10MVA), privately owned systems (closed distribution systems) and gas connections larger than 40m³/h (except for the connection

3 Government Gazette 2012, No. 20218.
5 Court of Justice EU Joint Cases C-105/12, C-106/12 and C-107/12, Staat der Nederlanden v. Essent and others (ECLI:EU:C:2013:677).
6 Court of appeal of Amsterdam, Cases 200.175.864/01 (Eneco) and 200.176.186/01 (Delta), 1 November 2016.
point on the gas system), and construction by third parties is allowed. System operators are also designated by law to perform metering services and to roll out ‘smart’ meters to all small-scale end users. In the legislative proposal to amend the Electricity Act 1998 and the Gas Act (see Section I.i, supra), the MEA, inter alia, proposed amendments to further constrain the system operators’ statutory tasks. This is, however, subject to intensive political debate as network operators are broadly considered to play a pivotal role in the energy transition.

Third-party access to Dutch transport and distribution systems is regulated and supervised by the ACM. The statutory tasks of system operators include the non-discriminatory provision of adequate capacity and quality of transport services and related services. The system operator may only deny access if the required capacity is reasonably not available, or if it cannot reasonably be required to provide all the capacity requested. The MEA may order the system operator to take the necessary measures to fulfil its statutory tasks. If the system operator does not take the required measures, the system operator may lose its ministerial approval. Alternatively, in the event of serious neglect by the system operator, the MEA may decide that the system operator should be placed under the supervision of a designated representative, who may give binding orders.

iii Tariffs

Tariff structures, conditions and maximum tariffs are set by the regulator (ACM). These maximum tariffs are based on the maximum tariffs for the previous years, adjusted for the rate of inflation, an efficiency factor (x) and a quality factor (q) in accordance with the Tariff Methodology Decision, set by the ACM. Maximum tariffs may vary per system operator. The efficiency factor is based on benchmarking and is set for the duration of one regulation period, which has, in practice, always been three years. Regulated rates for metering services to small-scale users are determined separately. The applicable tariffs are determined largely by the consumer’s connection capacity.

iv Security and technology restrictions

A 2013 amendment of the Electricity Act 1998 and the Gas Act introduced a statutory obligation for system operators to protect critical assets and processes within their business operation against terrorism, cyberattacks, sabotage, influenza pandemics and floods. System operators must implement risk analyses, take precautionary measures and maintain sufficient recovery capacity. System operators may transfer the costs of these security measures in the regulated tariffs.

In January 2016, a bill regarding rules on data processing and cybersecurity notification obligations was submitted to the Second Chamber by the Minister of Justice. The bill introduces, in short, a notification obligation in the event of a safety breach or loss of integrity of electronic information systems (ICT breaches). Vital suppliers (for both public and private sectors) are required to provide notification in cases where an ICT breach may lead directly, or indirectly (cascade effect), to disruption of society. Electricity, natural gas and drinking water suppliers (and operators) can be considered vital suppliers. The bill is under debate in the Senate at the time of writing.

7 Parliamentary Papers Second Chamber 2015/16, 34 388.
IV ENERGY MARKETS

i Development of energy markets

In the Netherlands there are three types of marketplace for gas and power: over-the-counter (OTC); the exchanges for gas and power; and the imbalance markets operated by TenneT and GTS respectively. Power day-ahead and intraday trades are traded on the power spot exchange APX. APX has its own clearing company for spot trading. On 17 April 2015, APX Group and EPEX Spot announced the integration of their businesses to form a power exchange for central western Europe and the United Kingdom. Gas spot, gas derivatives and power derivatives are traded on ICE ENDEX. Other exchanges in the Netherlands are operated by Powernext and EEX.

GTS operates Title Transfer Facility (TTF), a virtual market place that allows market parties to transfer gas that is already present in the GTS system (entry-paid gas) to another party.

In October 2015 the ACM approved new auction rules regarding cross-border trading in electricity (for long-term capacity) (the Allocation Rules for Forward Capacity Allocation (EU HAR)). According to the ACM, the new auction rules will lead to uniform regulation and more transparency. In turn, this will lower thresholds, making it easier for market parties to participate in these auctions. The most recent amendments to the auction rules of 29 June 2016 were also approved by ACM.8

ii Energy market rules and regulation

On 28 December 2011, the EU Regulation on Energy Market Integrity and Transparency (REMIT) (1227/2011) entered into force. It aims to counter insider trading and market manipulation and increase transparency in the wholesale markets for electricity and natural gas. REMIT is directly effective in the national legal system. However, some of its provisions require further national legislative action. In 2013, the Dutch Parliament adopted legislation amending the Electricity Act 1998, the Gas Act, the Financial Supervision Act and the Code of Criminal Procedure to bring legislation in the Netherlands in line with REMIT. This legislation:

- provides that the national energy regulator (the Competition Authority) may provide data and information to the Financial Markets Authority and to the public prosecutor, insofar as such data and information are relevant for the execution of tasks under REMIT by the Financial Markets Authority and the public prosecutor;
- authorises the Financial Markets Authority to divulge confidential data and information it has obtained pursuant to the execution of its tasks under the Financial Supervision Act to the Competition Authority and ACER, insofar as such data and information may contribute to the execution of the Competition Authority's and ACER's tasks under REMIT;
- adds REMIT prohibitions and obligations to existing provisions that the Competition Authority may enforce by an administrative penalty, an order for incremental penalty payments or an order for administrative coercion;
- proposes to qualify infringements of the REMIT insider trading and market manipulation prohibitions and the inside information disclosure obligation as criminal offences under the Economic Offences Act;

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8 ACM Decision of 13 October 2016, Case No. 16.0499.52.
allows the criminal courts to issue a temporary ban on professional activity;
allows the criminal courts to order a sequestration of assets;
obliges the Competition Authority to process the registration of a market participant pursuant to Article 9(1) of REMIT expeditiously; and
delegates discretionary power to the Minister of Economic Affairs to promulgate further rules on registration by Ministerial Decree.

iii Contracts for sale of energy

Businesses that wish to supply energy (natural gas or electricity) to consumers and small business owners are required to have a licence. Only suppliers that supply energy to small-scale users in a secure manner and against reasonable tariffs and conditions are thus allowed to enter this market. The ACM issues a supply licence only if the applicant in question has demonstrated the necessary organisational, technical, and financial skills.

Suppliers can enter into individual contracts for the sale of natural power or gas. There are no regulatory requirements that govern the rates of such purchases and sales. Licensed suppliers are only obligated to use the model agreement prescribed by the ACM and Energie Nederland (see Section II.ii, supra) in respect of sales to small end consumers. Furthermore, regulatory supervision of the supply rates exists in the form of a regulation whereby suppliers have to submit to the ACM every year, and four weeks in advance of any rate changes, the new applicable rates. If the ACM finds these rates to be excessive, it may impose a maximum rate.

iv Market developments

An important market development is the increase in regional and local power generation, often by end users, particularly by the use of solar PV. The total installed capacity had a fourfold increase in 2015, with over 200,000 new PV installations installed, resulting in a total registered capacity of 882MW. An important incentive for local sustainable production is the possibility to net electricity from the grid with the self-produced electricity. Effectively, the consumption of self-produced sustainable electricity is exempt from taxes and levies, resulting in a net advantage for the local energy producer of approximately €0.23/kWh (including commodity, energy tax, VAT and system tariffs). Under pressure from the Ministry of Finance, the MEA has however announced that he will review the netting facility in 2017. The rollout of smart meters is expected to be completed then, so that real time data will be available for production and consumption.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

On 6 September 2013, around 40 Dutch private and semi-public parties reached a covenant on the development of renewable growth in the Netherlands: the Energy Agreement. The core feature of the Agreement is a set of broadly supported provisions regarding energy saving, clean technology, and climate policy. The Energy Agreement implemented a comprehensive climate and energy policy programme aimed at long-term sustainability and set out agreed short to medium-term measures in 10 pillars.

One of these pillars is the increase of renewable energy production from the current 4.3 per cent to 14 per cent in 2020, and 16 per cent in 2023. The Energy Agreement identified the need for additional wind farm projects to be developed to reach a total of 4,450MW by
2023 (with 1000MW already in place or under construction). The government allocated a maximum of €18 billion to subsidies for renewable energy (SDE+) for offshore wind, commensurate with these targets. The full amount will be committed before 2020 to account for a wind farm construction period of four years.

On 1 July 2015, the OWEA (see above) entered into force. The OWEA regulates the construction, exploitation and decommissioning of wind farms in the Dutch territorial sea, or the Dutch exclusive economic zone.

The OWEA is part of an extensive road map to build a total of 3,500MW of new offshore wind energy production capacity by 2023, in addition to the 860MW currently in place (OWEZ, Amalia, Luchterduinen and Gemini) near shore and offshore.

As the operator of the offshore grid, TenneT TSO will build five standardised platforms of 700MW, each connected to the onshore high-voltage grid by two 220kV cables. The designation of TenneT as the operator of the offshore grid went through a separate legislative procedure and was part of an ‘emergency’ bill of February 2016 to amend the Electricity Act 1998 to formalise the designation of TenneT as operator for the offshore grid. The bill entered into force 1 April 2016.

The OWEA introduces a new procedure for offshore wind licensing within the three currently designated wind areas: Borssele, Hollandse Kust Zuid and Hollandse Kust Noord. Within these wind areas, the MEA will determine production ‘sites’ in ‘site decisions’. The site decision will include the results of the soil survey, the ecological soil survey, the archaeological and cultural heritage survey and other ecological surveys performed by the state. The site decision must thereby provide important information that will help licence applicants to choose the best available technique within the (environmental) constraints and to optimise their tender bids for a licence and SDE+ subsidy.

The OWEA licence procedure is a combined application procedure for SDE+ subsidies (a production subsidy) and the exclusive licence to build a wind farm within a designated site. The licence will be granted for a maximum period of 30 years. The combined licence and SDE+ application must be submitted to the Netherlands Enterprise Agency (part of the MEA). The exclusive licence shall be granted to the winner of the SDE+ tender. SDE+ subsidies are granted on a ranking basis, with the ranking ordered according to the tender price. The first Borssele tender, for 700MW, was won by DONG Energy with a (then) record-breaking amount of 7.27€/kWh. The second Borssele tender, again for 700MW, was won by a consortium of Shell, Van Oord, Eneco and Diamond Generating Europe Ltd, with an even lower amount of 5.449€/kWh. The third tender (Hollandse Kust Zuid I & II, aggregate 700MW) will open on 14 September 2017 and close on 28 September 2017. The Hollandse Kust Zuid I & II site decisions are currently pending appeal proceedings before the Administrative Court of the State Council. Appeals are brought by, among others, coastal organisations and residents near the Dutch coast who are mostly concerned about the visibility of the offshore wind turbines and the obstruction of a clear coastal view, but also by gas producers in the area and VisNed, the fishery organisation.

A fourth tender for 700MW will be held in 2018 and the final 700MW will be put out to tender in 2019.
ii Energy efficiency and conservation

In 2015, a bill amending the existing Energy Efficiency Act of 26 February 2011, the Electricity Act, the Gas Act and the Heat Act, implementing the EU Directive 2012/27, entered into force. The implementation covers many aspects relating to energy efficiency, including energy-saving requirements of appliances and the rollout of smart energy meters.

Energy efficiency and conservation are also important topics in the 2013 Energy Agreement in which an energy usage reduction target has been set of 100PJ by 2020. This reduction target is to be established primarily in the real-estate sector, but also in industry, agriculture and general businesses. Additional targets for energy reduction with respect to transport and mobility have been agreed separately in the Energy Agreement.

iii Technological developments

Encouragement of technological developments in the Netherlands is part of the Energy Agreement. Relevant results have been accomplished in the field of blue energy, where the first experimental 50kW installation has been commissioned on the Afsluitdijk. Blue energy is the technology used to generate power from the difference in salt concentration of salt and fresh water. It is expected that this technique can be scaled up relatively easy and may prove to be a reliable energy source in the future. Also experiments are conducted with offshore floating sea current turbines.

On 1 April 2015, the Experiments Decree on Locally Generated Renewable Energy entered into force, which enables consumers and companies to experiment with locally generated renewable energy. In the case of such an experiment, certain restrictions of the Electricity Act 1998 do not apply. The requirements with respect to the scope and content of the experiments are laid down in the Decree. The objective is to take away regulatory barriers to facilitate local renewable energy generation, a more efficient use of available energy infrastructure and create more commitment from end users of electricity. It is envisaged that some smart grid solutions may benefit from this instrument but it is too early to raise expectations.

In April 2016, the MEA published an internet consultation on a draft bill to facilitate the energy transition. In this draft bill, a paragraph has been included broadening the legal basis for experiments, making it possible to experiment with energy saving, efficient use of energy systems, new market models or tariff regulation concerning renewable energy. This bill was submitted to parliament on 8 December 2016 and is currently on hold because of the formation of a new government (see Section I.i, supra).

VI THE YEAR IN REVIEW

i Earthquakes in Groningen and natural gas production

On 1 April 2016, NAM submitted an up-to-date 2016 production plan (for the year 2016–2017) for gas extraction levels in the Groningen province to the MEA, in which NAM upholds the current annual production level of 27bcm (if no unforeseen circumstances occur). The 2016 production plan was followed by a consultation round with all relevant parties (i.e., the provinces Groningen and Drenthe, the SodM and the TCB (see Section II.i, supra)). This resulted in the final consent decision, published by the government on 30 September 2016. Subsequently, an interim relief judge of the Administrative Court of the State Council decided on 5 January 2017 that there is no reason to further reduce gas extraction (set at 24 billion
cubic metres per year), while awaiting a final judgment. The interim relief proceedings were started by some inhabitants of the Groningen province, to request the judge to stop gas extraction in the stricken area entirely.9

The Administrative Court of the State Council announced in February 2017 that the court has scheduled a hearing on 22 May 2017 for the substantive part of the 22 appeals that were brought against the final consent decision. A final judgment is expected a couple of months later.

To make current mining legislation more up to date and to be able to make decisions more prudently with regard to onshore mining projects, amendment of the Mining Act was needed. Several bills regarding, inter alia, (the reversal of) the burden of proof in the Mining Act were submitted in 2015 and 2016.10 These bills were approved on 21 December 2016, however not all parts of the bills have yet entered into force (see Section I.i, supra).

ii Coal-fired combustion plants and CO2 emission reduction

On 1 January 2016, the Decree amending the Activities (Environmental Management) Decree11 entered into force. This Decree amends regulations for large combustion plants by introducing a minimum required return (i.e., net electrical capacity) for coal-fired combustion plants of 40 per cent, which is calculated according to the principle of the best available techniques. Older coal-fired combustion plants, such as those started in the 1980s, with a lower return, will have to close down.

In a joint letter of 9 April 2016 to parliament the MEA and the State Secretary of the Ministry of Infrastructure and the Environment stated that they agreed on further measures to be taken concerning meeting goals on reduction volumes of greenhouse gas emissions. The statement comprises both short-term and long-term measures.12

In the short term, the government is focusing on the execution of the Energy Agreement. The government is also considering closing two coal-fired combustion plants (Amercentrale 9 and Hemweg 8), which became operational in the 1990s. Research is needed to investigate what the effects will be on greenhouse gas emission reduction of terminating these two coal-fired combustion plants, next to (the already planned) closure of three other plants (operational since the 1980s).

In a letter of 28 February 2017, the MEA informed Parliament that he will request an advice from the Council of State with regard to the legal implications resulting from two amendments submitted by MPs that aim at the closure of at least two coal-fired power plants by introducing minimum requirements of electrical performance of the plants. At the time of writing, further developments are on hold because of the formation of a new government.

In the long term, the government is focusing on reducing CO2 emissions (including enforcement of the emissions trading system. According to the government, this is the most cost effective way to meet the EU goals of 80 to 95 per cent emission reduction by 2050.

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9 Administrative Court of the State Council (court in preliminary relief proceedings), Case 201608211/2/ A1, 5 January 2017.
10 Parliamentary Papers Second Chamber, 2015/16, 34 390 (on evidentiary presumption gas production Groningen) and Parliamentary Papers Second Chamber, 2015/16, 34 348 (enforcement of the safety interest in mining and control within exploration, production and storage licences).
12 Parliamentary Papers Second Chamber, 2015/16, 32 813, No. 122.
On 24 June 2015, the District Court in The Hague rendered its judgment in the ‘Urgenda Climate Case’ and ordered that the state is obligated to limit the volume of greenhouse gas emissions by at least 25 per cent by the end of 2020 instead of the currently envisaged 17 per cent, compared with 1990 CO2-emission levels. The case was filed by the Urgenda Foundation together with 900 co-plaintiffs against the Dutch state. The Court’s judgment has been described as unique, in the sense that it forces a government to change its climate policies on the basis of the state’s ‘duty of care’.13

Following the rendering of the judgment, the Dutch state announced that it would appeal against the verdict. The state published its statement of appeal in April 2016.

As a reaction to, *inter alia*, the outcome of the Urgenda court case, five MPs of different political parties submitted the ‘Climate bill’ on 12 September 2016 to parliament.14 This bill should enable a framework that focuses on an irreversible and step-by-step reduction of Dutch CO2-emissions for the purpose of reducing global warming and climate change. Owing to the formation of a new government, the procedure of this bill has also been put on hold.

**VII CONCLUSIONS AND OUTLOOK**

The (then) record breaking tender amount of DONG Energy to realise the first offshore wind sites of Borssele marked the second half of 2016 and gave a boost to reach the renewable energy goals laid down in the 2013 Energy Agreement. With an even lower tender amount submitted and won by the Shell/Van Oord/Eneco/Diamond-consortium, offshore wind energy is in a stable position in the Netherlands. The upcoming tenders for Hollandse Kust will be interesting, not in the least in the light of recent tender results in Germany (April 2017) where one of the tenders was won without subsidies (for wind farms to be built in 2025). The question may arise whether this development in pricing towards grid-parity of offshore wind should be reflected in a new or amended subsidy regime.

The growth of solarPV, both in numbers and in size, will also be a very relevant development, in combination with the quest for efficient storage capacity and storage market roles to deal with the intermittence of (in particular) solar power and to avoid expensive investments in networks to facilitate peak load. Projects of 20, 50 and even 100MW are being developed and, together with a planned 6000MW onshore wind capacity, will have a very significant impact on grid stability and security of supply.

In the year to come, it will be interesting to see how the heat sector will develop and to what extent this will impact the gas supply to households. The reduced production from the Groningen field, on the one hand, and the call for more efficient (and more sustainable) heat, on the other hand, have resulted in plans whereby a moratorium is in practice on investments in new gas distribution networks in favour of heat networks, particularly in new housing projects. The possibilities of geothermal are reconsidered in feasibility studies, and new strategies are developed with respect to a ‘heat roundabout’ envisaged to supply heat to millions of consumers.

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14 Parliamentary Papers Second Chamber, 2015/16, 34 534.
Chapter 26

NIGERIA

Gbolahan Elias, Okechukwu J Okoro and Pelumi Asiwaju

I OVERVIEW

i Petroleum

The Nigerian petroleum industry is regulated by the Department of Petroleum Resources (DPR), an arm of the Federal Ministry of Petroleum (the Ministry). The Ministry is headed by the Minister of Petroleum Resources (the Minister). The petroleum industry is also dominated by major joint venture arrangements, production-sharing contracts and service contracts between the Nigerian National Petroleum Corporation (NNPC), wholly-owned by the federal government of Nigeria (FGN), and international oil companies with global operations (IOCs). A number of statutes and policies encourage indigenous companies to actively participate in the industry.

Activities in the petroleum industry are regulated by several laws. These laws regulate the ownership, control and enjoyment of rights, construction and maintenance of installations, and environmental protection in the industry. The principal law regulating the exploration, production and distribution of petroleum in Nigeria is the Petroleum Act 1969 (PA).

ii Electricity

The Nigerian Electricity Regulatory Commission (NERC), established under the Electric Power Sector Reform Act 2005 (EPSRA), regulates the Nigerian electricity industry. EPSRA is the legal framework for the electricity industry. Through EPSRA, the FGN unbundled and privatised the then state-owned monopoly, the National Electric Power Authority (NEPA) into the Power Holding Company of Nigeria, generation companies (Gencos), distribution companies (Discos) and the Transmission Company of Nigeria (TCN). Today, the Gencos and Discos are controlled by private sector investors. The FGN retains sole ownership of the TCN, but has entered into an operation and maintenance arrangement with a private company, Manitoba Hydro International Limited.

1 Gbolahan Elias is presiding partner, and Okechukwu J Okoro and Pelumi Asiwaju are associates at G Elias & Co.
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 licences, leases and permits required to operate in the industry. The DPR also regulates the abandonment and decommissioning of installations.

The DPR and Federal Ministry of Environment (FMoE) regulate the environmental aspects of the production, transmission, distribution and supply of petroleum and petroleum products in Nigeria. Also on environmental protection, the National Environmental Standards and Regulations Enforcement Agency (Establishment) 2007 Act, the Environmental Impact Assessment Act 1992 (the EIA Act) and the Environmental Guidelines and Standards for the Petroleum Industry in Nigeria 2002 prescribe the environmental and emission standards applicable to petroleum activities in Nigeria.

There is also a ‘local content’ regulator, the Nigerian Content Development and Monitoring Board (the Board), established under the Nigerian Oil and Gas Industry Content Development Act, 2010 (NCA). The Board is required to ensure the growth of ‘Nigerian content’ in the petroleum industry.

Other regulatory agencies whose functions have an impact on the industry include:

a the Joint Development Authority, which promotes and supervises petroleum activities in the Nigeria-Sao Tome and Principe joint development zone;

b the Nigerian Investment Promotion Commission, which registers foreign investments in Nigeria;

c the Central Bank of Nigeria (CBN), which under the Foreign Exchange (Monitoring and Miscellaneous Provisions) Act 1995 supervises foreign exchange dealings in Nigeria (including the importation of foreign capital and repatriation of export proceeds from oil and non-oil exports);

d the Niger Delta Development Commission, which formulates policies and guidelines for the development of the Niger Delta area and liaises with operating companies to ensure pollution prevention and control;

e the National Oil Spill Detection and Response Agency, which deals with waste emanating from petroleum production and exploration; and

f the Nigerian Ports Authority and Nigeria Customs Service acting under the Nigerian Ports Authority Act 1999, the Pre-shipment Inspection of Exports Act 1996 and the Customs and Excise Management Act 1959, all of which regulate the export of petroleum.
The NNPC is not a regulator. It is a vertically-integrated state-owned statutory corporation. The NNPC has various subsidiaries, one of which is the Nigerian Gas Company (NGC). The NGC owns and operates the main gas transmission systems in Nigeria. The Nigerian Petroleum Development Company Limited has the responsibility for petroleum exploration and production activities. The National Petroleum Investment Management Services, a division of the NNPC, oversees the NNPC’s interests in joint venture arrangements, production-sharing contracts and service contracts with IOCs. The Pipelines and Products Marketing Company Limited and NNPC Retail Ltd import and market refined petroleum products respectively.

There are a number of regulations made pursuant to the PA that regulate specific aspects of the industry. The Mineral Oils (Safety) Regulations 1962 prescribe standard safety measures for lessees and licensees. The Petroleum Regulations 1967 regulate importation, shipping, unshipping and landing of petroleum; storage of petroleum; transport of petroleum; fuelling of aircraft and so forth. The Petroleum (Drilling and Production) Regulations 1969 regulate applications for leases and licences, exploration and drilling, field development, and payment of fees, rents and royalties. The Petroleum Refining Regulations 1974 regulate construction, operation and maintenance of refineries.

The construction, operation and maintenance of oil pipelines are regulated by the Oil Pipelines Act 1956 and the Oil and Gas Pipeline Regulations 1995. The transportation of crude oil in Nigerian waters and payment of terminal dues on any ship evacuating oil from terminals in Nigeria are regulated by the Oil in Navigable Waters Act 1968 and Oil Terminal Dues Act 1969 respectively. The Associated Gas Re-injection Act 1979 regulates the re-injection of associated gas into oil wells. The Petroleum Profit Tax Act 1958 taxes profits from upstream mining operations in Nigeria.

**Electricity**

EPSRA is the principal statute for the electricity industry in Nigeria. Under EPSRA, NERC, as the regulator of the Nigerian electricity industry, issues regulations and orders giving effect to EPSRA. NERC is also vested with the power to grant licences for the generation, transmission, system operation, distribution, and trading of electricity. NERC is also required to promote competition and private sector participation, and ensure quality standards in the electricity industry. EPSRA further established the Rural Electrification Agency to promote, support and provide access to electric power by rural and semi-urban areas of Nigeria.

The Federal Ministry of Power (FMoP), guided by EPSRA and the FGN’s National Electric Power Policy 2001, formulates electricity policy in Nigeria. The FMoP is empowered under EPSRA to issue general policy directions to NERC on the electricity industry, and NERC is bound to comply except where such policy is in conflict with EPSRA or the Constitution. The Energy Commission of Nigeria (ECN) also plays a strategic role in the electricity industry. The ECN was established by the Energy Commission of Nigeria Act 1979 (as amended) with the mandate to plan and coordinate national policies in the field of energy, and has been promoting the use of renewable energy sources in generating electricity.

The TCN has two key operating officers: the systems operator and the market operator. The market operator administers the wholesale electricity market, promotes efficiency and competition. The systems operator is responsible for planning, administration and grid discipline. In addition, the National Inland Waterways Authority established under the National Inland Waterways Authority Act 1996, regulates inland waterways navigation and issues permits for generation projects requiring water usage.
ii Regulated activities

Petroleum

The petroleum industry consists of the upstream, midstream and downstream sectors. The rights to explore, prospect, produce, process and distribute petroleum and petroleum products are granted through the issuance of leases, licences and permits by the Minister and the DPR (in some cases) to operators in these sectors.

For the upstream sector, the relevant leases and licences are the Oil Exploration Licence (OEL), Oil Prospecting Licence (OPL) and Oil Mining Lease (OML). An OEL confers a non-exclusive right to explore for petroleum for a term of one year. An OEL can be further renewed for one year.

An OPL has a duration of not more than five years including renewals, and confers a right to prospect for petroleum. However, the duration of an OPL granted in respect of the deep offshore and inland basin is a minimum of five years and an aggregate period of 10 years. An OML has a duration of 20 years and is subject to renewal. The OML confers an exclusive right to explore, carry away and dispose of petroleum. A drilling rig licence is also required to operate a drilling rig while a permit is required to conduct seismic data survey.

For the midstream and downstream sectors, a licence is required to construct or operate a refinery or processing plant, export, import, store, sell or distribute petroleum and petroleum products. The approval of the DPR is required to construct and operate a petroleum products filling station, and to retail lubricants. A permit is required to survey the route for a pipeline. A licence is required to construct and operate a pipeline, any pumping station, storage tanks, loading terminals or other ancillary installations. Further, to construct pipelines, a right of way must be obtained from the state government on which the land is located. This may be conveyed through a certificate of occupancy or permit from the relevant state government or by special agreement with the owner of the land (subject to payment of compensation).

DPR permits are also required to render services in the petroleum industry. The permits are in three categories: general, major; and specialised. The general category covers minor supply, works and maintenance services. The major category covers rehabilitation, upgrade and fabrication works, onshore pipeline and storage facility maintenance, equipment supply, consultancy, survey and calibration. The specialised category covers pipeline laying, drilling, exploration, technical consultancy, dredging and environmental restoration services.

The procedures for obtaining these leases, licences and permits vary but are all overseen by the DPR. In addition, the EIA Act requires the issuance of a certificate stating that an environmental assessment of a petroleum project has been conducted before one can embark on such a project, and that the outcome has been officially approved. The environmental laws of some states make it mandatory to obtain a permit from the state environmental agency to construct or operate any project or activity that affects the environment.

Electricity

As with the petroleum industry, activities in the Nigerian electricity industry are also strictly regulated. Through EPSRA, a NERC licence is required to construct, own or operate an electricity generation, transmission, distribution, system operation or trading undertaking. Applications for licences are made in writing to the chairman of NERC, accompanied by the prescribed fees and in the manner prescribed by NERC.
Licences issued by NERC include generation licences, which authorise the licensees to construct, own, operate and maintain generation stations. A licence is not required, however, to construct or operate a generating plant not exceeding 1MW in capacity.

A transmission licence allows the licensee to carry out grid construction, operation and the maintenance of transmission system in Nigeria, or connect Nigeria with a neighbouring country. The holder of a transmission licence may also be required to carry out system operation and the procurement of ancillary services. A system operation licence authorises the licensee to carry out system operation such as generation and transmission scheduling, transmission management and coordination, procurement and scheduling of ancillary services and administration of wholesale electricity market.

A distribution licence holder has the right to construct, operate and maintain a distribution system and facilities such as supply of electricity, installation, maintenance and reading of meters, billing and collection. A licence is not required for a distribution station not exceeding 100kW in aggregate. A trading licence authorises the licensee to purchase, sell and trade in electricity. NERC may also issue a temporary bulk purchase and resale licence authorising the purchase of electrical power and ancillary services from independent power producers and Gencos for resale.

In addition to the licences required under EPSRA, the Factories Act 1987 requires factory owners (which includes electricity generating and distribution companies) to apply to the Director of Factories for registration within a month of commencement of business. A licence from the Minister of Water Resources is also required to undertake any hydroelectricity project as the Ministry of Water Resources regulates the diversion, storage, pumping or use on a commercial scale of any water.

iii Ownership and market access restrictions

Petroleum

Except for the general requirement to incorporate a Nigerian company before carrying on business in Nigeria, there are no restrictions on a foreign company acquiring an interest in the petroleum industry in Nigeria. The NCA, however, provides for certain privileges for companies in the industry with over 51 per cent Nigerian equity participation. Under the NCA, such companies will be given first consideration in the award of oil leases and licences. Also, in awarding contracts for the provision of services, Nigerian indigenous companies will be exclusively considered. The DPR also has a practice of not granting majority stakes in OPLs or OMLs to foreigners.

The Minister has the right to require refinery licence holders to deliver petroleum products to the FGN, or OPL or OML holders to deliver crude oil to a person with a refinery licence. Also, where there is a state of emergency or war, the Minister has the right of pre-emption of all petroleum obtained under a lease or licence subject to payment of an agreed price; or, if there is no such agreement, a fair price for the time being at the point of delivery as may be agreed; or in default of such an agreement, by arbitration. By the National Domestic Gas Supply and Pricing Policy (the Domestic Gas Policy) and National Gas Supply and Pricing Regulations 2008 (the Gas Pricing Regulations), OPL and OML holders are required to supply up to a specific volume of gas for domestic consumption. An OML holder is further required to relinquish one-half of the leased area 10 years after the grant of the OML.

The Minister may revoke an OPL or OML if the holder is not conducting operations in accordance with the basic approved work programme and good oilfield practice, or fails to pay
rent, royalties, furnish reports on its operations or comply with the PA, regulations and the
terms of the licence or lease. The Minister may also revoke these rights if the holder becomes
controlled directly or indirectly by a citizen of or a company incorporated in a country the
laws of which do not permit citizens of Nigeria or companies incorporated in Nigeria or
controlled by Nigerians to acquire, hold and operate petroleum concessions on conditions
that, in the opinion of the Minister, are reasonably comparable with the conditions upon
which such rights are granted to subjects of that country.

**Electricity**

EPSRA prohibits anyone holding a NERC licence from assigning or ceding his or her licence
or transferring his or her undertaking without the prior consent of NERC. Similarly, no
person holding a licence from NERC may, without NERC’s consent, acquire or affiliate
with, the licence or undertaking of any other licensee or person who is in the business of
generating, transmitting, distributing or trading electricity.

In addition, every licensee is required by NERC Regulations on National Content
Development for the Nigerian Electricity Supply Industry 2013 to develop a framework for
the development and promotion of ‘Nigerian content’ in the electricity industry. The licensees
are also mandated to maintain a technology transfer plan (detailing various technologies
deployed by the operator and the modalities for transfer to Nigerians where applicable).

**iv Transfers of control and assignments**

**Petroleum**

The prior consent of the Minister is required before any transfer of an interest, power or right
in a licence or lease whether by way of acquisition, merger, takeover, exchange or transfer of
shares, listing, testamentary devises, judgment or arbitral award. For the farm-out of marginal
fields, the consent of the President is required. The DPR is, however, to be notified prior to
the commencement of any such transaction. The responsibility for obtaining consent is that
of the assignor. Also, a production-sharing contract or joint venture agreement, depending
on the contractual arrangement of the parties, may require that the non-assigning parties
waive or assert their pre-emption rights.

Consent will only be granted where the Minister is satisfied that the proposed assignee
is of good reputation, has sufficient technical knowledge, experience and financial resources
to effectively carry out the operations under the licence or lease and is in all other respects
acceptable to the FGN. For the farm-out of marginal fields, the President will only give his
consent if he is satisfied that it is in the public interest to do so. In the case of a non-producing
marginal field, the marginal field must have been left unattended for an unreasonable time,
not less than 10 years, and the parties to the farm-out must be acceptable to the FGN.

**Electricity**

NERC has the statutory responsibility to consider whether or not to approve a merger,
acquisition or affiliation. To do so, NERC may require information from licensees, undertake
inquiries and establish or contract with an independent entity to provide monitoring services.
The prior consent of NERC is required for a licensee to assign or cede his licence or transfer
his undertaking, or any part of it, by way of sale, mortgage, lease, exchange or otherwise to
another. The prior written consent of NERC is required for a licensee to acquire, by purchase
or otherwise, or affiliate with, the licence or undertaking of any other licensee under the EPSRA. However, a distribution licensee may also be issued with a trading licence to provide electricity to customers.

The approval of the Securities and Exchange Commission is required for mergers, acquisitions, takeovers and business combinations. Mergers and schemes of arrangement are also required to be sanctioned by the Federal High Court. In addition, mergers, acquisitions and other forms of business arrangements concluded through schemes of arrangement are to be registered with the Corporate Affairs Commission (Nigeria's companies' house) to become effective.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Petroleum

The NNPC is vertically integrated. Through its subsidiaries, the NNPC engages in exploration, production, processing, importation, transportation, distribution and retail of petroleum and petroleum products. IOCs also have control over exploration, production and transportation facilities in the petroleum industry. Some IOCs have downstream operations in Nigeria, but those operations are not integrated with the upstream operations of the group. Notwithstanding that, third parties must be granted access to pipelines to aid transportation of petroleum from the field or well to processing plants or terminals for export.

Electricity

The Nigerian electricity industry was originally controlled by the NEPA (the old, state-owned monopoly). The NEPA controlled generation, distribution, transmission and trading of electricity. Through EPSRA, the NEPA was unbundled into the Power Holding Company of Nigeria, 18 successor companies consisting of six Gencos, 11 Discos and the TCN. With the unbundling and subsequent privatisation of the NEPA, EPSRA reduced vertical integration in the electricity sector with the aim of developing a competitive electricity market in Nigeria.

ii Transmission/transportation and distribution access

Petroleum

In Nigeria, petroleum is usually transported from the field and well through pipelines owned and operated by a holder of an oil pipeline licence. The licence holder has exclusive rights to use the land covered by the licence for the construction of a pipeline and ancillary installations required (e.g., pumping stations, storage tanks and loading terminals) for the conveyance of petroleum, and any substance (including steam and water) used or intended to be used in the production or refining or conveying of petroleum.

However, a third party may apply to the Minister for a right to use the pipeline constructed and operated by the licence holder. Before approving such use, the Minister must consult the applicant and the licence holder. The terms for the use of the pipeline are to be negotiated between the licence holder and the applicant. Where the licence holder and the applicant fail to reach an agreement, the Minister may determine such terms. The Minister, if satisfied with the application for use of a pipeline, may serve a notice on the licence holder to secure the applicant’s right to use the pipeline, regulate the charge payable and ensure that the applicant’s right is not prevented or impeded.
The NGC owns, operates and maintains most gas pipeline transmission systems in Nigeria. There are other private participants who own gas transmission facilities in Nigeria. Transportation and storage of gas are usually governed by gas transportation agreements. The NGC imposes terms and tariffs for gas transportation agreements. To boost the gas sector, a Gas Master Plan Infrastructure Blueprint, which provides for the development of central gas processing facilities and gas transmission systems, has been developed.

**Electricity**

In the electricity sector, Discos have monopolies over their distribution areas. However, a captive power generator (generating electricity exceeding 1MW for, and that is consumed by, the generator itself, and not sold to a third party) requires the prior written consent of NERC before it can supply surplus power not exceeding 1MW to an offtaker. Such a captive generator holder must apply for a generating licence before it can supply power exceeding 1MW to an offtaker. Also, embedded power generators (generation of off-grid power to be evacuated through a distribution network to end users) with a capacity above 20MW are required to evacuate the power produced through the grid.

In respect of third-party access to transmission, transportation and distribution facilities in the electricity sector, owners and operators of these facilities are not obligated to provide third-party access. There are also no restrictions on the provision of such third-party access. Therefore, third-party use of transmission, transportation and distribution facilities in the electricity sector is based on agreements between third parties and the owners or operators.

**iii Rates**

**Petroleum**

Under the PA, the Minister is to fix prices at which petroleum products may be sold in Nigeria. However, the Petroleum Products Pricing Regulatory Agency (PPPRA) Act 2003 created the PPPRA to determine the pricing policy of petroleum products, regulate the supply and distribution of petroleum products and moderate volatility in petroleum product prices. Retail petroleum product prices were previously fully subsidised by the FGN. In May 2016, the FGN removed the subsidy on petroleum products.

The price of gas in the domestic market is regulated by the Domestic Gas Policy and the Gas Pricing Regulations. The Domestic Gas Policy defines the policy of the FGN in respect of the pricing of gas to be supplied to customers in the downstream gas sector. The Department of Gas, established under the Gas Pricing Regulations, is to establish the aggregate price that shall be used as a basis for gas supply to the domestic market.

**Electricity**

NERC is responsible for creating tariff methodology in the electricity industry. In fixing the methodology, NERC is required to consider full cost-recovery plus reasonable return on investment, promotion of technology and market efficiency through incentives, fairness and openness to consumers, and reduction or elimination of cross-subsidies. NERC established the Multi-Year Tariff Order (MYTO) for the electricity industry. The MYTO provides a 15-year tariff path for the electricity industry, with limited reviews each year to cover changes in a limited number of parameters (such as inflation and gas prices) and major reviews every five years. Recently, NERC issued MYTO 2.1 for the period 1 January 2015 to 31 December 2018. On 1 April 2015, NERC approved an amendment to MYTO 2.1.
MYTO does not apply to embedded power. Embedded power is priced on a discrete basis to cover cost of production and distribution with a margin added. Purchases of embedded power are also subject to open tender.

iv Security and technology restrictions
The acquisition, promotion and development of technology in Nigeria are regulated by the National Office for Technology Acquisition and Promotion (NOTAP). NOTAP has regulatory oversight over all contracts for the transfer of foreign technology to Nigerian parties. The registrable contracts include use of trademarks and patented inventions; supply of technical expertise, detailed or basic engineering, machinery and plant; the provision of operating staff or managerial assistance; and training of personnel. Failure to register with NOTAP does not make a contract between a Nigerian and a foreign company for transfer of technology void or unenforceable, but NOTAP prohibits purchases of foreign currency from the CBN-regulated foreign exchange market to make payments under the unregistered contract.

IV ENERGY MARKETS
i Development of energy markets
The first utility company, the Nigerian Electricity Supply Company, was established in 1929, about 33 years after the first power generating station in Nigeria. From mainly hydroelectric and coal sourced energy, Nigeria has developed to a multi-source generation market (though gas is now the dominant source of power generation). The industry initially had distinct generation and transmission operations; energy was produced by the Nigeria Dams Authority and sold to the Electricity Corporation of Nigeria for distribution to end-users. These companies were integrated in 1972 to form NEPA, which was responsible for the generation, transmission, distribution of electricity and the overall management and administration of the energy market.

With the reforms introduced by the National Electric Power Policy 2001 and EPSRA, the Nigerian Bulk Electricity Trading Plc (the Bulk Trader) was incorporated. The Bulk Trader is licensed to purchase grid electricity in bulk from the Gencos and other independent power generation companies for resale to the Discos until such a time as the market would be fully competitive and the Discos achieve self-sufficiency. This arrangement is backed by both Nigerian and international governmental financial assistance in diverse forms. Another significant milestone in the energy market occurred when the National Integrated Power Project power plants built by the FGN were sold to private investors to encourage competition in the market.

ii Energy market rules and regulation
The energy market is regulated by NERC. NERC is responsible for rule-making and the licensing of market operators. The market rules in force govern the different stages the industry is anticipated to undergo; the ‘pre-transition’, ‘transitional’ and ‘medium’ stages. The pre-transitional stage involves the unbundling of NEPA, the old, state-owned monopoly. Trading arrangements in the transitional and medium stages are and will be through contractual arrangements, and the market is expected to be centrally-administered and fully competitive.
iii Contracts for sale of energy
The applicable documentation for sale of energy will generally depend on the stage of the market in force. The Bulk Trader, as the major purchaser of on-grid power, has its standardised bulk power purchase agreements for electricity off-take from the Gencos. Vesting contracts are used for the resale of electricity by the Bulk Trader to the Discos.

For natural gas sales, gas aggregation agreements are typically used for domestic supply obligation gas (gas that producers of petroleum in Nigeria must sell locally and not export), while gas sale agreements are used for non-domestic supply obligation gas. Increasingly, private producers are developing their own standard form gas sale agreements. Template alternative energy supply agreements are also available for renewable energy projects. For the transmission and delivery of evacuated electricity, the TCN enters into grid connection agreements and transmission use of system agreement.

iv Market developments
NERC has continued to grow and reform the electric sector. It grants generation licences to investors with both on-grid and off-grid intentions. Embedded generations are now popular and have been embraced by independent generators and the Discos. Some of the ready-made National Integrated Power Project plants that were privatised, with construction shortcomings yet to be fully fixed in many cases, have been commissioned and in some cases, installed with additional capacity and are now producing electricity. NERC has also expressed its intention to regulate the generation and distribution of electricity in unserved mini-grid areas.

The transitional stage of the electricity market, whereby wholesale buying and selling of electricity is based on contractual arrangements subject to regulatory rules, took off in the second month of 2015. When this stage of the market is fully in force and effect, it is expected that there will be greater investment certainty triggering investors’ interest and growth of the market. NERC’s MYTO 2.1 is also in place to govern electricity pricing for both individual and industrial users.

V RENEWABLE ENERGY AND CONSERVATION
i Development of renewable energy
The clamour for renewable energy arose in Nigeria as a result of increased awareness of the environmental impacts of fossil-based generation. It was not until 2006 that the actual need for sustainable energy can be said to have been recognised by the FGN with the formulation of a renewable energy plan as part of its national energy policy to depart from a monolithic fossil-fuel economy to one driven by an increasing share of renewable energy in the national energy mix.

The FGN, NNPC and NERC have encouraged the exploration and development of renewable energy in Nigeria because of the wide range of renewable natural resources (such as hydro-power, solar, wind, geothermal, biofuel). A Renewable Energy Division was created at the NNPC to develop renewable energy initiatives. The NERC through its Renewable Energy, Research and Development Division developed the feed-in-tariff regulations for renewable energy-sourced electricity to further support the aim of generating 2,000MW of renewables-sourced electricity by 2020 and to encourage favourable pricing for such electricity. NERC also grants licences for renewable power generation like solar and coal. The Nigerian Biofuel Policy and Incentives 2007 (which specifies a plan to produce biofuel primarily for thermal and power generation) includes several tax exemptions from withholding tax, capital
gains tax, value added tax and custom duties. There is a wide range of renewable energy projects at various stages of implementation. In fact, roads in numerous urban areas are lit or powered by solar sourced energy.

ii Energy efficiency and conservation

Efficiency and conservation are still poorly advanced despite the inclusion of basic policies and strategies, for the efficiency and conservation of energy in the national energy policy and the energy master plan. However, there are no definitive codes and regulations for energy efficiency and conservation. The FMoE’s renewable energy programme unit has introduced initiatives to address the need to source and deploy sustainable energy sources.

The ECN established the National Centre for Energy Efficiency and Conservation. This Centre is responsible for organising and conducting research and development in energy efficiency and conservation, and has conducted studies into promoting energy efficient appliances and light bulbs. Also the ECN in partnership with the Cuban government and with support from the Economic Community of West African States has advanced the usage of compact fluorescent lamps. Likewise, under the supervision of the FGN’s National Clean Cooking Scheme, there has been production and distribution of a purpose-designed biofuel stove.

In addition, NERC has expressed its intention to develop energy-efficiency labelling standards for domestic appliances and energy efficiency standards for luminaires, air conditioners and other household appliances. Market operators have advocated the use of energy-saving equipment that is now more readily obtainable in the Nigerian market such as high-efficiency voltage controllers.

iii Technological developments

Technological development in Nigeria is significantly slower than it should be. There are, however, indications that some Discos have signed memoranda of understanding to formalise agreements with the United States Trade and Development Agency to promote smart-grid solutions for Nigeria’s transmission and distribution challenges. We anticipate that these solutions will be in place in the near future.

VI THE YEAR IN REVIEW

i Petroleum

The fluctuation in crude oil prices, has continued to affect the revenues and cash flows of the indigenous operators of oil acreage in Nigeria. Revenues and cash flows are still being battered, with most struggling to meet their debt service obligations. To stay afloat, these companies have resorted to debt refinancings and, in some cases, limited equity injection.

Low crude oil prices have also affected the FGN’s oil revenues. As a result, in May 2016, the FGN announced the removal of subsidy on petroleum products. Subsidy payments were not included in the 2016 budget. The NNPC and the PPPRA recently introduced a ‘price modulation’ policy, under which the NNPC has become the largest supplier of product in the market and the pump price of fuel is reviewed quarterly. Nonetheless, due to the prevailing high cost of importation of petroleum products, mostly caused by lack of access to foreign exchange, the subsidy has been reinstated. However, subsidies are no longer paid to petroleum
marketers. Rather, the NNPC, as the major importer of petroleum products in Nigeria (over 90 per cent), bears the loss for the high landing costs of petroleum products. NNPC imports petroleum products and sells to the oil marketers who then sell to the end users.

ii Electricity

In the past year, NERC has continued to implement the MYTO-2015 electricity tariff, which became effective as of 1 February 2016. Although the new tariff has been criticised from several quarters, it eliminates all forms of fixed charges and has put in place effective mechanisms to ensure that customers are fully metered. In accordance with the provisions of the Nigerian Electricity Management Services Agency Act 2015, NERC has continued to take steps to ensure that the Discos provide meters for their customers. Sanctions have been threatened against Discos that did not comply with NERC’s directive before 1 March 2017.

VII CONCLUSIONS AND OUTLOOK

With the crude oil price slump and the coming into power of a new government at the federal level led by President Muhammadu Buhari, 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. Notwithstanding these calls, there are ongoing plans for a massive reform of the Nigerian oil and gas industry. To this end, the NNPC was reorganised internally and the Petroleum Industry Institutional Framework Governance Bill 2016 (PIGB) was introduced at the National Assembly. The PIGB aims to create commercially oriented and profit-driven (but government-controlled) business entities and regulators, and improve transparency and accountability. The current reaction from the federal government appears to be that the PIGB will be split and passed in four tranches. Stakeholders have frowned against such categorisation, as it may not efficiently address the core concerns of the industry.

The FGN is expected to continue the electricity industry reforms. Some observers think that the new administration will deregulate and privatise the power transmission business (which is under the control of the TCN wholly owned by the FGN) to attract more foreign direct investment into the electricity industry and enhance competition in the electricity market. There is, as yet, no express communication from the new government that any fundamental changes will be made to the electricity sector.
Chapter 27

POLAND

Krzysztof Cichocki and Tomasz Młodawski

I OVERVIEW

Demand for primary energy sources in Poland is currently estimated at 103.7 million tonnes of oil equivalent (Mtoe) per annum. It is satisfied primarily by coal (39.5 per cent), oil (25.1 per cent), natural gas (14 per cent), lignite (11.6 per cent) and others, including renewable energy sources (9.8 per cent). According to the information published by the Polish Main Statistical Office with respect to 2015, the renewable energy sources (RES) included in the Polish primary energy mix comprised solid biomass (72.22 per cent), biofuels (10.78 per cent), wind (10.76 per cent), biogas (2.64 per cent), water (1.82 per cent), heat pump (0.56 per cent), photovoltaic (0.52 per cent) municipal waste (0.46 per cent) and geothermal energy (0.25 per cent).

Local production satisfies the entire hard coal demand and approximately 25 per cent of natural gas demand in Poland. Oil demands are primarily met by import, with only 4 per cent of petroleum products coming from local crude oil production. On the other hand, lignite consumption is almost fully covered with local production, which stems from the fact that lignite is not customarily transported for great distances for economic reasons.

Final energy consumption in Poland is estimated at 67.2 Mtoe per annum and is based on energy demand of: industry (27.4 per cent), transport (28.1 per cent), residential (31.8 per cent) and services (12.8 per cent).

According to the government publication ‘Energy Policy of Poland until 2030’, the total consumption of primary energy in Poland should increase to 118.5 Mtoe per annum in 2030 and it should be satisfied by coal (31.0 per cent), oil (26.2 per cent), natural gas (14.5 per cent), lignite (8.2 per cent), renewable energy sources (12.4 per cent) and nuclear energy (6.3 per cent). At the same time, final energy consumption should increase to 84.4 Mtoe.

In line with EU policies for the reduction of greenhouse gas emissions, the Polish government continues policy aimed at achieving the envisaged 15 per cent share of RES in final energy consumption by 2020. In general, these actions are focused on the following basic aims: (1) to support RES consumption, with special emphasis on stable electricity generation units based on biogas; and (2) to promote nuclear power generation – with the flagship project of the first nuclear power plant to be developed in Poland by PGE EJ1, a subsidiary of Polish Energy Group SA.

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The primary regulation of the Polish energy industry is set forth in the following main statutes adopted by the Polish parliament (i.e., the Sejm and the Senate) and thereafter approved by the President of the Republic of Poland:

a. the 2011 Geological and Mining Law, which provides the general legal framework governing exploration for and exploitation of fossil fuels within Poland (including coal, lignite, hydrocarbons, uranium, etc.); and the use of underground reservoirs for storage of hydrocarbons, liquid fuels and the carbon dioxide processed in carbon capture and storage projects;

b. the 2014 Act on Special Hydrocarbon Tax and the 2012 Act on Tax on Extraction of Certain Minerals, which provide for additional tax burdens imposed on entities involved in the production of hydrocarbons;

c. the 1997 Energy Law, which provides for regulation of the entire electricity and district heating sectors and for the midstream and downstream oil and gas sectors, including production, transmission, storage and trading in liquid fuels;

d. the 2015 Act on Renewable Energy Sources, which provides for special regulatory framework covering operation of and support for renewable energy sources;

e. the 2007 Act on Reserves of Crude Oil, Petroleum Products, Natural Gas and on Procedures in Cases of Emergency in Security of Fuel Supply and Disturbance on the Oil Market (the Act on Reserves), which provides for certain obligations imposed on entrepreneurs involved in the natural gas and oil sectors, with these obligations being aimed at ensuring security of natural gas, oil and petroleum products supplies;

f. the 2006 Act on the System of Monitoring and Control over the Quality of Fuels;

g. the 2006 Act on Liquid Bio-components and Biofuels;

h. the 2016 Act on Energy Efficiency;

i. the 2000 Nuclear Law;

j. the 2011 Act on Preparation and Implementation of Investments in Nuclear Power Facilities and Associated Investments;

k. the 2009 Act on Investments with Respect to the Regasification Terminal in Świnoujście;

l. the 2007 Act on Emergency Management;

m. the 2016 Act on Rules for Management of State Property; and

n. the 2015 Act on Control of Certain Investments.

Under the statutes listed above, a number of governmental bodies, including the Council of Ministers, the Minister of Energy and the Minister of Environment, are authorised to lay down secondary legislation providing for more detailed regulations within the scope delegated to those bodies under the pertinent statute. Furthermore, the Council of Ministers is authorised under the 1997 Energy Law to adopt Poland’s overall energy policy, setting general goals to be achieved by, _inter alia_, enforcement of existing statutes and adoption of new legislation.

The competence to enforce the above-mentioned legislation and policies, and to exercise supervisory and regulatory powers over energy market participants, is vested in the following bodies:

a. the Minister of Environment, who is vested with power to grant authorisations for exploration and exploitation of fossil fuels within Poland and for the use of underground reservoirs for storage of hydrocarbons, liquid fuels and carbon dioxide;
b directors of mining offices, who are responsible for supervision of exploration and exploitation of fossil fuels and of the use of underground reservoirs for storage of hydrocarbons, liquid fuels and carbon dioxide;

c the President of the Energy Regulatory Office, who is vested with competence to, inter alia, (1) grant licences for production, storage, transmission, distribution, trading and supply of electricity, heat and fuels (including natural gas), and liquefaction and regasification of liquefied natural gas (LNG); (2) approve tariffs; (3) grant exemptions from tariff obligations; (4) approve grid codes; (5) certify operators of both gas and electricity transmission systems; (6) organise tenders for new electricity generation capacities; (7) grant tradable ‘white’ certificates to investors carrying out energy efficiency projects eligible to benefit from the support scheme based on tradable ‘white certificates’; (8) grant tradable ‘green’ and ‘red’ certificates to energy producers benefiting from the support schemes addressed to RES and combined heat and power plants; (9) organise ‘auctions’ selecting the RES installations eligible to benefit from the new support system in force as of 1 July 2016; and (10) control compliance with a number of obligations imposed on energy market participants (including those related to compulsory stocks of natural gas, coal and lignite, and to the public sale of electricity and gas) and to enforce financial penalties for non-fulfilment of these obligations;

d the Minister of Energy and the President of the Material Reserves Agency, who is responsible for enforcement of compulsory stocks of crude oil and liquid fuels;

e the President of the Office for Competition and Consumer Protection, who is responsible for enforcement of antitrust regulations (control of mergers and acquisitions, investigation and punishment for conclusion of anticompetitive agreements or abuses of dominant position, etc.); and

f courts considering appeals against the decisions issued by the above-mentioned authorities.

ii Regulated activities

The following types of activities performed within the territory of Poland require prior authorisation in the form of a licence:

a exploration for and exploitation of fossil fuels, including crude oil, natural gas, coal, lignite, uranium, etc.;

b development and exploitation of underground storage facilities;

c production of electricity except for generation performed in facilities with total installed capacity not exceeding 50MW, it being specified, however, that generation of electricity in RES installation with installed capacity exceeding 0.2 MW and using other fuels than biogas and biofuel is always subject to a licence requirement;

d production of heat except for generation performed in facilities with total installed capacity not exceeding 5MW;

e production of liquid fuels;

f storage of gaseous fuels, liquefaction of natural gas and regasification of LNG, and storage/transshipment of liquid fuels in storage/transshipment facilities, except for local storage of liquid gas in installations with capacity below 1MJ/s;

g transmission and distribution of fuels and energy (including electricity and heat), except for distribution of gaseous fuels in networks with capacity below 1MJ/s and distribution of heat where the total booked capacity does not exceed 5MW;
trading in fuels or energy (including electricity and heat) except for: (1) trading in solid fuels; (2) trading in electricity provided that trading is performed in installations with capacity below 1kV owned by the customer; (3) trading in LNG supplied from abroad to the delivery point in the Świnoujście LNG terminal; (4) trading in gaseous fuels provided that the annual turnover does not exceed €100,000; (5) trading in liquid gas provided that the annual turnover does not exceed €10,000; (6) trading in heat provided that the total ordered capacity does not exceed 5MW; (7) trading in gaseous fuels and electricity performed via the commodity exchange by certain qualified participants of exchange (including brokers, commodity exchange operators, clearing house or National Security Depository, etc.); and (8) trading in gaseous fuels and electricity performed by clearing house or National Security Depository in the course of fulfilment of their duties to settle over-the-counter (OTC) contracts; and transmission of carbon dioxide.

The exploration for and exploitation of fossil fuels is possible upon obtaining both an agreement setting up the mining usufruct rights within the areas specified therein, and the related licence granted by the Minister of Environment. In each case, the licences are limited to specific areas covered by the relevant mining usufruct agreement. Hydrocarbon exploration and production licences might be granted exclusively to the entrepreneurs that obtained positive opinions within the ‘qualification procedure’, which is aimed at preselection of entities that do not pose a threat to national security and – in the case of entrepreneurs intending to hold the status of licensed operator – ensuring the proper level of experience. Licences are granted upon completion of the tender procedure, which is intended to give priority to the most experienced and financially stable entrepreneurs, and prioritise the best method for the prospection or exploration and production of hydrocarbons, which means that each bid must be evaluated on the basis of the following criteria:

- the experience of the bidder in the prospecting or exploration and production of hydrocarbons;
- the technical and financial capacity of the bidder;
- the proposed technology to be utilised in the licensed operations;
- the scope and time frame of the proposed geological works and sampling; and
- the best remuneration for the mining usufruct right offered by the bidder within the tender process.

Entrepreneurs holding hydrocarbon exploration and production licences are also obliged to establish the security instrument assuring future performance of the obligations and duties related to the licensed activity.

The remaining energy licences for operation of installations and provision of services (i.e., other than for exploration and exploitation of fossil fuels) are granted by the President of the Energy Regulatory Office at the request of the interested party provided that they prove their compliance with statutory conditions, including: (1) having a registered seat within any country belonging to the European Economic Area or the Swiss Confederation (subject to certain exemptions); (2) having the technical and financial capacity to conduct licensed activities; and (3) provided that the granting of a licence to a given entrepreneur does not pose a threat to defence or security of the Republic of Poland and the applicant, its manager or its controlling entity has not been convicted for any (fiscal) crime related to the licensed activity.
activity. In addition, the licence for production or international trade in liquid fuels requires prior establishment of the security instrument, assuring the future performance of public duties (including taxes) related to the licensed activity.

Regulatory consent of the President of the Energy Regulatory Office is also required for development of direct lines, including those connecting electricity or natural gas production installations with end-customers who are not interconnected to the transmission or distribution grid or network.

iii Ownership and market access restrictions

In general, Polish law does not impose restrictions on ownership of existing and new energy assets and these may be owned by any natural or legal person, either seated in Poland or abroad. However, as an exception to the foregoing general principle, any new elements of the electricity and gas transmission networks used for the provision of transmission services may be owned exclusively by joint-stock companies incorporated in Poland and wholly-owned by the Polish State Treasury. The foregoing restriction arises from the fact that Polish law provides for the ownership unbundling of gas and electricity transmission system operators and it further provides that gas and electricity transmission system operators should be joint-stock companies wholly-owned by the State Treasury.

The licensed activities and services listed in Section II.ii, above may be generally conducted by any entrepreneur seated within any country belonging to the European Economic Area or the Swiss Confederation. However, as an exception to the foregoing general principle, gas and electricity transmission networks may be operated (and thus the related transmission services provided) exclusively by joint-stock companies incorporated in Poland and wholly-owned by the Polish State Treasury. Besides, in specific circumstances there might also arise certain restrictions on foreign control over licence holders, which stem either from the qualification procedure applicable to hydrocarbon licences (see Section II.ii, supra) or the fact that the authority may refuse to grant a specific energy licence or may withdraw a previously granted licence if it is justified by a need related to defence or the security of the Republic of Poland.

iv Transfers of control and assignments

Transfer of title to energy assets

Transactions concerning transfer of title to regulated energy assets are generally exempted from administrative approvals, except for common antimonopoly clearance. However, owners and operators of energy assets qualified as critical infrastructure under the 2007 Act on Emergency Management are subject to certain security obligations set forth in the 2007 Act on Emergency Management. In particular, owners and operators of the above-mentioned critical infrastructure are obliged to, inter alia, develop and enforce security and emergency plans for their assets.

Furthermore, under the 2015 Act on Control of Certain Investments, any direct or indirect acquisition of shares in ‘protected entities’ (entities engaged in, inter alia, the energy sector to be listed in a separate regulation of the Council of Ministers) shall be subject to prior notification to the Minister of Energy, who may raise objections to such transactions in certain circumstances, and in particular when it is justified on the grounds of public policy or public security. Under the aforementioned Act, both direct and indirect acquisition of shares resulting in achieving domination or a ‘significant participation’ in the protected entity is null and void if performed without the required notification, or despite the objection of the
Minister of Energy. In such cases, the shareholder shall also be deprived of its voting rights. Finally, achieving domination or gaining a significant participation without prior notification is subject to a fine of 100 million zloty or six months to five years’ imprisonment.

Transfer of licences

As regards transfer of administrative authorisations to conduct regulated energy businesses, it is generally not possible under Polish law to transfer an energy licence to a third party, except in certain situations, indicated below. Therefore, if any entrepreneur would like to acquire the energy assets within the asset deal and ultimately continue business based on those assets and previously conducted by the vendor, it is generally required to purchase the regulated assets and apply to the corresponding authority for a new licence.

Nevertheless, it is possible to transfer energy licences in the course of a merger of companies effected under the 2000 Code of Commercial Companies, provided that the pertinent energy licence held by the merged company was issued after 1 January 2001. Such transfers are effected by operation of law.

Besides this, the 2011 Geological and Mining Law provides for the limited possibility of assignment of the licence covering prospecting, exploration or production of fossil fuels; such an assignment is subject to the prior consent of the Minister of the Environment and is granted in the form of an administrative decision.

Change of control

Change of control over companies holding energy licences is not generally subject to regulatory approval of the licensing authority. However, a change of control may in specific circumstances result in withdrawal (and effectively loss) of the licence if: (1) the licensing authority determines that regulated activity conducted by the licence holder controlled by a new shareholder poses a threat to defence or security of the Republic of Poland; or (2) the licensee does not meet licence conditions as a result of the change of control (e.g., the new entity controlling the licensee has been convicted for any (fiscal) crime related to the licensed activity). Change of control may also be subject to antimonopoly clearance by the President of the Office for the Competition and Consumers Protection.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

Vertical integration and unbundling

Subject to certain de minimis exceptions applicable to the electricity and gas distribution systems operators, Polish law provides for the unbundling of electricity and natural gas transmission and distribution systems operators, and of operators of gas storage facilities (transmission, distribution and gas storage facilities operators). In particular, Polish legislation sets forth detailed regulations implementing the European accounting, management and legal unbundling rules as laid down for transmission, distribution and gas storage facilities operators in the 2009/72 Directive and 2009/73 Directive and it further provides for ownership unbundling rules applicable to electricity and natural gas transmission system operators (except for services provided with gas transmission network existing and owned by the vertically integrated companies as of 3 September 2009 where appointment of an independent system operator is available). It is also provided that the gas and electricity
transmission system operators should be joint-stock companies wholly-owned by the State Treasury, which results in there being only one electricity and one gas transmission system operator appointed in Poland.

In practice, over the past 10 years the State Treasury separated the existing transmission assets previously owned by vertically integrated undertakings (this separation being effected in the course of either transfer of assets or division of companies controlled by the State Treasury) and established two sole-shareholder companies controlled by the State Treasury: PSE SA, which is appointed as a transmission system operator for electricity; and OGP Gaz-System SA, which is appointed as transmission system operator for natural gas. OGP Gaz-System SA is also appointed as an independent transmission system operator with respect to the Polish section of the Jamal pipeline owned by the vertically integrated company EuRoPol GAZ SA – a joint venture between Polish company PGNiG and Russian company GAZPROM. The foregoing transmission system operators are responsible for development of their respective transmission networks within the territory of Poland, and for expansion of transborder interconnectors. OGP Gaz-System also established its wholly-owned subsidiary Polskie LNG sp. z o.o., responsible for development and operation of the LNG regasification facility in Świnoujście.

In turn, electricity and gas distribution systems are generally operated by separate companies belonging to vertically integrated undertakings, the most significant of them being local incumbents (ENEA in northwest Poland, ENERGA in northern Poland, TAURON in southern Poland, PGE in central and eastern Poland). Depending on the specific situation, distribution system operators (DSOs) are appointed with respect to either certain geographic areas (especially operators belonging to incumbent vertically integrated undertakings) or specific installations (e.g., operators of local distribution grid developed within industrial zones, office complexes, etc.). Nevertheless, Polish law does not provide for exclusive rights of DSOs to provide distribution services in a particular geographic area; the rights to provide distribution services are limited to installations operated by given DSOs.

ii  Transmission/transportation and distribution access

In general, Polish law implements the third-party access principle within the electricity and natural gas transmission and distribution sectors. According to the foregoing principle, the transmission and distribution system operators are required, subject to certain exemptions, to render services to all market participants on an equal, transparent and non-discriminatory basis. The foregoing principle is envisaged to foster competition in wholesale and retail electricity and natural gas market within the single European zone.

iii  Rates

Except for transborder transmission services provided based on prices set within the capacity allocation auctions, the remuneration for access to the transmission and distribution system is generally calculated based on rates set forth in regulated tariffs, which are developed by a given system operator and subject to review and approval by the President of the Energy Regulatory Office. According to Polish law, the rates set forth in tariffs should reflect actual (‘justified’) costs incurred by service providers in the course of the provision of their respective services, as well as reasonable return on capital employed. Except for the minimum rate of return for storage of natural gas, which is set in the 1997 Energy Law at 6 per cent, the rates of return are not provided in legal acts. The rates of return are established by the President of the Energy Regulatory Office in accordance with its own current regulatory policy adopted
with respect to a given type of business or sector. The algorithms used for calculation of the
tariff also include certain factors envisaged to encourage efficiency and cost reductions, which
are often established by the President of the Energy Regulatory Office in accordance with its
own current regulatory policy to restrain increase in prices. The foregoing regulatory power
vested in the regulator results in much uncertainty as to what rates are acceptable to the
authority in a given year.

iv Security and technology restrictions
The energy interests and security of Poland are protected by number of instruments spread
across several acts, including: (1) the power of a regulator to refuse or withdraw energy
licences if it is justified by needs related to defence or security of the Republic of Poland;
(2) the power of the Minister of the State Treasury to prevent or invalidate legal acts or
resolutions resulting in actual threats to the functioning, continuity of operation or integrity
of critical infrastructure; and (3) numerous obligations imposed on market participants, inter
alia, the obligation to diversify natural gas supplies, maintain compulsory stocks of crude oil,
petroleum products, natural gas and coal or lignite used for generation of electricity, and to
develop security and emergency plans for critical infrastructure.

IV ENERGY MARKETS
i Development of energy markets
The organised trade in electricity was originally established in Poland by Togowa Giełda
Energii SA (TGE). At present, TGE is controlled by Giełda Papierów Wartościowych
w Warszawie SA (the Warsaw Stock Exchange) and it operates the Polish Power Exchange
commodity exchange, allowing for (1) trading in electricity within the Polish national
electricity system, and in transborder exchanges with the neighbouring EU electricity
systems (market coupling) carried out in accordance with Commission Regulation (EU)
2015/1222 establishing a guideline on capacity allocation and congestion management;
(2) trading in emission allowances, certificates issued under the incentive schemes addressed
to RES and CHP installations, and energy-efficiency investments; (3) trading in natural gas;
and – from 2015 onwards – (4) entering into derivatives contracts based on commodities
traded at Polish Power Exchange. TGE also renders a system designed for public auctions of
power. Transactions executed at the Polish Power Exchange are cleared and settled by Izba
Rozliczeniowa Giełd Togarowych SA (the Warsaw Commodity Clearing House). The order
of priority of the physical performance via the transmission system of transactions concluded
within the Polish Power Exchange depends upon their respective grid codes.

ii Energy market rules and regulation
Trading in electricity and natural gas at the Polish Power Exchange is regulated by the
2000 Act on Commodity Exchange and by internal by-laws developed by the operator of the
commodity exchange and subject to the prior approval of the Polish Financial Supervisory
Commission. The remaining OTC electricity and gas sale agreements are regulated by the
1997 Energy Law and secondary legislation issued thereupon and by the grid codes that
are binding on market participants upon their approval by the President of the Energy
Regulatory Office.

All transactions covering wholesale energy products (made either on organised markets
or on an OTC basis) are subject to the transparency rules set forth in Regulation (EU)
No. 1227/2011 of the European Parliament and of the Council on wholesale energy market integrity and transparency (REMIT) and secondary legislation issued thereupon, which (1) prohibit market manipulation and insider trading; and (2) oblige market participants to disclose inside information and report to the EU Agency for the Cooperation of Energy Regulators on fundamental data and all transactions in wholesale energy products, including orders to trade.

### iii Contracts for sale of energy
In principle, electricity and natural gas may be traded either via commodity exchange or in OTC contracts. However, recent amendments to the 1997 Energy Law provide that:

- **a** every electricity producer is obliged to sell at least 15 per cent of its annual production via the commodity exchange or other organised trading platforms operated by the company operating the regulated stock exchange;
- **b** furthermore, the electricity producers entitled to compensation for the stranded costs are obliged to sell their outstanding production (i.e., not subject to the above-mentioned 15 per cent commodity exchange obligation) via the commodity exchange or other organised trading platforms operated by the company operating the regulated stock exchange or in public auction;
- **c** the above-mentioned obligations related to public sale of electricity do not apply to certain types of electricity (*inter alia*, electricity delivered via direct lines, electricity generated in installations with total installed capacity not exceeding 50MW or renewable energy sources or certain CHP installations, and electricity used for the producer’s own purposes or for statutory tasks allocated to system operators); and
- **d** the entrepreneur trading in natural gas is obliged to sell via the commodity exchange or other organised trading platforms operated by the company operating the regulated stock exchange at least 55 per cent of natural gas introduced into Polish gas transmission system, it being specified that the foregoing obligation does not apply to certain quantities of natural gas (*inter alia*, compulsory stocks, natural gas exported from Poland or used for own purposes of the gas trader or used for statutory tasks allocated to system operators).

### iv Market developments
At present, the main goals of the Polish legislature and regulators include (1) restructuring and strengthening the coal mining industry; (2) securing long-term profitability of large conventional system power plants by, *inter alia*, organisation of the power supply capacity market; and (3) supporting the most efficient CHP and RES generation, while at the same time limiting the budget allocated for incentive schemes.

### V RENEWABLE ENERGY AND CONSERVATION

#### i Development of renewable energy
RES operators currently benefit from a number of incentives, including (1) an incentive scheme based on an obligation imposed on certain market participants (mainly electricity suppliers and major end users) to acquire and redeem green certificates corresponding to a pre-defined percentage of electricity sold to end customers or pay a substituting fee (the fee working in practice as maximum level of support available to beneficiaries); (2) exemption from excise tax; (3) reduction of interconnection fees payable by certain RES energy
producers; and (4) preferential financing, etc. In general, the current incentive system does not differentiate in the level of support depending on the RES technology applied (biomass, wind, photovoltaic, etc.) or generation capacity of a given RES installation. It does not provide RES operators with stable support as the level of support depends on the global amount of RES energy supplied to the market in a given period (thus if the overall production of RES energy is higher than the general aim set forth in the law, the level of support is lower).

The foregoing drawbacks of the current system resulted in the adoption of the new 2015 RES Act, which significantly changed the RES support system as of 1 July 2016. The 2015 RES Act introduced the new auction-based support system under which auctions shall be carried out at least once a year to select the most competitive RES operators authorised to benefit from support in the form of either:

a. a 15-year long-term power purchase agreement concluded with the obliged purchaser and providing for sale of electricity for the price agreed within the auction – in the case of RES installations below 0.5MW; or

b. the right to compensation of the difference between (1) the envisaged revenues from the sale of actually generated electricity for the price agreed within the auction and (2) the market value of the same electricity calculated based on average daily prices of electricity quoted at the commodity exchange – in the case of RES installations with installed capacity of 0.5MW or higher.

The above is valid provided that the period of support in any form must end no later than 31 December 2035, save for offshore wind installations where the expiration date may be extended to 31 December 2040.

Financial resources available to RES producers under the new auction system will be collected from the final energy consumers by DSO and TSO (RES Payers) and then transferred through the state-controlled company Settlement Operator SA to the RES operators selected within the auction either directly or – in the case of RES installations below 0.5MW – through obliged purchasers.

The operators of RES installations commissioned before 1 July 2016 may be authorised to choose whether to benefit from the current support scheme based on the tradable certificates of origin (acquired rights) or the new auction system, but in any case the total period of support available to the existing RES cannot exceed 15 years from the first generation confirmed by green certificate. Besides this, the current support scheme based on tradable green certificates will be adjusted to:

a. limit the total period of support to 15 years from commissioning of given installation; and

b. limit the amount of support addressed to multi-fuel power plants using biomass and hydro-power installations.

The Polish parliament also adopted the 2016 Act on Investments in Wind Power Plants, which negatively affected onshore wind-farm businesses in Poland, including:

a. setting of a minimum distance between wind turbines and buildings, which negatively affected viability of projects including wind farms under construction and modernisation of existing wind farms; and

b. changes to the rating of wind turbines for the purposes of property tax, which resulted in a significant increase in property tax paid on wind turbines.
ii Energy efficiency and conservation
The main incentive scheme relating to energy efficiency and conservation is based on tradable white certificates, which are granted to investors that undertake to make investments related to energy efficiency. According to the 2016 Act on Energy Efficiency, certain market participants (including electricity suppliers and major end-users) are obliged to acquire and redeem white certificates corresponding to a certain percentage of energy and gas sold to end-users or pay a substituting fee (the fee working in practice as the maximum level of support available to beneficiaries). Apart from the foregoing incentive scheme, there are preferential financing schemes offered by governmental funds and banks (e.g., the National Fund for Environmental Protection and Water Management) addressed to energy-efficiency investments.

iii Technological developments
The Polish government supports the development of RES and CHP generation and investments aimed at energy efficiency, with such investments currently benefiting from, inter alia, (1) incentive schemes based on tradable certificates; (2) tax exemptions; (3) reduction of interconnection fees; (4) preferential financing; (5) exemption of ‘prosumers’ from licensing obligations; and (6) support for investments in smart grid and smart metering, etc. Besides this, under the new 2015 RES Act the RES operators are able to benefit from the new auction system (see Section V.i, supra), while RES prosumers are able to benefit from the feed-in tariff, which will allow for the automatic sale of electricity generated in micro-installations at a price equal to 100 per cent of the electricity market price.

VI THE YEAR IN REVIEW
Polish energy policy is subject to significant changes arising from adoption regulations that would, in particular, strengthen the coal-mining sector, support stable (including coal, lignite, gas and biogas-fired) power generation units, strengthen security of electricity and gas supplies as well as creating level playing field for businesses related to liquid fuels, impose increased administrative and tax burdens on onshore wind-farm developers and operators and increase the overall reliability of the distribution grid, as well as ensuring proper levels of security within the Polish energy market, including state instruments to block potential hostile takeovers of energy companies currently controlled by the Polish state. Major developments in the Polish energy market in this year include:

a the entry into force and further amendments to the new RES Act adopted by the Polish parliament on 20 February 2015, which restrains the costs of the RES support system and guarantees stable revenues from RES generation to the entities that won the auction (see Section V.i, supra);

b entry into force of the 2016 Act on Investments in Wind Power Plants which negatively affected onshore wind-farm businesses in Poland (see Section V.i, supra);

c legislative works on introduction of the capacity market in order to support investments in power plants with stable generation profile;

d adoption of the Act of 22 July 2016 on Amendments to the 1997 Energy Law, which introduced additional licence requirements applicable to production, storage, transhipment and trade in liquid fuels as well as extended the natural gas storage obligations;
The implementation of the ‘quality regulation’ providing for a potential decrease of tariff revenues as a penalty for the incumbent distribution system operator not meeting the ambitious reliability targets established by the President of the Energy Regulatory Office in respect of power distribution services; and enforcement of the Act of 24 July 2015 on Control of Certain Investments, which vests in the Minister of Energy powers of control over energy company takeovers (see Section II.iv, supra).

VII CONCLUSIONS AND OUTLOOK
The Polish energy market is still under reconstruction stemming from the implementation of European energy and climate change policies, technological revolution, and a need to foster market competition and replace worn energy assets developed more than 40 years ago. On the other hand, the government is aware of the costs related to reconstruction and it would like to prepare balanced reforms that will not become excessive burdens for the Polish industry and customers. In practice, the delayed reforms and uncertainty with respect to future regulation restrained investments in energy projects (especially development of RES installation and conventional power generation), which may have a negative impact on the future energy security, especially for generation capacities after 2018 when a number of old and worn power plants will be decommissioned. Therefore, the Polish government currently seems to be determined to complete regulatory reforms to ensure the progress of energy investments and avoid disturbances in the energy market.
I  OVERVIEW

In recent years, following the publication of European Union directives for the implementation of the electricity\(^2\) and natural gas\(^3\) internal markets, the legislation and regulation of the energy sector in Portugal have undergone significant changes.

From production to supply, both in the electricity and the natural gas industries, all activities must be developed by legally separate entities, except for some specific cases. The liberalisation of these sectors in mainland Portugal has almost been concluded, and with the abolition of end-user energy supply tariffs due to happen on 31 December 2020, all consumers will shift to the liberalised markets.

Generation and supply of electricity and natural gas are free and mostly deregulated activities, while the operation, maintenance and exploration of infrastructures such as transmission and distribution networks, liquefied natural gas (LNG) terminals and storage facilities are regulated activities, with access rates set administratively by the national regulatory authority, the Energy Services Regulatory Authority (ERSE).\(^4\)

Currently, the Portuguese government’s policy for the energy sector is set out in the National Plan of Action for Energy Efficiency 2013–2016 (PNAEE 2016) and in the National Plan of Action for Renewable Energies 2013–2020 (PNAER 2020), both approved by Ministers’ Council Resolution No. 20/2013 of 10 April. The PNAEE 2016 and PNAER 2020 are intended to be tools for a better energy strategy by establishing the means of achieving international goals and commitments\(^5\) assumed by Portugal in matters of energy efficiency and the use of renewable resources, without losing sight of economic rationale and the need to ensure adequate levels of energy prices, which do not prejudice the competitiveness of Portuguese companies or the minimum living standards of the general population.

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4  Taking into account their geographical limitations, electricity and natural gas activities on the archipelagoes of Azores and Madeira continue to be developed by vertically integrated companies, and therefore the considerations that follow refer mainly to mainland Portugal.

5  In the context of the European ‘20-20-20’ measures, Portugal committed to achieve an overall reduction of primary energy consumption of 25 per cent and to have 31 per cent of its gross final energy consumption fuelled by renewable sources.
Given the scarceness of fossil fuel resources in the country and the current economic
and financial situation of the country, these Plans of Action focus primarily on the reduction
of the country’s energy dependence, the increase of energy generation using renewable
resources and the promotion of energy efficiency and sustainable development, namely by:

- ensuring the continuance of measures that guarantee the development of an energetic
  model with economic rationale, which provides sustainable energy costs;
- ensuring a substantial improvement of the country’s energy efficiency; and
- maintaining the reinforcement to diversify primary energy sources, revaluating the
  investments made in renewable technologies and presenting a new remuneration
  model for more efficient and prominent technologies.

The PNAEE 2016 and PNAER 2020 have the following five major objectives:

- to comply with Portugal’s commitments to establish a greater economic rationale;
- to significantly reduce greenhouse gas emissions;
- to reinforce primary energy sources diversification, thus contributing to enhancing
  Portugal’s security of supply;
- to improve the energy efficiency of Portugal’s economy, particularly in the state sector,
  thus reducing public spending and promoting an efficient use of available resources;
  and
- to improve economic competitiveness by reducing consumption and costs related to
  companies’ functioning and household economy management, freeing resources to
  boost internal demand and new investments.

II REGULATION

i The regulators

The national regulatory authority of both the electricity and natural gas industries is ERSE,
a public entity with administrative and financial independence. ERSE’s by-laws were
enacted by Decree-Law No. 97/2002, of April 12, and recently amended by Decree-Law
No. 212/2012 of September 2012.

ERSE is in charge of regulation, supervision and sanctioning in the aforementioned
sectors, from generation to supply. Recently, Law No. 9/2013, which came into force on
28 January 2013, established the Energy Sector Sanctioning Regime, which substantially
reinforced ERSE’s sanctioning competence and powers. Later, Decree-Law No. 84/2013 of
25 June revised ERSE’s by-laws, completing the implementation of Directives 2009/72/EC
and 2009/73/EC.

Alongside ERSE, the General Directorate of Energy and Geology (DGEG),
a state-administered entity with financial independence, has the task of implementing and
developing the state’s policies regarding energy matters and the exploitation of geological
resources.

As such, and in most cases, the DGEG is the competent entity for granting licences and
other administrative authorisations concerning energy-related activities, such as generation
or exploration licences.

In summary, while ERSE is the independent national regulatory authority for electricity
and natural gas, the DGEG is the body that represents the state on energy matters, also being
competent to grant licences and receive the corresponding applications or requests.
Regarding the upstream oil sector, the DGEG, via its oil exploration and production division is the competent authority to, among other things:

- manage, organise and integrate all data and technical information resulting from oil exploration and production activities and other relevant data;
- promote and carry out specialised studies aimed at establishing the value of oil resources;
- promote the oil potential of Portuguese basins throughout the industry;
- negotiate and ensure the proper procedures to grant (by direct negotiation or public bidding), transfer and annul exploration and production rights;
- prepare and supervise licences for preliminary evaluation and concession contracts;
- evaluate work programmes and specific technical projects during the execution of the contracts; and
- regulate and supervise the activities during the execution of contracts, ensuring that legal provisions and regulations are followed, including those related to health, safety and environmental protection.

In relation to the downstream oil sector, following Decree-Law No. 244/2015 of 19 October, Entidade Nacional para o Mercado de Combustíveis, EPE (ENMC), acting through the members of government responsible for finance and energy matters, is the competent authority to, among other things:

- monitor, jointly with DGEG, security of supply of the national petroleum system and follow up on the supply conditions concerning raw petroleum and petroleum products, as a function of future consumption necessities;
- monitor the functioning of the raw petroleum and petroleum products market;
- give opinions on licensing procedures of large petroleum facilities, notably refining, transportation and storage;
- approve registration of suppliers of petroleum products; and
- receive complaints concerning activities in the liquefied petroleum gas value chain.

ENMC also has powers concerning the regulation of biofuels and the constitution and maintenance of oil reserves.

However, the Portuguese state budget for 2017 anticipates the extinction of ENMC and foresees that ERSE shall become the competent entity to regulate the liquefied petroleum gas and fuel sectors.

The core legal framework for the electricity sector is composed of Decree-Laws No. 29/2006 of 15 February and No. 172/2006, of 23 August, and in the natural gas sector, by Decree-Laws No. 30/2006 of 15 February, and No. 140/2006 of 26 July (which have all undergone significant changes in recent years). The main legal framework for the oil and gas upstream sector is Decree-Law No. 109/94, of April 28 and, for the downstream sector, Decree-Law No. 31/2006, of February 15, recently amended by Decree-Law No. 244/2015, of October 19.

Regulations put into force by ERSE, such as the Commercial Relations Regulation, the Tariffs Regulation, the Quality Standards of Service Regulation and the Infrastructures Operation Regulation,6 and those put into force by the DGEG, such as the Transmission Network Regulation and the Distribution Network Regulation constitute other significant sources of law governing these industries.

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ii Regulated activities

In the electricity industry, transmission and distribution are activities that are subject to administrative authorisations.

The operation and exploration of the national transmission and distribution networks are awarded by means of concession agreements entered into with the Portuguese state, granting the concessionaires the exclusive right to explore the networks within a determined geographical area, for periods of 50 or 35 years.

Besides the national distribution network, there are also municipal distribution networks, mainly composed of low-voltage grids. The right to explore these networks is also granted through concession agreements, but these are awarded by the respective municipalities and are valid for a period of 20 years.

In the natural gas industry, the exploration and production, transmission, distribution and operation of LNG terminals and of LNG storage facilities are also regulated, subject to administrative authorisations.

The operation of the national transmission and distribution networks, of LNG terminals and LNG storage facilities is also granted by means of concession agreements, offering the exclusive right to develop these activities for 40 years within a certain geographical area.

Additionally, there are some local natural gas distribution networks with no physical connection to the national distribution network, which may be operated by obtaining a licence, valid for a period of 20 years. The request for its attribution should be directed to the Minister of the Economy and Employment and delivered to the DGEG’s office.

The right for prospection, exploration, development and production of oil is granted by the Minister of the Economy and Employment through a concession agreement.

Regarding remuneration, aside from production, income and real estate taxes, and some sporadic fees, there is no legal obligation for production sharing, the concessionaire is exempted from paying royalties, and it is free to sell the oil, except in the event of war or public emergency. The concessionaire is also entitled to freely dispose of all findings of natural gas, being exempt from any production taxation.

The concession agreements for the aforementioned activities are granted by means of a public procurement process.

Lastly, licensing for oil downstream activities is not required (other than licensing for the facilities where the activities are being carried out).

iii Ownership and market access restrictions

Electricity generation is a free activity, being subject only to obtaining a generation licence. The licensing entity may vary upon the generation technology or geographical location where the generation plant is to be installed. Prior to entry into industrial exploration, the generation groups of the facility must also obtain an exploration licence, granted after an inspection that ensures they meet all technical and safety conditions to start operating.

Generation licences do not have a term, unless the power is generated using public domain water resources, or the generation plant is installed in maritime space that is under sovereign or national jurisdiction, in which cases the term of the generation licence will be that of the licence or concession agreement that confers the right to use public domain resources.

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7 Which, in general terms, refers to high and medium-voltage grids.
The transmission network operators (TNOs) of the electricity and natural gas sectors are subject to a full ownership unbundling regime.

Under this regime, no entity may hold an equity participation greater than 25 per cent of the share capital of the TNO. Also, the TNO or the companies that control it may not, directly or indirectly, exercise control or any rights over companies dedicated to generation or supply of electricity or natural gas. Equally, companies dedicated to generation or supply of electricity or natural gas or companies that control such, directly or indirectly, cannot exercise control or any rights over the TNO.

Subject to certain exceptions that relate to the historical role of the electricity TNO, the TNO is also strictly forbidden from acquiring electricity or natural gas for selling purposes.

In the downstream oil sector, entities that carry out storage and pipeline transport of petroleum or petroleum products must be legally independent from entities that conduct refining, distribution by pipeline or supply of petroleum or petroleum products.

iv Transfers of control and assignments
The transfer or encumbrance of any assets related to activities granted through concession agreements must obtain prior authorisation from the competent Ministry.

Concentration operations that meet some predetermined conditions must be notified to the Portuguese Competition Authority and are subject to its prior approval.

After being notified, the decision should be issued within 30 or 90 days, depending on whether or not a detailed investigation of the concentration operation is required.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling
Currently, the operation and exploration of the national transmission network of electricity and natural gas is carried out in accordance with the full ownership unbundling regime. This means that the company that operates the national transmission network may not integrate any group of companies dedicated to the generation, distribution or supply of electricity or distribution or supply of natural gas.

Under this context, EDP Energias de Portugal SA, formerly the company that held the monopoly in the electricity industry, was required to spin off any assets related to the transmission network into a separate company, thus forming REN Rede Eléctrica Nacional SA. Similarly, GALP Energia SA was also forced to dispose of its natural gas transmission assets, which are now owned and operated by REN Gasodutos SA.

In 2012, in line with the latest European directives, the Portuguese legal framework for the electricity and natural gas sectors allows transmission activity to be developed by a vertically integrated company. In this case, however, the transmission system operator must be a legal entity separate from the rest of the companies, forming an independent transmission operator (ITO). The ITO must observe strict independence obligations and comply with several independence criteria to avoid falling foul of discriminatory behaviours,

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8 The definition of ‘control’ refers to the definition provided for in Council Regulation (EC) No. 139/2004 of 20 January 2004, regarding the control of concentrations between undertakings (the EC Merger Regulation).

9 Both companies are wholly-owned by REN Redes Energéticas Nacionais SGPS, SA, a listed company.
namely those set out in Article 9 of Directives 2009/72/EC and 2009/73/EC. Compliance with such obligations and independence criteria is assured by means of a certification process, monitored by ERSE and the European Commission, and that the ITO must fulfil to develop transmission activity.

The distribution of electricity and natural gas is subject to a legal unbundling regime. This means that operators of distribution networks must be independent from a legal, organisational and decision-making process standpoint from other activities unrelated to distribution. Distribution companies that serve fewer than 100,000 clients are not subject to the legal unbundling regime, but they must still implement accounting and functioning unbundling measures.

Supply activities are also subject to the unbundling regime, implying that they must be legally separate from other activities. The last-resort supplier is also bound by this unbundling regime, even in relation to common suppliers.

The operation of LNG terminals and storage facilities is also subject to the legal unbundling regime. To a lesser extent unbundling requirements also exist in the downstream oil sector (see Section II.iii, supra).

ii Transmission/transportation and distribution access

To ensure equal market conditions for all market participants, the concessionaires of transmission and distribution activities in electricity and natural gas must comply with specific public service obligations: to guarantee equal access conditions to all market participants and to abstain from adopting any discriminatory behaviour or practices.

Where facilities for transport by pipeline and storage of petroleum or petroleum products are declared as being in the public interest, holders of such facilities are also obliged to act in a non-discriminatory manner.

The ensuring of equal conditions to all market players for the access and use of infrastructure is intended to create effective market conditions, promoting competition and thus enhancing consumers’ experience in these markets.

iii Terminalling, processing and treatment

The access and use of LNG terminals and storage facilities is also regulated, under the same terms as for distribution networks. Rates are determined by ERSE according to the Tariffs Regulation, and all users must benefit from equal commercial conditions.

The only exception is for storage facilities. Part of the storage capacity is operated under regulated conditions by REN Armazenagem SA, with rates determined by ERSE. The other part of the storage capacity is operated by Galp Energia SA and access to these facilities can be made under a negotiated access regime, with leeway to negotiate access and use terms.

The rates of services rendered by the LNG terminal (reception and unloading of natural gas, liquefaction, storage and loading) are regulated, being established by ERSE according to the terms of the Tariffs Regulation.

iv Rates

Rates for the transmission and distribution of electricity and natural gas are determined by ERSE according to the Tariffs Regulation.

ERSE also determines the matters that must necessarily be included in the network use agreement, such as duration, interruption of service conditions, payment methods and
terms of resolution, which vary depending on the contracting parties (generators, suppliers, network operators or consumers). The general terms of the network use agreement are submitted to ERSE for prior approval.

The Portuguese tariff system is constructed in such a way that for each regulated activity there is an associated regulated tariff, and the tariff applicable to each client is made up of the total of the various activity tariffs.

Tariffs for the use of regulated infrastructures are based upon the provider’s cost plus a reasonable rate of return, which will determine the operator’s allowed revenue. The reasonable rate of return is also established by ERSE for a certain period.

The allowed revenue and the provider’s cost for the activity of transmission and distribution of electricity is determined in accordance with the Electricity Tariffs Regulation.

The formula used to calculate the allowed revenue of the transmission network operator includes the application of efficiency factors to the provider’s costs, to reward efficient spending and investments, along with incentives for the maintenance and operation of equipment that is at the end of its life.

In the transmission and distribution of natural gas, the formulae used to determine the allowed revenue of the service provider are set out in the Natural Gas Tariffs Regulation.

Although these are not specifically determined in this regulation, it is established therein that the cost of the TNO’s activity will be subject to efficiency incentives to be determined by ERSE.

v Security and technology restrictions

The concessionaires of electricity and natural gas transmission activities are also in charge of managing and monitoring the National Electric System (NES) and the National Natural Gas System (NNGS).

The concessionaires of electricity and natural gas transmission activities have the following responsibilities:

a) assuring the long-term capacity of the NES and the NNGS;

b) providing information to other network operators to:

• maintain safe operation;

• estimate the level of reserves needed for medium-term safety of supply (especially the level of water reserves); and

• in general, form a central part in the NES and NNGS;

c) operating the transmission network; and

d) coordinating with all other networks and infrastructure operators, generations units and suppliers.

In cooperation with the DGE, the concessionaire of electricity transmission activity published a Report for Monitoring the Safety of Supply of the NES for 2013–2020. This report describes, inter alia, the NES, provides future grid scenarios, planned and installed capacity, and levels of power generation by source.10

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10 Available at www.dgeg.pt.
IV ENERGY MARKETS

i Development of energy markets

The Iberian Electricity Market (MIBEL), a regional, organised electricity market was put in place by Portugal and Spain in July 2007.

One important aspect of MIBEL’s functioning is the principle of reciprocal recognition of agents. Under this principle, if an agent is granted the status of producer or supplier by one country, this implies automatic recognition by the other country, granting equal rights and obligations to that agent.

The management of the Iberian spot electricity market is the responsibility of OMEL, the Spanish division of the Iberian Energy Market Operator.

In the spot electricity market, transactions are executed by the participation of agents on the daily and intraday market that aggregate the Spanish and Portuguese zones of MIBEL. Trading on the daily market is based on a daily auction, with settlement of energy at every hour of the following day.

There are various intraday sessions subsequent to the daily market auction in which agents can trade electric power for the various hours of the day covered by that market. Trading is also done by auction.

The financial settlement of the transactions occurs weekly, and guarantees must be deposited.

Producers, self-producers, external agents (non-resident entities), suppliers, representatives and qualified consumers can be spot market agents.

OMIP is the operator of the Portuguese division of MIBEL and is responsible for the management of the derivatives trading market. OMIP holds a 100 per cent stake in OMIClear, which has the role of clearing house and central counterparty in all operations executed on the market managed by OMIP, also being able to clear trades on the over-the-counter market or even other markets that have, as underlying assets, energy-based products.

On the OMIP trading platform, all elements of the futures contracts are standardised (e.g., volume, underlying asset and minimum price variation). Therefore, when an agent opens a position, it need only choose the contract it will trade, the relevant quantity and the price (except if it is a market offer). A key characteristic of these contracts is that they are marked to market on a daily basis.

The operations carried out on OMIP are registered in trading accounts and simultaneously registered in clearing accounts through which the financial settlement of the contracts is assured.

The recently implemented Iberian natural gas market, MIBGAS, held its first trading session on December 2015. MIBGAS is managed by MIBGAS, SA and offers its users the possibility of trading within-day, day-ahead, balance of month and month-ahead products at an Iberian level.
ii  Energy market rules and regulation

The legal framework for the organisation of MIBEL is based on the MIBEL Agreement,\textsuperscript{11} signed on 1 October 2004. It establishes the general principles for the organisation and management of MIBEL and, in particular, the framework for the organisation of the spot market and the derivatives market.

The MIBEL derivatives market, because of its financial nature, is directly subject to Portuguese law and jurisdiction and, therefore, to the legislation applicable to this type of market, which is primarily:
\begin{itemize}
  \item[a] the Securities Code;
  \item[b] the Securities Market Commission (CMVM) Regulations; and
  \item[c] the CMVM Instructions.
\end{itemize}

The derivatives market is under the direct supervision and regulation of the CMVM, in coordination with ERSE.

Notwithstanding the powers granted to the Portuguese authorities, the regulation and supervision of the derivatives market is carried out in conjunction with the equivalent Spanish authorities, the National Energy Commission and the National Securities Market Commission.

In addition, regulation of MIBEL takes place through market rules developed by the market operators, OMIE and OMIP, which have the duty of developing and jointly applying all the market rules.

MIBGAS and trading conducting therein, on the other hand, are governed solely by Spanish law.

iii  Contracts for sale of energy

Any entity (producers, suppliers, consumers or other agents from the organised market) registered as a market agent may enter into a bilateral agreement, either for electricity or natural gas.

With respect to the legal and regulatory applicable provisions, the terms of such contracts are dependent upon each market agent’s agreement. The market agents must notify the transmission network operator (as global system manager) of the completion of such an agreement and indicate the term for which it is executed.

iv  Market developments

The process of phasing out of end-user regulated electricity and natural gas tariffs is currently under way. Decree-Law No. 75/2012 of 26 March approved the timetable for the gradual phasing out of such tariffs for normal low-voltage electricity consumers, and Decree-Law No. 74/2012 of 26 March also established that for natural gas for either 31 December 2014 or December 2015 (depending on the contracted power or annual gas consumption). After several extensions, Decree-Law No. 15/2015 of 30 January, and Order No. 97/2015 of March 30, further pushed back the expiration date for the end of all regulated tariffs to 31 December 2017.

\textsuperscript{11} The Agreement between the Portuguese Republic and the Kingdom of Spain relative to the constitution of an Iberian Electrical Energy Market.
Pursuant to the enactment of recent legislative instruments, the predicted date for the end of all regulated tariffs was once again delayed, this time to 31 December 2020. During this period, transitory tariffs with a gradually increasing premium component will apply and also be updated quarterly by ERSE.

In the energy supply sector, it is worth noting the set-up of the Logistics Operator for Supplier Switching, created to facilitate electricity and natural gas ‘switching’ procedures for consumers and businesses.

V RENEWABLE ENERGY AND CONSERVATION

In February 2013, the Council of Ministers approved the National Action Plan for Energy Efficiency for the period 2013–2016 (PNAEE) and the National Action Plan for Renewable Energy for the period 2013–2020 (PNAER). The main objective of the PNAEE is to envisage new actions and targets for 2016, integrating the concerns regarding the reduction of primary energy for 2020 contained in the EU policy on energy efficiency.

The PNAER was also defined in light of the current situation (oversupply of electricity generation due to lower demand) with a view to adapting and mitigating costs. The plan continues to focus on renewable energy sources – very relevant in the promotion of a balanced energy mix – to enhance security of supply and reduce the risk of the price variability of certain commodities and its corresponding implications for the national energy bill.

i Development of renewable energy

With the purpose of reducing energy imports and dependence, and following the enactment of several European directives, Portugal has introduced guaranteed remuneration schemes for renewable electricity generators (i.e., a ‘feed-in tariff’ system), prompting the development of wind and solar generation, as well as cogeneration, in the country.

Nevertheless, in the wake of the financial assistance programme (a memorandum of understanding underwritten by the Portuguese government, the European Union, the International Monetary Fund and the European Central Bank), which ended in 2014, legislative measures seeking to curb guaranteed remuneration were procured, although precautions were taken to avoid impacting significantly on existing feed-in tariffs and undermining the legitimate expectations of the private parties in the market (and including changes that have been negotiated with participants in the renewables sector).

While Decree-Law No. 35/2013 of 28 February reduced the term during which special-regime generators have the right to receive the corresponding feed-in-tariff, the Decree also established the possibility of special-regime generators (except for small hydropower plants) adhering to certain alternative remuneration mechanisms; in general, these allow for an extension of the period during which the special-regime generators receive a special tariff or guaranteed remuneration.

Successive amendments to Decree-Law No. 23/2010, of March 25, (the most recent of which was executed by Decree-Law No. 68/2015, of 30 April) and related regulation thereof, have reduced feed-in-tariffs and the cap on installed capacity (reduced from 100MW to 20MW of installed capacity) for eligibility to benefit from cogeneration feed-in tariffs.

In relation to micro generation of electricity, Decree-law No. 153/2014 has also reduced the guaranteed remuneration for small generation power plants while allowing for self-consumption electricity generation and facilitating the licensing or registration of both.
Pursuant to a recent Ministerial Order (268-B/2016 of the Secretary of State for Energy affairs, enacted on 13 October 2016), it was determined that public funds granted to existing renewable energy projects with guaranteed remuneration (such as EU funds) shall be offset against future feed-in tariff payments. This measure has yet to be implemented by the government.

ii Energy efficiency and conservation

In 2008, the government introduced the PNAEE, a plan of action that establishes the main policies and energy-efficiency measures to be developed to achieve a target of a 10 per cent reduction in the country’s energy consumption. Recently, the PNAEE was revised and the government set new goals to be achieved in matters of energy efficiency until 2016.12

After the establishment of the PNAEE, the Energy Efficiency Fund was created,13 which finances the programmes and measures provided for in the plan.

In 2011, the government, by Decree-Law No. 29/2011 of 28 February, created a specific public tender procedure to expedite and facilitate the formation and execution of energy efficiency contracts, to be entered into by the public administration and private companies to implement measures improving energy efficiency in public buildings.

ERSE has tried to ensure that regulation of the sector galvanises actions that contribute to the promotion of energy efficiency. In the Tariffs Regulation for the electricity sector, a competitive mechanism called the Consumption Efficiency Promotion Plan (PPEC) has been established to promote measures for managing demand. In the electricity PPEC, incentives are awarded for the promotion of measures aimed at improving efficiency in electricity consumption through measures taken by suppliers, network operators and organisations that promote and protect the interests of electricity consumers in mainland Portugal and in the autonomous regions, and that are aimed at consumers in different market segments. The actions result from specific measures proposed, subject to a selection process, whose criteria are defined in the Rules for the Consumption Efficiency Promotion Plan. This process allows the selection of the most promising measures for energy efficiency to be implemented by the aforementioned promoters, taking into account the amount available in the PPEC annual budget, which is approved at the start of each regulation period for each one of its years.

Decree-Law No. 38/2013 of 15 March transposed into national law a set of provisions relating to the greenhouse gas emission allowance trading scheme, namely Directive 2009/29/EC of the European Parliament and of Council of 23 April 2009. In particular, this Decree states that from 2013 onwards the emission allowances that are not allocated free of charge shall be auctioned and the revenues from the auctions shall be applied in measures that contribute to the development of a competitive low-carbon economy (this mechanism is currently regulated by Order No. 3-A/2014). It is also established that the amounts to be transferred to the SEN should be used to offset the extra costs incurred with respect to the purchase of electricity from special-regime generators.

12 Council of Ministers Resolution No. 20/2013 of 10 April.
iii Technological developments

Driven by the growing dependence on oil for energy and by the environmental impact of the use of fossil fuels, Portugal is investing in new energy models for mobility that aim to improve quality of life and reduce pollution.

This has led to the creation of the Electric Mobility Network, an integrated network linking 1,300 charging stations in Portugal, managed by MOBI.E, which will enable electric vehicles to recharge, using a charge card.

Its main goal is to contribute to a more sustainable mobility model, promoting the integration of electric power coming from renewable sources into the functioning and development of cities, and maximising its advantages.14

In March 2011, Portugal initiated the large-scale implementation of the Electric Smart Grid, in charge of a consortium headed by EDP Distribuição SA.

The first phase of the project consists in the implementation, in the city of Évora, of 30,000 electric power meters, or ‘energy boxes’. This project seeks to promote energy efficiency, microgeneration and electric mobility. Consumers will have new services, new billing methods and innovative price plans at their disposal, which will allow greater flexibility of choice, so consumers can adjust their needs to match their consumption requirements. Speed, transparency and convenience are the concepts underpinning the new services on offer.15 It is expected that by 2020 smart grids will represent 80 per cent of European power distribution networks.

The licensing procedure for WindFloat, the offshore floating-platform wind-generation project to be installed off the northern coast of Portugal, is also nearing completion.

VI THE YEAR IN REVIEW

2016 was a year of a slight growth for the Portuguese economy, which has been slowly recovering from the Eurozone recession.

Where transactional activity is concerned, the sector remains strong. In this regard, the acquisition by an international solar energy promoter of a project for one of the largest investments in solar energy in Europe (around 200MW and occupying an extension of land of around 400 hectares), which is envisaged to sell electricity at market prices, was one of the landmark transactions for the sector in 2016.

In 2013 the Portuguese government implemented the ‘extraordinary energy-sector contribution’ (contribuição extraordinária sobre o sector energético), the revenues from which were intended, primarily, to reduce the tariff deficits being generated in the electricity sector. Following this extraordinary contribution, which continued into 2015 and 2016, the government set up the Fund for the Systemic Sustainability of the Energy Sector, with the goal of creating of policies of a social and environmental nature related to energy-efficiency measures and the reduction of the tariff deficit in the energy sector, and funded in part from the revenues obtained through the special contribution. The Portuguese state budget for 2017 establishes the extension of this extraordinary contribution into 2017.

The successive extensions of this extraordinary contribution have resulted in litigation cases, currently pending in the Portuguese courts.

15 More information on this project can be found at www.inovgrid.pt/en.
Also worth noting is the restructuring of social tariffs in Portugal. Social tariffs have been deeply reformed in 2016 in order to be more accessible and usable for the interested parties (i.e., people undergoing economic difficulties).

VII CONCLUSIONS AND OUTLOOK

The Portuguese power market is currently a mature market with a generation mix in which green energies have a significant weight, both in terms of installed capacity and power output. The natural gas market has room for expansion considering that there are still interior regions that do not have distribution networks. However, tepid economic growth and the need to keep grid tariffs low means that ‘connections’ growth in this sector will remain slow in Portugal.

The main challenges in the energy market in Portugal relate to the completion of the liberalisation of the electricity and natural gas industries. Although market efficiency is expected to increase and competition within the market should benefit end users, the full effects of liberalisation are not yet certain.

In the foreseeable future, it is expected that there will be a place for ‘community power’, through the increase in self-generation capacity by households and consumers. The implementation of smart grids and affordable rooftop photovoltaic enables consumers to become self-sufficient, and even net sellers of electricity.

In relation to this, we see electric vehicles slowly moving to conquer a relevant market share, in part due to technological advances mentioned above (and also advances in battery energy storage).
Chapter 29

SENEGAL

Mouhamed Kebe and Codou Sow-Seck

I OVERVIEW

The Senegalese energy sector is notable on one hand for its relatively small size, and on the other hand for the predominance of imported liquid fuel.

Given the high costs of fuel, for several decades the sector faced a deep crisis, marked by a lengthy electricity shortage.

This situation impacted adversely on the growth of the country, and prevented it from efficiently attracting foreign investment.

To tackle the problem, the government of Senegal (GoS) took steps to improve the sector and make it more reliable. Several measures were taken to this effect.

In 2011, further to an assessment of the sector, the GoS implemented a 2011–2015 electricity emergency plan. The main object of this plan was to set up a strategy aiming at piloting the sector towards a sustainable path.

In October 2012, the GoS adopted a Letter of Development Policy for the Energy Sector. The Letter of Development Policy outlines the sector policy objectives of the newly elected government to improve the sector’s performance in the medium term. The main axes of the Letter of Development Policy for the Energy Sector are:

1. ensuring energy security and increasing energy access for all;
2. developing a policy mix combining thermal generation, bio-energy, coal, gas, and renewables and seizing the opportunities of regional interconnections;
3. continuing and accelerating the liberalisation of the energy sector by encouraging independent production and institutional reform of the sector;
4. improving the competitiveness of the sector in order to lower the cost of energy and reduce sector subsidies; and
5. strengthening regulation of the sector.

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5. strengthening regulation of the sector.

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The GoS also set up a special fund to support fuel provision for electricity generation (the Special Fund for Energy).

In 2013, the GoS adopted a plan for developing production facilities based on an energy policy mix combining coal, natural gas, hydroelectricity and renewable energies. The upshot of these measures was the enactment of several laws and regulations aiming to adapt the regulatory framework to these new policies.

II REGULATION

i The regulators

The regulators of the energy sector in Senegal are:

- the Minister of Energy;
- the Electricity Sector Regulatory Commission (CRSE), which is an independent authority responsible for regulating the production, transmission, distribution and sale of electricity; and
- the National Committee for Hydrocarbons, created by Act No. 98-31 of 14 April 1998 on import, refining, storage, transport and distribution of hydrocarbon, which is a consultative organ.

The regulators are different for each segment of the energy sector:

- the CRSE deals with the electricity segment; and
- the National Committee for Hydrocarbons deals with the oil and gas segment.

Minister of Energy

The Minister of Energy develops and proposes general policy and standards for the electricity sector to the President of the Republic. He also grants licences and concessions provided by the Energy Act, and has the power to remove them. The Ministry of Renewable Energy is responsible for framing policies for the promotion of electricity generation from renewable energy sources and thus plays a key role in formulating policies and monitoring decisions taken in consultation with the Ministry of Energy and other relevant stakeholders for promoting decentralised renewable energy applications.

Electricity Commission

The Electricity Commission has, as part of its regulatory mission, a number of main responsibilities that include advisory functions and decision-making powers. In its advisory functions, it contributes to the development of national strategies related to the electricity sector:

- advising the Minister of Energy on all legislative and regulatory plans for the electricity sector; and
- offering to the Minister of Energy orders related in particular to the rights and obligations of companies, third party access to the network and business relationships with their customers.

The Commission also has powers to take individual decisions in the energy sector. Thus, it has the skills to:

- examine applications for a licence or concession;
- ensure compliance with the terms of the licences and concessions;
c make changes to general licences, concessions or their specifications;
d ensure compliance with technical standards;
e ensure compliance with competition in the sector;
f determine the structure and composition of tariffs; and
g apply, if necessary, sanctions to operators for breaches of duty.

The Commission also has broad powers of investigation in the sector.

National Committee for Hydrocarbons
The National Committee for Hydrocarbons gives opinions and recommendations relating to the hydrocarbon sector on the request of the Minister of Energy and Mines. It suggests law modifications, gives opinions on licence requests and suggests sanctions against licence holders violating their obligations. It also conducts periodic consultations with operators, consumers and the other institutions of the hydrocarbon sector; analyses and evaluates the impact of the liberalisation rules on the performances of the sector; and follows the evolution of prices.

Main sources of law and regulation
The applicable law in Senegal on the energy sector mainly consists of the following laws and decrees.

Electricity segment
a Act No. 98-29 of 14 April 1998 relating to the electricity sector;
b Decree 1998-333 of 21 April 1998 related to the organisation and functioning of the electricity regulation commission;
c Decree No. 98-334 of 24 April 1998, laying down the conditions and terms of deliverance, withdrawing licences or production licences, and the distribution and sale of electricity;
d Decree No. 98-335 on the principles and procedures of determination and revision of the tariff conditions;
e Decree No. 98-336 of 21 April 1998 on equity between companies in the electricity sector; and
f Act No. 2002-01 of 10 January 2002 repealing and replacing Article 19, paragraphs 4 and 5, and Chapter IV of Law No. 98-29 of 14 April 1998 on the Electricity Sector

Oil and gas segment
a Act No. 98-05 of the Petroleum Code dated 8 January 1998;
b Decree No. 98-810 of 6 October 1998, setting out the terms and conditions of application of Law No. 98-05 of the Petroleum Code dated 8 January 1998;
c Decree No. 98-338 of 21 April 1998, fixing the conditions of exercise of the activities of import, storage, transport and distribution of hydrocarbons; and
d Decree 2011-529 of 26 April 2011 laying down the terms of use of natural gas produced from the wells of the national subsoil.
Senegal

Renewable energy

a Act No. 2010-21 of 20 December 2010 on the framework law on renewable energy; and

b Decree No. 2011-2013 implementing the Act on renewable energies and related to conditions of purchase and pricing of the electricity produced by power plants from renewable energy sources, and the conditions of their connection to the grid.

ii Regulated activities

In the oil and gas segment, approvals are granted to undertake the following petroleum operations:

a prospection;

b exploration of hydrocarbons;

c temporary exploitation; and

d exploitation of hydrocarbons.

In the electricity segment, approvals are required from the Minister of Energy on a proposal from the commission of electricity regulation to conduct the following activities:

a the production and sale of electric energy;

b the distribution of electric energy; and

c the sale of electric power industry.

Furthermore, only the National Electricity Company of Senegal (SENELEC) is entitled to exercise a wholesale purchasing activity, and transport and sell wholesale electric power throughout the national territory for a period to be defined by a concession contract with the Minister for Energy. It also owns about half of the generation capacity, with the remainder being owned by independent power producers (IPPs) that generate electricity and sell it exclusively to SENELEC.

Senegal was among the first countries in Sub-Saharan Africa to introduce private sector participation in the power sector in the late 1990s. The first IPP was GTi, a 52MW combined cycle oil-fired power plant commissioned in 2000. The second IPP was Kounoune, a 67.5MW power plant commissioned in 2008. The track record of IPPs in the country has been mixed, mainly as a consequence of variations in the quality of fuel delivered, grid instability and other technical difficulties that have reduced electricity output from these plants. Some of these issues have been resolved and the GoS remains committed to relying on private sector investment to bridge the generation gap.

SENELEC is the concessionaire for the transmission and distribution network in Senegal (with the exception of Manantali interconnection) and operates in a monopoly condition for the purchase and sale of wholesale power.

In the electricity sector, the Minister of Energy grants licences or concessions based on proposals from the CRSE. The process for obtaining licences other than those relating to independent production of electricity or concessions is as follows:

a the applicant addresses his or her request for a licence or concession to the Minister of Energy. A copy of this application is also addressed to the President of the Regulatory Commission of Electricity Sector; and

b the Minister of Energy sends the file to the CRSE for its opinion.
Before issuing an opinion on an application for a licence or concession under the Energy Act, The Commission:

a publishes the fact that it is proposed to grant a licence or concession; and

b indicates the period, which may not be less than 30 days from the date of publication of the application, during which any interested party may apply, and in which he or she must be duly answered.

In the event that the applicant submits more than one application for a licence or concession, the statement is made in such a way that they can be granted or denied at the same time.

In the event that a licence application or licence is refused, the Minister of Energy must provide the candidate with the reasons for rejection, which must be objective, non-discriminatory and properly documented. The candidate may appeal for judicial annulment of the rejection.

Assuming that the CRSE gave a favourable opinion and without reserve, the Minister of Energy has a period of 45 days to issue the concession or the licence that has been applied for. If there is failure to reply within that time, the licence or concession is deemed to be granted automatically. The report is compiled by the CRSE.

The company seeking a concession or licence is not excused from obtaining all approvals required under applicable regulations, including town planning, security personnel, the public and the environment.

It must, in addition, comply with any applicable provisions on competition. The licence for production of electric energy is granted automatically by the Minister of Energy at any selected company following a call for tenders for a independent production, launched for this purpose by SENELEC.

The selection process of an independent producer is subject to the approval of the CRSE.

iii Ownership and market access restrictions

There is no discrimination against businesses conducted or owned by foreign investors. In fact, there are no barriers regarding 100 per cent ownership of businesses by foreign investors in most sectors, including the hydrocarbon sector. Article 5 of the Petroleum Code provides expressly that the state may authorise a company to undertake petroleum operation irrespective of its nationality.

In the electricity segment, there are limitations on cross equity participation between the various activities in the electricity segment, that cannot exceed a certain threshold.

iv Transfers of control and assignments

The process of approval for transfer is different depending on whether it concerns the electricity sector or the hydrocarbon sector.

Regarding the electricity sector, any transfer or merger and acquisitions operations must be brought to the attention of CRSE at least three months before they come into effect.

Within this period, the CRSE has three months to ensure that participation does not confer on its holder the direct or indirect control of the company concerned, and particularly its trade policy, in which case it shall issue to the parties a letter of no objection. If necessary, it invites the parties to modify the draft agreements that have been submitted.
Regarding the oil and gas segment, the Petroleum Code states that the hydrocarbon exploitation titles, conventions or service contracts may be assigned or transferred to entities that possess the technical and financial capabilities to carry out the petroleum operations subject to prior authorisation.

Requests for assignment and transfer, unless such transactions are made between affiliated companies, must be addressed to the Minister of Energy for approval. This approval will be deemed given if the Minister does not provide notification of his or her justified refusal within 60 days from the receipt of the request.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Under Senegalese law, the activities of production and distribution of electricity are regulated. To promote fair competition between different actors in the electricity sector, equity investments among different segments of the industry are controlled. The holder of a distribution concession, except SENELEC, cannot acquire, directly or indirectly, an interest in the share capital of a production licence holder or the latter in the capital of the first, except where:

a the capacity of production facilities of the production licence holder does not exceed 15 per cent of the total production capacity of electric power in the territory of Senegal, this threshold could not be exceeded thereafter; or

b such facilities use the following sources of energy: solar wind and tidal power.

Any acquisition must be brought to the attention of the Commission.

However, the production, transmission and distribution of electricity by power plants and transmission and distribution networks, including backup facilities, are free provided they are issued by a company or household for own consumption or to those of its affiliated companies, since such power stations or networks are established within private property without encroaching on the domain of the state or the national field.

Nevertheless, the exercise of activities for own consumption is subject to a prior declaration addressed to the Minister of Energy who may authorise the sale of any production surplus subject to compliance with the provisions of Article 19, paragraph 5.

As part of a concession or a service contract, the right to operate a hydrocarbon deposit entitles the holder to the right to transport, according to the stipulations of the agreement or service contract, the product resulting from its operations to the storage points for processing, loading or consumption.

Hydrocarbon transportation rights may be transferred to third parties, individually or jointly, by any holder of exclusive rights to operate under the conditions set out in the agreement or service contract.

ii Transmission/transportation and distribution access

Companies holding a production licence for electricity shall submit to the Regulatory Commission, upon signature, grid connection contracts they conclude with holders of transmission or distribution concessions.

It is prohibited for providers of service to grant exclusivity or preferential access.
A company performing transmission or distribution of electric energy cannot deny access to electricity producers if their request is normal and made in good faith, nor can they apply discriminatory prices. Only differences between producers on an objective basis can justify differences in tariffs.

### Rates

Tariff conditions are defined in the specifications annexed to licences or concessions. They are determined on a capped price basis and not on the cost of the service. They are applicable for a determined period previously defined in the said specifications. The holder of a licence or concession is able to vary the rates charged to consumers within the limits of the defined capped price.

The Minister of Energy and the CRSE set the fares and allow income levels they consider sufficient to allow the licence or concession holder, operating efficiently, to obtain a normal rate of return relative to a base charge fee.

### IV ENERGY MARKETS

#### i Development of energy markets

The Senegalese energy market is composed of:

- private industrial units;
- SENELEC; and
- independent power producers.

To accomplish the tasks assigned to it under the concession contract and the specifications, SENELEC launches tenders at the auction, according to the provisions of an order made by the Minister of Energy to receive required supply offers from companies pursuing or contemplating engaging in an activity of production of electrical energy.

The CRSE monitors compliance with the principles of fairness, transparency and non-discrimination in appeal procedures, tendering and selection of supply offers. SENELEC concludes, after tendering, contracts for the purchase of electric energy.

Senegal is marked by an energy crisis, and the government has implemented a plan titled Plan Takkal to deal with this situation. The government felt it was necessary to take a number of measures to redress the energy deficit.

In the segment of gaseous products, it was decided to reserve the use of gas obtained from national subsoil for SENELEC and independent power producers. These independent producers are required, whatever the source of the energy they produce, to supply their entire production to SENELEC.

#### ii Energy market rules and regulation

Pursuant to the energy law texts, SENELEC alone may exercise a wholesale buying activity, transportation and wholesale of electricity throughout the national territory for a period defined by a concession contract signed with the Minister of Energy and by the specifications attached to it.

During the period referred to, SENELEC has the quality of a single buyer of electricity. Under the Electricity Act SENELEC is granted, for a period, the monopoly of wholesale buying and transport. However, a large place is given to the private sector both in production and in distribution and sale of electrical energy.
Regarding the oil and gas segment, the hydrocarbon deposits carriers may be required, under conditions laid down in their agreement or service contract, to assign priority products of their operations to cover the domestic consumption needs of the country. In this case, the transfer price should reflect the international market price.

After meeting the domestic needs of the country, the farmers’ production share can be exported freely and free of all duties and export taxes.

### iii Contracts for sale of energy

Any company planning to sell electricity must obtain a licence for this purpose from the Minister for Energy. Attached to the licence are specifications that determine the territorial scope where appropriate, the duration and the public service obligations that are imposed on the incumbent. It indicates the type and consumption of electrical energy customers that the owner can service.

### V RENEWABLE ENERGY AND CONSERVATION

#### i Development of renewable energy

The energy crisis and the high dependence of Senegal on non-renewable energy have led the government to review its policy on supply facilities, including turning to renewable energy.

The GoS has made power sector development a key component of its Plan Sénégal Emergent, which aims to make Senegal an emerging economy by 2035. The country’s ability to achieve this ambitious goal depends in large part on tackling key challenges including moving away from dependence on imported fossil fuels, ensuring affordability and expanding electricity access – particularly in rural areas.

Moreover, Senegal is a country with a strong favourable natural potential for development of renewable energy such as solar, wind, hydropower and biomass.

**Potential for renewable energy**

**Solar**

Senegal is endowed with a large solar energy resource. Over most of country’s territory, the solar irradiation is above 2,000kWh/m²/year (Ministry of Renewable Energy). This provides good prospects for photovoltaic solar power projects. The falling prices of photovoltaic panels and system components make solar a very attractive solution, particularly when the costs of the alternatives – imported oil products – are high.

**Wind energy**

Senegal’s wind power potential is concentrated along the coast and in particular the section of the coast between Dakar and Saint-Louis.

**Hydro**

Senegal has about 3 billion cubic meters per year of renewable groundwater resources, excluding those groundwater resources that overlap with surface water. The Senegal River represents a significant hydroelectric potential estimated at 1,200MW and partially exploited at Manantali plant (200MW) commissioned in 2002, providing electricity to Senegal, Mali and Mauritania via an interconnection line.
To promote this green energy, Senegal has implemented an incentive legal framework for the production, storage, transportation and sale of renewable energy. It is in this context that Act No. 2010-21 on orientation law of renewable energy and its implementing Decree No. 2011-2013 were adopted.

These laws include tax incentives to attract investment. Purchases of materials and equipment for production, operation and self-consumption of renewable energy benefit from tax incentives, as do purchases of materials and equipment for research and development in the field of renewable energy.

Regarding biofuels, companies whose production is for the domestic market enjoy a tax exemption on their operating revenues for a period of five years. Similarly, purchases of materials, seeds and seedlings for cultivation and use of biofuels are exempt from value added tax and customs duties.

**Regulatory framework for sustainable energy**

The regulatory framework in Senegal comes in the form of decrees that are promulgated periodically. The two most important and recent decrees for implementing the Law on Renewable Energy were issued in December 2011.

They lay down the purchase and remuneration conditions for electricity generated by renewable energy plants, the conditions for the connection of these plants to the grid and the conditions for purchase and remuneration of surplus electricity from captive power plants generating electricity from renewables.

However, reduced taxes and customs duties applicable to renewable energy equipment are only considered on a case-by-case basis. The decrees are therefore aimed at eliminating inefficiencies, decreasing the cost of supply to consumers and promoting development funding for the energy sector.

The implementing decrees of the Renewable Energy Law are as follows.

Decree No. 2011-2013 provides conditions of power purchase and remuneration for electricity generated by renewable energy plants and the conditions of their connection to the grid. It also provides the formula for the avoided cost, which serves as a reference for calculating the power purchase price cap. It also contains elaboration on renewable power purchase obligation and feed-in tariffs for different renewable energy technologies.

Decree No. 2011-2014 provides the conditions of power purchase of surplus renewable energy-based electricity from self-producers. It has fixed the maximum intake from renewable energy sources. It has also determined the purchase price, conditions of purchase of surplus energy, connection to the grid, etc.

Law No. 2010-22 of 15 December 2010 of the biofuel sector – this law on the orientation of the biofuels sector, was adopted in 2010 with the aim of creating favourable conditions for the development of the biofuels sector and providing answers to the problems of economic growth, based on a policy of energy self-sufficiency through the development of biofuels. The law therefore covers all components of the biofuels sector including production, processing, storage, transport, marketing and distribution. It determines the operating environment for all forms of biofuels and the conditions and standards for their production and exploitation on Senegal’s national territory, or through international cooperation.
Chapter 30

SOUTH AFRICA

Lido Fontana and Sharon Wing

I OVERVIEW

The transformation in the South African energy sector in relation to renewable energy hardly progressed in 2016. This is because of state-owned power provider Eskom Holdings SOC Limited (Eskom) pushing back on its obligation to sign any further power purchase agreements with 36 independent power producers (IPPs) from bid windows 3.5 (principally the Redstone CSP project) and 4 (the preferred bidder announcements in respect of round 4.5 are also significantly delayed with no certainty on when these will be announced). There is also significant uncertainty with respect to the Small Scale Renewable IPP Programme. Eskom argues that renewable energy is too expensive, and that it is being compelled to buy electricity it did not negotiate (as the Department of Energy has been the procuring body in respect of the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) in South Africa, with Eskom being required to sign a standardised form of power purchase agreement).

Although the implementation of new renewable energy projects have stagnated, it should still be noted that investments in renewable energy under the REIPPPP programme have been approximately 193 billion rand of private sector investment as of June 2016.

With the apparent decline in support for renewables, there have been apparent positive steps forward in the conventional energy sector with two significant coal baseload power projects (Khanyisa and Thabametsi) being announced as preferred bidders, and progress being undertaken towards financial closure. Once operational, both projects will collectively add 863.3MW to the national electricity grid. In addition, the South African government has called for expressions of interest for a proposed 600MW gas-fired power project alongside one or more state-owned companies. This project will exist in parallel with South Africa’s 3,123MW LNG-to-Power IPP Procurement Programme, which saw a preliminary information memorandum being released by the Department of Energy on 4 October 2016.

The South African government has also indicated support for development of shale gas in South Africa, and Eskom released a request for information for a nuclear new-build programme that it is planning, to add 9600MW to the national power grid. Several ministerial determinations (i.e., regulations providing for state procurement of additional
energy capacity) pertaining to coal, gas and nuclear have been determined by the Minister of Energy; however, the nuclear determination was recently overturned by the courts in South Africa (this will be discussed later in this chapter).

II REGULATION

i The regulators

In South Africa, energy regulation is split among three regulators, being:

a the National Energy Regulator (NERSA), established under the National Energy Regulator Act, 2004, which regulates electricity, piped gas and petroleum pipelines industries;

b the National Nuclear Regulator (NNR), established under the National Nuclear Regulator Act, 1999, which regulates nuclear energy; and

c the Petroleum Agency of South Africa (PASA), established under the Mineral and Petroleum Resources Development Act 28, 2002 (MPRDA), which regulates petroleum exploration and production.

Each of these Acts, together with other key legislation regulating the relevant industry (the Electricity Regulation Act, 2006 (the Electricity Regulation Act) in the case of electricity; the Petroleum Pipelines Act, 2003 in relation to the petroleum industry; the Gas Act, 2001 (the Gas Act) as regards piped gas; the Nuclear Energy Act, 1999 in the case of nuclear energy; and the MPRDA in respect of petroleum exploration and production) establish the framework for energy regulation in South Africa. That legislation, together with regulations, notices, rules and guidelines issued thereunder grant expansive regulatory power to the regulators, including the powers to issue, amend and revoke licences, as well as to approve tariffs.

ii Regulated activities

Under the Electricity Regulation Act, a licence is required for the operation of each of electricity generation, transmission and distribution facility and in respect of the import, export and trading of electricity (collectively, the Licensed Activities). That Act provides exemptions for licences in respect of (1) any generation plant constructed and operated for demonstration purposes; (2) any generation plant constructed and operated for own use; (3) any non-grid connected electricity supply other than for commercial use; and (4) any other activity relating to the Licensed Activities in respect of which NERSA has determined that a licence is no longer needed. In relation to the last referenced exemption, NERSA may require that persons undertaking such activities nevertheless register the activities with NERSA.

A person obliged to hold a licence in terms of the Electricity Regulation Act must apply to NERSA for the licence in the form and applying the procedure prescribed. The application must be accompanied by the prescribed licence fee. The information required to form part of such an application includes, among other things, (1) a description of the applicant, including the vertical and horizontal relationships with other persons engaged in the operation of the relevant Licensed Activity; (2) the administrative, financial and technical abilities of the applicant; (3) a description of the proposed generation, transmission or distribution facility to be constructed or operated; (4) a detailed specification of the services that will be rendered under the licence; (5) a general description of the type of customer to be served; (6) the tariff and price policies proposed to be applied; and (7) evidence of
compliance with the Integrated Resource Plan. The process entails publication of notices of the application in appropriate newspapers or other media, the applicant responding to objections to the application being granted, and culminates in NERSA making a decision on the application within the prescribed period.

In terms of the National Nuclear Regulator Act, 1999, no one is allowed to procure a site, construct, operate, decontaminate or decommission a nuclear installation except under the authority of a nuclear installation licence. The process prescribed for the making, consideration and issue of such licences is similar to that outlined above, albeit that the 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 such other body or person as the chief executive officer of the NNR determines.

Licences are also required for the storage, transportation and reticulation of gas and petroleum through petroleum pipelines. The licences for the storage, transportation and reticulation of petroleum through pipelines are issued by NERSA. Although the procedure for applying for the licenses is similar to that of Licensed Activities, only owners of storage, transportation and reticulation facilities respectively, may apply for licences for the storage, transportation and reticulation of petroleum.

Licences for exploration or production rights in petroleum resources are generally issued pursuant to bidding processes initiated by the Minister of Mineral Resources. The Minister invites applications for exploration and production rights in respect of designated blocks on predefined terms and conditions. Successful applicants are still required to submit applications to PASA for a reconnaissance permit, technical cooperation permit, exploration right or production right. In certain instances, the Minister will upon consideration of PASA’s recommendations either grant or refuse the application. In the event that the application is granted, the exploration right or production right must be registered with the Mineral and Petroleum Titles Registration Office, while the permits must be filed and noted with the Mineral and Petroleum Titles Registration Office. The rights issued by the Minister of Minerals Resources only constitute limited real rights.

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, while the balance of the country’s electricity was sourced mainly from municipalities. Like electricity generation, transmission and distribution capacity was restricted to the state and state-owned entities.

In 2011 the South Africa government launched the Integrated Resources Plan, which called for the doubling of the country’s electricity capacity from its 2010 level of 238,272GWh using a diverse mixture of energy sources, mainly coal, gas, nuclear and renewables, including large-scale hydro to be imported from other countries in the southern African region.

The REIPPPP has served as the primary vehicle through which the South African government has procured renewable energy from private sector power producers. That programme provides that projects developed thereunder must be 40 per cent owned by South Africans with people of colour holding a minimum of 12 per cent (with a target of 20 per cent),

5 Section 10(2)(a)–(h) of the Electricity Regulation Act, 2006.
6 Section 73(1) of the MPRDA.
7 Section 5(1) of the MPRDA.
and a minimum of 2.5 per cent ownership by local communities (those communities within a 50km radius of the project). In addition to the ownership requirements, REIPPPP bidders are also required to bid on other non-price factors known as ‘economic development requirements’, which are designed to achieve the government’s Integrated Resource Plan objectives of promoting job growth, domestic industrialisation, community development and black economic empowerment (a programme designed to counter the adverse economic impacts of apartheid by initiating, among other things, ownership and control of capital by South Africans of colour, women and disabled persons (Historically Disadvantaged Persons or HDSA), as well as skills transfer and enterprise development of legal entities owned by HDSAs).

The Coal Baseload IPP Procurement Programme provides that 51 per cent of each project must be owned by South Africans. Ownership criteria for the gas-to-power and nuclear procurement is still unknown. Save as outlined above, there are no foreign ownership or aggregate holdings constraints under the REIPPPP and the Coal Baseload IPP Procurement Programme.

The preliminary information memorandum (PIM) for the Liquefied Natural Gas to Power Independent Power Producer Procurement Programme (LNG-to-Power IPP Procurement Programme) was released on 4 October 2016 by the Department of Energy. The PIM provides insight into the proposed LNG-to-Power IPP Procurement Programme and provides the basic framework being considered by the Department of Energy 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. However, at the time of writing there is no certainty when the RFQ will in fact be issued. In all probability the RFQ will only be released once the Department of Energy has finalised the contentious updated Integrated Resource Plan, which was released for public comment in December 2016 (discussed infra).

The Petroleum and Liquid Fuels Charter, issued under the MPRDA provides a framework for black economic empowerment within that industry. Holders of exploration and production rights are obliged to reserve shareholdings for HDSAs in their respective companies. Companies active in the upstream sector are obliged to reserve participation interest of not less than 9 per cent for HDSAs, while companies in the midstream and downstream sectors must reserve a 25 per cent participating interest for HDSAs. These companies must further make contributions towards the funding of skills development initiatives.

iv Transfers of control and assignments

Transfer of control and the assignment of a licence issued in respect of Licenced Activities, including generation licences issued to IPPs, are restricted by conditions imposed on the licensee by NERSA. Accordingly, each licence must be reviewed on a case-by-case basis to determine what specific approvals are required for its transfer. However, the Electricity Regulation Act generally provides that a licensee may not cede or transfer its powers or duties under a licence to any other person without the prior consent of NERSA. The transfer of control and the assignment of licences issued to IPPs are further regulated by

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Section 15(1)(k) of the Electricity Regulation Act, 2006.
the Implementation Agreement between the South African Department of Energy and the IPP; that agreement provides for, *inter alia*, government support for the development and financing of relevant IPP projects.

A nuclear licence is not transferable in terms of the National Nuclear Regulator Act, 1999.

Regarding the transfer of control and the assignment of a licence or permit in the petroleum sector, the position is as follows: (1) a reconnaissance permit is not transferable, nor does it grant the holder any exclusive right; (2) a technical co-operation permit is not transferable, but the holder of the right has an exclusive right to apply and be granted an exploration right over the area described in that permit; (3) an exploration right is transferable and the holder has an exclusive right to apply for and be granted a renewal of the right, or for a production right, over the area described in that exploration right; and (4) a production right is transferable and the holder has an exclusive right to apply for and be granted a renewal of that production right.

The consent of the Minister of Mineral Resource must be obtained in the event that a holder wishes to cede, transfer, let, sublet, assign, alienate or otherwise dispose of a prospecting right or exploration right or interest in such a right, or a controlling interest in a company that holds such a right (except in the case of a change in controlling interest in a listed company). An application for the Minister’s consent must set out and prove that the transferee has the required technical and financial ability to comply with the obligations imposed on the holder of the exploration or production right.

A licence granted to a person or entity under the Gas Act may not be assigned to another party, is valid for a period of 25 years and may be renewed after the expiry of the licence period.

### III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

#### i Vertical integration and unbundling

**Electricity**

The Independent System and Market Operator (ISMO) Bill was introduced in 2011. The ISMO Bill intended to restructure the electricity supply industry by providing for the establishment of the ISMO as a state-owned company autonomous from Eskom to serve as the dedicated procurer of electricity for onward sale to wholesale off-takers. The ISMO Bill, when established would have removed the operation of the transmission grid from Eskom and allow for easier access to the grid by IPPs.

However, the ISMO Bill was suddenly withdrawn in its final stages of being adopted by its sponsor, the Department of Energy (DoE), in June 2015.

In 2015, the government had apprised the market that a new ISMO Bill was being drafted; however, a draft has not yet been released for public comment.

**Gas**

The gas pipeline network comprises the Rompco Pipeline9 (used to transport gas from Mozambique into South Africa), which is the main pipeline network in South Africa, and

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9 This is a joint venture between South African Gas Development Company Limited (iGas), Companhia Limitada de Gasoduto (CMG) and Sasol Gas Holding Proprietary Limited.
several other short-range pipelines, which are privately owned. Owners of these pipelines are compelled under their licence conditions to grant access to third parties on commercially reasonable terms only to the extent that they have uncommitted capacity in these transmission pipelines.

**ii Transmission/transportation and distribution access**

The transmission of electricity is currently being undertaken exclusively by Eskom. Save for contractual commitments under wheeling agreements with Eskom, there is no obligation on Eskom to provide third-party access to the transmission grid. Eskom distributes electricity directly to customers and to municipalities, who redistribute the same (see Section IV on energy markets, *infra*).

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, it still remains a complicated process. NERSA has said that it is currently working on developing a standardised framework for these arrangements.

The Gas Act provides that a licensee of a gas transmission pipeline must provide access to its transmission pipelines to third parties, while the Petroleum Act provides that a licensee of a petroleum pipeline must provide access to its loading facilities and uncommitted capacity in storage facilities to third parties. These requirements will be provided as conditions on a licensee’s licence. However, a distributor is not compelled to grant access.

**iii Rates**

**Electricity**

Eskom’s tariffs are regulated by NERSA under the Electricity Regulation Act. These tariffs are based on Eskom’s costs plus a reasonable rate of return.

A suite of supply policy guidelines for the integrated national electrification programme 2016/2017 was released by the Department of Energy (the integrated national electrification programme’s objective is to achieve universal access to electricity by 2012, which date was changed to 2019 and is one of the pillars of the South African government’s energy transformation strategy, born in the 1998 White Paper on Energy Policy).

The objective of the policy guidelines is to develop and provide a suite of supply frameworks in line with the 1998 White Paper Policy and guidelines, thus providing a uniform set of standardised supply options and connection fees, as well as a uniform approach to electrification tariffs for electrification customers for all licensed entities providing electricity.

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10 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 DoE is mandated to regulate the tariffs applicable to the manufacturing, wholesaling and retailing of petroleum products through the implementation of the Petroleum Products Act, 1977 and the responsibility resides with the Controller of Petroleum Products (this is too wide a matter to be discussed in this chapter).

iv Security and technology restrictions

South Africa’s nuclear legislation,\(^\text{11}\) which is based on several international conventions to which South Africa is a party,\(^\text{12}\) provides for the establishment of internationally endorsed protocol on nuclear safety, political and financial risk and ultimate state liability. The NNR is mandated to provide for the protection of persons, property and the environment against nuclear damage as the competent authority for nuclear regulation in South Africa.

The NNR has regulatory requirements developed in accordance with the National Regulator Act, the South African Nuclear Energy Policy (2008), Minimum Information Security Standards and IAEA Nuclear Security Series No. 7. The IAEA Nuclear Security Series No. 7 is the International Atomic Energy Agency implementing guide on Nuclear Security Culture, which prescribes characteristics, attitudes and behaviour of individuals, organisations and institutions in supporting the establishment of effective nuclear security. The development of the regulatory requirements is to assure nuclear security or physical protection systems at nuclear installations or associated actions in South Africa.\(^\text{13}\)

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 to, \textit{inter alia}, regulate trading activities such as electricity resale (buying and selling). Eskom purchases electricity that is supplied by IPPs to the national grid and in turn sells the electricity to industrial, mining, commercial, agriculture and residential customers in South Africa, some members of the Southern African Development Community and redistributors (municipalities), who in turn redistribute electricity to businesses and households within their areas.

Section 155(6)(a) and (7) Schedule 4B of the Constitution\(^\text{14}\) lists electricity reticulation as a competence of municipalities in South Africa. Each municipality is a service authority for the electricity reticulation function for the whole of its jurisdictional area and has the right to set tariffs in respect of its sale of electricity in its areas of jurisdiction. On 30 October 2014, the

\(^{11}\) Nuclear Energy Act 46 of 1999.
\(^{12}\) 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 Radiology Emergency, 1986; the Convention on Physical Protection of Nuclear Material, 1979. See also: www.nti.org/treaties-and-regimes/treaties/.
\(^{13}\) 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 onsold to multiple customers by persons with bulk supply points, such as bodies corporate and office parks (known as Resellers). These Resellers are ‘non-licensed traders’ of electricity in terms of the Electricity Pricing Policy. Resellers are not required to hold a distribution licence, but they must be registered with the licensed authority (generally a municipality) from which the bulk connection was obtained.

To resell electricity the licensed authority must complete a service level agreement with the Reseller to operate in its area of jurisdiction. The Reseller is also obligated to supply its customers with information on tariffs and tariff structures.

South Africa is part of the Southern African Power Pool (SAPP), which includes several Southern African utilities. While SAPP faces a number of major challenges such as lack of maintenance of infrastructure, high transmission losses and limited funds to finance new investments, the energy volumes traded by Eskom since its inception in 1996 (around 4,500GWh) have increased steadily to over 9,977GWh a year since 2003.

ii Natural gas
Natural gas is likely to be a key feature of the South African energy mix as it will facilitate South Africa’s transition from coal to a low-carbon energy sector and provide for its long-term energy security. Some noteworthy developments in the gas sector during 2016 are given below.

Shale gas
Exploration right applications have been submitted to the Department of Mineral Resources to explore the possibility of a shale gas resource of 485 trillion cubic feet in the Karoo Basin. The South African government, based on available scientific evidence provided (we assume from the Strategic Environmental Assessment mandated in 2015 to provide a science-based assessment to improve government understanding of the risks and opportunities of shale gas development and to inform on shale gas regulations by 2017), has now allowed for the shale gas development in the Karoo Basin (this development was, however, announced in the first quarter of 2017). To date, none of the exploration right applications for the rights to explore for shale gas have been granted.

600MW gas
The government of South Africa commenced with the invitation for interested parties to respond to the expression of interest, which closed on 20 June 2016 for the Gas 600MW IPP Procurement Programme in order for the government to determine the private sector interest in seeking appointment as a strategic partner to one or more state-owned companies to implement the project.

Gas pipeline

Although there is only one main gas pipeline network in South Africa (see Section III, supra), on 1 March 2016, SacOil Holdings Limited announced that a cooperation agreement had been concluded with new partners and the China Petroleum Pipeline Bureau for the construction of an estimated US$6 billion, 200km, large-diameter pipeline to transport natural gas from Mozambique’s Rovuma Basin to Gauteng, South Africa.

iii Nuclear

The South African government has committed itself, by means of its Nuclear Energy Policy and Integrated Resource Plan, to an energy mix consisting of coal, gas, hydro, nuclear, solar and wind.

The following developments have catapulted nuclear into high gear:

a. Eskom’s submission of a final environmental impact assessment to the Department of Environmental Affairs;

b. the submission of a nuclear installation site licence application to the National Nuclear Regulator for assessment;

c. a ministerial determination was published in a Government Gazette on 14 December 2016, providing for new generation capacity of 9,600MW from nuclear energy (see Section VI, infra); and

d. on 20 December 2016, Eskom released a request for proposals for South Africa’s new-build programme after the aforementioned determination was published by the Minister of Energy.

The development of nuclear power has been met with constant opposition in relation to the environmental and financial impact it may have. In fact, the Western Cape High Court delivered a judgment on 26 April 2017, ruling that the following are unlawful, unconstitutional and have been reviewed and set aside:

a. the decision to table Russian IGA before parliament in terms of Section 231(3) of the Constitution;

b. the decision to table the agreement for cooperation between the government of the Republic of South Africa and the United States of America concerning Peaceful Uses of Nuclear Energy before Parliament;

c. the decision to table the agreement between the government of the Republic of Korea and the government of the Republic of South Africa regarding the Cooperation in the Peaceful Uses of Nuclear Energy;

d. the ministerial determination dated 14 December 2016 (discussed supra); and

e. the determination gazetted on 21 December 2015 (discussed in the 2015 chapter) in relation to the requirement and procurement of nuclear new generation capacity.

Accordingly, requests for proposals or for information issued pursuant to the determination were also set aside. The Department of Energy has decided not to appeal the judgment and has advised that it will start the nuclear procurement process afresh.
V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

Background
The South African energy sector has undergone extensive transformation in recent years. In August 2011, the government’s Department of Energy launched the REIPPPP, an unprecedented, world-class procurement programme with the audacious goal of the country producing 17,800MW of renewable energy by 2030. This objective was set against a backdrop of the country’s then current generation capacity becoming increasingly inadequate to meet the ever rising electricity demand of a growing economy. The inadequacy manifested in Eskom, with a monopoly over generation and transmission capacity, implementing rolling blackouts throughout the country in late 2007 and early 2008. Rolling blackouts resurfaced in 2014 and early 2015. Although widespread load-shedding has not occurred since September 2015, consumer trust in Eskom’s ability to deliver reliable power supply is conditioned on a wait-and-see approach.

After the electricity blackouts in 2008, the country decided to draw investor interest by initiating a process to introduce renewable energy feed-in-tariffs (REFIT) to facilitate the introduction of renewable energy into the power system. In 2009, NERSA published REFITs with proposed tariffs designed to cover generation costs plus a real after-tax return on equity of 17 per cent, fully indexed for inflation.

However, in 2011, NERSA terminated the REFIT programme because the National Treasury was of the opinion that the REFIT approach contravened public finance and procurement regulations. The REFIT programme was subsequently terminated and replaced by the REIPPPP.

The Integrated Resource Plan (IRP)
The initial IRP sets out the South African government’s strategy for the establishment of new generation and transmission capacity for the country for the period 2010 to 2030. It calls for the doubling of the country’s electricity capacity from its 2010 level of 238,272GWh, using a diverse mixture of energy sources, mainly coal, gas, nuclear and renewables, and including large-scale hydro to be imported from other countries in the southern African region. The initial IRP further details how this demand should be met in terms of generating capacity, type, timing and cost. The initial IRP also serves as an input to other government planning functions, inter alia, economic development, funding, environmental and social policy formulation. It is also a process by which the requirement for further investment in electricity generation capacity for South Africa is determined.

At the time that the IRP was initially promulgated, the South Africa government advised that the IRP should be viewed as a ‘living plan’ that would be revised by the DoE every two years to ensure its relevance with regard to (among other things) technological and environmental developments in the global arena. An update to the IRP was provided for public comment in November 2013; however, this document was subsequently gazetted and remains of no binding relevance. On 2 November 2016, the Minister of Energy released drafts of an updated Integrated Energy Plan (IEP) and an IRP on 22 November 2016. The IEP serves as the government’s master plan for the entire energy system, with its focus on the broader objective of reducing the overall energy intensity of the country. The IEP regulates
energy industries and promotes electric power investment, greater employer benefits and more favourable environmental impact. The IRP on the other hand, being the subordinated legislation to the IEP, focuses specifically on electricity.

The updated IRP has received more attention due to the South African government (and Eskom) promoting the importance of nuclear power within the overall electricity provision forecasts to 2050. The Minister of Energy announced that public consultation would be held on the draft IRP during December 2016 and January 2017. This would then allow the South African government to make the necessary adjustments and promulgate the updated IRP in 2017, once approved by Cabinet. The first consultation was held on 7 December 2016, where major issues were raised. Some critics believe that the cost assumptions for solar PV and wind were too high and that if proper costs were reflected there would be no need to construct a nuclear plant up to 2050. Eskom, on the other hand, is unhappy that the updated IRP will delay the construction of new nuclear plants for 15 years. In addition, the updated IRP has not considered concentrating solar power and co-generation into its future energy mix.

What is the IPPPP?

The Independent Power Producer Procurement Programme (IPPPP) was introduced as a vehicle for securing private sector investment for the development of new electricity generation capacity. The 1998 White Paper on Energy Policy identified that IPPs were expected to play a key role in developing and producing new electricity capacity in the country.

The REIPPPP was initiated with a request for proposals in August 2011, in terms of which IPPs were invited to bid in a competitive process. Although progress in the renewable energy sector has stagnated, a legal opinion sought by the South African Renewable Energy Council, relating to Eskom’s refusal to sign the power purchase agreement with 35 IPPs, has been publically released. The opinion from senior counsel (advocate/barrister) in South Africa concludes that preferred bidders of the REIPPPP programme are entitled to approach the courts to enforce Eskom’s obligation to such agreements. \(^{17}\) It is unclear whether the preferred bidders will pursue any court action to force Eskom to sign the outstanding power purchase agreements or whether they will wait for the South African government to force Eskom’s hand.

VI THE YEAR IN REVIEW

i 2016 determinations

Section 34 of the Electricity Regulations Act\(^ {18}\) empowers the Minister of Energy to:

- change the way in which IPPs are involved in power production in South Africa through regulations pronouncing on new capacity requirements. These regulations have become colloquially known as Determinations;
- ‘determine the new generation capacity needed to ensure uninterrupted supply of energy’; and
- determine the energy sources, and the buyers and sellers of electricity generation.


\(^{18}\) Act 4 of 2006.
The Minister of Energy, in consultation with NERSA, published five Determinations in various Government Gazettes during 2016. The Ministerial Determinations of 2016 can be summarised as follows:

a. The Determination published on 20 April 2016: The Determination allocates 3750MW to be generated from coal, from cross-border projects for the years 2025 to 2030.

b. The three Determinations published in the Government Gazette on 27 May 2016 where:
   - 600MW is to be generated from gas that may be generated from any gas type or source and generated using any appropriate technology, notwithstanding that the IRP 2010–2030 may not have contemplated such technology or have considered it viable. It may be required by the procurer (the Department of Energy) that one or more state-owned companies participate as minority strategic partners in any such independent power producer.
   - It was determined that a new generation capacity is needed to contribute towards energy security, including 100MW to be generated from gas, liquid fuels or both. The new generation capacity may be generated from any gas type or source, and may be generated using any appropriate technology, notwithstanding that the IRP 2010–2030 may not have contemplated such technology or have considered it viable. In addition, the new generation capacity shall be established by Eskom at the existing Ankerlig Power Station for the purposes of providing dedicated back up power to Koeberg Nuclear power station.
   - 1500MW of renewable energy is to be generated from solar technologies. The Determination also specified that electricity will be procured from IPPs through one or more IPP procurement programmes, tendering processes, direct negotiations with one or more project developers or other procurement procedures. The Department of Energy may include as a requirement that one or more state-owned companies participate as minority strategic partners in any such independent power producer. The energy shall be generated from projects located within one or more Solar Parks situated in the Northern Cape, and that the procurer (being the Department of Energy) may include storage solutions, notwithstanding that the IRP 2010–2030 may not have contemplated such technology or have considered it viable.

c. On 14 December 2016, a further determination was published in the Government Gazette in respect of nuclear energy, and determined that 9,600MW of energy should be generated from nuclear energy. The energy produced shall be procured through

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tendering procedures that are fair, equitable, transparent, competitive and cost-effective, and provide for private sector participation. In addition, the procurer will be Eskom. (Note: in the court ruling, the determinations were rendered void.)

The Determinations found in (a) and (b) determined that the procurer would be the Department of Energy; the buyer would be Eskom; and the capacity shall be procured through one or more IPP procurement programmes as contemplated in the New Gen Regulations.

VII CONCLUSIONS AND OUTLOOK

2016 brought political challenges that lessened growth in the renewable energy space. Time will tell whether the South African government will buckle under political pressure and force Eskom to sign the outstanding power purchase agreements. If the South African government were to remain pro-nuclear and fasttrack the procurement of state-owned and operated nuclear power, this will probably limit developments in the renewable energy sector in order to pave the way for nuclear development.
Chapter 31

SPAIN

Antonio Morales

I OVERVIEW

In Spain the energy sector is highly regulated. Its strategic and technical importance requires a strong regulatory framework that ensures a constant supply of energy at the lowest possible cost and meets all local and European environmental requirements.

This regulatory framework has undergone significant changes in the past decade, mainly imposed by European legislation, with the introduction of the directives for the internal electricity market in 1996 and 2009 and for the 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 of the Spanish energy sector, the ‘tariff deficit’ – the negative correlation between electricity costs and the income obtained from regulated electricity activities.

The reform started with the enactment of Royal Decree-Law 9/2013 of 13 July (RDL 9/2013), whereby certain urgent measures were taken to ensure the financial stability of Spain’s electrical system. The main changes introduced by this regulation aimed to provide the industry with a uniform, transparent and stable regulatory framework, as well as to give economic and financial sustainability to the electricity system and avoid the generation of a tariff deficit. Furthermore, on 27 December 2013, the Electricity Sector Act 24/2013, of 26 December (the Electricity Act 24/2013) was published in the Spanish Official State Gazette. It contained, among other things, the main principles set out in RDL 9/2013 in respect of the remuneration of renewable energy generators. The reform was also completed with a number of royal decrees and further regulations approved during 2014. For instance, the following regulations were enacted at the end of 2013:

a) Royal Decree 1047/2013 of 27 December, which established the methodology for calculating the remuneration for electricity transmission; and

b) Royal Decree 1048/2013 of 27 December, which established the methodology for calculating the remuneration for electricity distribution.

The remuneration scheme established by the Spanish government through the structural reform of the energy industry that started in July 2013 and continued in 2014 deserves particular mention. On 11 June 2014, the regulation on renewable energy electricity generation activity was passed by means of Royal Decree 413/2014 (RD 413/2014), which regulates electricity generation activity using renewable energy sources, cogeneration

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2 2009/72 of 13 July.
3 2009/73 of 13 July.
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and waste. On 16 June 2014, Ministerial Order IET/1045/2014 (MO IET/1045/2014) approving the remuneration parameters for standard facilities applicable to certain electricity production facilities based on renewable energy sources, cogeneration and waste was passed. Those regulations established a new remuneration system for facilities producing electricity from renewable energy sources, cogeneration and waste, which replaces the former remuneration regime.

Furthermore, the gas market has also undergone several changes, specifically with regard to the remuneration framework for regulated gas activities (gas distribution, transmission, regasification and storage activities) that was approved by the Spanish government by means of Royal Decree-Law 8/2014 of 4 July (RDL 8/2014), which approved urgent measures to encourage growth, competitiveness and efficiency. The said regulation was incorporated definitively into the Spanish legal system through the enactment of Act 18/2014 of 15 October (Act 18/2014). This Act included commercial deregulation measures and also established an energy efficiency system in line with EU directives.

During 2015, several new regulations were passed by the government. On 16 January 2015, the Spanish government approved the draft bill that modifies the current Act 34/1998, of 7 October, on the Hydrocarbons Sector (the Hydrocarbons Act), by means of which an organised market will be created to encourage competition in the gas sector, allowing other suppliers to enter into restricted markets such as the gas market. This regulation was finally approved on 21 May 2015 through the enactment of Law 8/2015, which amends Act 34/1998, of 7 October, on the Hydrocarbons Sector and establishes certain tax and non-tax measures in respect of the exploration, research and exploitation of hydrocarbons.

On 31 July 2015, Royal Decree 738/2015 was passed, which regulates the production of electricity and the procedure for distributing power in non-mainland territories’ electricity systems.

The most important regulation passed by the government during 2015 was Royal Degree 900/2015, of 9 October, which regulates the administrative, technical and economic requirements for the methods of supplying and generating electricity for self-consumption.

On 28 November 2015, the Official State Gazette published two main regulations: Royal Decree 1073/2015 and Royal Decree 1074/2015, both of 27 November. The first of these, Royal Decree 1073/2015, modifies certain provisions in the Royal Decrees on the remuneration of electricity networks (Royal Decree 1073/2015), specifically Royal Decree 1047/2013, of 27 December 2013, for transmission, and Royal Decree 1048/2013, of 27 December 2013, for distribution, referred to above. Among other aspects, Royal Decree 1073/2015 eliminates the yearly update of unitary values based on the consumer price index, in accordance with Law 2/2015, of 30 March, on de-indexing the economy. The second regulation, Royal Decree 1074/2015, modifies certain regulations in the electricity industry to ensure they are in line with the Spanish government’s electricity reforms of the past few years (Royal Decree 1074/2015).

During 2016, the reform of electricity distribution remuneration was concluded. Ministerial Order IET 980/2016 of 10 June established the remuneration of the different distribution companies in accordance with the new legal framework started by the Electricity Act 24/2013.

One of the main amendments passed on 2016 was the Royal Decree Law 7/2016 of 23 December, on financing the cost of the social tariff and protective measures to the vulnerable consumer of electricity (Royal Decree Law 7/2016), which amended the Electricity Act
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24/2013. The new financing mechanism allocates social tariff costs to company sectors based on the number of customers of their retail subsidiaries, and opens the possibility for highly vulnerable consumers to avoid the interruption of their electricity supply.

The Energy Efficiency Directive 2012/27/EU of the European Parliament and Council (Directive 2012/27/EU) was partially transposed in Spain by Royal Decree 56/2016 of 12 February (Royal Decree 56/2016) in terms of energy audits, accreditation schemes for energy services providers and energy auditors, as well as promoting energy efficiency in production processes.

II REGULATION

i The regulators

The framework for power distribution between the state and the autonomous regions is directly established in Article 149(1)(22) and (25) of the Spanish Constitution. The former reserves the 'authorisation of electrical installations when their use affects another region or the transport of energy out of its territorial scope' to the state's exclusive jurisdiction. The latter provides that the state has jurisdiction over establishing the basis of the energy regime. According to this framework, facilities within each region are also authorised, and the legal bases of the energy sector have developed.

The state's broad jurisdiction in this area is reflected in the basic state legislation, which establishes the sector's regulatory framework: the Electricity Act 24/2013 replaced and repealed the Electricity Act 54/1997 and amended the Hydrocarbons Act. Since these two laws (as enacted and as amended) are very comprehensive and wide-ranging, in practice there is little space for the autonomous regions to regulate.

The Electricity Act 24/2013 consists of 80 articles and is divided into 10 titles, 20 additional provisions, 16 transitional provisions, a repealing provision and six final provisions, and it introduced, among others, the following legislation:

a The principle of economic and financial sustainability of the electricity system.

b Article 14 of the Electricity Act 24/2013 regulates the remuneration of the different activities involved in the supply of electricity. The remuneration system is financed by means of the income obtained from regulated activities and is based on objective, transparent and non-discriminatory criteria. Additionally, Section 7 determines that the Spanish government may establish a specific remuneration for the promotion of production from renewable sources, cogeneration and waste.

c With regard to generation activity, the Electricity Act 24/2013 eliminated the former distinction between an ordinary and a special regime, establishing different economic regimes in accordance with the technology and the capacity of the generation facilities.

d Specific rules on the Voluntary Price for the Small Consumer (PVPC) mechanism are set out in the Electricity Act 24/2013. As this reform seeks to guarantee the supply of electricity at the lowest possible price, the PVPC is the highest price that the major electricity retailers may charge certain consumers.

In addition to the above, Act 3/2013, of 4 June, created a new regulatory body, the National Markets and Competition Commission (CNMC), which encompasses different supervisory authorities in different sectors: the former National Energy Commission, the
National Competition Commission, the Telecommunications Market Commission, the Rail Regulation Committee, the Airport Economic Regulation Commission, and the National Postal Industry Commission.

Within energy matters, Act 3/2013 transferred certain functions, originally developed by the former National Energy Commission, to the Ministry of Industry, Energy and Tourism, such as inspecting, initiating and conducting certain penalty proceedings, responding to claims made by consumers and informing them about their rights and dispute resolution methods, among others.

ii Regulated activities

The main activities involved in the supply of energy are the following: generation, transportation, distribution and supply (or commercialisation). As natural monopolies, transportation and distribution are considered regulated activities; whereas generation and supply operate in a free-market system.

Royal Decree 1955/2000, of 1 December, as amended by the Electricity Act 24/2013, regulates the regime applicable to transportation, distribution, commercialisation and supply activities. The management of transportation, as a regulated activity, is entrusted to Red Eléctrica de España, which is also the system operator.

Additionally, Royal Decree 1955/2000 states that the construction, expansion, modification and operation of production facilities, as well as transportation and distribution, require certain permissions. This Royal Decree has been modified by Royal Decree 1074/2015 in relation to the guarantees that must be provided in the authorisation process for production facilities and by Royal Decree 56/2016 that establishes new authorisation criteria for thermal power stations whose thermal power is greater than 20MW to generate electricity; and also for their substantial renewal, including the obligation of the administrative authorisation applicant to submit a cost–benefit analysis to adapt the planned facility to high-efficiency cogeneration.

Administrative authorisation is needed for the draft technical installation document to be processed in conjunction with the environmental study. An application must be filed with the Directorate-General for Energy Policy and Mining, which is then forwarded with the required documentation to the Ministry of Industry, which makes the decision. If the application is approved, the Ministry will indicate the time within which the application must be submitted for project-implementation approval, which – once approved – allows the owner to construct or establish the installation. The application must be submitted to the industry and energy sub-office where the facility is located. A decision must be arrived at within three months by the Directorate-General for Energy Policy and Mining, specifying a deadline for the construction of the facility.

Once a project is duly implemented, an operating authorisation allows energy to be transmitted to the facilities for commercial exploitation. The application to operate must be submitted to the industry and energy sub-office and should be accompanied by the final certificate of work.

Some autonomous regions have specific regulations for electrical installations, but they follow basically the same administrative procedure as established by the foregoing state regulations.
iii Ownership and market access restrictions

Electricity network operation (transmission and distribution) is subject to significant economies of scale, which gives them an element of natural monopoly, as it is inefficient to introduce competition into these activities. The Electricity Act 24/2013 (which replaces Law 54/1997, of 27 November, to, among other concerns, ensure the financial stability of the Spanish electricity industry) establishes an obligation to separate legal and accounting matters within regulated electric activities (transportation and distribution) that are provided under a financial regime. Deregulated activities (generation and supply) are carried out by operators in a free market and their remuneration is being governed by the laws of supply and demand.

Directive 2009/72/CE and its subsequent incorporation into Spanish law go into greater detail on this aspect and impose an obligation on vertically integrated groups to functionally separate their activities to ensure the autonomy of management and decisions of those responsible for the transportation and distribution networks. In addition, it purports to preserve the confidentiality of commercially sensitive information available to those responsible so as not to compromise competition in deregulated activities.

The former Electricity Act 54/1997 and the current Electricity Act 24/2013 and subsequent legislative developments establish and define the role of the different participants in the electricity sector:

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, in Spain, 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 set 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) is the company that assumes the management of the bids for and sale of electricity in the daily and intraday power market in exchange for a regulated fixed fee within the territory of the Iberian Peninsula (Spain and Portugal). OMIE is regulated by the Santiago International Agreement,
regarding the implementation of an Iberian electricity market (MIBEL) between the Kingdom of Spain and the Republic of Portugal, and subject to the rules and regulations governing Spain’s electricity sector. Half of OMIE’s stock is owned by the Spanish company OMEL, with the other half held by the Portuguese company OMIP SGPS, SA.

The system operator (Red Eléctrica de España) is the company whose main function is to perform activities associated with the technical operation of the electricity system, ensuring the continuity and security of the electricity supply and proper coordination of production and transportation systems.

On 10 October 2015, the Official State Gazette published Royal Decree 900/2015, which regulates the administrative, technical and economic requirements for supplying and generating electricity for self-consumption, establishing a regulatory framework that guarantees the economic sustainability of the system and adequate distribution of system costs.

It also stipulates the tolls and charges payable for self-consumption, in accordance with the Electricity Act 24/2013, which already established that self-consumption must contribute to financing the costs and services of the system to the same extent as other consumers (the criticised ‘tax on the sun’). Specifically, Royal Decree 900/2015 imposes the aforementioned tolls and charges on self-producers, both at a fixed cost according to installed power capacity and at a variable cost according to the electricity self-consumed. The regulation also considers a specific surcharge for those who use batteries to store some of the electricity produced by their solar panels. There are two exceptions to this rule whereby consumers are exempt from paying costs:

- consumers on islands; and
- small consumers with a contracted capacity of no more than 10kW.

Accordingly, a record of self-consumption facilities has been created so that system operators and electricity distributors are aware of generation facilities within their networks, and to therefore ensure the correct operation of the electricity system under safe conditions. Royal Decree 900/2015 establishes two categories of self-consumption depending on the size of the facilities: (1) facilities with a capacity generation lower than 100kW, which may feed their excess capacity into the grid, but without receiving any compensation in return; and (2) large producers – facilities with a capacity generation higher than 100kW, which may charge for the excess energy that they feed into the grid, at the current wholesale market price when the energy is provided. Nevertheless, such activity is, from a legal point of view and for tax purposes, equal to production activity and consequently subject to power generation charges and to the 7% tax on energy production.

Lastly, the Royal Decree gives consumers, installers and other agents a period of six months to adapt to its provisions.

On 24 December 2016, the Royal Decree Law 7/2016 was published in the Spanish Official State Gazette and amended Electricity Act 24/2013 in relation to the financing mechanism of the cost of the social tariff. It allocates social tariff costs to company sectors on the basis of the number of customers of their retail subsidiaries. The social tariff will cover the difference between the PVPC and a base value that may vary depending on the categories of vulnerable consumers established.
In addition, it creates another group of ‘severe vulnerable consumers’ whose supply cannot be interrupted, as well as co-financing their invoices by the relevant administration and by the obligated companies of the sector.

iv Transfers of control and assignments

Royal Decree 1955/2000 also establishes the authorisation process for the transfer of installations. The request for authorisation for facilities transfer must be sent to the Directorate-General for Energy Policy and Mining, enclosing supporting documentation about the applicants. A decision must be rendered by this department within three months (failure to respond positively within three months means the application is deemed rejected), prior to the report of the CNMC. The applicant then has six months to confirm the transfer, following which, provided that it is not formalised, the authorisation will expire. As mentioned before, Royal Decree 1074/2015 amended Royal Decree 1955/2000 in relation to the guarantees that must be provided in the authorisation process of production facilities.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Energy (electricity or natural gas) is transported from the point where it is generated to the point of consumption by large industrial consumers that are directly connected to the transmission system and to the point of intersection with the distribution networks (substations), through which power is carried to the remaining consumers.

The electricity transmission network is made up of lines of voltage equal to or greater than 220kV, international connection lines regardless of voltage, transformers of 400/220kV, transformer compounds of voltage equal to or greater than 220kV, and other elements of voltage equal to or greater than 220kV. There are also international interconnection facilities connecting Spain with other Spanish territories, which have a voltage transport function lower than 220kV.

Transport networks are developed when new investment is periodically approved by the Ministry of Industry. The construction of network sections included in this planning is regulated, and remuneration is calculated by the regulator in accordance with the approved methodology contained in the regulations, defined in Royal Decree 1047/2013. Law 17/2007 established the single-carrier model, with Red Eléctrica de España as the owner of the entire transportation network. As the system operator, it must comply with the relevant instructions by filing investment plans for future years.

ii Transmission/transportation and distribution access

Power distribution brings the energy from the output of transport networks (electricity or gas) to the final consumer. Electrical distribution facilities comprise voltage lines lower than 220kV, which are not considered part of the transport network.

Prior to June 2009, distribution companies were also responsible for servicing a regulated tariff supply to consumers. Since then, regulated supply has disappeared, creating a ‘last-resort supply’ (TUR), which will be managed by ‘suppliers of last resort’, who must supply electricity at a price no higher than that fixed by the government. At present, specific rules on the current PVPC were set out in the Electricity Act 24/2013. This Act restricted the tariffs to two groups of consumers: (1) consumers considered vulnerable; and (2) consumers who temporarily do not have a supply contract with a free-market retailer and are not
entitled to the application of the PVPC. Therefore, the Spanish government will establish by regulations the provisions required to determine the PVPC and last-resort supply, with these being configured as regulated tariffs. Also, the electricity supply will be carried out in accordance with Royal Decree 216/2014 of 28 March, which sets 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.

Distributors must build, maintain and operate power grids linking transport to consumption centres. For the proper development of these functions, distributors have the obligation to expand distribution facilities when needed to meet new demands for electricity, at all times ensuring an adequate service quality level, and differentiating by type of consumption and area. Furthermore, distributors are responsible for supply measurement, applying consumer tolls or access fees.

Distributors are required to keep a points-of-supply database, always maintaining confidentiality. They must send the required customer information to the Supplier Switching Office and provide reports to the transporter about their network incidence and maintenance plans to ensure certainty of supply.

Finally, distribution companies must also provide information to clients, the Ministry of Industry, Tourism and Trade, autonomous communities, the Supplier Switching Office, and the system operator. They must also submit their investment plans annually. Distribution companies, in the exercise of their activities, are entitled to payment by the administration.

Notwithstanding the foregoing, prior to the approval of Royal Decree 222/2008, laying down the 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 Royal Decree 1048/2013, which established the methodology for calculating the remuneration of distribution activities.

### iii Terminalling, processing and treatment

The Hydrocarbons Act laid the foundations for a reorganisation of the gas system, far removed from the monopoly in which Gas Natural SDG group performed all the activities within the natural gas industry. This Act introduced (1) separation of regulated activities and competition activities, (2) free access for third parties to gas infrastructure, (3) establishment of regulated access charges, (4) progressive full-trade wholesale and retail liberalisation, and (5) regulation of minimum security and strategy.

The Hydrocarbons Act was amended in 2007 by Law 12/2007 of 2 July, which transposed the major changes to the rules of European Union Directive 2003/55/EC (subsequently repealed by Directive 2009/73/CE), to promote the creation of a competitive internal energy market:

- rearrangement of the powers of the different regulatory authorities;
- development of the rules governing access to networks;
- the functional separation of regulated activities;
- regulating the activity supply of last resort;
creation of the Supplier Switching Office; and

establishing a schedule of tariff system adaptation and natural gas supply for the supply of last resort.

Directive 2009/73/CE concerning common rules for the internal natural gas market aimed at making a definite contribution to the creation of an internal energy market through the following principles:

- effective separation of network activities from supply and production activities;
- increase of the powers and independence of the national regulators, who must cooperate across a network of energy regulators, but who have the capacity to make binding decisions and impose sanctions;
- the creation of supranational transmission system operators by achieving EU-wide market integration; and
- improvement of the functioning of the gas market and, specifically, greater transparency and access to free storage facilities and LNG terminals.

Furthermore, the Spanish Hydrocarbons Act was amended by Act 11/2013, of 26 July, concerning measures to support entrepreneurship and stimulate growth and job creation. This regulation introduced several amendments by virtue of which distribution agreements are more strictly regulated. Therefore, sale agreements within the sector ‘cannot contain exclusivity clauses which […] set, recommend or affect, directly or indirectly, the retail price of fuel’ and clauses that ‘determine the sale price of fuel with reference to a particular fixed, maximum or recommended price, or any others that contribute to indirect fixing of the sale price’ shall be void and deemed deleted. Additionally, the Electricity Act 24/2013 repealed Article 83 bis of the Spanish Hydrocarbons Act.

As stated above, Royal Decree-Law 8/2014 and Act 18/2014 introduced several measures aimed at ensuring sustainability and accessibility to the hydrocarbons sector through the establishment of a new remuneration framework for gas distribution, transmission, regasification and storage activities. The purpose of the reform was to ensure the principle of financial and economic sustainability, so that the revenues generated by the gas market are used to finance system costs. Consequently, the revenues must be sufficient to cover all system costs; otherwise, measures should be adopted to increase or reduce the equivalent revenues to maintain the costs-revenues balance. Additionally, regulatory periods of six years were established, but subject to revision every three years (sub-regulatory periods of three plus three years).

For gas distribution, remuneration for the aggregate of the distributor’s facilities is linked to the number of customers connected and to the volume of gas supplied.

For gas transmission, regasification and storage activities, this remuneration system established a common methodology for all facilities of the core network, based on the annual net value of the assets, removing any value update or adjustments made during the regulatory period. The remuneration is composed of the following elements:

- a 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, which was published on 22 May, amends the previous Hydrocarbons Act to bring it more into line with the current situation, to increase competition and transparency in the hydrocarbons sector, reduce fraud, ensure greater consumer protection, reduce costs for the consumer and adapt the rules on infringements and penalties.

With respect to natural gas, the Law seeks to create an organised natural market that offers consumers more competitive and transparent prices, and allows the entry of new suppliers to increase competition. In this regard, the measures introduced by Law 8/2015 can be summarised as follows: a market operator for the organised gas market will also be appointed; any authorised natural gas installer may carry out inspections (this was previously the responsibility of distributors); the entry of new suppliers is encouraged through the mutual recognition of licences to supply natural gas to other EU member countries where there is an existing agreement; and certain measures have been adopted regarding minimum security inventories, giving suppliers greater flexibility at lower cost, without impairing the security of supply, and enabling the Corporation for Strategic Oil Reserves to maintain strategic natural gas inventories.

With regard to the development of fracking, the Law introduces a tax on the value of the extraction of gas, oil and condensates, which establishes a levy of between 1 per cent and 4 per cent on the production of unconventional gas. It also sets a fee of €125,000 to be paid for each inland exploration survey and production well. The Law provides with particular force that the revenue collected from both the tax and the fee shall revert to the autonomous regions and municipalities where the wells are located. Moreover, the companies that hold exploitation concessions must pay 1 per cent of the value of the production to the owners of the land around the wells, even where these areas are intended for an activity other than hydrocarbon extraction.

On 31 October 2015, Royal Decree 984/2015, of 30 October, was published, which regulates the organised gas market and third-party access to natural gas system installations. This Royal Decree contains the basic regulations for the operation of this new organised gas market, along with other measures, such as the inspection procedures for gas installations. In compliance with Article 32 of Royal Decree 984/2015, the Organised Gas Market Agents Committee was established on 28 January 2016. This Article regulates the organised gas market and third-party access to natural gas system facilities. The Agents Committee is formed by representatives of the agents, Spain’s National Commission for Markets and Competition (CNMC), the transmission system operator, the market operator and the party responsible for the settlement services.

To sum up, Law 8/2015 provides for the creation of an organised gas market on the Iberian peninsula, and nominates MIBGAS SA as its operator. This mandate is statutorily developed in Royal Decree 984/2015, which regulates the organised gas market and third-party access to natural gas system facilities; in the Resolution of 4 December 2015, issued by the Secretary of State for Energy, which approves the market’s rules, the adhesion contract and the decisions of the organised gas market; and in Circular 2/2015, of 22 July, issued by the CNMC, which lays down the balancing rules for the gas-system transmission network. The MIBGAS trading platform is used for the purchase and sale of natural gas with physical delivery at the virtual balancing point for within-day, day-ahead, balance-of-month and month-ahead products.
**iv Rates**

Remuneration for transportation and distribution are administratively established in response to investment costs, operation and maintenance, and network management, according to a calculation model defined by the regulator by royal decree and in accordance with provisions established in the former Electricity Law 54/1997 and the current Electricity Act 24/2013 (Article 14.8). Thus, the remuneration is established by reference to the costs required to build, operate and maintain the facilities complying with the principle of covering the electricity supply at the lowest cost. Accordingly, Royal Decrees 1047/2013 and 1048/2013 establishing the methodologies for calculating the remuneration for transportation and distribution activities have been implemented.

This remuneration methodology is based on the following remunerative principles:

- **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, which will last for six years, but the remuneration parameters can be reviewed before the start of each regulatory period.

The remuneration methodology of transportation activity should comprise economic incentives for the improvement of the availability of the facilities and any other goal. In the case of distribution, the remuneration methodology must include the formula for remunerating other regulated functions performed by distribution companies, as well as any incentives that may be appropriate for the improvement of the supply’s quality, reduction of losses, combating fraud, innovating technology and any other goals.

**v Security and technology restrictions**

Security in relation to transportation facilities of electrical energy is relevant from the perspectives of both industrial safety and security of supply.

Industrial safety is dealt with by Law 21/1992 of 16 July and the Electricity Act 24/2013, and is understood as safety aimed at risk prevention and control, as well as protection against accidents and disasters capable of causing harm to the population or damage to flora, fauna, property or the environment. Security of supply is dealt with under the sector-specific regulations. The Electricity Act 24/2013 states in this regard that the ‘few basic technical rules needed will be established to ensure the reliability of electricity supply and installations of transport network’.

**IV ENERGY MARKETS**

**i Development of energy markets**

According to the Electricity Act 24/2013, electricity production takes place in the electrical power production market in a free-competition regime. The electricity production market is composed of all energy purchase and sale business transactions and other services related
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to the supply of electricity. It includes forward markets, a daily market, an intraday market, the resolution of system technical constraints, ancillary services and the management of deviations.

The Spanish electricity market has historically offered competitive prices for end users compared with other European markets. The Iberian Electricity Market was started in 2007, and the results of integration in the market have been obvious: while in the second half of 2007 the average price differential between the Portuguese and Spanish electricity systems was €10 per MWh, this fell to €0.3 per MWh by 2010, with identical rates on both sides of the border for the majority of the time.

The operation of the wholesale market at any given time is determined by the mix of generation structure, import capacity, the imperfect meshing of the network, the inelasticity of demand and the system reserve margin. The market-design rules can make this operation more or less efficient, but cannot make up for significant deviations in these factors.

From the opening to competition of the generation market in January 1998 to 2005, almost all of the transactions in wholesale energy were carried out in the pool. Forward markets and bilateral contracts have been developed gradually with the evolution of the regulations. Thus, in recent years, the energy involved in the daily market run by OMIE has ranged between 45 and 55 per cent of demand, with the remainder opting for bilateral transactions.

Despite the reduction in the quantities traded in the daily market, its price still represents the main visible energy price reference and the underlying settlement of bilateral contracts, the over-the-counter (OTC) market and forward markets organised by OMIP.

In this context the significant increase in OTC negotiations on the financial market should also be noted. The volume of energy traded in this market went from 6 per cent of domestic demand in 2007 to 10 per cent in 2010.

The low prices in the Spanish wholesale market compared with their European counterparts have reflected the influence of generation technology’s price takers. As an illustrative example, in the period from December 2009 to March 2010 the market price showed a very substantial fall even below fuel price, reaching an average of €19.6 per MWh in March 2010, reflecting, *inter alia*, prices of zero euros per MWh for almost 300 hours. One of the main causes of this was a 1.91 per cent reduction in demand, along with growth in wind production coinciding with intense rainfall.

### ii Energy market rules and regulation

Since 1998, the Spanish electricity sector has undergone a major transformation as a result of regulation changes resulting from the adoption of Directive 96/92/EC, the main objective of which was to create an internal market for electricity in the EU by liberalising electricity generation and sale.

The electricity markets are regulated by:

\( a \) a market operator, responsible for the preparation of the daily operation of the system, matching offers and demands, supervised by a committee of representatives of producers, distributors, traders and qualified consumers;

\( b \) a system operator, ensuring continuity and security of supply (Red Eléctrica de España);

\( c \) the Electricity System Commission, which protects consumer interests and ensures the transparency of the whole system;

\( d \) the Industry and Energy Ministry must supervise the correct operation of production activities and consumption of electricity;
e autonomous communities, which also have direct responsibilities in regulating their electrical systems; and

f the European Union, which establishes the general framework of the electrical system in all countries of the Union through directives and legal regulations.

Royal Decree 949/2001 (amended by Royal Decree 984/2015 on organised gas market and third-party access), which regulates third-party access to gas infrastructure and establishes an integrated economic system of the natural gas for regulated activities paid under rates, tolls and regulated fees, as amended, also sets out the basic criteria for remuneration of regulated activities, setting tariffs and fees to be paid by individuals for the use of gas installations.


iii Contracts for sale of energy

Participants in the energy market may freely agree the terms of contracts for the sale of electricity to subscribe, subject to the terms and minimum content, under the Electricity Act 24/2013 and its implementing regulations. MIBEL consists of the forward markets managed by OMIP and the daily market and intraday markets managed by OMIE.

Electricity traded through daily and intraday markets is remunerated on the basis of the prices resulting from the balance between supply and demand of electricity offered. In other words, it is a marginal pricing market in which the price and trading volume in each hour are set according to the point of equilibrium between supply and demand. Electricity traded through bilateral contracts or the physical or term market is remunerated on the basis of the price of the firm’s contracted operations in those markets.

iv Market developments

Historically, the energy market has functioned properly, but in recent years a technology-driven influx of price takers has distorted its proper functioning. This has caused a reduction in the wholesale market price, which, together with a reduction in the thermal gap, is not sending the right economic signals to garner investment in new capacity.

This situation will only deteriorate in the future, as the progressive decarbonisation production mix forecasts a greater presence of non-renewables, relegating thermal technologies to the role of providing back-up power, with only a residual role as contributor energy, and jeopardising the recovery of investment. Incentives for investment and the availability of service, established in Order ITC/3127/2011, of 17 November, have not sent 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 supply security was introduced in 2011 with the aim of ensuring a level of domestic coal consumption according to the provisions of the National Coal Plan (which justifies the operation of these plants for security of supply and capacity for each state to give priority to indigenous sources for up to 15 per cent of production). This regulatory change involves the generation of coal that is bought (10 plants totalling 4,700MW) at a regulated price, while production in the process of withdrawal of the production–demand balance (imported coal and combined cycle) does not receive any compensation. Nevertheless, according to the Framework Agreement for Coal Industry and Mining Districts for the period 2013–2018, the said incentivising mechanisms expired
at the end of 2014. The Spanish government proposed renewing the incentives granted to power plants that burned national coal. For that purpose, on 31 March 2015, the Spanish government presented a draft Proposal of Order regulating an incentive for investment in environmental performance improvement for electricity generating facilities from indigenous coal to the Commission on the Monitoring of the Coal Plan for the period 2013–2018. The draft Proposal of Order was subject to prior review by the CNMC and notification to the European Commission. The CNMC issued its report on 30 September 2015, stating that the measures established in the draft Proposal of Order were not justified with regard to the necessity and proportionality of the objective, and expressly pointed out that such measures could fall within the scope of the definition of state aid under European law and thus be duly notified to the European Union pursuant to Articles 107(1) and 108(3) of the Treaty on the Functioning of the European Union. The European Commission responded negatively to the draft Proposal of Order in February 2016.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

The Electricity Act 24/2013 eliminated the former distinction between ordinary and special-regime installations and replaced them with a remuneration system based on the technology and capacity of the generation facilities. Under the former remuneration system, special-regime installations, which include renewable energy sources, were not subsidised in the state budget. Instead, they were included in electricity rates, causing a ‘tariff deficit’; however, it was not only renewable energy premiums that generated a tariff deficit, so did other items, such as regulated tariff billing. In fact, the special-regime premiums caused only one-third of the tariff deficit.

Royal Decree 6/2009, dated 30 April, had previously attempted to limit the increase of the aforementioned general tariff deficit; however, it was not sufficient, given that only a year later further steps needed to be taken by the government and Royal Decree-Law 14/2010 was passed for this purpose. In this context, the purpose of Royal Decree-Law 1/2012 was to limit the impact of renewable premiums in the tariff deficit, thus reducing costs; in similar terms, Royal Decree-Law 2/2013 aimed to mitigate the tariff deficit by modifying the remuneration system of regulated activities as well as the remuneration formula for special-regime facilities.

In addition, there were several regulatory changes during 2012 and especially during 2013 in relation to energy production from renewable sources, cogeneration and waste.

As stated above, the Spanish government has accomplished a structural reform of the Spanish energy sector, starting with the enactment of RDL 9/2013. This regulation focused on addressing ‘the pressing need to immediately adopt a series of urgent measures that will ensure the financial stability of the national electrical grid and, likewise, the advisability of overhauling the regulatory framework so that it can adapt to the events and situation that define the electricity sector at any given period, with the objective of maintaining the sustainability of the electrical system’.

The RDL 9/2013 regulation abolished the former remuneration system based on a regulated tariff (the only one in existence since RDL 2/2013 was enacted), even for generation facilities in operation at the time this regulation entered into force. It replaced the previous regime with a system in which power plants producing electricity from renewable energy sources, cogeneration and residual waste receive ‘a specific remuneration that is composed of an amount per installed power unit/facility (which covers, where applicable,
the investment costs for a standard plant that cannot be recovered from the sale of electrical power), in addition to an amount for the operation itself (which covers, where applicable, the difference between operating costs and the revenue obtained from the market by said standard power plant).

This specific remuneration is calculated on the basis of a ‘standard power plant, over the useful regulatory life thereof and based on the business activity that would be carried out by an efficient and well-managed company’. Thus, production facilities receive a ‘reasonable profitability’ based on standardised costs and revenues for a standard power plant.

The provisions contained in RDL 9/2013 relating to the remuneration system for producers of energy from renewable sources, cogeneration and waste were basically carried into the Electricity Act 24/2013. Accordingly, Section 5 of Article 14 of the said Act determines that the remuneration for generation activities includes the following concepts:

- 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 said standard power plant.

This specific remuneration, that allows power plants producing electricity from renewable energy sources, cogeneration and waste to achieve a reasonable rate of return, is calculated on the basis of a ‘standard power plant, over the useful regulatory life thereof and based on the business activity that would be carried out by an efficient and well-managed company’.

The RD 413/2014 defines the concept ‘reasonable rate of return’ by referencing the pre-tax return on the secondary market average yield on 10-year government bonds for the 24 months prior to May of the previous year as of the beginning of the regulatory period, increased by a differential. Each regulatory period will last for six years, with the first starting on 14 July 2013 and lasting until 31 December 2019.

Notwithstanding the above, those facilities that benefitted from a feed-in tariff regime as of 14 July 2013 will receive a reasonable rate of return based on the pre-tax return on the secondary market average yield on the 10 years prior to the entry into force of RDL 9/2013 government bonds, plus 300 basis points. The specific remuneration will be granted to new power plants producing electricity from renewable energy sources, cogeneration and waste, by means of a competitive tendering process respecting transparency.
non-discrimination and objectivity principles. Once power plants producing electricity from renewable energy sources, cogeneration and waste have completed their useful regulatory life, they would not be entitled to receive any specific remuneration and would merely obtain the income associated with participation in the electricity market. Lastly, the remuneration parameters based on standardised costs and revenues for a standard power plant are set forth in MO IET/1045/2014.

On 1 August 2015, the Official State Gazette published Royal Decree 738/2015, which mainly regulates electricity production activity and the dispatch procedure in non-mainland electricity systems. This Royal Decree establishes a scheme similar to the previous system, with remuneration for fixed costs (which include fixed investment and fixed operation and maintenance costs) and for variable costs (including fuel and variable operation and maintenance costs), and takes into account, within the costs of these systems, the taxes arising from Law 15/2012, on fiscal measures for energy sustainability. Certain aspects of the methodology have been changed to improve the efficiency of the system. The Royal Decree also implements matters already contained in Law 17/2013, of 29 October 2013, to guarantee supply and increase competition in these systems.

The Royal Decree entered into effect on 1 September 2015 and includes, for certain measures, a transitional period that started on 1 January 2012. In accordance with additional Provision 11, the full and final effectiveness of the Royal Decree is subject to the European Commission not raising any objections with regard to its compatibility with Community law.

On 13 February 2016, Royal Decree 56/2016 was published in the Spanish Official State Gazette partially transposing Energy Efficiency Directive 2012/27/EU. Royal Decree 56/2016 sets forth the obligation for large-scale enterprises and groups of companies to carry out energy audits as a measure for organisations to know their situation regarding energy use, and to contribute to the saving and efficiency of energy that is consumed.

It imposes the obligation to carry out energy audits for large-scale companies that meet the following requirements:

- it must employ more than 250 workers; or
- have a turnover over than €50 million and a balance sheet exceeding €43 million.

The obligation also applies to groups of companies defined as per in the provisions of the Spanish Commercial Code that fulfil the applicable above-mentioned requirements. Small and medium sized companies are exempt from this obligation.

The energy audits must be performed by qualified energy auditors, and the obligation is subject to inspection by the competent authorities in matters of energy efficiency. The audits must cover at least 85 per cent of the total energy consumption of the obliged company’s facilities located in Spain that are involved in the industrial, commercial and service activities. Such audits must be performed at least every four years from the date of the previous energy audit.

The sanctions for non-compliance include fines of up to €60,000 according to Law 18/2014 approving urgent measures for growth, competitiveness and efficiency.

An Administrative Energy Audit Register will be created in the Ministry of Energy, Tourism and the Digital Agenda, to record the information notified by the companies under the scope of Royal Decree 56/2016. It will be public and free of charge.
ii Energy efficiency and conservation

Objectives and actions on energy efficiency in Spain are part of the policy objectives and progress set by the regions’ institutions. Also, in addition to the objectives approved in the European Council in spring 2007 of reducing greenhouse gas emissions and increasing renewable energy, a target was included of improving energy efficiency by 20 per cent in 2020 in the EU compared with the baseline scenario (the target block is commonly called 20-20-20 targets). Unlike the target for 20 per cent renewables and 20 per cent reduction of carbon dioxide emissions, the efficiency target is not binding and has been distributed by Member States.

In line with European objectives set forth in Directive 2009/28/EC of the European Parliament and of the Council, of 23 April 2009, on the promotion of the use of energy from renewable sources, the only public reference in a Spanish context has been the 20 per cent target of improving energy efficiency in the government’s ‘Strategy for a Sustainable Economy’ in December 2009, which included a target of 20 per cent reduction in energy usage by 2020 compared with the scenario at that time.

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: Plan of Action 2005–2007, Plan of Action 2008–2012 and Plan of Action 2011–2020. 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:

a legislative actions, generally far-reaching, and representing a complex set of recommendations, regulations, rules of functioning, constraints and generally binding rules;

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 plan, some of the key energy-efficiency measures stated in the Spanish Action Plan 2011–2020 include those in the transportation, building, utilities and cogeneration sectors.

iii Technological developments

One of the main goals within the European Union is to fully achieve energy interconnection and, for that purpose, the European Commission passed the Third Energy Package, which came into force in March 2011. The Third Energy Package sought to accelerate investments in energy infrastructure, to enhance cross-border transactions and provide access to diversified sources of energy.

The European Commission considers the connection of ‘energy islands’, that is, Spain and Portugal on the Iberian Peninsula and Estonia, Latvia and Lithuania in the Baltic Sea region, along with the rest of the internal market as a high priority goal.

A recent example of electricity interconnection as technological developments is the new interconnection grid established between and Spain and France. Both countries have recently finished a €700 million project of common interest that doubles the electrical
connection capacity between France and Spain. It was co-financed by both countries through the incorporation of the company INELFE (50 per cent owned by Red Eléctrica de España and 50 per cent by Réseau de Transport d’Électricité).

VI  THE YEAR IN REVIEW

As described above, the Spanish energy sector has undergone a broad reform as a consequence of the government’s attempts to reduce the ‘tariff deficit’ and to re-establish a positive correlation between electricity costs and the income obtained from regulated electricity activities. The main reforms during 2016 are related to the regulation on the new financing mechanism of the cost of the social tariff in the Electricity Act 24/2013 and on the efficiency in the supply of energy, in particular:

a  On 24 December 2016, Royal Decree 7/2016 amended Electricity Act 24/2013 in relation to the financing mechanism of the cost of the social tariff. It allocates the social tariff cost to sector companies on the basis of the number of customers of their retail subsidiaries. It creates another group of ‘severe vulnerable consumers’ whose supply cannot be interrupted, as well as co-financing their invoices by the relevant administrations and by the obligated companies of the sector. The social tariff will cover the difference between the PVPC and a base value that may vary depending on the categories of vulnerable consumers established. It imposes the obligation of bearing the social tariff cost to certain companies of the sector.

b  Royal Decree 56/2016 partially transposes Directive 2012/27/EU on energy efficiency and imposes the obligation to carry out energy audits for large-scale companies that meet the following requirements: they must employ more than 250 workers; or have a turnover of more than €50 million and a balance sheet exceeding €43 million. The obligations also apply to groups of companies as per the provisions of the Spanish Commercial Code that fulfil the applicable above-mentioned requirements. These energy 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. The audits must be carried out at least every four years from the date of the previous energy audit.

VII  CONCLUSIONS AND OUTLOOK

Spain depends heavily on foreign energy and needs all available resources. Its energy system is still in a state of revision, both in the electricity and gas sectors, which creates uncertainty for international investors, who demand safe, predictable and transparent markets. Additionally, the retrospective effect of certain measures adopted since 2013 (i.e., RDL 9/2013) concerning renewable-energy incentives, along with tax relief, have brought uncertainty to potential investors. The main objectives for the Spanish government in the short term are to shore up the markets and counter this uncertainty, but it is also important to outline definitively the energy mix required over the next 20 years; once defined, this plan should remain in place for that length of time.
Chapter 32

SWITZERLAND

Georges Racine

I OVERVIEW

The Swiss energy sector has its own distinctiveness. Switzerland has been referred to as the ‘water tower’ of Europe; indeed, hydropower accounts for about 59 per cent of electricity production in the country, while nuclear power accounts for about 32.8 per cent. Other conventional thermal and ‘new’ renewable energies, including solar, wood, biomass, wind, geothermal and ambient heat, account for about 8.2 per cent.²

Despite the country’s high dependence on nuclear energy, the Federal Council has decided to gradually phase out nuclear power. On 21 May 2017, Swiss voters endorsed (by a majority of 58.2 per cent) Energy Strategy 2050, thereby paving the way for a new Energy Act to come into force on 1 January 2018. The new law sets forth extensive measures to reduce energy consumption, increase energy efficiency and promote renewable energy. This followed an earlier referendum on 27 November 2016, by which Swiss voters rejected (by a majority of 54.2 per cent) the introduction of a cap on the lifetime of existing nuclear power plants in Switzerland, and the Swiss Federal Council’s decision of 4 May 2016 to indefinitely delay the full liberalisation of the Swiss electricity sector.

The Swiss electricity market has been described as being highly fragmented due to the number of market participants. Such a high number is peculiar, considering the size and population of the country.

Electricity represents approximately 25 per cent of Swiss energy consumption, while oil and gas represent about 50.6 per cent and 13.5 per cent respectively. Coal, wood, industrial waste and other renewable energies constitute the remaining 10.3 per cent.³

Switzerland produces neither oil nor gas. As such, this chapter focuses on the electricity industry.

II REGULATION

i The regulators

The Swiss energy institutional framework comprises a number of federal offices, regulatory authorities and specialised agencies. The Federal Office of Energy (FOE) is the office

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responsible for all questions relating to energy supply and energy use. It sits under the Federal Department of the Environment, Transport, Energy and Communications (DETEC), which is responsible for ensuring sustainable development and the provision of basic public services in the interests of society, the environment and the economy.

The FOE pursues the following objectives:

\textit{a} it creates the necessary conditions for ensuring a sufficient, well diversified and secure energy supply that is both economical and ecologically sustainable;
\textit{b} it imposes high safety standards in the areas of production, transportation and distribution of energy;
\textit{c} it sets out to promote efficient energy use, increase the proportion of renewable energy in the overall energy mix and reduce the level of carbon dioxide emissions; and
\textit{d} it promotes and coordinates energy research and supports the development of new markets for the sustainable supply and use of energy.

A number of commissions support the FOE, including the Energy Research Commission (CORE), the Commission for Radioactive Waste Disposal (CRW), the Administrative Commission of the Decommissioning Fund and the Disposal Fund for Nuclear Installations (ACDFDFNI), the Nuclear Safety Commission (NSC) and the Commission for Connection Conditions for Renewables Energies (CCRE).

The CORE assists with the formulation of guidelines governing energy research and the implementation of research findings. Its members represent the industrial sector, the energy industry, universities and various energy agencies and research institutions in Switzerland.

The CRW is an independent body that is responsible for advising the FOE and the Federal Nuclear Safety Inspectorate (ENSI) (see below) on geological aspects of nuclear waste disposal.

The two funds administered by the ACDFDFNI were established to secure the necessary financing for the disposal of radioactive waste and spent-fuel elements, and the decommissioning of nuclear installations after their shutdown.

As an advisory body for the Federal Council, DETEC and ENSI, the NSC examines fundamental issues relating to nuclear safety and may submit comments for the attention of the Federal Council and DETEC regarding reports by ENSI on nuclear safety. It took over the duties of the former Federal Commission for the Safety of Nuclear Facilities on 1 January 2008.

The CCRE advises cantonal authorities and the FOE on the formulation of recommendations and enforcement tools for the implementation of connection conditions for independent producers.\footnote{www.uvek.admin.ch/index.html?lang=en; www.bfe.admin.ch/index.html?lang=en.}

The Federal Office for the Environment (FOEN), which also sits under DETEC, plays an important role alongside the FOE. It is responsible for ensuring that natural resources are used sustainably, that the public is protected against natural hazards, and that the environment is protected from unacceptable adverse impacts.

In accordance with DETEC's sustainability strategy, the FOEN pursues the following goals:

\textit{a} long-term preservation and sustainable use of natural resources (land, water, forests, air, climate, biological and landscape diversity) and elimination of existing damage;
In order to achieve these goals the FOEN has been assigned the following responsibilities:

- environmental monitoring to provide a sound basis for the management of resources;
- preparation of decisions, to secure a comprehensive and coherent policy of sustainable management of natural resources and prevention of natural hazards; and
- implementing the legal foundations, supporting enforcement partners and providing information on the state of the environment and on the appropriate use and protection of natural resources.5

The Federal Electricity Commission (ElCom) is the independent regulatory authority for the electricity sector. It is responsible for monitoring compliance with the Federal Electricity Act and the Federal Energy Act, taking all necessary related decisions and pronouncing rulings where required.

When the new Electricity Supply Act entered into force on 1 January 2008, ElCom was formally entrusted with the task of supervising the liberalisation of Switzerland’s electricity market. As an independent regulatory authority at the federal level, ElCom is responsible for securing the smooth transition from a monopoly situation in the electricity supply sector to an electricity market based on the principles of competition. ElCom’s duty is to ensure that the liberalisation of the market does not result in excessive tariff increases and that the network infrastructure is properly maintained and expanded in order to guarantee an adequate supply of electricity.

ElCom has been entrusted with extensive judicial powers to effectively perform its various duties. It monitors compliance with the provisions of the Electricity Supply Act and the Energy Act, and can pronounce legally binding decisions and rulings as necessary.

The specific duties of ElCom are to:

- verify the electricity tariffs of customers who do not have free access to the network, as well as the remuneration paid for the input of electricity into the grid. It is authorised to prohibit unjustified increases in electricity prices, and may order the reduction of excessively high tariffs, taking action on the basis of complaints or in its official capacity;
- mediate and pronounce rulings on disputes relating to free access to the electricity network;
- rule on disputes relating to cost-covering remuneration of electricity input that is to be paid to producers of electricity from renewable energy sources;
- monitor supply security and the condition of the electricity networks;
- in the case of shortfalls in cross-border transmission lines, to regulate the allocation of network capacities and coordinate its activities with the European electricity market regulators; and
- ensure that the transmission network is handed over to the national system operator (Swissgrid) according to schedule.

ENSI is the national regulatory body with responsibility for the nuclear safety and security of Swiss nuclear facilities. It is an independent body constituted under public law.

ENSI is supervised by an independent board elected by the Federal Council and reports directly to it. Its regulatory remit covers the entire life of a facility, from initial planning, through operation, to final decommissioning, including the disposal of radioactive waste. Its remit also includes the safety of staff and the public and their protection from radiation, sabotage and terrorism. ENSI is also involved in transport of radioactive materials to and from nuclear facilities and in the continuing geo-scientific investigations to identify a suitable location for the deep geological disposal of radioactive waste.  

ii Regulated activities

Articles 76 and 89–91 of the Swiss Federal Constitution address energy matters and bind the Confederation and the cantons to provide a satisfactory, diversified, secure, economic and environmentally compatible energy supply.

According to the Constitution, the Confederation is in charge of determining the principles of the use of all domestic and renewable energies in particular, as well as legislating in certain specific areas such as nuclear energy, hydropower generation and transmission and delivery of electricity. Legislation concerning all other areas is to be provided by the cantons. Consequently, energy laws can vary considerably among cantons.

At the federal level, the principal pieces of legislation are:

a. energy: the Energy Act 1998;
b. hydropower: the Hydropower Act 1916 and the Water Protection Act 1991;
c. electricity: the Electricity Act on Electric Facilities for Low and High Voltage 1902 and the Electricity Supply Act 2007;
e. CO2: the CO2 Emission Reduction Act 1999; and

The Federal Electricity Supply Act, which was adopted by Parliament in 2007, provides for an opening of the market in two stages, starting on 1 January 2009. In the first five years (2009–2013), only end-consumers with an annual consumption of more than 100,000kWh per site were granted free access to the market. Households and other small-scale end consumers were also supposed to be able to freely choose their electricity supplier as of 1 January 2014, but that full market liberalisation has been delayed, due to the main objective of market liberalisation – the creation of a competitive and secure electricity supply with transparent pricing – not having been achieved.

Negotiations between the EU and Switzerland to enter into a comprehensive long-term energy treaty began at the end of 2007. The primary aim of such an accord (obtaining this agreement is considered one of the top priorities for Switzerland) would be the mutual access to the free energy market. The negotiations, which were at an advanced stage, came to a halt immediately following the adoption by the Swiss people (9 February 2014) of the Swiss popular initiative ‘Against Mass Immigration’.

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iii Policy

The Swiss Federal Constitution, the Energy Act, the CO2 Act, the Nuclear Energy Act and the Electricity Supply Act are all integral parts of the instruments defining a sustainable and modern Swiss energy policy. In addition to legal instruments, the energy policies of the federal government and the cantons are both based on the presentation of energy perspectives as well as on strategies, implementation programmes and the evaluation of energy-related measures at the municipal, cantonal and federal levels.

Energy policy was only anchored in the Swiss Federal Constitution in 1990, when provisions were added stipulating that the federal government and the cantons are obliged to use their competences to ensure an adequate, broad-based, secure, economical and ecological energy supply, and the economical and efficient use of energy. This comprehensive list of requirements places high demands on energy policy at the federal and cantonal levels, while demonstrating how difficult it is to find suitable solutions.

Since 1990, all cantons have drawn up their own energy legislation and regulations, and with the enactment of the Federal Energy Act and the Federal Energy Ordinance on 1 January 1999, the Federal Council fulfilled the mandate it had received following the approval by the electorate of the energy provisions in 1990.

The energy perspectives as drawn up by the Federal Council have served as a basis for all political decisions in the energy field and have been reviewed and updated regularly since the establishment of the General Energy Plan in the mid-1970s.

On 4 May 2016 the Federal Council confirmed that it was indefinitely delaying the full liberalisation of the Swiss electricity market. Due to the economic and political implications of full liberalisation, the Federal Council launched a public consultation process, which took place between 8 October 2014 and 22 January 2015. Following its review of the report on the consultation process and in light of the conflicting views expressed therein, the Federal Council has indicated that full liberalisation will depend on:

a. the evolution of the energy pact with the European Union;

b. the progress achieved with Energy Strategy 2050;

c. the prevailing market conditions; and

d. the revision of the Federal Electricity Supply Act.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

The most significant change in the structuring of the transmission and distribution grid in the Swiss electricity market has been the gradual liberalisation in the past decade of the high-voltage transmission network, and more specifically the separation of the transmission network from other core elements in the electricity market such as distribution, power generation and trading.

The liberalisation of the transmission network was facilitated in large part by the foundation of Swissgrid in 2005 as the Swiss transmission system operator (TSO) and the gradual transfer since then of operational responsibility and legal ownership of the network to Swissgrid.
The transfer of the transmission grid to Swissgrid has consolidated the network (which was previously split up into eight control areas) into one zone covering the entire country. The combined Swiss transmission system is now 6,700km long and connects to transmissions systems of neighbouring countries at over 40 points.7

On 1 January 2009, the number of Swissgrid shareholders increased overnight from eight electricity companies, directly or indirectly majority-owned by the Swiss cantons (Alpiq AG, Alpiq Suisse SA, Axpo Power AG, Axpo Trading AG, BKW FMB Energie AG, CKW AG, ewz and Repower AG) to 17 shareholders as part of the opening up of the previously closed system. There are now over 30 electricity generators and distributors that share ownership of Swissgrid.8

The Swiss Electricity Supply Act mandated that the transfer of the transmission network from the original owners to Swissgrid be completed by the end of 2012. By the beginning of 2013, most of the network components had been transferred with the remainder completed at the beginning of 2015.

The separation of the transmission network from vertically integrated generation and supply companies occurred in three separate stages (principally between January 2009 and January 2015):

\( a \) separation of accounting functions from distribution, production and trading activities;

\( b \) legal separation and restructuring of operating entities into subsidiaries; and

\( c \) transfer of legal ownership of the network to national operator Swissgrid.9

Swissgrid now owns and operates the Swiss transmission system and has overall responsibility for ensuring security of supply. Its main areas of responsibility are:

\( a \) the transportation of electricity from the producing power plant to the end consumer via regional and local distributors; and

\( b \) the trading of electricity exported and imported from the rest of Europe.

To regulate the behaviour of Swissgrid and other players in a newly liberalised market, the Swiss Transmission Code was introduced in December 2013 as a regulatory mechanism to define the technical and organisational principles governing the Swiss transmission system.10

The regulations govern the relationship between Swissgrid and the distribution system operators, power generators and end consumers, as well as other market players and defines the minimum requirements for the operation, use and connection to the Swiss transmission system.

Due to Switzerland's central location in Europe, approximately one-third11 of all electricity flow through the Swiss transmission network is transmitted from one neighbouring country to another. Swissgrid coordinates its transnational activities through its membership of the European Network of Transmission System Operators for Electricity.

Swissgrid is also part of the TSO Security Cooperation, an initiative between 13 TSOs to ensure secure energy supplies among its members. The initiative brings together a standing

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9 The transfer to Swissgrid was registered in the commercial register on 3 January 2013.
11 25TWh of 78TWh in 2014, according to Swissgrid (2015).

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security committee and uses a joint real-time information system (the Real-time Awareness
and Alarm System) and shared IT platform to meet its main objective of increasing security
on Europe’s high voltage transmission network.12

Swissgrid has been a shareholder of the auction platform Capacity Allocation Service
Company since 2010, which acts as a service company and single point of contact for
the implementation and operation of the power transmission capacity allocation between
counties in Europe.

ii Transmission/transportation and distribution access

The Electricity Supply Act stipulates that electricity grid operators must allow power
generators access to the transmission and distribution network. The expenses incurred
for making these connections are borne by the individual generators. Power generators of
electricity from renewable sources (particularly hydropower) are given priority when it comes
to allocating capacity on the grid.

Swissgrid must also by statute allow other regulated third parties access to the grid
without discrimination, on a transparent and non-discriminatory basis. Access to the network
may be denied, however, for ‘legitimate business reasons’, including when the safe operation
of the network could be endangered or when the network is congested.

iii Rates

Swissgrid sets the rates for use of the transmission grid. These are subject to provisions of the
Electricity Supply Act and also to review by ElCom. The legislation stipulates that the tariffs
(for all distribution and transmission grids) shall not exceed the recoverable costs, fees and
royalties. Recoverable costs consist of the operating and capital expenditure associated with
Swissgrid’s operation of the grid.

ElCom acts as a price monitor and regulator for the Swiss transmission network
operated by Swissgrid. ElCom is vested with the power to order reductions and to prohibit
tariff increases.

ElCom takes a proactive approach to its price monitoring duties and has ordered the
lowering of grid usage tariffs on several occasions, notably in four consecutive years from
2009 to 2012. These tariff reduction orders were, however, struck down by the Federal
Supreme Court in 2013. The method by which ElCom calculates tariffs was subject to
another Supreme Court Ruling in 2016 that is expected to have a significant impact on how
ElCom is able to regulate tariffs in future.

ElCom also rules as a judicial authority on general disputes relating to network access
and tariffs. ElCom monitors electricity supply security and regulates issues relating to
international electricity transmission and trading.13

Swissgrid sets the tariffs for use of the grid in accordance with statutory requirements
and publishes them at the end of March annually.14

Swissgrid announced in March 2017 that tariffs for the transmission grid will be
‘drastically’ reduced in 2018. It attributes this reduction to the ‘drop in operating costs

brought about by Swissgrid’s ongoing efforts to increase efficiency.\textsuperscript{15} According to Swissgrid’s plan, the tariff for general ancillary services will decrease by 20 per cent in 2017 and grid usage tariffs by between 6 and 8 per cent (grid usage tariffs are predicted to be 20 per cent lower in 2018 than five years ago). Lower ancillary costs are made possible, according to Swissgrid, as a result of lower control power costs. Swissgrid attributes these lower costs to the increase in the number of providers, leading to more competition.

Swissgrid’s grid usage tariff\textsuperscript{16} (charged to the distribution system operators directly connected to the transmission grid) is split up in three components:

\begin{itemize}
  \item[a] working tariff (the energy component);
  \item[b] power tariff (the power component); and
  \item[c] fixed basic tariff (per weighted outflow point).
\end{itemize}

The working tariff is calculated on the basis of the active energy consumed by end consumers directly connected to the transmission grid, and in the case of a grid operator (of which there are more than 800 in Switzerland), the active energy used by end consumers connected to its grid and all lower-level grids. The actual active energy being consumed is multiplied by the working tariff published by Swissgrid.\textsuperscript{17}

The power tariff is calculated on the basis of the annual average of the actual monthly ‘quarterly-hour’ peak demand values used by each end consumer directly connected to the transmission grid and by end consumers connected to its grid and all lower-level grids. Deductions are made for the energy required for a power plant’s own consumption and the pump energy used by pumped storage power plants (if declared by the grid operator directly connected to the transmission grid).

If a customer (either end customer or distribution system operator) has feed-out points into the transmission grid, then the tariff calculation is based on the ‘quarter-hourly’ netted values after the appropriate deductions are made. Similar deductions are made to take into account the energy required for power generation and pump energy.

For the fixed basic tariff calculation, each feed-out point for a grid distribution operator is weighted using the ‘K-factor’, where the share of energy being fed out is considered in relation to a formula based on the sum of energy being fed in and out; from an average taken over the previous 12 months.\textsuperscript{18}

The grid usage tariff is therefore the result of the following formula:

\begin{itemize}
  \item[a] multiplying the energy volume by the working tariff;
  \item[b] multiplying the monthly peak output by one twelfth of the power price; and
  \item[c] multiplying the number of weighted feed-out points by the fixed basic tariff per weighted fee-out point.
\end{itemize}

\begin{itemize}
  \item[16] The grid use tariff covers the cost of renewal, development and maintenance of the transmission grid, as well as of operations and monitoring via the control centres.
\end{itemize}
Switzerland forecasts that, in 2018, 6 per cent of electricity price paid by end consumers will go towards the operation and maintenance of the national transmission grid and that 48 per cent of costs will be attributed to the distribution grids.19

iv Security and technology restrictions

The most significant technology restrictions (and sources of vulnerability) on the Swiss transmission and distribution grids are caused by the fact that most of the network is 40 to 50 years old (and only a third of the network dates from after 1980). Until 2013, planning for the development and expansion of the network was carried out at a local level and therefore considerable work remains to be done to modernise the grid.

Additionally, the limited number of transfer points on national borders with main trading partners Germany, France, Italy and Austria (approximately 40) means that capacity is limited and congestion can occur. The Strategic Grid 2025 is an initiative put in place with the main objective of upgrading the grid in order to ensure that it is technically secure, environmentally friendly and economically efficient.20

Swissgrid acts as the single point of contact for other national TSOs and foreign electricity distributors in the negotiation and scheduling of cross-border supply to fill gaps in the Swiss domestic supply. Swissgrid also facilitates capacity auctions for cross-border supply.

Swissgrid is responsible for the safe operation of Switzerland’s high-voltage network from two linked control rooms, operational around the clock and every day of the year.21 Swissgrid controls a comprehensive IT infrastructure from which it is able to map a real time model of the Swiss transmission network from approximately 40,000 data points. Thousands of measurements and switch positions from the network are collected and processed in cycles of less than 20 seconds.22 With these many data points, the system is unquestionably vulnerable to cyberattacks.

The Swiss Federal IT Steering Unit is tasked with implementing a national strategy for the general protection of Switzerland against cyber risks.23 Produced annually, the latest report on progress was published in 2016.24 The report does not, however, contain any specific policy for dealing with cyber threats to the electricity grid.

Swissgrid announced in January 2016 that it would establish a new Technology business unit in order to design and implement a digitisation and automation strategy.25 The Swissgrid research and development unit is tasked with developing new technologies for the efficient transmission of electricity, including the new ‘smart grid’ and ‘super grid’ initiatives. The R&D unit also provides support for third-party innovation projects through sponsorship deals and partnership programmes.26

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IV ENERGY MARKETS

i Development of energy markets

The decision by the Federal Council to indefinitely delay the full liberalisation of the electricity market followed an earlier announcement on 7 March 2016 by major hydropower producer ALPIQ of its intention to divest up to 49 per cent of its hydropower portfolio with a total installed capacity of 5.2GW. The stake for sale represents roughly 8 per cent of the total Swiss hydropower production or 5 per cent of Switzerland’s total power production.

The sale process initiated by ALPIQ is a testament to the challenges facing Swiss hydropower producers. Under Energy Strategy 2050, the share of hydropower is expected to be well over 50 per cent. Yet for the time being, hydropower producers are struggling. Wholesale prices remain low and the Swiss franc remains strong. Profitability of Swiss power plants has come under strain due to:

- high subsidies for new renewable energies (e.g., wind and solar power);
- low prices for primary energies (e.g., oil, gas and coal);
- the stagnation of the world economy;
- lower carbon dioxide taxes; and
- high duties.

Producers like ALPIQ lack access to end consumers in the non-liberalised segment of the Swiss market, while their traditional clients (including power distributors and large-scale consumers that benefit from partial liberalisation) have been buying abroad.

The Swiss energy market comprises several hundreds of players, including a small number of major consortia with vertically integrated operations, and about 80 power producers, who differ considerably in terms of size and operations. The vast majority of market players are publicly owned regional and local utilities that distribute electricity to their local municipalities. Only some of these regional and local distributors can produce electricity. The largest utilities are responsible for approximately 80 per cent of the power production and 90 per cent of the energy supplied in the country.

ii Contracts for sale of energy

As there is no power exchange in Switzerland, Swiss trading companies trade on the Powernext in Paris, the Energy Exchange in Austria and the Leipzig-based European Energy Exchange.

The Dow Jones Swiss Electricity Price Index (SWEP), which was initiated by Aare-Tessin AG für Elektrizität and Elektrizitäts-Gesellschaft Laufenburg AG, and launched in cooperation with Dow Jones in March 1998, provides price indications for over-the-counter electricity trading in Switzerland for next-day delivery. The SWEP is the volume-weighted average of the profile adjusted price for hour 12 of all transactions having an impact on hour 11am to 12pm, also taking into account the Index for the past 20 days.27

On 30 October 2013, Elcom gave its green light to an accord between Swissgrid and the European power exchange EPEX Spot. This accord paved the way for the introduction of market coupling at the Swiss border, which is expected to make power trading more efficient. As a power exchange, EPEX Spot is already overseeing short-term electricity wholesale trade in Switzerland.

27 www.djindexes.com/mdsidx/?event=ene.
V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

Historically, Switzerland’s longest-serving and most important source of renewable energy has been hydropower, but the ‘new’ renewables including solar, wood, biomass, wind, geothermal and ambient heat also play an increasingly important role in today’s Swiss energy mix. Such role will be accelerated with the endorsement by the Swiss people of Energy Strategy 2050. The revised Energy Act that will come into force on 1 January 2018 specifically aims to increase the use of renewable energy, especially from domestic sources, in addition to securing an economic and ecological supply and distribution of energy and using energy economically and efficiently. To that effect, it sets forth specific goals and measures, including the following:

a the domestic production of hydroelectric power will be increased to 37,400GWh by 2035, while domestic electricity production from other renewable sources will be increased to 4,400GWh by 2020 and 11,400GWh by 2035;

b the current feed-in compensation for energy from renewable sources (i.e., solar, wind, biomass and geothermal energy) will be extended until 2022, and large-scale hydroelectric power plants and photovoltaic and biomass power plants may obtain subsidies until 2030;

c subsidies for local renewable sources and energy efficiency measures will be financed by increases in the grid fee;

d promotion of the construction and expansion of power plants, by declaring that renewable sources use is a national interest equal to the protection of nature and heritage; as a result, it will become more difficult to object against new power plants by referring to nature and heritage protection;

e the cantons will have to provide fast approval procedures for the construction and expansion of power plants;

f recourse to the Federal Supreme Court regarding disputes over planning approvals for power plants, will be possible only for legal issues of fundamental importance; and

g the right to use self-produced energy will be expanded.

ii Energy efficiency and conservation

The new Energy Act that will come into force on 1 January 2018 also presents goals and measures targeting energy saving and efficiency, including the following:

a a substantial reduction in energy and electricity consumption is to be achieved by 2035. Compared to the 2000 figures, average energy consumption per person per year is to be reduced by 16 per cent by 2020 and 43 per cent by 2035. Average electricity consumption per person per year is to be reduced by 3 per cent by 2020 and 13 per cent by 2035;

b the existing subsidy programme for energy building refurbishments is to be continued after 2019. The subsidies will be increased and partly financed from revenues of the carbon dioxide (CO2) tax. In addition, tax deductions for such refurbishments will be extended;

c as of 2021, the average CO2 emission of new passenger cars must be reduced to 95g of CO2/ km (currently 130g of CO2/km). The average CO2 emission of delivery vans and light-duty vehicles must be reduced to 147g of CO2/km; and
The existing mechanical electricity meters are to be replaced by smart metering systems that provide more specific data and allow efficient electricity supply and consumption.

VI THE YEAR IN REVIEW

Five major events have marked the Swiss energy sector within the past 12 months or so. Firstly, the announcement on 7 March 2016 by major hydropower producer ALPIQ of its intention to divest up to 49 per cent of its hydropower portfolio sent chilling waves across the sector. Second, the decision on 4 May 2016 by the Federal Council to indefinitely delay the full liberalisation of the electricity market, entailing that only those consumers with an annual consumption of more than 100,000KWh remain free to access the market. Third, the adoption on 30 September 2016 by the Parliament of a revised Energy Act. Fourth, the rejection on 27 November 2016 by the Swiss people of an initiative aimed at imposing a cap on the lifetime of the existing nuclear power plants in Switzerland. Finally, the endorsement in 2017 by the Swiss people of Energy Strategy 2050, which was a clear vote in favour of a sustainable, renewable and local power supply and against new nuclear power plants.

VII CONCLUSIONS AND OUTLOOK

The tremors of Fukushima are still being felt on Swiss soil more than six years after the disaster. Added to prevailing market conditions and technological developments, these have caused the Swiss government to go for a major shift in its energy policy, the Swiss Parliament to pass new legislation that gives a clear green light to increased use of renewable energy and greater energy efficiency, and a majority of the Swiss people to adopt a new state of mind toward Energy Strategy 2050. It remains to be seen whether market conditions will evolve positively as a result and whether end consumers will benefit from it all. 41.8 per cent of Swiss voters voted against Energy Strategy 2050 and the abandonment of nuclear energy, while 57.7 per cent of eligible voters never made it to the polls.
I OVERVIEW

Following the elections held in Turkey in November 2015, Mr Berat Albayrak was appointed as the new Energy and Natural Resources Minister. Minister Albayrak has since adapted the same policy as that of his predecessor, and declared that in the long term Turkey aims to (1) increase its general energy storage capacity; (2) increase storage obligation rates for imports; (3) use different energy storage options; and (4) support investments in the energy sector, with a particular focus on renewable energy. In the past decade, Turkey increased its installed capacity from 39,800MW to 74,000MW and Turkey’s energy consumption increased from 160 billion kWh to 278 billion kWh. The minister further announced that Turkey is planning to make an investment of 18 billion Turkish liras to strengthen the infrastructure of its electricity supply system network in the coming five years. As it did in 2015 and 2016, Turkey continues to take concrete steps to meet energy demands and to keep increasing the figures until 2023. In addition to relevant targets for electricity and natural gas, Turkey is also planning to enact a separate coal law, considering the specific needs of operating coal mines and the use of coal to meet energy demands. This shows that, while focusing on renewable energy investments, Turkey will continue to use coal as an energy resource in its energy strategies. All in all Turkey, aims to stop being an energy importer and start exporting energy in the coming years.

Turkey’s strategy and targets for 2023 are:

- increasing total installed power to 120,000MW;
- increasing the share of renewable energy sources to 30 per cent;
- maximising the use of hydropower;
- increasing wind-power installed capacity to 20,000MW;
- installing power plants with 1,000MW of geothermal and 5,000MW of solar energy;
- extending the length of electricity transmission lines to 60,717km;
- reaching a power distribution unit capacity of 158,460MVA;
- extending the use of smart grids;
- raising the natural gas storage capacity to 5 billion m³;
- establishing an energy stock exchange with a diversified product range;

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1 Okan Demirkan is a partner and Melis Öget Koç and Gökçe İldiri are associates at Kolcuoğlu Demirkan Koçaklı Attorneys at Law.


Among these targets, establishment of an energy stock exchange with a diversified product range will not only support market liberalisation, but also ensure transparency and help maintain a healthy balance between national energy supply and demand. Turkey enacted a new Electricity Market Law\(^5\) (EML) in 2013.\(^5\) The EML provided for the establishment of an electricity exchange market. The EML contemplated that this electricity exchange market would be administered through a newly incorporated company called EPİAŞ.\(^7\) EPİAŞ was established on 12 March 2015 in line with the EML.

The Turkish electricity market is one of the fastest growing electricity markets in the world, with an approximately 5.5 per cent annual increase on average over the past 13 years, where the average growth rate has been 9 per cent in 2010 and 2011.\(^8\) Natural gas consumption in Turkey is increasing as well. According to the Ministry of Energy and Natural Resources (MENR), natural gas demand is expected to increase by 2.9 per cent per year until 2020. Because of insufficient petroleum and natural gas sources, Turkey is still dependent on imports. Turkey imports petroleum mainly from Iran, Russia, Iraq, Saudi Arabia and Kazakhstan, and natural gas from Russia,\(^9\) Turkmenistan, Azerbaijan and Iran, in addition to its long-term liquefied natural gas (LNG) imports from Nigeria and Algeria.\(^10\)

With the enactment of the Natural Gas Market Law\(^11\) (NGML) in 2001, the Petroleum Pipeline Corporation (BOTAŞ)\(^12\) lost its monopoly in natural gas importation, distribution and sales. However, BOTAŞ maintains its key market position, as it owns and operates the natural gas transmission network and still imports approximately 83.80 per cent of the natural gas consumed in Turkey,\(^13\) and 100 per cent of natural gas export from Turkey is still by BOTAŞ.\(^14\) After BOTAŞ’s natural gas agreement with Russia expired in 2011, four privately owned companies – Enerco, BosphorusGaz, Avrasya Gaz and Shell Gaz – signed agreements with Gazprom and obtained import licences for importation of natural gas from Russia. According to the Energy Market Regulatory Authority’s (EMRA’s) Natural Gas Market Report, Akfel Gaz, Batı Hattı Doğal Gaz (West Line) and Kibar Enerji are the other

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\(^4\) The current coal-fired installed capacity is 15,900MW.

\(^5\) Entered into force on 30 March 2013.

\(^6\) In addition to the EML, many long-awaited regulations entered into force in 2013 in line with EML, such as the Electricity Market Licence Regulation, the Electricity Market Distribution Regulation and the Electricity Market Connection and Use of the System Regulation.

\(^7\) Enerji Piyasaları İşletme Anonim Şirketi.


\(^9\) In 2015, the biggest share of imports is 55.3 per cent from Russia. However, by increasing spot LNG imports, the share of imports from Russia has decreased from 65 per cent to 55 per cent.

\(^10\) Turkey also imports spot LNG.


\(^12\) The Petroleum Pipeline Corporation, BOTAŞ is a state-owned company.


companies that hold natural gas import licences as of 2015. On the other hand, as of the end of 2015, there are 43 import (spot LNG) licensed companies, and only two of them (BOTAŞ and Egegaz) realised spot LNG imports.

As per the High Planning Council’s decision on 16 December 2016, Turkey aims to reach a 5 billion cubic metres working gas capacity in 2023 within the scope of the Tuz Gölü (Salt Lake) Natural Gas Underground Storage Project, which was initiated on 10 February 2017. In addition, recently, the Silivri Natural Gas Storage Facility, with a working capacity of 2.84 billion standard cubic metres, was taken over by BOTAŞ to ensure seasonal supply-demand balance and supply security.

Turkey enacted a new Turkish Petroleum Law (TPL) in 2013, abolishing the former Petroleum Law. Then, the Turkish Petroleum Law Implementation Regulation entered into force in early 2014. An amendment law proposing substantive changes to the Natural Gas Market Law (the Draft Amendment Law) was prepared in 2012 and submitted to the Turkish Grand National Assembly (the Turkish Parliament) on 4 August 2014, within the 24th legislative session (2011–2014). However, the draft amendment law has not been enacted within the said legislative session, so it became void at the end of that legislative session. Accordingly, at the time of writing, these amendments still have not been enacted. On the other hand, another amendment to the NGML came into effect on 17 June 2016, which will be explained in detail in Section II, infra.

In line with Turkey’s substantial demand potential and its renewable energy targets, Turkey has also introduced the Regulation on Generating Electricity Without a Licence; the Regulation on Documentation and Support of Renewable Energy; the Regulation on Renewable Energy Resource Areas; the Regulation on Technical Evaluation Of Solar Energy Based Licence Applications; the Communique on Wind and Solar Measurements for Preliminary Licence Applications; and the Contest Regulation on Pre-Licence Applications Regarding Generation Facility Based on Solar and Wind Energy.

II REGULATION

i The regulators

The MENR is responsible for preparing and implementing energy policies, plans and programmes in coordination with its affiliated institutions. EMRA is responsible for

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17 Entered into force on 11 June 2013.
18 Entered into force on 22 January 2014.
19 Entered into force on 2 October 2013.
20 Entered into force on 1 October 2013.
21 Entered into force on 9 October 2016.
22 Entered into force on 1 June 2013.
23 Entered into force on 17 June 2014.
24 Entered into force on 13 May 2017.
regulating and supervising the operation of the electricity, downstream petroleum and downstream natural gas markets.\textsuperscript{25} It exercises its powers through EMRA’s board.\textsuperscript{26} With its competence to regulate and supervise the energy markets, EMRA has the following duties:\textsuperscript{27}

\begin{itemize}
\item[\textit{a}] issuing licences;
\item[\textit{b}] drafting, amending, enforcing and auditing performance standards, as well as distribution and customer services;
\item[\textit{c}] setting out the pricing principles indicated in the law; and
\item[\textit{d}] maintaining the development and performance of infrastructure for implementation of new power trading and sales methods.
\end{itemize}

The primary legislation for the electricity market is the EML and the Electricity Market Licence Regulation.\textsuperscript{28} While the Petroleum Market Law,\textsuperscript{29} the Liquefied Petroleum Gas Market Law,\textsuperscript{30} and the Petroleum Market Licence Regulation\textsuperscript{31} govern downstream petroleum activities, the NGML and the Natural Gas Market Licence Regulation\textsuperscript{32} govern downstream natural gas activities. As for the upstream market, the TPL governs upstream oil and gas activities,\textsuperscript{33} and the Law on Transit Passage through Petroleum Pipelines\textsuperscript{34} (the Transit Law) governs the transit passage of oil and gas.

\section*{ii Regulated activities}

\subsection*{Electricity}

To conduct any one of the following market activities, companies must obtain a licence from EMRA:

\begin{itemize}
\item[\textit{a}] generation;
\item[\textit{b}] transmission;
\item[\textit{c}] distribution;
\item[\textit{d}] wholesale;
\item[\textit{e}] retail;
\item[\textit{f}] market operation;
\item[\textit{g}] import; and
\item[\textit{h}] export.
\end{itemize}

The EML abolished the ‘auto-production licence’ system, and the existing auto-producer licences have been automatically converted to generation licences. However, individuals or legal entities (1) generating electricity for their own needs, and (2) having facilities or

\begin{footnotesize}
\textsuperscript{25} The General Directorate of Petroleum Affairs is the regulatory authority responsible for upstream market.
\textsuperscript{26} The Energy Market Regulatory Board.
\textsuperscript{28} Entered into force on 2 November 2013.
\textsuperscript{29} Entered into force on 20 December 2003.
\textsuperscript{30} Entered into force on 13 March 2005.
\textsuperscript{31} Entered into force on 17 June 2004.
\textsuperscript{32} Entered into force on 7 September 2002.
\textsuperscript{33} Under the TPL, the definition of ‘petroleum’ includes both crude oil and natural gas.
\textsuperscript{34} Entered into force on 29 June 2000.
\end{footnotesize}
equipment that are not operating in parallel to the transmission and distribution network, are
not required to obtain a licence, as long as they remain disconnected from the transmission
and distribution networks and do not engage in wholesale or retail activities.

The EML introduced the new ‘supply licence’, which combines wholesale and retail
sale licences. The EML also introduced the ‘preliminary licence’ mechanism for generation
licence applications. A preliminary licence is issued for a specified term, to those having
applied (to EMRA) to conduct electricity generation activities. The preliminary licence’s
purpose is to enable the applicants to obtain the necessary permits, approvals and licences, as
well as to acquire ownership or usufruct rights to the land where the generation facility is to
be located, during the application’s evaluation by EMRA. The EML and Electricity Market
Licence Regulation determine the detailed requirements of the regulatory approval process
to obtain a preliminary licence and generation licence. According to recent changes to the
Electricity Market Licence Regulation, the term of a preliminary licence will be determined
by EMRA, depending on the prospective facility’s source type and installed capacity. The
term can be between 24 and 36 months.

The new Regulation on the Amendment to the Electricity Market Licence Regulation\(^{35}\)
separates preliminary licence applications for renewable energy resource areas (RERAs) from
those made by other entities generating electricity. Under the Electricity Market Licence
Regulation, generation licences are granted for a term of 10 to 49 years. However, the term
of generation licences granted for a RERA cannot exceed 30 years. The Regulation on the
Amendment to the Electricity Market Regulation also sets forth procedures to be followed
for obtaining a preliminary licence for a RERA.

The EML defines the market activities that may be conducted without a licence. Under
the EML and the Regulation on Generating Electricity without a Licence, generation facilities
with an installed capacity of up to 1MW of renewable energy resources are exempt from this
licensing requirement. Moreover, if a company generates more electricity than it consumes, the
surplus may be sold in the same distribution region in which it is generated, within the scope
of the Renewable Energy Resources (RER) Support Mechanism. The Council of Ministers
is authorised to increase the maximum installed capacity for a renewable energy plant to
operate without a licence, up to 5MW. Certain amendments to the Regulation on Generating
Electricity without a Licence came into force on 23 March 2016 and 22 October 2016.
Pursuant to these amendments, a maximum capacity of 1MW per transformer centre can be
allocated to individuals or legal entities generating solar or wind energy (excluding rooftop
installations), regardless of the number of consumption facilities owned by that individual or
legal entity. When calculating the 1MW limit, both the individual or legal entity or entities
in which such persons have direct or indirect control are considered as the same person. These
amendments introduced a minimum self-consumption ratio, which places a maximum limit
for the excess energy that can be sold to distribution companies. Accordingly, the installed
capacity of unlicensed wind and solar generation facilities cannot exceed 30 times the capacity
of the consumption unit associated with the generation unit.

Among other significant changes, the new amendments introduced certain share
transfer restrictions. Accordingly, shareholders of companies that applied for grid connection
for unlicensed electricity generation projects (based on solar and wind energy) are prohibited
from transferring any of their shares in these companies. The prohibition period applies
from the date of application until the temporary acceptance date. The Regulation on the

\(^{35}\) Entered into force on 24 February 2017.
Amendment to the Electricity Market Licence Regulation\(^\text{36}\) provides certain exceptions to the above limitation: this limitation will not apply to: (1) changes in the shareholding structure of publicly listed legal entities with regard to their publicly listed shares, and changes in the shareholding structure of legal entities with publicly listed shareholders, with regard to the publicly listed shares of these shareholders; (2) direct or indirect changes in the shareholding structure of the relevant legal entity, due to exercise of pre-emption rights by the entity’s shareholders; (3) indirect changes in the shareholding structures of the relevant entities, resulting from changes in their foreign shareholders’ shareholding structures; and (4) direct or indirect changes in the shareholding structure of the relevant entity, caused by a public offering of the entity’s shares or the shares of its direct or indirect shareholders.

**Downstream petroleum and natural gas**

The following downstream petroleum market activities require a licence:

- refining;
- processing;
- lubricant oil production;
- storage;
- transmission;
- eligible consumer;
- bunker delivery;
- distribution;
- transportation; and
- dealership.

Under the NGML, the following activities require a licence:

- import;
- export;
- transmission;
- storage;
- wholesale;
- distribution; and
- sale, distribution and transmission of compressed natural gas.

### iii Market restrictions

**Petroleum**

In the downstream petroleum market, a distributor’s market share cannot exceed 45 per cent of the total domestic petroleum market and a distributor’s sales via its own dealers (i.e., dealers owned by the distributor) cannot exceed 15 per cent of that distributor’s total domestic market share.

Another restriction regarding distributors and dealers derives from the Competition Board interventions. According to Article 5 of the Competition Authority’s Block Exemption Communique on Vertical Agreements, non-compete undertakings for indefinite terms or those exceeding five years can no longer be granted a block exemption from the prohibition of agreements, concerted practices or decisions that restrict competition in a specific market.

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\(^{36}\) Entered into force on 22 October 2016.
According to the Competition Board’s latest decisions, all personal or real rights related to dealership agreements (such as loan contracts, equipment contracts and long-term lease contracts and long-term usufructs) must be limited to five years.

**Natural gas**

Under the NGML, import companies cannot conclude new natural gas purchase agreements (except for LNG) with countries that currently have existing natural gas sale and purchase agreements with BOTAŞ. The barrier to market entry is actually even higher, because under EMRA’s Board Decree No. 725 (Decree No. 725), EMRA must obtain BOTAŞ’s opinion on whether or not such import activity will affect the performance of BOTAŞ’s obligations arising out of its existing contracts (in BOTAŞ’s capacity as a natural gas importer). In addition, Decree No. 725 requires consultation with BOTAŞ (in its capacity as a transmission system operator) on the technical suitability of the proposed importation through BOTAŞ’s transmission network.

The Draft Amendment Law proposing important changes to the NGML, which became void at the end of the 24th legislative session, was going to abolish the prohibition on import companies from concluding new natural gas purchase agreements with countries that currently have existing natural gas purchase agreements with BOTAŞ. Although it did not enter into force, we believe that the said draft law is still a useful tool for understanding the government’s intentions for the future. In any case, another amendment to the NGML came into effect on 17 June 2016. The NGML and the Natural Gas Market Licence Regulation required import licence holder applicants to (1) conclude lease contracts with storage licence holders to ensure storage of 10 per cent of their annual gas import or (2) to obtain a commitment from storage licence holders confirming that they will have such storage capacity within the following five years. However, the current total capacity of the storage facilities in Turkey is below 10 per cent of the nation’s annual gas import amount. With the above amendment to the NGML, EMRA became authorised to change the commitment amount, and set the applicable storage commitment percentage at 6 per cent. A similar obligation is imposed on wholesale licence applicants. Accordingly, wholesale licence holders must take the required storage-related measures within five years of the issuance of the licence.

Under the NGML, the MENR’s opinion is not required for natural gas market licences. However, if the Draft Amendment Law is passed as is, then the NGML will have a provision whereby EMRA will have to obtain the MENR’s opinion for granting import and export licences.

Under the NGML, no company can sell natural gas corresponding to more than 20 per cent of the estimated national consumption levels determined by EMRA. Moreover, importers cannot import more than 20 per cent of estimated national consumption.

**iv Transfers of control and assignments**

In the electricity market, in general, licence transfer is not permitted under the Electricity Market Licence Regulation. However, with EMRA’s approval, legal entities holding an electricity generation licence are permitted to transfer rights and obligations related to their licences (1) to another legal entity by way of merger or spin-off; and (2) to another legal entity established under the same shareholding structure. Furthermore, legal entities holding an electricity generation licence may transfer the generation facility to another legal entity
seeking to conduct electricity generation activities, by way of sale, transfer or lease, subject to EMRA's approval. Correspondingly, the legal entity acquiring the generation facility must obtain a new generation licence from EMRA, before such transfer.

In addition to the above-mentioned transactions, the Electricity Market Licence Regulation provides the possibility of granting step-in rights to banks and financial institutions that provide loans to licence holders, allowing them to request licence transfers from EMRA. The transferee will undertake all obligations of the former licence holder under the loan agreement. These types of transactions are not considered as 'licence transfer'. The transaction mentioned in item (2), supra, and the transactions relating to project financing allow the transferee to obtain a generation licence that maintains the terms and conditions applicable to the former licence.

The Electricity Market Licence Regulation also sets forth certain share transfer restrictions as stated in the Electricity section (Section II.ii, supra). Under Article 6 of the EML and Article 19 of the Electricity Market Licence Regulation, direct or indirect changes in shareholding structure or share transfers (aside from certain exceptions set forth under the Electricity Market Licence Regulation) are forbidden within the preliminary licence period. EMRA may cancel a preliminary licence if such a transaction occurs.

After obtaining a generation licence, the following share transfers are subject to EMRA's prior approval:

- direct or indirect acquisition of shares representing at least 10 per cent of the licence holder company's share capital (5 per cent if the company is publicly traded);
- share transfers resulting in a change of the company's control, regardless of the change in the shareholding percentage of the shares; and
- share pledge for legal entities holding a generation licence, the tariffs of which are regulated.

Similar to the restrictions in the electricity market, licence transfer is not permitted in the natural gas market under the Natural Gas Market Licence Regulation. However, with EMRA's approval, legal entities holding a licence are permitted to transfer rights and obligations related to their licences to another legal entity by way of merger. This transaction is not considered to be a 'licence transfer'.

In addition, the Natural Gas Market Licence Regulation provides the possibility of granting step-in rights to banks and financial institutions that provide loans to licence holders, allowing them to request licence transfers from EMRA. The transferee will undertake all obligations of the former licence holder under the loan agreement. Furthermore, the Natural Gas Market Licence Regulation also sets forth certain share transfer restrictions. In the natural gas market, licence holders must obtain EMRA's approval for any of the following transactions:

- transferring of 10 per cent or more shares (5 per cent or more in publicly held companies) in licence holding companies;
- transferring of shares, resulting in any shareholder's shares exceeding 10 per cent or decreasing below 10 per cent in licence holding companies;
- transferring of any shares in natural gas storage licence holding companies;
- any transaction resulting in acquisition of the right to vote in the licence holder company;
- share pledges;
- creating or lifting privilege over shares or issuing a dividend right certificate; and
- merger, in accordance with Article 43 of the Natural Gas Market Licence Regulation.
III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Electricity

TEİAŞ\(^{37}\) conducts all of Turkey’s electricity transmission activities. The distribution network is divided into 21 regions, with a different distribution company in each region. All of these companies have recently been privatised. TEDAŞ\(^{38}\) no longer operates any distribution companies, but continues to own the distribution assets.

The shareholders of distribution utilities can own the newly established retail sales utilities’ shares. However, as of 1 January 2016, distribution utilities will not be able to purchase administrative and support services from companies under the parent company’s control. Additionally, as of 1 January 2016, retail sales companies and distribution utilities must use different physical premises and information system infrastructures.

Natural gas

Under the NGML, market participants active in more than (1) one market activity or (2) a single market activity in more than one facility, must keep separate accounts for each activity or facility. Cross-subsidisation between accounts is prohibited. In addition to this account separation, companies holding distribution licences must also maintain separate accounts for their natural gas sale and transportation activities.

Although the NGML stipulated that BOTAŞ was to be unbundled, beginning in 2009, BOTAŞ has not yet been divided into separate legal entities. The plan is to divide BOTAŞ into three separate companies: the first for conducting transmission activities; the second for operating LNG facilities and conducting storage activities; and the third to perform other natural gas market activities.

ii Transmission/transportation, distribution and storage access

Electricity transmission and distribution

TEİAŞ is required to meet individual and company demands for connection to the transmission network. In cases where system connection and use of the system by generation companies are possible, the licence holder and TEİAŞ or the distribution licence holder must conclude connection and system usage agreements.\(^{39}\)

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37 The state transmission entity.
38 The state distribution entity.
39 (1) The Electricity Market Grid Regulation; (2) the Electricity Market Tariff Regulation; (3) the Electricity Market Distribution Regulation; and (4) the Electricity Market Connection and Use of the System Regulation regulate the terms and conditions regarding the applicable tariffs for connection to and use of the system. The Regulation on Connection to and Use of the System regulates the principles regarding connection to and use of the system, while the Grid Regulation and the Tariff Regulation regulate the terms and conditions regarding the applicable tariffs for connection to and use of the system. More recently, the Regulation on Amendment of the Regulation on Electricity Market Connection to and Use of the System and the Regulation on Amendment of the Grid Regulation were published in the Official Gazette dated 30 July 2016. These amendment regulations set forth certain capacity limits for connection of consumers to the system.
Petroleum transmission and storage

Companies holding distribution or storage licences cannot discriminate among third parties of equal status for access to transmission and storage networks. Transmission and storage licence holders that have spare capacity in their facilities must meet the transmission and storage demands of third parties if these demands conform to, *inter alia*:

1. the tariff of the licence holder;
2. the capacity of the relevant facility; and
3. the minimum amount in the tariff of the licence holder.

Natural gas transmission and distribution

Companies holding distribution or transmission licences cannot discriminate among third parties of equal status for access to transmission and distribution networks. Licence holders may only decline third-party access requests if:

1. their capacity is not sufficient;
2. they cannot perform their existing obligations otherwise; or
3. they may be ordered to pay significant financial compensations owing to their existing contractual obligations.

If an applicant undertakes to cover the expenses to overcome the lack of capacity or connection situations, access cannot be denied.

Distribution companies must connect all consumers within their region. A connection agreement must be concluded between the distribution company and consumers, and the technical connection and service lines must be established.

LNG and natural gas storage

There are only four operational storage facilities (two LNG and two underground terminals) in Turkey (five companies have underground storage licences, while only three companies have LNG storage licences). The number of storage facilities explains the insufficiency of storage capacity in Turkey. However, Turkey aims to increase its total storage capacity with the new Tuz Gölü Natural Gas Underground Storage Project and the Aliaga Floating Storage and Regasification Unit. In addition, on 30 September 2016, a consortium consisting of three companies, Tekfen, Tesisat and HMB, signed two agreements with licence holders Toren Doğalgaz Depolama ve Madencilik Anonim Şirketi and Gaz Depo ve Madencilik Anonim Şirketi to supply, construct and operate an underground natural gas storage facility in Mersin as part of the Tarsus Underground Storage Project.40

Companies holding storage licences must provide storage services to users in an objective and fair manner. In principle, except for the exclusive grounds mentioned above for distribution and transmission networks, companies must accept storage requests. On the other hand, in practice, there are only eight storage licences in force.41 As the current storage capacity is insufficient, third-party access is practically impossible.42

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40 www.bloomberght.com/haberler/haber/1924507-tekfen-723-milyon-euroluk-sozlesme-imzaladi
41 Three new storage licences were issued in May 2015, June 2015 and September 2016.
42 EMRA is fully aware of the existing storage conditions in Turkey. Considering the current circumstances, EMRA does not strictly monitor the performance of storage-related obligations and, in practice, does not impose penalties on market participants even if the obligations are not met.
iii Tariffs

Electricity

EMRA is responsible for regulating connection and use, including transmission and distribution tariffs, in the electricity sector. Licence holders must prepare and submit their tariff proposals to EMRA by the end of October every year. EMRA must complete the examination and evaluation of these proposals before the effective date of the relevant tariff.

Natural gas

As it does in the electricity market, EMRA regulates connection tariffs, storage tariffs and tariffs pertaining to the control of transmission and dispatch in the natural gas market. Companies using the gas transmission system are subject to connection tariffs. Fees can be determined freely between the parties, provided that EMRA’s connection tariff principles are reflected in the relevant connection agreements.

iv Security and technology restrictions

There are various pieces of legislation in Turkey dealing with the security of energy infrastructure facilities. Turkey is also a party to international agreements and forums regarding the security of critical infrastructure facilities.

IV ENERGY MARKETS

i Development of energy markets

In Turkey, supply licence holders can conduct electricity trading activities. Electricity traders must either conclude a bilateral electricity purchase agreement with another licence holder or contribute to the organised markets themselves, to participate in the electricity market.

As for natural gas, since there is no energy exchange in Turkey yet, gas trading is physical and regulated in each separate licence and the Network Operation Manual of BOTAŞ. However, the newly introduced Regulation on the Natural Gas Organised Wholesale Exchange Market provides that a natural gas organised wholesale exchange market will be established on 1 April 2018. Reportedly, EPİAŞ is currently working on the technical infrastructure for establishment of this new exchange market. In Turkey, gas trading is conducted by four types of licence holders:

- production lease;
- import licence;
- export licence; and
- wholesale licence.

43 E.g., the Transit Law; the General Directorate of BOTAŞ, Technical Security and Environment Regulation on Construction and Operation of Crude Oil and Natural Gas Facilities; the Turkish Criminal Code; the Petroleum Market Law; the NGML; and the BOTAŞ Transmission Network Operation Principles.

44 E.g., NATO and Critical Infrastructure Facilities; the Convention on Nuclear Safety; the Energy Charter Treaty; the INOGATE Project (Interstate Oil and Gas Transport to Europe); the Convention on Cybercrime; the OSCE Strategy Document For the Economic and Environmental Dimension; and the Decision on Protecting Critical Energy Infrastructure from Terrorist Attacks.

45 I.e., wholesale, export, import and retail sales.

46 The licence holder can conduct petroleum trade. However, it cannot conduct natural gas trade without a wholesale licence.
Under the NGML, a company holding an import licence does not need a separate wholesale licence to perform natural gas wholesale activities.

ii Energy market rules and regulation

In addition to the EML and the Electricity Market Licence Regulation, electricity trading is particularly regulated by the Regulation on Electricity Market Balancing and Settlement.\(^47\) The Regulation on Electricity Market Balancing and Settlement sets forth the principles and procedures regarding the day-ahead market and real-time balancing of the active electricity demand and supply, as well as settlement of trade in these markets. On the other hand, natural gas trading is regulated under the provisions set forth in each separate licence and the Network Operation Manual of BOTAŞ.

iii Contracts for sale of energy

Electricity is traded mostly through bilateral agreements on an over-the-counter basis. Agreements are not subject to EMRA’s approval and, thus, all commercial terms and conditions are freely negotiable. Electricity can also be traded on a day-ahead and real-time basis.

As for natural gas, suppliers and consumers must conclude private law contracts to participate in natural gas trading. A natural gas sale agreement is the primary agreement executed within the framework of natural gas sale and purchase activities.

In addition to a natural gas sale agreement, the following agreements must be concluded by the parties:

a. operation agreements;

b. system connection agreements; and

c. lease agreements.

iv Market developments

Turkey aims to create a liberal and competitive energy market and increase investment opportunities by establishing an energy exchange market. Aside from this, Turkey’s involvement in international oil and gas pipelines significantly supports its aim to become, in the short term, a regional energy hub.

International oil and gas pipelines

The transit passage of oil and gas through Turkey is governed by the Transit Law. However, for the Transit Law to apply as the legal regime of a transit pipeline, there must be an international agreement regarding that pipeline. The Transit Law, the international agreement (generally an intergovernmental agreement (IGA)) and the project agreements apply as the legal regime to the transit pipeline.

In addition to ‘transit’ pipelines through Turkey (e.g., the BTC Pipeline and the contemplated TANAP\(^48\)), there are pipelines that transport oil or gas to or from Turkey.

\(^{47}\) Entered into force on 14 April 2009.

\(^{48}\) The Trans-Anatolian Natural Gas Pipeline.
These are non-transit pipelines, such as the Kirkuk–Yumurtalık Crude Oil Pipeline. The legal regime applicable to these pipelines is either in the form of a Council of Ministers’ Decree (pursuant to the former Petroleum Law\(^{49}\) (PL)) or an IGA signed specifically for that pipeline. There are currently two international crude oil pipelines in Turkey:

- the Baku–Tbilisi–Ceyhan (BTC) Crude Oil Pipeline, transporting crude oil from Azerbaijan to Ceyhan, Adana (transit); and
- the Kirkuk–Yumurtalık Crude Oil Pipeline, transporting crude oil from Iraq to Adana (import).

Currently, the following pipelines exist for the import or export of natural gas:

- the Baku–Tbilisi–Erzurum Pipeline, transporting natural gas from Azerbaijan’s Shah Deniz gas field (Stage I) to Turkey (import);
- the Blue Stream Natural Gas Pipeline, transporting natural gas from Russia to Turkey through the Black Sea (import);
- the Interconnector Turkey–Greece, transporting natural gas between Turkey and Greece (export);\(^{50}\)
- Russia–Turkey Western Route Natural Gas Pipeline crossing Ukraine, Romania and Bulgaria to Turkey; (import); and
- Iran–Turkey Natural Gas Pipeline, transporting natural gas from Iran to Turkey (import).

The following contemplated projects will make Turkey a true oil and gas transport hub:

- TANAP, to transport natural gas from Azerbaijan’s Shah Deniz gas field (Stage II) to Europe, through Turkey;
- the Trans Adriatic Natural Gas Pipeline Project, to transport natural gas from Turkey to Southern Italy and further to Europe through Greece and Albania;
- the Trans Caspian Natural Gas Pipeline Project, to transport natural gas from Turkmenistan to Erzurum, Turkey and possibly to Europe;
- the Mashreq–EU Natural Gas Pipeline Project, to transport natural gas from the Mashreq countries to Turkey, Iraq and the EU;
- Turkey–Bulgaria Natural Gas Pipeline Project, to transport natural gas from Turkey to Bulgaria;
- the Northern Region of Iraq–Turkey Natural Gas Pipeline Project, to transport natural gas from the Northern Region of Iraq to Turkey; and
- the Turkish Stream Natural Gas Pipeline, which will replace the South Stream Project and transport gas from Russia across an offshore section under the Black Sea to Turkey and from there onto European markets. On 10 October 2016, Turkey and the Russian Federation signed an IGA for construction of the Turkish Stream pipeline.

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\(^{49}\) Entered into force on 16 March 1954.

\(^{50}\) Under the IGA signed for the Interconnector Turkey–Greece, it is possible to use this pipeline for import as well. However, it is currently used only for export.
V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

In recent years, investments in electricity generation from renewable energy sources have increased greatly. One of Turkey’s targets is to increase the share of electricity generated from renewable energy sources to 30 per cent by 2023. This is expected to entail the increase of wind-power installed capacity to 20,000MW, as well as the installation of new power plants, with 1,000MW of geothermal and 5,000MW of solar energy.

Incentive regime

The principles and procedures to be applied on the utilisation of renewable energy resources for the purpose of generating electrical energy are mainly governed by the Law on the Utilisation of Renewable Energy Resources for the Purpose of Generating Electrical Energy\(^{51}\) (the RER Law). The renewable energy resources covered by the RER Law are wind, solar, geothermal, biomass, biogas (including landfill gas), wave, stream, tidal, river and arc type hydroelectric generation facilities with a reservoir area of less than 15 kilometers. In January 2011, the RER Law underwent a significant set of amendments, upon which the feed-in tariffs and other incentives were introduced. With the amendments in January 2011, the RER Law established a renewable energy support mechanism (RERSM). This mechanism includes price, terms, procedures and principles regarding the payments to be made to individuals generating energy using renewable energy resources within the scope of the RER Law.

In order to achieve Turkey’s 2023 target of increasing the share of renewable energy sources to 30 per cent, the EML and the RER Law were amended on 4 June 2016. In addition to these amendments, the Regulation on Certification and Supporting of Renewable Energy Resources (the RERSM Regulation) was also amended on 1 May 2016. Before the amendments, power plants within the scope of the RERSM Regulation were subject to a system in which the generated energy was sold to the market operator without a generation limitation or a risk regarding the price or amount of energy generated. In addition, power plants were free of obligation regarding the balance mechanism. Therefore, they did not have to pay any imbalance expenses. The RER Law guaranteed the prices in terms of US cents, and access to loans were relatively easy due to predictable cash flows. Power plants operating under the RERSM portfolio system could sell all of their products to a market operator, and did not have to engage in any market activity. With the amendments in the RERSM Regulation, power plants within this regulation’s scope may now sell the generated energy directly to the free market.

The RER Law provides that the prices in Schedule I (see below) will apply for 10 years for those generation facilities subject to the RERSM and commissioned until 31 December 2020.\(^{52}\)

<table>
<thead>
<tr>
<th>Type of facility</th>
<th>Prices applicable (US$ cent/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydroelectric</td>
<td>7.3</td>
</tr>
<tr>
<td>Wind</td>
<td>7.3</td>
</tr>
<tr>
<td>Geothermal</td>
<td>10.5</td>
</tr>
</tbody>
</table>

\(^{51}\) Entered into force on 18 May 2005.

\(^{52}\) Although the initial date set in the RER Law was 31 December 2015, a Council of Ministers’ Decree dated 18 November 2013 extended the incentive term until 31 December 2020.
Turkey

<table>
<thead>
<tr>
<th>Type of facility</th>
<th>Prices applicable (US$ cent/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biomass (including landfill gas)</td>
<td>13.3</td>
</tr>
<tr>
<td>Solar power</td>
<td>13.3</td>
</tr>
</tbody>
</table>

The RER Law further provides that renewable energy facilities can, subject to a Council of Ministers’ Decree, benefit from certain tax incentives, such as customs duty and VAT. Additional incentives are provided if domestic equipment is used in facilities commissioned before 31 December 2020.

ii Energy efficiency and conservation

Under the Energy Efficiency Law, the EECC regulates energy efficiency activities. This law sets forth several mandatory obligations. It also includes provisions regarding energy efficiency education and awareness.

The Energy Efficiency Law requires industrial entities to appoint an energy efficiency controller. These entities must inform the GDRE of their annual energy consumption. Furthermore, industrial businesses may (1) voluntarily submit projects that increase efficiency or (2) conclude agreements with the GDRE, undertaking to reduce their consumption levels by at least 10 per cent, in return for certain incentives.

iii Technological developments

Renewable energy is a developing sector in Turkey. Although Turkey has remarkable potential in terms of renewable energy resources, there is currently insufficient legislation encouraging technological developments in the renewable energy sector.

VI THE YEAR IN REVIEW

i Privatisations

Following the completion of the privatisation of all state-owned electricity distribution companies in 2013, Turkey has been focusing on the privatisation of generation assets. In 2015, 2016 and 2017 Turkey privatised several electricity generation assets owned by EÜAŞ. Below is a summary of privatisations that have been completed by 1 May 2017:

<table>
<thead>
<tr>
<th>Power plant</th>
<th>Privatisation year</th>
<th>Approximate bid value (millions of Turkish liras)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Orhaneli and Tuncbilek TPP</td>
<td>2015</td>
<td>521</td>
</tr>
<tr>
<td>Soma B TPP</td>
<td>2015</td>
<td>685</td>
</tr>
<tr>
<td>Manavgat HPP</td>
<td>2016</td>
<td>370</td>
</tr>
<tr>
<td>Fethiye HPP</td>
<td>2016</td>
<td>128</td>
</tr>
<tr>
<td>Karacaoren 1 and Karacaoren 2 HPP</td>
<td>2016</td>
<td>515</td>
</tr>
</tbody>
</table>

54 The Energy Efficiency Coordination Committee.
55 E.g., the use of labelled equipment in industrial companies and buildings.
56 The General Directorate of Renewable Energy.
57 This article only includes certain significant developments until 1 May 2017.
58 The state generation entity.
Below is a summary of privatisations that were approved but are still waiting for parties’ signatures by 1 May 2017:

<table>
<thead>
<tr>
<th>Power plant</th>
<th>Privatisation year</th>
<th>Approximate bid value (millions of Turkish liras)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kadıncık 1 and Kadıncık 2 HPP</td>
<td>2016</td>
<td>864</td>
</tr>
<tr>
<td>Doğankent, Kürtün ve Torul HPP</td>
<td>2016</td>
<td>1,225</td>
</tr>
<tr>
<td>Şanlıurfa HPP</td>
<td>2017</td>
<td>247</td>
</tr>
<tr>
<td>Adıgüzel ve Kemer HPP</td>
<td>2017</td>
<td>341</td>
</tr>
</tbody>
</table>

In addition to the privatisation of electricity generation assets, the tender for privatisation of İGDAŞ\(^{59}\) is also expected. Furthermore, on 28 December 2016, the Privatisation Administration approved the privatisation of TP Petrol Dağıtım AŞ, a petroleum distribution company, for 490 million liras.

ii  **İPİAŞ**

The EML introduced the ‘market operation activity’, to be conducted by a newly incorporated company, namely İPİAŞ. İPİAŞ was finally incorporated on 12 March 2015. İPİAŞ’s purpose is to lead the development of organised energy exchange markets in Turkey; to supervise and manage these energy exchange markets in an effective, transparent and reliable manner; to create added value to national economy by maximising the trading volume in the energy sector; and to provide a transparent and competitive environment for both domestic and foreign investors. TEİAŞ and Borsa İstanbul (BI) each hold 30 per cent of the corporation’s total shares, with the remaining 40 per cent held by various major market participants, namely, private energy companies. Under this shareholding structure, TEİAŞ and BI hold Class A and Class B shares, whereas private energy companies hold Class C shares.

iii  **Pending projects**

The Akkuyu Nuclear Power Plant, in Mersin, will be the first nuclear power plant in Turkey. The Akkuyu Nuclear Power Plant is planned to have four power units with capacity of 1,200MW each and a total capacity of 4,800MW.\(^{60}\) The EIAR\(^{61}\) of the project was approved by the MEU\(^{62}\) on 1 December 2014. The generation licence for the project is issued to be effective as of 15 June 2017 and the licence will be valid for 49 years.\(^{63}\) It is expected that its first unit will be operational in 2020.

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59 Istanbul’s natural gas distribution company.
61 Environmental impact assessment report.
62 The Ministry of Environment and Urbanisation.
In May 2013, Turkey signed an IGA with Japan for the construction and operation of a nuclear power plant in Sinop. This US$20+ billion project will be constructed and operated by the consortium formed by Mitsubishi Heavy Industries, Itochu and GDF Suez. The discussions regarding the memorandum of understanding (MoU) between Turkey and Japan regarding the Sinop Nuclear Power Plant Project were concluded and the MoU was delivered to the Japanese Embassy for signature in August 2014. The IGA and the MoU (along with the draft HGA) were published in the Official Gazette on 10 April 2015 and became a part of Turkish legislation. This plant is expected to become operational in 2023.

Following the success of the Baku–Tbilisi–Ceyhan Crude Oil Pipeline, Turkey became the obvious candidate for hosting pipelines transporting petroleum and natural gas from the Caspian to Europe. In line with this approach, Turkey and Azerbaijan signed an IGA for the construction and operation of the TANAP. Attached to the IGA is a HGA signed between Turkey and the TANAP project company. The Turkish government places great importance on this project, which will be the longest energy pipeline in the region at approximately 2,000km. On 24 July 2014, Turkey approved the EIAR prepared for the TANAP project. In September 2014, the Turkish Parliament approved:

- the memorandum of understanding between the Republic of Turkey and the Republic of Azerbaijan regarding the TANAP system;
- the text of amendment to the HGA between the Republic of Turkey and the TANAP project company.

The Council of Ministers’ Ratification Decrees for these two texts were published in the Official Gazette on 21 October 2014. The construction works started on 17 March 2015 with the ground laying ceremony, which was attended by Turkish, Azerbaijani and Georgian presidents.

In January 2013, Turkey and the UAE signed an IGA for what was going to be the largest foreign direct investment in Turkey to date, with a value of approximately US$12–14 billion. The project entailed the construction and operation of a coal-based power plant, in Turkey’s Afşin-Elbistan region. The project was initially planned to start in mid-2013. However, because of other priorities, in August 2013, TAQA decided to defer its investment decision. After TAQA deferred its investment decision, companies from the State of Qatar, Japan, China and South Korea started to compete for this project.

### Shale gas

In recent years, along with the rising of the importance of shale gas in the world, importance has been given to searching for shale gas in Turkey. For this purpose, Sarıbuğday-1 in 2012, Konacık-1 in 2013, Ağçay-1 in 2014 and Çeşmekolu-1 and Çakıcı-1 wells in the Trakya Region in 2015 and 2016 respectively were opened in Southeastern Anatolia. Studies are under way to evaluate data obtained from the wells. Apart from the South-Eastern Anatolian region, it is also believed that there are significant amounts of available shale gas in the

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64 According to the final version of the shareholders agreement, signed in March 2015, while BOTAŞ holds 30 per cent stakes in the TANAP project company, BP holds 12 per cent. Southern Gas Corridor Closed Joint Stock Company holds the remaining stakes.

65 With a capacity of up to 8,000MW.
Hamitabat and Mezardere areas of the Thracian region, which have yet to be taken into the scope of the operating agreement, but which may be put on the agenda in the coming period.66

v Solar and wind-based energy generation licence applications

Significant developments were also witnessed in renewable energy investment in 2015 and 2016. EMRA received applications for solar-based energy generation licences between 1 and 7 April 2015. Although the designated total capacity for solar-based generation licences is 600MW, applications were submitted for nearly 8,900MW. Thus, several contests will be organised in different regions to decide who will obtain the generation licence in the relevant region.

Below is a summary of the contests held in 2014 and 2015, and the respective regions:

<table>
<thead>
<tr>
<th>Packages</th>
<th>Date</th>
<th>Districts</th>
</tr>
</thead>
<tbody>
<tr>
<td>First package</td>
<td>12 May 2014</td>
<td>Elazığ</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Erzurum</td>
</tr>
<tr>
<td>Second package</td>
<td>29 January 2015</td>
<td>Siirt–Batman–Mardin</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Şanlıurfa–Diyarbakır</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Antalya</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Muğla–Aydın</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Denizli</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Burdur</td>
</tr>
<tr>
<td>Third package</td>
<td>30 January 2015</td>
<td>Konya 1</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Konya 2</td>
</tr>
<tr>
<td>Fourth package</td>
<td>28 April 2015</td>
<td>Adana–Osmaniye</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Sivas</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Kayseri</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Niğde–Nevşehir–Aksaray</td>
</tr>
<tr>
<td>Fifth package</td>
<td>29 April 2015</td>
<td>Kahramanmaras–Adıyaman</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Malatya–Adıyaman</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Van–Ağrı</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Bitlis</td>
</tr>
<tr>
<td>Sixth package</td>
<td>30 April 2015</td>
<td>Karaman</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Mersin</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Isparta–Afyon</td>
</tr>
</tbody>
</table>

In addition, on 13 May 2017, the new Contest Regulation on Pre-Licence Applications Regarding Generation Facility Based on Solar and Wind Energy67 entered into force and superseded the old regulations. Under the new regulation, the contests will not be carried out on applicant's contribution rate basis. Instead, the minimum offer over the prices indicated in the RER Law Schedule I will be considered. Under the Contest Regulation on Pre-Licence

67 Entered into force on 13 May 2017.
Applications Regarding Generation Facility Based on Solar and Wind Energy, the date and place of contests will be determined by TEİAŞ, in the event of multiple applications for a specific field.

vi TPL

The TPL introduced a more liberal and investor-friendly regime than the provisions of the PL imposed on upstream participants. With this new law, Turkey is now divided into only two petroleum districts, namely onshore and offshore. Previously there were 18 petroleum districts.

Perhaps the most significant change introduced by the TPL is the abolition of the ‘national interest’ concept. On the basis of this concept, the TPAO had a statutory right to obtain exploration licences on behalf of the state, and by virtue of this right the TPAO had an advantage in respect of the exploration licence application process. With the abolition of this concept, the TPAO no longer has that privilege.

vii New Electricity Market Law

The EML aims to address various new issues that have long been awaited in the market, such as the introduction of a ‘preliminary licence’ mechanism for generation licence applications. This law also provides for the establishment of an electricity exchange, which will create a whole new market of its own and become a significant investment opportunity.

viii Law on the Construction and Operation of Nuclear Power Plants and Energy Sale (Law No. 5710)

Law No. 5710 and the Regulation on the Principles and Procedures for Competition and Contracts within the Framework of Law No. 5710 are the main pieces of legislation that govern the procedures and principles for the construction and operation of nuclear power plants and the sale of energy generated from those plants.

In March and April 2017, the TAEA issued three new regulations in the field of nuclear energy. The Regulation on the Construction Inspection of Nuclear Power Plants provides for the procedures on construction of nuclear power plants in accordance with nuclear security principles. The two other regulations (i.e., the Regulation on the Management System in

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68 Although these enactments took place in 2013, we will provide brief information on them in this chapter because of their importance.
69 The long-awaited TPL was enacted in 2013, replacing the PL after nearly 60 years.
70 Another novelty of the TPL is the abolition of the restriction on the number of licences a company can obtain for a single petroleum district. Under the PL, companies were limited to eight licences per district.
71 Among some of the other novelties is that the TPL allows petroleum right holders to market and export natural gas that they have produced to wholesale companies, export companies, distribution companies or to eligible consumers without being subject to any conditions regarding storage capacity.
72 Although these enactments took place in 2013, we will provide brief information on them in this chapter because of their importance.
73 The EML entered into force in March 2013.
74 Entered into force on 21 November 2007.
75 Entered into force on 31 March 2017.
VII CONCLUSIONS AND OUTLOOK

Considering economic expansion, rising per capita income, positive demographic trends and the rapid pace of urbanisation that are the main drivers of Turkey’s growing energy demand, Turkey’s energy demand is estimated to increase by approximately 7 per cent each year until 2023. Because of this increase in energy demand, the Turkish energy market has been experiencing vast changes. These changes include liberalisation, attracting private sector participation and the establishment of a competitive market.

Turkey’s long-term energy policies and strategies will keep Turkey’s focus on diversifying its energy resources. At present, domestic resources provide approximately 26 per cent of the total energy demand, the remainder being imported. Turkey’s costs for importing crude oil and natural gas are currently as high as US$56 billion. This accounts for more than half of the country’s foreign trade deficit. Because of insufficient domestic energy generation, Turkey’s primary goal is to strengthen its security of supply. Turkey aims to diversify its energy supply routes and sources, such as nuclear energy, and to increase the share of renewable energy.

Turkey’s importance in the energy markets is not just increasing as a growing consumer with a huge domestic market, but also as an energy transit hub. Although Turkey has limited energy resources, its position is critical for petroleum and natural gas trade between the East and the West, as it lies between energy-demanding European countries and energy-rich eastern countries. Turkey is a natural transit country for the maritime and pipeline transportation of gas and oil. Accordingly, international crude oil and natural gas pipelines and pipeline projects hold great importance and improve Turkey’s role as a reliable transit country.

76 Entered into force on 8 April 2017.
77 Entered into force on 5 April 2017.
I OVERVIEW

The United Arab Emirates (UAE) is a federation of the seven emirates of Abu Dhabi, Dubai, Sharjah, Ajman, Fujairah, Ras Al Khaymah and Umm al-Quwain. The city of Abu Dhabi in the emirate of Abu Dhabi is the federal capital. Abu Dhabi is the largest emirate by area (making up about 86 per cent of the country’s area) and the richest in terms of oil resources. Dubai is the second-largest emirate by size (accounting for about 5 per cent of the country’s total area) and the largest by population. Together, Dubai and Abu Dhabi account for about two-thirds of the country’s population and form the core of its economy.

The UAE’s economy has traditionally been dominated by the petroleum industry but successful efforts at economic diversification have reduced the share of the oil and gas sector in the country’s GDP to 25 per cent. The UAE has an open economy with one of the highest per capita incomes in the world and a sizeable annual trade surplus. The currency is freely convertible and funds can be freely repatriated. The country’s free zones – offering 100 per cent foreign ownership and zero taxes – are a major conduit for foreign investment in the country. The geographical location of the UAE, situated at the tip of the Arabian Peninsula, makes it a central trading post connecting the Far Eastern economies with the Middle East, Africa and Europe. With modern communication and thriving ports, the UAE has emerged as an important trading hub between the Indian sub-continent, Europe, Africa and the Middle East.

The powers of the federal and the emirate governments are enumerated in the State Constitution of 1971. Although the country’s government is based on a federal structure, the individual emirates enjoy considerable economic and political autonomy and each emirate largely pursues its own economic policies. Even though Article 120 of the UAE Constitution gives the federal government exclusive legislative and executive jurisdiction over electricity services in the country, in practice the larger emirates of Dubai and Abu Dhabi, and to some extent Sharjah, and more recently the northern emirate of Ras Al Khaymah, formulate and implement their own electricity policies. Hence, although there is a Federal Ministry of Energy (which formulates and implements the federal electricity policies), federal legislation on electricity is fairly limited.

Because of the significance of Abu Dhabi and Dubai within the Federation, this chapter focuses primarily on the electricity sector in these two emirates, in addition to the federal laws and policies on electricity.

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1 Masood Afridi is a partner and Adite Aloke is an associate at Afridi & Angell.
The generation, transmission and distribution of electricity in the UAE is dominated by four water and power authorities. Three of these authorities are owned by the governments of the emirates of Dubai, Abu Dhabi, and Sharjah, whereas the authority that operates in the smaller northern emirates is federally controlled. These state-owned authorities serve as the exclusive purchasers and distributors of electricity in the respective emirates. While the private sector has been allowed to participate in the generation of electricity, transmission and distribution is performed exclusively by state-owned authorities.

Abu Dhabi and Dubai are the only emirates so far that have private sector participation in the energy sector. In line with extant regulations, private participants can own up to 40 per cent economic interest in electricity generation plants in Abu Dhabi and up to 49 per cent in Dubai. There has been speculation regarding the introduction of a privatisation policy by the federal government for the northern emirates; however, no formal announcement has been made so far.

Currently, only Dubai and Abu Dhabi have enacted laws creating specialised regulatory bodies for the electricity sector. These consist of the relatively recently constituted Dubai Supreme Council of Energy (DSCE) and the Dubai Regulation and Supervision Bureau (the RSB Dubai) in Dubai, and the Regulation and Supervision Bureau of Abu Dhabi (the RSB). The Federal Ministry of Energy (Ministry of Energy) regulates the sector at the federal level and works in conjunction with the Federal Electricity and Water Authority (FEWA) to implement the federal government’s electricity policy in the northern emirates.

Increasing population growth and urban development has been responsible for electricity demand in the UAE to grow at double-digit rates, and demand is expected to continue to grow at about 10 per cent annually for the next decade because of increasing population growth and industrial development. There is currently insufficient power generation capacity in the northern emirates of the UAE, and demand in these emirates is being met by construction of additional capacity as well as the supply of power from the larger emirates through the Emirates National Grid (ENG). Some industrial projects have not been able to secure sufficient power supply and have had to resort to captive power generation.

A number of major power projects, both in the field of conventional and renewable energy, are under development to meet the country’s existing and future electricity needs.

II REGULATION

i The regulators

Federal

The Ministry of Energy, the primary regulator at the federal level, was formed pursuant to Federal Decree No. 3 of 2004 by merging the Ministry of Petroleum and Mineral Resources with the Ministry of Electricity and Water. In 2008, the Ministry of Energy was restructured pursuant to Cabinet Resolution No. 11 of 2008 making it responsible for establishing policies for the water and electricity sectors in the UAE and ensuring that other authorities and companies in the state comply with its policies. A separate directorate for the electricity sector was established within the Ministry of Energy, called the ‘Department of Electricity and Desalinated Water’.

In 2014, the federal government further restructured the Ministry of Energy to introduce three new departments:

a the Clean Energy and Climate Change Department;
The restructuring was intended to create a more specialised and robust central regulatory authority at the federal level. However, the Ministry of Energy has had little influence in directing policy and implementing projects in the larger emirates of Abu Dhabi and Dubai and remains focused on assisting the smaller emirates in meeting their growing electricity demand.

FEWA, which was established pursuant to Federal Law No. 31 of 1999 (the FEWA Law) as amended by Federal Law No. 9 of 2008, is the dominant player in the northern emirates and engages in all segments of the market, including generation, transmission and distribution. The Ministry of Energy has announced a strategic energy plan to develop the federal government’s electricity services by attracting private investment in the sector. Most of the new power projects announced in the northern emirates since the launch of this policy in 2007 have, however, been in the public sector.

**Abu Dhabi**

Abu Dhabi’s electricity sector is regulated under Law No. 2 of 1998 Concerning the Regulation of Water and Electricity Sector (Abu Dhabi Electricity Law), as amended by Law No. 19 of 2007 and Law No. 12 of 2009. The RSB is the regulatory body responsible for implementing the legal framework and its authority includes the power to:

- issue licences to conduct regulated activities;
- monitor licensees and ensure compliance with terms of licences issued; and
- make regulations as it sees fit for the regular, efficient and safe supply of electricity in the emirate.

The Abu Dhabi Water and Electricity Authority (ADWEA) owns (either wholly or as majority shareholder) and controls, either directly or indirectly, the entities responsible for the generation, transmission and distribution of electricity in the emirate.

Both the RSB and ADWEA were established under the Abu Dhabi Electricity Law.

**Dubai**

Dubai’s legislation on the electricity sector was historically limited to Dubai Law No. 1 of 1992 (the DEWA Law), as amended by Decree No. 13 of 1999 and Decree No. 9 of 2011, establishing the Dubai Electricity and Water Authority (DEWA). Dubai has enacted a number of laws to modernise and open the sector to private investment. Two new regulatory bodies have been created: the DSCE,\(^2\) established under Dubai Law No. 19 of 2009 (DSCE Law), as the apex regulator for the energy sector, and RSB Dubai, established pursuant to Dubai Executive Council’s Resolution No. 2 of 2010, as the specialist regulatory authority for the electricity sector.

As the primary regulator of the energy sector, the DSCE regulates the exploration, production, storage, transmission and distribution of petroleum products (natural gas, liquid

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\(^2\) Member organisations of the DSCE are DEWA, Dubai Aluminium Company Ltd, Emirates National Oil Company, Dubai Supply Authority, Dubai Petroleum Establishment, Dubai Nuclear Energy Committee, Dubai Municipality, Department of Petroleum Affairs and the Road and Transport Authority.
petroleum, petroleum gases, crude oil) and electricity. It ensures that the energy and electricity sources satisfy the current and future demands of the emirate of Dubai at affordable prices. The DSCE also proposes any and all initiatives related to the energy sector, which includes the privatisation of its electricity assets and implementing the provisions of Dubai’s Law No. 6 of 2011 Regulating the Participation of the Private Sector in Electricity and Water Production in the Emirate of Dubai (the Dubai Electricity Privatisation Law).

RSB Dubai is authorised to regulate the electricity sector subject to the supervision of the DSCE. RSB Dubai is mainly responsible for regulating, licensing and supervising the electricity generating service providers, facilities and properties. It also determines and establishes standards and controls for electricity generation in the emirate and proposes legislation governing the electricity sector in Dubai.

As with the other emirates, the main player in the electricity market is DEWA, Dubai’s state-owned integrated power generation, transmission and distribution authority.

ii Regulated activities

All activities connected to the generation, transmission and distribution of electricity in the UAE are regulated and require specific licences from the relevant regulatory authorities.

Under the Abu Dhabi Electricity Law, regulated activities include electricity generation, transmission, distribution and supply to premises. Any person or entity intending to carry out these activities is required to be licensed by the RSB Dubai.

Under the Dubai Electricity Privatisation Law, regulated activities include ‘any activity related to generating electricity […] for the purpose of supplying to the Transmission System with produced electricity’ (the transmission system is owned and operated by DEWA). All activities relating to electricity generation, transmission, distribution and supply of electricity are considered regulated activities in Dubai and require a licence from RSB Dubai.

iii Ownership and market access restrictions

As indicated earlier, Abu Dhabi has allowed private sector participation of up to 40 per cent in its power generation sector. In furtherance of its legislative policies in this regard, in 2015 Dubai awarded 49 per cent of the ownership of phase 1 of Hassyan, a 2400MW clean coal power plant, to a consortium led by Harbin Electric International and ACWA Power (Hassyan Clean Coal Project). At the federal level, the private sector participation has yet to materialise in the northern emirates with the exception of Ras Al Khaymah (which has allowed UTICO, a private sector utility company, to participate in the electricity generation, transmission and distribution of the emirate).

Under Federal Law No. 2 of 2015 on Commercial Companies (the Companies Law), foreigners are restricted to own up to a maximum of 49 per cent of a UAE company (other than in the free zones) with the majority 51 per cent required to be owned by UAE nationals. The power sector is no exception to this requirement and even if 100 per cent private ownership were to be allowed in the power sector, a privately owned power generation, transmission or distribution company would need to be majority locally owned.

Although this restriction is a deterrent to foreign investment, it is not an insurmountable hurdle as informal arrangements exist to enable the foreigner investors to transfer 100 per cent

3 Federal Law No. 2 of 2015 on Commercial Companies abrogated Federal Law No. 8 of 1984 (as amended).
beneficial interest in local companies to themselves. It is common for foreign investors to enter into side agreements with the local majority-owning partners by virtue of which the foreign shareholders assume management powers and at the same time transfer to themselves the economic interest in the shares held by the local. The local shareholder is usually paid a fixed fee as part of this arrangement for acting as a local sponsor. The authorities in the UAE have so far tolerated this practice, and as long as there is no dispute between the parties, the arrangement works to the benefit of all shareholders. The enforceability of these side agreements is questionable and untested in the local courts. Although the local partner could, in theory, take over the business by revoking the side agreements, the arrangement works well in the vast majority of cases and offers a practical way forward for foreign investors wishing to do business in the UAE.

Although the UAE free zones allow for 100 per cent foreign ownership, the free zone companies are not allowed to conduct business outside the free zones and within UAE proper. To date, there are no power generation, transmission or distribution companies in any of the free zones in the UAE. Electricity rates are subsidised throughout the UAE and it is therefore not viable for private producers to construct power plants within the free zones. Furthermore, the state-owned authorities in the emirates of Dubai and Abu Dhabi have sufficient capacity to meet present and anticipated future needs, and this has therefore not necessitated private investment in the sector in the free zones.

The UAE’s electricity laws themselves do not impose any specific ownership restriction on foreign investors in the UAE, nor do they necessarily require government participation in the sector. As a matter of policy, in Abu Dhabi, although two or more foreign joint venture partners are permitted to own up to 40 per cent of a project company, the RSB ensures that a foreign entity does not own more than 25 per cent of the market by capacity.

Most power companies in the UAE (with some exceptions such as UTICO) are either wholly or majority owned by the federal or respective emirates’ governments, and the sector is dominated by the state-owned water and electricity authorities. Of these, the DEWA and ADWEA, being the largest two, account for about 88 per cent of the UAE’s entire installed capacity. As of the figures available for 2015, ADWEA accounts for approximately 54 per cent of the UAE’s entire power generation capacity (at 15,546 MW), DEWA for 34 per cent (at 9,656 MW), Sharjah Electricity and Water Authority (SEWA) for 9.5 per cent (at 2,840 MW) and FEWA for about 2.5 per cent (at 703 MW).

**Abu Dhabi**

ADWEA was established pursuant to the Abu Dhabi Electricity Law, and is responsible for all matters relating to formulation, development and implementation of policies for the electricity sector in Abu Dhabi, including privatisation. ADWEA is managed by a board and headed by a chairman, appointed by royal decree (Emiri decree). In addition to managing the public sector entities, ADWEA has established joint ventures with private sector companies.

ADWEA wholly owns the Abu Dhabi Water and Electricity Company (ADWEC), the single buyer of water and electricity in Abu Dhabi, and Abu Dhabi Transmission and Dispatch Company (TRANSCO), the main transmission company in the emirate.

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4 ADPC has the following subsidiaries: Abu Dhabi Water and Electricity Company; Abu Dhabi Transmission and Dispatch Company; Al Mirfa Power Company; Abu Dhabi Distribution Company; and Al Ain Distribution Company.
ADWEA has established a long-term programme for the privatisation of the electricity sector. To date, a number of independent water and power producers (IWPPs) have been established as joint-venture arrangements between ADWEA and various international power companies as BOO (build, operate, own) projects. In accordance with long-term arrangements, IWPPs are committed to selling their production to ADWEC.

The major IWPPs include:

- Arabian Power Company;
- Emirates CMS Power Company;
- Emirates SembCorp Water and Power Company;
- Fujairah Asia Power Company;
- Gulf Total Tractebel Power Company;
- Ruwais Power Company;
- Shuweihat Asia Power Company PJSC;
- Shuweihat CMS International Power Company; and
- Taweelah Asia Power Company.

The ownership of the IWPPs is split 60:40 between ADWEA (or its subsidiaries) and the foreign investor. The project companies are usually structured as joint stock companies incorporated in Abu Dhabi. The most common ownership structure is one in which ADWEA incorporates an intermediate holding company to own a 60 per cent stake, which is in turn held 10 per cent by ADWEA and 90 per cent by the Abu Dhabi National Energy Company PJSC (also known as TAQA). A few project companies have other ownership structures.

Dubai

DEWA was established as an independent public authority owned by the government of Dubai, responsible for the development and provision of utilities in the emirate. DEWA is managed by a board of directors whose members are appointed by Emiri decree.

DEWA is an integrated supplier owning and operating in all segments of the electricity market in Dubai. DEWA owns and operates 12 plants in the emirate whose individual capacities vary between 400MW to 2,200MW, with a total installed capacity of 10,000MW. Although the Dubai government wants to promote private investment in its electricity

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5 The Shuweihat S2 IWPP, owned by Ruwais Power Company was commissioned in October 2011, adding a further 1,510MW to Abu Dhabi’s power generation capacity and 100 million imperial gallons of potable water each day.

6 In February 2011, a PPA for the Shuweihat 3 power plant was signed between ADWEC and Shuweihat Asia Power Investment BV, a company 60 per cent-owned by ADWEA and 40 per cent by Sumitomo Corporation of Japan and Korea Electric Company (each holding 20.4 per cent and 19.6 per cent respectively). This plant has been operational since September 2014 and generates 1,647MW.

7 Jeffery Delmon and Victoria Rigby Delmon, *International Project Finance and PPPs: A Legal Guide to Key Growth Markets 2012*, Chapter 16, p. 26 (2012). TAQA, in which ADWEA owns a 51 per cent ownership stake, was established under Abu Dhabi Decree No. (16) of 2005 and serves as ADWEA’s investment arm in the emirate and abroad. Other Abu Dhabi government entities own a further 21.5 per cent of TAQA with the total government shareholding being 72.5 per cent. The remaining 27.5 per cent of TAQA is owned privately. The shareholding of TAQA provided on its website is not consistent. The shareholding is also stated as follows: ADWEA 52.4 per cent, other government entities 22.1 per cent and non-government shareholding 25.6 per cent.
generation sector, to date, all of the power generation capacity of Dubai, except for captive power produced by certain entities (e.g., Dubai Aluminium Company Ltd), is owned by DEWA.

In 2011 Dubai passed the Dubai Electricity Privatisation Law, which is broadly modelled on the Abu Dhabi Electricity Law. The Dubai Electricity Privatisation Law authorises DEWA to establish project companies, by itself or in collaboration with third parties, for the generation of electricity.

To date, four independent power projects (IPPs) have been launched in Dubai. The first IPP is Al Hassyan 1 IPP, a 1,500MW gas-fired power plant, for which bids were solicited in December 2011. The project has, however, been deferred indefinitely.

In 2015, a consortium of ACWA Power and TSK Electronica y Electricidad SA won the bid to set up a 200MW photovoltaic plant in the second phase of the Mohammed bin Rashid Al Maktoum Solar Park8 (Shuaa Solar PV Project), which will be operational by Q2 2017.

Subsequently, the Hassyan Clean Coal Project was launched by DEWA and the consortium of ACWA Power and Harbin Electric was awarded the project9. In 2016, the major engineering procurement and construction contract for the Hassyan Clean Energy Project was awarded to Harbin Electric International and General Electric. The project is proposed to be operational by 2023.

DEWA also released an expression of interest in October 2016 for the largest concentrated solar power project in the world (CSP), based on the IPP model. The first phase of the CSP project (200MW) is proposed to be operational by April 2021, and DEWA aims to generate 1,000MW using this technology by 2030. Further to the expression of interest, DEWA released the request for proposals to qualified bidders in January 2017 and the submission date for this tender is May 2017.

Another development in 2016 was the selection of the consortium led by Abu Dhabi Future Energy Company (Masdar), including the Spanish companies FRV (Fotowatio Renewable Ventures) and Gransolar Group for construction of the 800MW third phase of the Mohammed bin Rashid Al Maktoum Solar Park (Solar Park)10 on the IPP model.

In addition to the above, Mohd Abdulla Haji Yousuf Khoory & Co. LLC (trading as Union Paper Mills) was granted an electricity generation licence in November, 2016 in relation to a 3MW biomass boilers’ facility at Al Quoz, Dubai.

In 2012, DEWA added a further 900MW to its installed capacity through an expansion of the Jebel Ali Power and Desalination Station ‘M’ plant from 1,135MW to 2,060MW (Jebel Ali Power Station). A further expansion of the Jebel Ali Power Station is now proposed, which will add a further 700MW to its installed capacity. Recently, DEWA has awarded a turnkey construction contract to Siemens for the expansion of the M-station, which is expected to complete in April 2018.

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8 The special purpose vehicle set up to establish the project is Company Shuaa Energy 1, in which DEWA is a 51 per cent stakeholder and the remaining 49 per cent is held by the consortium of ACWA and TSK.
9 The special purpose vehicle set up to establish the project is Hassyan Energy Phase 1 PSC, in which DEWA is a 51 per cent stakeholder and the remaining 49 per cent is held by the consortium of ACWA and Harbin.
10 This is a 12 billion-dirham solar power project launched in January 2012 by Sheikh Mohammad Bin Rashid Al Maktoum, expected to have a total installed capacity of 5000MW by 2030.
Northern emirates
FEWA is responsible for the generation, transmission and distribution of electricity in the northern emirates of Ajman, Ras Al Khaymah, Fujairah and Umm al-Quwain.

FEWA is governed by a board of directors whose members hold office for a term of three years. FEWA is authorised under the FEWA Law to establish private power generation plants in the northern emirates. A number of projects are presently under development in these emirates but these are primarily owned in the public sector.

FEWA acts as the single point of sale for all power generated in the northern emirates. Electricity transmission and distribution networks within the northern emirates are also primarily owned and operated by FEWA. However, recently, TRANSCO has expanded its operations to assist FEWA in planning, developing and operating its water and electricity transmission assets in the northern emirates. In addition to FEWA, certain private power companies such as UTICO are involved in the generation, transmission and distribution of power in the emirate of Ras Al Khaymah.

Sharjah
Sharjah created its own electricity authority in 1995, known as SEWA (established pursuant to Sharjah Emiri Decree No. 1 of 1995, as amended by Emiri Decrees No. 2 of 2000, No. 46 of 2006 and No. 20 of 2008), which is authorised to 'own, manage, operate and maintain' power stations and electricity transmission lines. As with the other emirates, SEWA is responsible for the generation, transmission and distribution of electricity in Sharjah. SEWA is authorised to determine electricity prices and connection fees, which are subject to approval by the Ruler of Sharjah.

Ras Al Khaymah
On 10 March 2013, the Ruler of Ras Al Khaymah issued an Emiri Decree No. 4 of 2013 On the Establishment of the Ras Al Khaymah Electricity and Water Authority (RAKEWA) (the RAKEWA Law). This authority is tasked with the regulation, management, operation and maintenance of power stations, water desalination plants, electricity distribution and transport networks in the emirate. The new authority is also responsible for controlling prices of electricity and water in the emirate. Most importantly, the authority is responsible for fulfilling the electricity needs of the emirate, planning for the generation, transport and distribution of electricity in the emirate and managing the government’s investments in the sector.

RAKEWA is to be managed by a board appointed by the Ruler of Ras Al Khaymah, to be headed by a chairman. The board is authorised to issue regulations relating to the electricity sector, which shall be binding on all entities involved in the electricity and water sectors in the emirate.

Despite the establishment of RAKEWA, FEWA continues to own, manage and operate the electricity resources situated in the emirate and is the de facto authority on ground. The RAKEWA Law does not contain any provisions for the transfer of assets from FEWA to RAKEWA and it is presently unclear whether RAKEWA will replace FEWA in Ras Al Khaymah or if the two authorities will operate jointly in the emirate.
**Transfers of control and assignments**

Any transfer of control or assignment of an interest in an IWPP requires the consent of the relevant regulator.

Under the Abu Dhabi Electricity Law, a licence may not be transferred unless it specifically permits its transfer. Prior consent of RSB is required for any transfer (including the creation of security over assets of the licence holder), and the consent may be subject to such conditions as the RSB may consider appropriate.

Under the Dubai Electricity Privatisation Law, licensed entities are not permitted to transfer or assign their licences without the prior approval of RSB Dubai. In addition, licensed entities may not dispose-off, sell, lease or otherwise transfer, including granting of a security interest over, their 'main assets' without prior approval from RSB Dubai. Main assets are those moveable and immovable assets necessary to conduct the regulated activities and operate the electricity generation facilities.

In addition, the Companies Law contains a statutory pre-emptive right in favour of existing shareholders in the case of limited liability companies and joint stock companies.

### III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

#### i Vertical integration and unbundling

The electricity transmission and distribution networks in the UAE are firmly owned and controlled by the state-owned water and power authorities, each of which enjoys a monopoly in its particular area of operation. These authorities are vertically integrated and operate in all three segments of the market.

**Abu Dhabi**

ADWEA’s wholly owned subsidiary TRANSCO operates Abu Dhabi’s transmission networks. TRANSCO supplies electricity from the generation companies to the two distribution companies of Abu Dhabi, each of which is also wholly owned by ADWEA. These are:

- **Abu Dhabi Distribution Company (ADDC)**, which operates in the city of Abu Dhabi and the western region of the emirate; and
- **Al Ain Distribution Company (AADC)**, which operates in Al Ain city and the surrounding areas.

In response to the power shortages faced in the northern emirates, TRANSCO has become involved in the planning, development and operation of electricity transmission networks in the northern region. TRANSCO’s involvement, given its resources and experience, coupled with ADEWA’s supply of its excess power, has largely alleviated the power problems faced by these emirates in the past.
United Arab Emirates

Dubai

DEWA is the sole purchaser of electricity in Dubai and presently owns all the generation, transmission and distribution capacity of the emirate.\(^{11}\) DEWA’s transmission and distribution network is constantly being expanded as new real estate and industrial projects are set up across Dubai.

Over the past few years, DEWA has further enhanced the electricity transmission networks of the emirate. This includes construction of substations at Jebel Ali (December 2012), the International Media Production zone (February 2013), the Dubai Marina (May 2013), Seih Al Dahl (February 2014) and Dubai Academic City (2016). As of 2016, DEWA had 21 400kV substations, 222 132kV substations, 111 33kV substations and 31,961 11 and 6.6kV substations. In February 2017, DEWA announced its plans to build 97 new 132/11kV substations over the next three years to be located at the Solar Park, and other locations to support the expansion of other power plants in Jebel Ali and Al Aweer. This was followed by an announcement by DEWA in April 2017 of its plans to build three new 400kV substations over the next three years.

Sharjah

SEWA is the sole purchaser of electricity in Sharjah and presently owns all the generation, transmission and distribution capacity of the emirate.

Because of the increased demands in electricity and energy, SEWA has recently embarked on improving and expanding its electricity transmission and distribution network on a large scale. SEWA has commissioned and inaugurated the Al Khan power transmission and distribution station (worth 105 million dirhams) in 2016, to ensure the reliability of power supply throughout areas such as Al Khan, Al Nahda and Al Taawun in Sharjah and has announced its plans of building three 132kv and five 33kv distribution stations in 2017.

Northern emirates

FEWA performs many of the same functions in the northern emirates with respect to electricity distribution and transmission as TRANSCO in Abu Dhabi and DEWA in Dubai.

The northern emirates have been suffering insufficient power and electricity generation. For this reason and because of increased demand for electricity, FEWA has announced a number of new projects to expand and improve its electricity network. The notable projects\(^{12}\) are as follows:

\(^a\) in May 2013, FEWA signed two contracts with the Saudi National Contracting Company Limited to commission a 33/11kV transmission station and upgrade a number of 33/11kV and 132/33/11kV stations in the western region (Ajman and Umm Al Quwain), the central and eastern region (Fujairah and Dibba) and the northern region (Ras Al Khaymah); and

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\(^{11}\) As of 2016, DEWA operates a network of overhead lines (1,125 kilometres of 400kV, 413 kilometres of 132kV and 113 kilometres of 33kV lines) and underground cables (23 kilometres of 400kV, 1,800 of 132 kV, 2,052 kilometres of 33kV and 29,384 kilometres of 6.6 and 11kV lines) that are, in turn, connected to a distribution system of lower voltage substations and distribution lines.

\(^{12}\) Other plans include: building four new power stations, expanding the current electricity network, building 25 new power plants, expanding 17 power plants and completing 23 power stations within 2016. It is expected that at least five power plants will be built in Umm al-Quwain, 10 in Ras Al Khaymah and five in Fujairah.
in 2016, FEWA inaugurated Al Hamra substation in Umm al-Quwain and plans future expansion of the same. In the same year, FEWA signed a memorandum of understanding with Siemens for the construction of a 2.2GW plant in the northern emirates to enhance electricity generation and distribution and another memorandum of understanding with Mitsobishi Electric for the installation of a number of 132/33/11KV substations in the northern emirates.

**Emirates National Grid**

The ENG project was launched in 2001 under a Cabinet Resolution No. 79/4 of 2001 ‘On the National Project of Linking the Power Grids’ to connect and enable sharing of power between the UAE’s seven emirates. The ENG project was launched by the Ministry of Energy with the purpose of enhancing integration between the various electricity and water authorities in the UAE, each of which contributed proportionately to the capital investment required to build the ENG. The ENG is owned by the following authorities in the proportions stated below:

- **a** 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 the middle of 2006, whereas SEWA’s connection to ENG was completed in May 2007. Connection to the remaining northern emirates transmission networks was completed in April 2008.

On account of its larger production capacity and extensive distribution network, ADWEA has increasingly been assisting the other emirates in meeting their power demand. ADWEA exported about 13,664GWh of electricity to other emirates via the ENG in 2012, up from 12,228GWh in 2011. Renewable energy sources such as solar and nuclear power will increasingly contribute to the ENG. Currently, the solar power is transmitted to the ENG from Shams 1 solar power plant and plans are under way for nuclear energy and further solar power to be transmitted from the Barakah nuclear energy power plant and photovoltaic panels respectively.

**The Gulf Cooperation Council (GCC) Grid**

The UAE is also connected to the rest of the GCC through the GCC Grid, through which it can trade electricity with the remaining GCC countries. About 56MW (peak time) of electricity was exported by Abu Dhabi to the GCC Grid in 2011 whereas 7MW (peak time) was imported in 2012. Ideas have been put forward to expand power grids to Egypt and European networks (through Turkey) and trade energy beyond the GCC region.

**ii Transmission/transportation and distribution access**

**Abu Dhabi**

The Abu Dhabi Electricity Law requires ADWEC to purchase all power produced within the emirate. Although the Abu Dhabi Electricity Law contemplates private ownership in all segments of the electricity supply chain, so far private ownership has been limited to generation only.
**United Arab Emirates**

**Dubai**

The Dubai Electricity Privatisation Law prohibits a licensed entity from selling electricity to any entity other than DEWA.

**iii Rates**

**Abu Dhabi**

ADWEC, being the single buyer of electricity in the emirate of Abu Dhabi, purchases electricity from the power producers under long-term power and water purchase agreements (PWPPAs) and sells it to the distribution companies via annual bulk supply tariff (BST) agreements. The distribution companies pay ADWEC the BST for the electricity purchased and receive revenue from their customers and a subsidy from the government. TRANSCO is paid a transmission use of system (TUoS) charge by the distribution companies.

The components making up the electricity tariff in Abu Dhabi are the following:

- **a** BST, which is the charge paid by the distribution companies to ADWEC for its generation costs (in turn paid by ADWEC to power producers).
- **b** TUoS, which is the charge paid by the distribution companies to TRANSCO for use of its transmission network.
- **c** Distribution use of system, which is the fee that the distribution companies charge for use of their distribution network.
- **d** Sales cost, or the cost incurred by the distribution companies for serving customers for meter reading and billing.
- **e** Government subsidy, consisting of direct payments from the government to the distribution companies. The quantum of the subsidy allows the government to determine the electricity tariffs for different classes of consumers. The higher the subsidy, the lower the tariff charged.

The electricity tariff is determined by adding components (a) to (d) and subtracting (e).

The rates charged by the state-owned power companies (ADWEC, TRANSCO, ADDC and AADC) are subject to government control, exercised via the RSB. The RSB sets their revenue target on the basis of which the control prices are determined. The remainder of the revenue is paid as a subsidy by the government to the distribution companies. All transactions between the power sector companies and any related tariffs are required to take place on the basis of their economic costs. This helps the government keep subsidies to a minimum.

The BST is calculated for each calendar year on the basis of parameters prescribed by the RSB. The calculation of BST requires the estimation of the costs for procuring and dispatching electricity generation to meet the forecasted demand. Starting 2012, the structure of the BST comprises three components (expressed in fils per kWh) charged on an hourly basis for electricity purchased at different times of the day, for 'Fridays' and 'non-Fridays' and in different months of the calendar year. These three components are:

- **a** a system marginal price charge estimated to indicate the short-term marginal costs (excluding backup fuel (BUF) costs) of providing units at different times of the day;
- **b** a BUF levy charge estimated to reflect the additional costs associated with the burning of backup fuel rather than primary fuel; and
- **c** a high-peak period charge assessed to cover the costs associated with the estimated capacity payments and charged only in the peak demand occurring months of June to September, inclusive.
The TUoS charge paid to TRANSCO covers the investment, operation and maintenance costs of the infrastructure of the transmission systems, excluding assets that are dedicated entirely to a particular customer. These include substations, overhead lines, cables and associated equipment. TUoS charges also cover the costs of the economic scheduling and dispatching of electricity generation.

The rates payable to the power generation companies are determined on the basis of the PWPAs entered by them with ADWEC. These PWPAs are further discussed below.

Contracts for power generation are awarded based on a competitive bidding process after the government invites tenders to meet the emirate’s power generation requirements. The bidding process is managed by ADWEA starting from pre-qualification of bidders and issuance of request for proposals through to selection of the successful bidder.

Electricity rates paid by consumers in Abu Dhabi are subsidised. In fact, UAE nationals benefit from even greater subsidies than those given to expatriate workers. The rates payable in Abu Dhabi were substantially revised in 2015 with the introduction of a slab tariff scheme and an increase of 40–60 per cent in the applicable rates. The revised rates as published by the RSB on its website for 2017 are divided according to consumer categories as follows:

- **a** UAE nationals (flats): 6.7 fils per kWh until 30kWh/day, 7.5 fils post 30kWh/day;
- **b** UAE nationals (villas): 6.7 fils per kWh until 400kWh/day, 7.5.5 fils post 400kWh/day;
- **c** non-UAE nationals (flats): 26.8 fils per kWh until 20kWh/day, 30.5 fils post 20kWh/day;
- **d** non-UAE nationals (villas): 26.8 fils per kWh until 200kWh/day, 30.5 fils post 200kWh/day;
- **e** industrial establishments (below 1MW): 28.6 fils per kWh;
- **f** industrial establishments (above 1MW): 27.0 fils per kWh at off peak hours, 36.6 fils per kWh at 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.

**Dubai**

The DEWA Law empowers the board of directors of DEWA to control electricity prices charged by DEWA, subject to the Ruler’s approval; however, since the promulgation of the DSCE Law, the electricity prices have been determined by the DSCE and DEWA now sets its prices in accordance with the DSCE’s directives. The DSCE Law empowers the DSCE to impose a ‘definite tariff based on cost when necessary’. The DSCE is also authorised to approve fees and tariffs on the services offered to the public by ‘energy service providers’ (meaning the power generation, transmission and distribution companies).

In 2011, Dubai passed Executive Council Decision No. 16 of 2011 on the Approval of the Electricity and Water Tariff in the emirate of Dubai (the Dubai Tariff Decision), which sets out the electricity and water tariffs for Dubai. The Dubai Tariff Decision provides for a slab tariff scheme and authorises DEWA to add the ‘fuel price difference’ to the electricity tariffs charged to consumers. The consumers are divided into (1) industrial (2) residential; and (3) commercial. UAE nationals are subject to tariff rates equal to roughly one-third of the rate applied to other residential consumers.

DEWA has since 2011 increased electricity rates and pursuant to the Dubai Tariff Decision, introduced a variable fuel surcharge in its electricity tariff. The electricity tariff
in Dubai now comprises the electricity consumption charges, the fuel surcharge and meter charge. The fuel surcharge component requires consumers to pay for any fuel cost increases using 2010 fuel prices as the benchmark, thereby passing on the risk of international fuel price fluctuations to the consumer. This has enabled the company to increase revenues, reduce demand growth and earn higher profits. The present fuel surcharge rate applicable in the emirate of Dubai is 6.5 fils/kWh.

As with Abu Dhabi, power projects in Dubai are proposed to be awarded on the basis of a competitive bidding process. DEWA is responsible for managing the bidding process in the emirate (bids for the Hassyan Clean Coal Project were solicited through DEWA). IWPPs, once established in the emirate, will enter into PWPAs with DEWA for the offtake of their power production capacity.

IV ENERGY MARKETS

i Development of energy markets

The electricity market for private power producers in the UAE is comprised of the state-owned water and power authorities each of which acts as the single point of sale in their respective areas of operation.

Contracts for power generation are awarded on the basis of a competitive bidding process, administered by ADWEA in Abu Dhabi, DEWA in Dubai, SEWA in Sharjah and FEWA in the northern emirates. To date, Abu Dhabi has permitted up to 40 per cent private ownership and Dubai has permitted up to 49 per cent private ownership in the generation of electricity.

ii Energy market rules and regulation

Under the Abu Dhabi Electricity Law, ADWEC is required to contract with power producers for the purchase of all production capacity from licensed operators in the emirate. ADWEC is authorised to allow ‘by-pass sales’ from power producers directly to eligible consumers provided that:

- the first independent commercial power generation project in the emirates shall have commenced commercial operations;
- the majority of the shares in the company are privately owned; and
- the RSB issues a report stating that the energy market in the country is stable enough for it to be in the public interest that the sale of electricity by producers to eligible consumers be permitted.

To date, no ‘by-pass sales’ of electricity have been allowed by ADWEC in Abu Dhabi and all existing producers in the emirate are required to sell their production exclusively to ADWEC.

Similarly, power producers in Dubai are obligated by law to sell their entire production capacity to DEWA.

All power generation companies in the northern emirates and Sharjah are required to sell their power production to FEWA or SEWA respectively. With the establishment of RAKEWA, the functions presently being performed by FEWA in Ras Al Khaymah may be taken over by RAKEWA in the future. FEWA is, however, presently the principal authority for the electricity sector in the emirate. The government of Ras Al Khaymah is the only emirate thus far to have allowed a private sector utility company, UTICO, to participate in the generation, transmission and distribution of electricity in the emirate.
iii Contracts for sale of energy

ADWEC pays the generation companies the tariff agreed under the PWPA. The PWPA serves both as a grant of concession and offtake agreement.\(^{13}\)

The PWPA usually have a term of about 20 to 25 years from the commencement of commercial operations. Payments to IWPP by 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 ADWEC is required to procure and supply fuel to the electricity producers under the Abu Dhabi Electricity Law. ADWEC acquires the natural gas from two sources, the Abu Dhabi National Oil Company and Dolphin Energy Limited (purchased from Qatar via a pipeline connecting both states) for onward supply to the power producers.

Power plants are required to stock diesel oil and crude oil as backup fuel. According to the standard PWPA, generation companies have to stock up enough backup fuel for their plants to run at full capacity for seven days.

PWPA payment rates under some of the agreements are subject to annual indexation against US and UAE inflation or the US$/dirham exchange rate.

ADWEC is required by the standard PWPA to pay certain other supplemental payments to the IWPPs, such as start-up, shut-down costs 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.

To date, Dubai has only signed three power purchase agreements:

\(a\) the first with a consortium led by ACWA Power and TSK, for the Shuaa Solar PV Project;

\(b\) the second with a consortium led by Harbin Electric International and ACWA Power for the construction of phase 1 of the Hassyan Clean Coal Project; and

\(c\) the third with Masdar, for the 800MW third phase of the Solar Park.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

High energy use, encouraged by subsidised energy prices and the construction of energy intensive industries such as aluminium smelting has resulted in the UAE having one of the highest per capita carbon footprints in the world. The development of renewable energy is

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therefore crucial in reducing the country’s carbon footprint and diversification of its economy away from fossil fuels. The UAE has announced that it aims to produce 7 per cent of electricity from renewable sources by 2020.

A number of showcase projects have been launched in Abu Dhabi and Dubai to kick-start the development of renewable energy in the country.

**Abu Dhabi**

Abu Dhabi established Masdar\(^\text{14}\) to spearhead the emirate’s renewable energy initiative. Masdar City, a project of Masdar on the outskirts of Abu Dhabi city, is proposed to be run entirely on renewable energy as a zero carbon emissions city. Masdar City has also won the rights to host the headquarters of the International Renewable Energy Agency.

Masdar currently produces 17,500MWh of electricity annually, at its solar photovoltaic power plant located at the Masdar City for supply of clean power to the project. It has also launched a carbon capture and storage project in the UAE.

Most significant is Masdar’s 100MW solar power plant\(^\text{15}\) at Madinat Zayed, which was inaugurated on 17 March 2013. Known as Shams 1, it is one the largest parabolic trough power stations in the world. This project is expected to be followed by the Shams 2 and Shams 3 solar power projects. Among other sustainable projects launched by Masdar in the UAE are Masdar City’s 10MW solar PV array in Abu Dhabi, Masdar City’s 1MW rooftop installations, a 100MW photovoltaic plant in Al Ain, a 30MW onshore wind farm on Sir Bani Yas Island, a grid-connected solar photovoltaic panel on Murawah Island, the Um Al Zomul solar photovoltaic plant, and a 543kWp photovoltaic plant that delivers energy to Rashid Abdulla Omran Hospital. With the success of its pilot project involving the installation of solar photovoltaic cells on 11 school and government buildings across the emirate, Masdar proposes to further expand the installation of solar panels to reduce dependence on hydrocarbon fuels.

Masdar is also actively expanding its international investments in clean renewable energy; some of its projects include the Seychelles wind power project (6MW), the Mauritania solar power project (15MW), Spain’s Gemasolar (20MW), Valle 1 and 2 solar power projects (100MW), United Kingdom’s Dudgeon offshore wind farm (402MW), Jordan’s Tafila Wind Farm (117MW), Baynouna solar power project (200MW), Egypt’s Siwa solar photovoltaic plant (10MW), Samoan wind farm on the island of Upolu (1,500MW), Serbia’s Tesla wind farm (158MW), Tonga’s Vava’u island solar power project (512KW), Scotland wind farm (30MW) and the Noor 1 and Noor 2 solar photovoltaic plants (250MW) in Morocco. Masdar is also a 20 per cent stakeholder in the London Array wind farm in the United Kingdom, which produces 650MW of electricity. In partnership with the International Renewable Energy Agency, the Abu Dhabi government also granted US$57 million in loans to Argentina, Cuba, Iran, St Vincent and the Grenadines and Mauritania to finance renewable energy projects. Masdar is also involved with the UAE-Pacific Partnership Fund in developing renewable energy projects in the Pacific Islands. Currently, four new solar

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\(^{14}\) Masdar is a wholly owned subsidiary of Mubadala Development Company, one of the Abu Dhabi government’s main investment arms.

\(^{15}\) The project company, Shams Power Company, is 80 per cent owned by Masdar and 20 per cent by Total SA.
projects are under way in the countries of Kiribati, Fiji, Tuvalu and Vanuatu. An agreement was signed between Masdar and New Zealand to develop a solar photovoltaic power plant (1MW) in the Solomon Islands.

E.ON Masdar Integrated Carbon, a joint venture between E.ON and Masdar, develops and invests in carbon abatement projects in industry, power and oil and gas across Africa, Asia and the Middle East under the UN’s clean development programme.

Dubai

The DSCE developed the Dubai Integrated Energy Strategy 2030 and Dubai Clean Energy Strategy 2050 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. This Solar Park is expected to have a total installed capacity of 5000MW by 2030. The project is being implemented by the DSCE in Dubai and is being managed and operated by DEWA. The first phase was completed in 2013, which consists of the construction of a 13MW solar photovoltaic power plant and a substation to connect the facility directly to DEWA’s power grid. The second stage, the Shuua Solar PV Project, is under construction based on the IPP model, and is expected to be operational by Q2 2017. In June 2016, DEWA announced the Masdar led consortium as the selected bidder for the 800MW third phase of the solar park.

In July 2013, Dubai launched a waste-to-energy conversion project through a landfill gas recovery plant at the waste collection site in Al-Qusais. To date, this is the first landfill in the region to run its entire operation with electricity generated from landfill gas. In due course, the plant is expected to increase capacity from its current 1MW to 20MW by 2020. Plans to implement a similar project in the Jebel Ali landfill are also proposed by the government.

In 2013, DEWA and DSCE established Etihad Energy Service Company (Etihad ESCO), which will serve, notably, to retrofit existing buildings and lower the water and energy consumption of such buildings.

DEWA has launched the Shams Dubai Initiative, which aims to encourage energy efficiency by equipping residential and commercial buildings with solar panels and connecting the panels to DEWA’s electricity grid. In 2014, in line with this initiative, the emirate of Dubai issued Executive Council Resolution No. 46 of 2014 Concerning the Connection of Generators of Electricity from Solar Energy to the Power Distribution System in the emirate of Dubai (Resolution 46) to encourage the generation of electricity using solar panels. Resolution 46 enables DEWA consumers to supply power to DEWA’s grid by connecting their solar panels and the power supplied to DEWA can then be adjusted against the consumer’s electricity bill.

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16 The Dubai Clean Energy Strategy 2050 was announced by the Dubai Supreme Council of Energy as part of its participation in the World Future Energy Summit held in Abu Dhabi in January 2017. The Dubai Clean Energy Strategy 2050 intends that 7 per cent of Dubai’s total power output will come from clean energy by 2020, 25 per cent by 2030 and 75 per cent by 2050.
In 2015, Dubai established the Dubai Green Fund (Fund), worth US$27 billion, which provides easy loans to investors in the clean energy sector. DEWA will provide the seed capital for the Fund, with additional investment from the private sector, international banks and large investment companies.

In 2016, DEWA inaugurated one of the largest single rooftop arrays in the Middle East and North Africa region, a 1.5MW direct current photovoltaic generation project at the Jebel Ali Power Station, and successfully connected it to DEWA’s grid.

As mentioned previously, DEWA issued a request for proposal to all qualified bidders for the CSP in January 2017, for the fourth phase of the Solar Park. The submission date for this tender is May 2017.

Currently DEWA is working to develop an Innovation Centre, equipped with the latest renewable and clean energy technologies to raise awareness on sustainability, while enhancing national capabilities and increasing competitiveness. The Innovation Centre will be equipped with the latest clean and renewable energy technologies, and will serve as a museum and exhibition for solar energy. The centre will also feature two solar testing facilities, the first will specialise in testing PV solar panels, while the second will focus on CSP. The centre is currently testing 30 photovoltaic panel types from global specialist manufacturers.

Dubai has also established the Dubai Carbon Centre of Excellence, responsible for encouraging and developing strategies towards reducing the emirate’s dependence on carbon fuels and reducing carbon emissions.

**Sharjah**

Like Dubai, Sharjah launched SEWA 2020 Vision in 2016 to enhance power efficiency in sustainable development. SEWA intends to reduce power and water use by at least 30 per cent over the next five years (i.e., by 2020). To achieve this vision, SEWA has launched various projects, which include: setting up the first electric-vehicle charging station, completing a solar-powered road lighting project in Al Saja’a and Al Barashi, and replacing the current electrical infrastructure with modern facilities such as a smart metering system and networks to save energy.

**Northern emirates**

In 2014, UTICO, a privately owned utility company, called for the construction of a new 40MW solar plant in Ras Al Khaymah. UTICO has also collaborated with Shanghai Electric to set up a clean-coal power plant project (270MW) in Ras Al Khaymah. Both projects have been deferred indefinitely.

Recently, FEWA installed 11,000 smart electricity and water metres in Ajman. Additionally, in 2016, FEWA announced a 1.3 billion-dirham funding budget to improve the electricity network in the northern emirates. FEWA is expected to expand 17 power stations and construct 25 power distribution stations in Umm Al-Quwain, Ras Al Khaymah and Fujairah.

**UAE renewable energy prospects**

Although the UAE’s recent steps towards developing more renewable energy projects in the country are commendable, the projects launched so far will fulfil only a small part of the country’s total energy requirements. Despite the announcement to produce 25 per cent of the country’s total energy requirements from renewable sources by 2030, the UAE has not set itself a mandatory renewable energy target. The UAE’s electricity demand is expected to
grow at close to 10 per cent for the next decade, which will require a substantial increase in conventional gas and diesel-powered plants. Furthermore, most conventional power plants in the UAE also host water desalination plants, making the development of such additional capacity crucial in fulfilling the country’s growing water requirements. The country’s primary focus is therefore expected to continue to remain in developing conventional power and water desalination plants.

To encourage private investment in renewable energy, the government needs to enact formal legislation to regulate the development of renewable energy. A subsidy for renewable energy sources combined with a feed-in tariff that guarantees that electricity generated from renewable sources will be purchased for a minimum price can be introduced as a further incentive.

Nonetheless, recent initiatives in the field of renewable energy have made the UAE one of the most dynamic and exciting markets for renewable energy in the region.

**Nuclear energy**


The UAE aims to produce a significant part (approximately 9 per cent) of its electricity from nuclear technology. The UAE released a nuclear policy in 2008 and has since then promulgated a regulatory framework for development of nuclear energy in the country. In addition to collaborating with the IAEA and the World Association of Nuclear Operators, the UAE has signed cooperation agreements with France (2008), Korea (2009), the United States (2009), the United Kingdom (2010), Australia (2012), Canada (2012), Russia (2012), Argentina (2013) and Japan (2013) for the development of peaceful use of nuclear energy.

The Federal Authority for Nuclear Regulation (FANR), the federal nuclear energy regulator headquartered in Abu Dhabi, was established in 2009 under Federal Law No. 6 of 2009 Concerning the Peaceful Use of Nuclear Energy. The FANR is tasked with the responsibility of setting up the procedures and measures to be followed for the development of nuclear technology in the UAE. The FANR has issued regulations governing, *inter alia*, licensing, site location, design, construction, commissioning and operation, as well as standards for safety, transportation and storage facilities, radioactive waste management and physical protection of nuclear materials. The UAE has also created the International Advisory Board (IAB), an independent body consisting of independent international experts on nuclear energy who will offer guidance to the country’s nuclear programme on compliance with international safety, security and proliferation standards. The IAB is presently chaired by Hans Blix, the former IAEA Director General.

The UAE has been making rapid strides in establishing its first nuclear power station, the Barakah Nuclear Energy Plant (Barakah), in Abu Dhabi. The Emirates Nuclear Energy Corporation (ENEC), an Abu Dhabi government-owned company established by Federal Law No. 21 of 2009, is constructing Barakah, which will have a total capacity of 5,600MW. The project consists of the construction and installation of four 1,400MW reactors.
Construction of Unit 3 began in 2014 and it is now 69 per cent complete. All four units are 78 per cent complete and the project is proposed to be operational by 2020. Once the four reactors are online, the facility will deliver up to a quarter of the UAE’s electricity needs.

In 2016, ENEC signed a deal with TRANSCO to transmit nuclear power generated from Barakah through TRANSCO’s power lines to the ENG.

ii Energy efficiency and conservation

The UAE has one of the highest rates of electricity consumption per capita. This high usage is encouraged by the electricity and water subsidies given by the government to its citizens and in certain emirates to foreign expatriates. Dubai has progressively reduced and removed most of its electricity subsidies and Abu Dhabi is contemplating similar measures. Efficiency in energy usage is now being recognised as one of the key issues in trying to meet the country’s growing energy needs in a sustainable manner.

In 2010, Abu Dhabi imposed a mandatory rating system for construction of energy-efficient buildings in the emirate under the Estidama initiative. Starting from September 2010, all new development communities, private buildings and villas in the emirate are required to meet the minimum of one-pearl rating. All government led projects have been mandated to meet a two-pearl rating (the highest being a five-pearl rating). Masdar City, an eco-city project within Abu Dhabi, plans to expand its community and target a four-pearl Estidama rating to set an example as the leading energy efficient community.

The Dubai government has also enacted the ‘Green Buildings Regulations’ to encourage sustainable building practices. These regulations are enforced by the Dubai Municipality and apply to all new buildings constructed (including changes or additions to existing buildings) in the emirate. To this end, RSB Dubai has licensed nine energy service companies to retrofit more than 30,000 buildings in the emirate of Dubai to make them more energy efficient. Recently, the Emirates Green Building Council issued the technical guidelines for retrofitting existing buildings.

In 2016, Dubai and Sharjah launched projects to replace current infrastructure with energy efficient facilities. Both emirates are currently replacing street lights with LED lights. In Dubai, existing buildings are currently being retrofitted by Etihad ESCO while Sharjah is replacing and renovating its cables and meters.

To attract foreign private investment in the sector, Dubai has created a free zone dedicated to the development of green technologies and energy conservation, and known as the Energy and Environment Park (EnPark). EnPark is also Dubai’s first master-planned community built on sustainable principles. In 2015, EnPark combined with another free zone, Dubiotech, to create Dubai Science Park.

Through recent investment in its transmission system, DEWA succeeded in reducing the percentage of line losses in its electrical network to 3.26 per cent in 2016 from 6.28 per cent in 2001 and has simultaneously increased the efficiency of its energy generation by 22 per cent between 2006 and 2014. As part of its demand growth management strategy, DEWA has introduced a slab tariff that has been successful in reducing demand growth to 3 per cent despite a 5 per cent growth in end users in 2011. FEWA also has a slab tariff in place for the northern emirates whereas ADWEA is proposing to launch a similar tariff structure in the near future.
iii Technological developments

Masdar has established the Masdar Institute of Science and Technology (MIST), a state-of-the-art research centre and university, in partnership with Massachusetts Institute of Technology. MIST is a graduate-level university that aims to provide solutions to issues of sustainability, focusing on advanced energy and sustainable technologies, through research.

Although it is a brand new institute, according to its website, over 30 research projects are currently under way, covering solar beam down, innovation ecosystems, smart grids and aviation biofuels. In addition, according to its website, a number of patents are already pending registration.

MIST is likely to play a leading role in development of advanced technologies in the UAE in the coming years.

In 2015, Masdar launched Masdar Solar Hub, a solar testing and research and development hub for photovoltaic and solar thermal technology. In the same year, DEWA Innovation Centre, which consists of a laboratory for research and development in clean energy, was inaugurated.

Once completed, the Solar Park is expected to include, inter alia, the following: a centre for innovation equipped with the latest renewable energy technologies, a research and development centre to conduct tests in relation to social and industrial needs for renewable energy; two test technologies for photovoltaic panels and concentrated solar power; a solar testing facility; and a training centre and special conference centre for the exchange of information.

VI THE YEAR IN REVIEW

The UAE has seen double-digit increase in the demand for electricity in recent years and is expected to continue seeing rapid growth in the coming years.

To meet this growing demand, Abu Dhabi and Dubai have allowed private power companies to participate in its energy sector for a number of years. Following the enactment of the Dubai Electricity Privatisation Law in 2011, Dubai awarded the construction and partial ownership of a number of projects on the IPP model, including the Hassyan Clean Coal Project and the ACWA-TSK solar power plant. FEWA has followed Abu Dhabi and Dubai’s example and permitted private sector participation in its electricity network with the participation of UTICO in the electricity network of Ras Al Khaymah and its future plans commencing 2017. However, it seems as though transmission and distribution networks will continue to be owned mainly by the state-owned monopolies and the status there is unlikely to change in the foreseeable future.

The UAE is recognising the need for the efficient use of energy and electricity and is currently revamping its existing infrastructure. In addition to the construction and expansion of power stations, the UAE is involved in other projects such as replacing street lights with LED lights, renovating cables and meters, and retrofitting existing buildings. Consideration has also been given to connecting renewable energy sources to the electric grid. These projects are in line with Dubai Law No. 06 of 2015 on Protection of the Electricity Grid and Public Water Systems in the Emirate, which is intended to protect the electricity and water transmission and generation infrastructure in Dubai.

High subsidies and heavy reliance on fossil fuels for generation have resulted in the UAE having one of the highest per capita carbon footprints in the world. There is growing recognition that the energy demand cannot be met only through investment on the supply
side, and that demand-side management programmes and energy conservation measures are equally important in matching demand with supply. Reduction in subsidies over time (and increases in electricity tariffs) coupled with the introduction of slab tariffs in Dubai and the northern emirates have helped curb demand growth in these areas and relieved pressure on the sector. Because of the effectiveness of the slab tariff introduced by DEWA, Abu Dhabi is also proposing to introduce a slab tariff in the near future.

Green building regulations and a mandatory rating scheme have been introduced in Dubai and Abu Dhabi respectively to encourage energy conservation. In accordance with these regulations, the Emirates Green Building Council in Dubai has further issued the Technical Guidelines for Retrofitting Existing Buildings.

The country has set itself the goal of ensuring 25 per cent of its energy requirements in 2030 (and 75 per cent in 2050) are met from renewable sources. To meet these targets, a number of projects have been launched.

Dubai has recently inaugurated a solar energy park that will, on completion in 2030, have the capacity to produce 5,000MW of electricity. This park is also expected to have testing facilities with the latest renewable energy technologies and special conferences to develop the solar energy sector.

Abu Dhabi has launched the zero carbon emissions and zero waste Masdar City project to be powered exclusively by renewable energy sources and to attain a four-pearl Estidama rating to set an example as the leading energy efficient community in the UAE. Masdar, the owner of the project, continues to develop various other renewable projects within the UAE and internationally.

Dubai has established a Dubai Green Fund and established Etihad ESCO, which is expected to contribute towards the development of the renewable energy sector and an energy efficient community.

A specialist regulatory body for the nuclear energy sector has been created. New regulations governing various segments of the nuclear chain are being developed and issued. Construction work on the Barakah nuclear power plant is currently under way in the emirate of Abu Dhabi, and commissioning is expected in 2020. An agreement was also signed in 2016 to transmit nuclear power to the ENG.

Although efforts at diversification are commendable, the sector looks set to continue to be dominated by the existing players. With growing demand for electricity across the UAE, the authorities are continuing to invest significantly in hydrocarbon-based power generation facilities, which are increasingly being supplemented by development of alternative and renewable energy.

**VII CONCLUSIONS AND OUTLOOK**

As seen above, in addition to the drive towards privatisation, notable developments towards energy diversification and introduction of renewable sources have taken place. These developments, however, currently remain restricted to the government sector despite the various initiatives that were launched to permit private sector participation.

The state-owned monopolies in the various emirates are likely to continue to dominate the sector in the foreseeable future. The requirement under the Companies Law to maintain majority ownership in local hands means that foreign private investors will have to work with the local water and power authorities as junior partners or, when full private ownership is permitted within the sector, with local partners as the majority shareholders.
Although Abu Dhabi and Dubai have seen foreign investment in the electricity sector for a number of years, the other emirates are increasingly beginning to recognise the benefits of encouraging private sector participation. This change in attitudes is driven principally by the increased demand in electricity on account of population and economic growth, as well as the current low oil prices, which have reduced the availability of government funds compared with previous years.

The energy sector in the UAE is likely to continue seeing rapid changes and as the economy continues to grow, demand is likely to create opportunities for private investment in the sector. Although, the GCC Grid has not taken any significant steps in the last few years, the completion of the GCC Grid and its proposed expansion to Egypt and European countries (through Turkey) will create further opportunities for private sector investment in the sector by enabling cross-border trading of power. Furthermore, in line with diversifying energy sources and preserving energy, the UAE is expected to continue its projects such as retrofitting buildings, establishing solar parks and energy efficient communities, which will require the investment and research capabilities of the private sector. Despite the encouragement for private investment in alternative energy sources and energy efficiency measures, investment in the sector looks likely to continue to be led by the state-owned water and power authorities.
I OVERVIEW

The United Kingdom has one of the most mature and dynamic electricity and gas markets. The country was a pioneer in the drive towards liberalisation, starting with the Energy Act 1983 that opened up the supply markets. The liberalisation was later bolstered by an ambitious privatisation programme in the late 1980s and 1990s, which led to the creation of wholesale markets where generators could sell electricity in real time. At present, the market is fully liberalised and privatised.

The United Kingdom has since pushed an energy agenda focused on decarbonisation, demonstrated by the country’s national 2020 renewable energy targets, which exceed those required under the European Renewable Energy Directive. This has resulted in strong growth for renewable generation over the past decade with subsidies providing attractive returns and investment opportunities. In the wake of the 2008 financial crisis, government policy has given increased attention to lowering the cost to consumers. In addition, concerns about the intermittent nature of renewable generators and their growing share of the generation profile of the United Kingdom have shifted policy focus towards ensuring security of supply. The result has been a reconfiguration of subsidy support mechanisms, with the twin aims of lowering the cost of new technologies and incentivising the construction of baseload generation. This regulatory shift, together with the uncertainty resulting from Brexit, has led to a slowdown in growth for new renewable projects and a converse increase in activity in the secondary market for operational renewable assets. However, there is sustained optimism in the energy sector, particularly in relation to emerging technologies such as battery storage (especially co-located with existing renewable projects), and the opening up of transmission (onshore and offshore) projects to private investors.

II REGULATION

i The regulators

Gas and Electricity Markets Authority (GEMA)

GEMA is the regulator of both the gas and electricity markets in Great Britain (GB). The Utility Regulator for Northern Ireland, an independent non-ministerial government

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1 Munir Hassan is a partner and Filip Radu is an associate at CMS Cameron McKenna Nabarro Olswang LLP.
2 This chapter focuses on Great Britain and only gives a brief overview of electricity and gas regulation in Northern Ireland.
United Kingdom
department, regulates the electricity and gas markets in Northern Ireland. Its duties are to
protect the short and long-term interests of electricity, gas, water and sewerage consumers
with regard to price and quality of service; promote a robust and efficient water and sewerage
industry; deliver, where appropriate, high-quality services; promote competition, again where
appropriate, in the generation, transmission and supply of electricity; and to promote the
development and maintenance of an economic and coordinated natural gas industry.

For the GB market, similar duties are performed by GEMA. GEMA consists of a panel
of individuals appointed by the Secretary of State for a specified term of not less than five
years, but it is independent of government and has no stakeholder participation. GEMA's
duties are set out in the Gas Act 1986 (as amended) (the Gas Act), the Electricity Act 1989 (as
amended) (the Electricity Act), and the Utilities Act 2000 (as amended) (the Utilities Act),
and it has powers in relation to granting and administering licences, as well as concurrent
authority with the Competition and Markets Authority (CMA) on the application and
enforcement of certain competition rules. GEMA operates through its office, the Office of
Gas and Electricity Markets (Ofgem), to which it delegates the day-to-day administration
of its functions. Ofgem is therefore often more commonly referred to as the regulator in
common parlance.

GEMA's objectives are enshrined in the relevant sections of the Gas Act and the
Electricity Act. While these are varied and at times inconsistent, GEMA's principal objective
is to protect the interests of existing and future consumers in relation to electricity and gas
and, wherever appropriate, to achieve this by promoting effective competition.

On a day-to-day basis, Ofgem exercises GEMA's powers to grant and modify the
conditions of licences, to monitor the activities of gas and electricity companies, and, where
necessary, takes enforcement action to ensure these companies comply with their statutory
and licence obligations. Ofgem also exercises GEMA's power to impose financial penalties on
licence holders for breaches of such obligations.

The regulatory framework is responsive to changes in the market through Ofgem's
ability to modify the licence conditions. This is done through industry code modification
panels (see below). Appeals in respect of such modifications can be made to the CMA.

GEMA also has the power to modify the various industry codes. This power is
conferred by the relevant licence condition under which a network operator (e.g., National
Grid Electricity Transmission plc (NGET) or National Grid Gas plc (NGG)) is required to
‘own’ the code in question, and currently is not subject to any specific statutory constraints.

**CMA**
The CMA is the United Kingdom’s lead competition and consumer body established under
the Enterprise and Regulatory Reform Act 2013 (ERRA). GEMA, as energy regulator, has
concurrent powers with the CMA with regard to the energy sector. ERRA requires sectorial
regulators, including GEMA to consider applying competition law before using their
sector-specific powers. The provisions of the Competition Act 1998 and the Enterprise Act
2002 (the Enterprise Act) as amended by ERRA dealing with anticompetitive practices play
a particularly important role and are jointly applied and enforced by GEMA and the CMA.

To improve the effectiveness of these concurrent powers, the CMA is required under
ERRA to publish an annual report, in consultation with the sector regulators, on how the
cooperation under the joint competition powers has worked.

Under the Enterprise Act, the CMA may investigate the functioning of competition
within a market in the United Kingdom as a whole (as opposed to targeting specific actions
of companies) and open an investigation where it has reasonable grounds for suspecting that any feature, or combination of features, of this market restricts or distorts competition in the supply or acquisition of any goods or services. In the case of the gas and electricity sector, Ofgem may refer a market to the CMA for a market investigation or the CMA may direct Ofgem to transfer the case to it. The CMA recently conducted an extensive energy market investigation and on 24 June 2016 published its final findings and remedies.\(^3\) Although it found the wholesale electricity market was generally ‘working well’, it identified two aspects of the regulatory regime that adversely affected competition, namely:

a. the absence of locational charging for transmission losses; and  

b. the mechanism for allocation of Contracts for Difference.

Following the final CMA decision, on 3 August 2016 Ofgem published a strategy for the implementation of the CMA remedies and then issued its detailed implementation plan on 9 November 2016.

The CMA also has powers to hear appeals in relation to price controls set by Ofgem for network companies (price controls are explained in Section III, infra). Two such appeals were brought in 2015 by British Gas Trading Limited (BGT) and Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc (together, ‘NPg’) in respect of the RIIO-ED1 price controls set by Ofgem. The result was the dismissal of two out of the three grounds of appeal for NPg and four out of five grounds of appeal for BGT.

**Health and Safety Executive (HSE)**

The HSE is the national independent regulator with regard to health and safety of GB. It was established under the Health and Safety at Work Act 1974 and is responsible for the regulation and enforcement of workplace health and safety in GB and for producing guidance and carrying out research in relation to occupational risks.

In Northern Ireland the role is performed by the Health and Safety Executive for Northern Ireland.

**Office for Nuclear Regulation (ONR)**

The ONR is responsible for the regulation of nuclear safety and security across the United Kingdom. The ONR reports to the Department for Work and Pensions, although it also works closely with the Department of Energy and Climate Change.

**Environment Agency**

Responsibilities in relation to environmental regulation in GB have largely been devolved to governments in each of England, Wales and Scotland. For example, in England, the Environment Agency is a non-departmental public body sponsored by the Department for Environment, Food and Rural Affairs. It is responsible for protecting and improving the environment and promoting sustainable development in England.

In Wales, since April 2013, environmental and other natural resources-related matters have been the responsibility of Natural Resources Wales. The role of the environmental agencies regarding electricity is limited to pollution-related matters, so mainly relate to

\(^3\) [www.gov.uk/cma-cases/energy-market-investigation](http://www.gov.uk/cma-cases/energy-market-investigation).
conventional generation and nuclear, although additional environmental matters also arise in relation to consenting. The Environment Agency in England is also responsible for limiting and preparing for the impacts of climate change.

In Northern Ireland, the Northern Ireland Environment Agency is the body responsible for the protection, conservation and promotion of the national environment.

**Department for Business, Energy and Industrial Strategy (BEIS) and the Department for the Economy (DFE)**

While not regulators, BEIS and DFE are government departments responsible for setting the policies affecting the UK electricity and gas markets. The Secretary of State for Business, Energy and Industrial Strategy is responsible for making decisions, setting policy and implementing legislation affecting the sector and is accountable on matters including security of supply and sustainability in the GB energy sector. BEIS is responsible for formulating UK energy policy, which is implemented through legislation. In addition, there are some regulatory powers that are reserved to the Secretary of State directly. For example, the Secretary of State is authorised to make orders under the Electricity Act granting exemptions from the requirement to hold a licence, where certain criteria are met.

The corresponding government ministry in Northern Ireland is DFE, which assumed most of the roles and responsibilities of the former Department of Enterprise, Trade and Investment.

**ii Regulated activities**

The regulatory framework in GB operates through a system of legislation, licences and industry codes with an independent regulator responsible for the regulation of the sector and for enforcing any breaches of the rules. In the case of both electricity and gas, there is a prohibition on carrying out the licensable activity without a licence (unless an exception applies).4

Licences are granted by the Secretary of State, by way of Ofgem, to the entity carrying out the particular activity. In line with European Third Energy Package rules, a licensee may not hold a transmission, distribution or interconnection licence if it already holds another licence.

The regulatory regime for gas has recently undergone reform through the development of the European Union-wide Network Codes. Regulation (EC) No. 715/2009, provided for the establishment of Network Codes to help facilitate cross-border network access and market integration. Changes to the electricity sector are also under way pursuant to Regulation (EC) No. 714/2009 regarding harmonising the technical, operational and market rules governing electricity grids. Under this latter EU legislation, the Agency for the Cooperation of Energy Regulators and the European Network of Transmission System Operators for Electricity are developing European Union-wide codes and guidelines for matters such as system operation (pending), balancing activities (pending), demand connection (adopted), grid connection for generators (adopted), capacity allocation and congestion management (adopted), and forward capacity allocation (adopted), among others.5

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4 There are criminal sanctions for breaching these requirements unless covered by an exemption (Electricity (Class Exemptions from the Requirement for a Licence) Order 2001 (SI 2001/3270)).

5 For a full list of the EU-wide electricity codes and guidelines, as well as their status, see http://ec.europa.eu/energy/node/194.
Electricity

Unless an exemption applies, a licence is required for the following specified activities under the Electricity Act:

1. generation;
2. participation in transmission (defined to cover both the operation and ownership activities);
3. distribution;
4. supply; and
5. participation in the operation of an electricity interconnector.

From September 2012, providing smart metering services also requires a licence. The position regarding electricity storage is currently unclear, although Ofgem is working with industry stakeholders to develop a regulatory definition for this technology (see more in Section VI, *infra*).6

Gas

As with electricity, the Gas Act makes it an offence for an entity without a licence to carry out any gas transportation, interconnection, gas shipping, supply or smart metering (unless an exemption applies). For example, a licence to transport provides the right to convey gas through pipeline systems, while an interconnector licence gives the licensee the right to operate the cross-border transportation of gas. The activity of gas shipping consists of buying gas from producers or importers and arranging for its transport (with gas transporters) via a pipeline system to a gas supply point, to then sell it on to gas suppliers.

Gas storage is subject to regulation but is not separately licensed.

A licence on its own does not give an entity the right to carry out other activities such as develop a project. Separate rights need to be secured in relation to land rights, planning requirements, decommissioning, etc., and the licensee would need to comply with other relevant legislation. In practice, this means obtaining authorisations from other regulatory bodies noted above (e.g., the HSE).

iii Ownership and market access restrictions

There are no specific restrictions on foreign investment or ownership of energy companies or assets in the United Kingdom. However, an additional certification process requires Ofgem to assess, in consultation with the European Commission, whether foreign ownership or control poses a security of supply risk (Electricity and Gas (Internal Markets) Regulations 2011).

In a similar vein, the unexpected decision to delay sign-off on final approvals for Hinkley Point C announced by the newly installed Conservative government demonstrates that the executive branch has indirect levers in ensuring control over ownership of national critical infrastructure. In this instance, the government pointed to concerns over spiralling costs and security of supply to delay the signing of the final contracts, particularly the Contract for Difference awarded to Hinkley Point C securing the price of its output at £92.50/MWh

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(double the wholesale price at the time). In the event, the government approved the project; however, it established new legal safeguards mainly through a mechanism that will allow it to prevent any transfer of ownership in UK critical infrastructure without its consent or knowledge, including that of EDF in Hinkley Point C.

iv Transfers of control and assignments
There are no specific restrictions on control in a licence but assignments require prior written consent of the licensing entity. This is likely to require the incoming party to satisfy the Secretary of State that it is able to meet the licence obligations, and follows a similar vetting process as that for a new applicant. In practice, transfers are usually effected by transfer of the company that holds the relevant licences. The transmission, distribution and interconnection licences include obligations to ring-fence the regulated asset, which provides an additional level of control to Ofgem.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Electricity
The GB market was privatised in the early 1990s and has been fully unbundled, thus serving as a model for many other markets. In GB the legal separation of electricity supply and distribution activities was introduced by the Utilities Act as part of further restructuring of the market. As a result, distribution and supply are treated as separate licensed activities and licences may in principle not be held by the same person.

Under the provisions of the Third Energy Package transmission system operators (TSOs) must be certified as complying with ownership unbundling. This means that transmission interests (ownership and operation of transmission systems) must be separate from generation and supply activities. As the UK position did not readily fit within the Third Package model but was considered sufficiently well developed and independent to meet the aims of the Third Package, a derogation applies in relation to vertically integrated UK TSOs pursuant to Article 9(9) (Section 10E (4), Electricity Act 1989). Scottish Hydro Electric Transmission plc and Scottish Power Transmission Limited, the Scottish owners, were granted certification on grounds of Article 9(9) subject to certain conditions and information-sharing restrictions.

Gas
A single regulatory framework applies across GB in respect of the gas sector. Under the Gas Act there is no distinction between gas transmission and distribution activities: both activities are dealt with by the provisions relating to gas transportation.

ii Transmission/transportation and distribution access

Electricity

Transmission and distribution
In 2005, the British Electricity Trading and Transmission Arrangement (BETTA) introduced a single transmission system for the whole of GB and divided the transmission role between a GB TSO, currently NGET, on the one hand, and the existing transmission system owners
on the other. Both activities – transmission operator and owner – are licensable and the transmission owners are required by law to make their respective transmission systems available to the TSO, which is responsible for the real-time balancing of supply and demand.

The Electricity Act imposes a duty on transmission licence holders to develop and maintain an efficient, coordinated and economical system of electricity transmission; and to facilitate competition in the supply and generation of electricity. This primary obligation is supplemented by detailed provisions in the respective transmission licences dealing with issues such as compliance with industry codes, charging methodology and non-discrimination.

NGET, a private company listed on the London Stock Exchange, is the holder of the transmission licence and owner of the transmission network in England and Wales, as well as being the TSO for the whole of GB. NGET is also the designated system operator for electricity interconnectors, where it performs system operator to system operator functions.

The respective transmission networks in northern Scotland and southern Scotland are owned by Scottish Hydro Electric Transmission plc and Scottish Power Transmission Limited. In Northern Ireland, the TSO is System Operator Northern Ireland and Northern Ireland Electricity owns the transmission assets.

There is also a market for offshore transmission owners (OFTO) with increasing participation. Ofgem has granted a number of licences for electricity transmission connections to offshore wind farms following competitive tenders. The regulator is currently running the OFTO Tender Round 5 process for which invitations to tender were issued in April 2016 in relation to the Dudgeon, Race Bank and Rampion offshore wind farms, and an Enhanced Pre-Qualification was launched for Galloper and Walney Extension. The OFTO Tender Round 6 process is expected to commence in 2018, potentially for the Hornsea, East Anglia and Beatrice offshore wind farms. To date, there are 14 operational OFTOs in place (having a total investment value of around £3.1 billion) with a collective capacity of four.

Ofgem is currently working on developing competitive tenders for the design, procurement, construction and operation of new, separable, and high-value onshore transmission assets (designated as competitively appointed transmission system operators (CATOs)). The first tender is currently projected to run in the early part of 2019; however, this is subject to further design of the tender process by Ofgem.

Transmission and distribution is largely regulated though a series of industry codes. NGET has the licence obligation to maintain and administer various industry codes dealing with the operation and use of the transmission system, including the Connection and Use of System Code (CUSC), the Grid Code and, in conjunction with ELEXON, the Balancing and Settlement Code (BSC).

The CUSC sets out the main rights and obligations in relation to the connection to, and use of, the National Electricity Transmission System, along with additional provisions on some ancillary and balancing services. The Grid Code deals in detail with matters such as connection conditions, operational liaison and safety coordination, and all material technical aspects relating to connections to, and the operation and use of, the transmission system. The governance of balancing and settlement arrangements is set out in the BSC, to which all generation or supply licensees must be party.

Access

Pursuant to its licence, NGET must not discriminate between any persons or class or classes of person in the provision of use of the system or in the carrying out of works for the purpose of connection to the transmission system.
Distribution Network Operators (DNOs)

The electricity distribution system in GB is organised along geographic lines with various regional monopolies. England and Wales are divided up between 12 DNOs, while there are only two DNOs in Scotland and one DNO in Northern Ireland. As at June 2016, the DNOs active in GB are owned by the following six groups: Electricity North West Limited, Northern Powergrid, SSE, SP Energy Networks, UK Power Networks, Northern Ireland Electricity Networks, and Western Power Distribution. The DNO in Northern Ireland is Northern Ireland Electricity. Each DNO holds an electricity distribution licence and owns and operates the local electricity distribution system.

Pursuant to the Electricity Act, DNOs must develop and maintain an efficient, coordinated and economical system of electricity distribution and facilitate competition in the supply and generation of electricity. As with transmission, the electricity distribution licence conditions subject the DNOs to obligations such as non-discrimination in the provision of use of system and connection to system; safety and security; and use of system and connection to system charges.

Similar to the obligations of NGET under its transmission licence, under the terms of their distribution licence conditions, DNOs are each required to maintain and comply with the Distribution Code dealing with technical aspects relating to connections to and the operation and use of the licensee's distribution system, and one of the objectives of the licences and the codes is to facilitate competition in the generation and supply of electricity.

Access

Under the Electricity Act, DNOs have an obligation to make a connection between their distribution system and any premises when requested to do so by the owner of the premises or an authorised electricity supplier. Pursuant to the licences, DNOs must not discriminate between any persons or class or classes of persons in the carrying out of works for the purpose of connection to the licensee's distribution system, or in the provision of use of the system, and must on application made by any person offer to enter into an agreement for use of the distribution system.

Gas

Transportation

The GB gas transmission network, the National Transmission System (NTS) – a high-pressure pipeline system that transports gas from entry terminals to various gas distribution networks (GDNs) and large industrial customers – is owned and operated by NGG. However, in May 2005, the Uniform Network Code (UNC) enabled companies other than NGG to own gas networks.

The UNC, which is maintained by the Joint Office of Gas Transporters, is the contractual framework that forms the basis of arrangements between the owners and operators of the gas transportation systems in GB and the users of those systems. Similar to the CUSC, the UNC is given effect by a Shipper Framework Agreement, in the form of a contract between a gas transporter and an individual shipper user, by virtue of which they agree to be bound by the provisions of the UNC. In addition to entering into a Shipper Framework Agreement, to become a shipper user under the UNC an applicant must satisfy certain admission requirements including the need to hold a gas shipper licence under the Gas Act.
Within their authorised area, gas transporters must develop and maintain an efficient and economical pipeline system for the conveyance of gas and, in so far as it is economical to do so, are under a duty to provide connection to that system and to convey gas. Additionally, the Gas Act imposes a general duty to facilitate competition in the supply of gas, and to avoid any undue preference or undue discrimination when connecting premises, or a pipeline system operated by an authorised transporter, to any pipeline system operated by the transporter, or in the terms on which the transporter undertakes the conveyance of gas by means of such a system.

The Gas Act is supplemented by detailed provisions on charging for connection and transportation services, standards of performance and system development obligations in the individual licences held by gas transporters.

**Distribution**

Similarly to the electricity distribution system, gas distribution in GB is organised along geographic lines. There are eight GDNs in GB covering different geographic regions, which are medium and low-pressure pipeline systems. Four of the GDNs (East Midlands, West Midlands, North West England and East of England (including North London)) are owned by NGG, while the remaining four GDNs are owned and operated by Northern Gas Networks Limited (North East England (including Yorkshire and Northern Cumbria)), Wales & West Utilities Limited (Wales and South West England) and Scotia Gas Networks Limited (Scotland and Southern England (including South London)). On 8 December 2016, NGG announced it had agreed to sell a 61 per cent equity interest in its gas distribution business to a consortium made up of Macquarie Infrastructure and Real Assets, Allianz Capital Partners, Hermes Investment Management, CIC Capital Corporation, Qatar Investment Authority, Dalmore Capital and Amber Infrastructure Limited/International Public Partnerships. Similarly, on 17 October 2016, SSE announced it had agreed to sell a 16.7 per cent equity stake in SGN to wholly owned subsidiaries of the Abu Dhabi Investment Authority, for a headline consideration of £621 million.

There are also a number of smaller gas transportation networks connected to the GDNs and owned and operated by six independent gas transporters (IGTs). The IGTs compete with each other and the GDN owners to provide gas transportation services. Unless an exemption applies, each IGT and GDN owner is required to hold a gas transporter licence.

**Access**

Under the Gas Act, gas transporters must, following any reasonable requests for connection, grant access to their pipeline system, in so far as it is economical to do so, convey gas by means of that system to any premises and comply with any reasonable request to connect to a pipeline system operated by another authorised transporter.

Access to the gas network is provided on an entry-exit basis instead of on a point-to-point basis. As access rights comprise entry and exit capacity at entry and exit points, shippers are required to book entry capacity and exit capacity to flow and take gas (there are relatively few entry points – principally gas terminals at which gas is landed from offshore fields).

**iii Rates**

For electricity, the rates payable for connection to and use of the transmission system are set out in NGET’s charging statements. The charges are broadly made up of the following:
transmission network use of system charges: to recover the revenue for the transmission system owners, that is NGET, the Scottish transmission owners, OFTOs, and in future CATOs;

b balancing services use of system charges: to recover the cost of balancing the transmission system, and which depend on the amount of balancing required; and

c connection charges: to recover the cost of installing and maintaining connection assets used by the party connecting to the transmission system. It takes into account the asset value, asset age and maintenance costs. Connection charges are not normally paid by generators in the United Kingdom (England and Wales).

On 13 March 2017, Ofgem launched a consultation focused on review of residual charges both at transmission (TNUoS charges) and distribution (DUoS charges) level (for more information, see Section VI, infra). Residual charges are intended to top up and make up for any deficit in the revenues allowed to be recovered by network companies after forward-looking charges have been levied. In contrast, forward-looking network charges are intended to send signals to market for matters such as where to place generation, fuse size, etc., but these are not being reviewed at the moment.

**Price control**

Ofgem regulates the prices for regulated assets pursuant to the licence terms of the given gas or electricity licensee. The current price control model is known as RIIO (Revenue=Incentives+Innovation+Outputs). These RIIO price controls set out the revenue that the network companies are allowed to recover and what they are expected to deliver, as well as specifying details of the regulatory framework over the eight years from 2013 to 2021 for transmission and gas distribution, and from 2015 to 2023 for electricity distribution.

The RIIO price controls are established against framework objectives set by Ofgem, against which the network companies present a business plan detailing how they intend to meet the objectives. The business plans are evaluated and approved by Ofgem. The process places major value on stakeholder engagement in the decision-making, efficient investment in services, innovation in networks and reduction of carbon outputs.

Additionally, in its final report on the energy market investigation the CMA has proposed a transitional price cap for customers on prepayment meters from 2017–2020.

**iv Security and technology restrictions**

While there are no specific security and technology restrictions in GB, concerns around national security, cybersecurity and data processing come up in the context of electricity and gas markets. These are typically dealt with through bilateral contracts and protocols.

**IV ENERGY MARKETS**

**i Development of energy markets**

*Electricity*

GB was among the pioneers of electricity sector liberalisation from the mid-1980s, when the Energy Act 1983 created the requirement for the state-owned area boards to offer private
generators access to their networks and to purchase the power they generated. Since 1991, the electricity market was privatised and the parties are now free to trade on the basis of bilateral contracts.

Northern Ireland operates a separate wholesale electricity market with a pool system, the Single Electricity Market, which is integrated with the wholesale electricity market in the Republic of Ireland. A distinct market therefore operates across the island of Ireland.

**Gas**

Gas trades, subject to licensing requirements, can be traded by gas shippers within the NTS and at exit points on the gas system. This is usually done on the basis of standard-term contracts and in line with the requirements of the UNC.

The regulatory regime for gas has recently undergone reform through the development of the European Union-wide Network Codes. Regulation (EC) No. 715/2009 provided for the establishment of Network Codes to help facilitate cross-border network access and market integration. These Network Codes were thought necessary because of the increased interconnection and trade between EU countries and the need to manage gas flows. These Codes further inform the trading of gas.

**ii Energy market rules and regulation**

Energy market rules are largely set out in industry codes such as the Grid Code, the CUSC and the BSC. Compliances with these is governed through licence conditions.

The BSC is particularly relevant for market trading. It seeks to ensure that total electricity generation and demand are balanced in real time, through a balancing mechanism operated by National Grid. It also quantifies imbalances between the amounts of electricity traded and the actual electricity generated or consumed, and regulates how these are paid for through a post-event imbalance settlement process operated by ELEXON. The BSC contains the rules and governance arrangements for the balancing mechanism and imbalance settlement processes. These arrangements, and the scope of the BSC, were subsequently extended to Scotland in April 2005 under the BETTA. Most electricity trading is done on the basis of industry standard contracts (Grid Trade Master Agreements (GTMAs) or an International Swaps and Derivatives Association Master Agreement with a GTMA index) or by way of bespoke power purchase agreements between generators and suppliers.

Electricity trading is also subject to market transparency regulation and requires disclosure of price-sensitive information to the market. The Regulation on Wholesale Energy Market Integrity and Transparency, initially adopted in December 2011, extends the concept of the Market Abuse Directive to physical gas and power, and requires market participants to disclose physical inside information, and to avoid attempted and actual market manipulation and abuse. More recently, when it comes into force in 2017, the forecast Markets in Financial Instruments Directive will significantly narrow the exemptions currently available to commodity derivatives trading firms to ensure that 'participants on commodity derivatives markets [are] subject to appropriate regulation and supervision'. It is worth noting that although the United Kingdom voted to leave the European Union, the government has given assurances that it will continue to implement EU legislation until the Article 50 procedure is complete, and thereafter, a proposed Great Repeal Bill will incorporate EU law into national legislation.
iii  Contracts for sale of energy

Generators, electricity suppliers, electricity traders and large customers can enter into commercially negotiated contracts to buy and sell electricity. The volumes (not commercial details) of the resulting trades are notified to the system and market operators, and any failure to achieve these notifications (called imbalances) are priced and settled. Trading takes place on a half-hourly basis with gate closure – set one hour ahead of real time – and participants notifying the system operator of their intended final physical position. After this point, no further contract notification can be made and settlement is based on positions at gate closure.

iv  Market developments

There are a number of changes affecting the UK energy and gas markets. For example, in electricity transmission in GB, there are plans to introduce competitive auctions to build new onshore transmission lines. Ofgem is also continuing to run auctions for competition in offshore transmission.

There has also been a rise in the number of new entrants to the electricity supply markets. This is in line with government aims to decrease the dominance of the ‘Big Six’ vertically integrated utilities in the domestic supply market.

The introduction of the GB capacity market in 2013 has also given rise to more attention being paid to demand-side response and how it is able to provide security of supply during times of system stress. In this respect, National Grid has launched a new demand-side response product, namely the Demand Turn Up ancillary service (for which 138.6MW has been purchased for spring/summer 2017). The service is procured by National Grid and was introduced in 2016 to encourage large energy users and generators to either increase demand (i.e., take energy off the network) or reduce generation.

V  RENEWABLE ENERGY AND CONSERVATION

i  Development of renewable energy

The United Kingdom has a long-established renewable energy policy. At the national level, the United Kingdom, via the Climate Change Act 2008, has committed to a reduction of greenhouse gas emissions by 34 per cent by 2020 and 80 per cent by 2050 in comparison with 1990 levels.

The current main driver for renewable energy policy in the United Kingdom is the EU Renewable Energy Directive (RED). The RED aims to reduce the EU’s dependency on fossil fuels and to foster low-carbon and sustainable energy generation. EU Member States agreed under the RED to jointly achieve a target of 20 per cent of energy consumption from renewable sources by 2020. Beyond the 2020 renewable targets, EU countries agreed in 2014 on a policy framework for 2030 including targets for a 40 per cent cut in greenhouse gas emission, 27 per cent share on renewable energy consumption and at least 27 per cent reduction on energy use. However, pursuant to the 2014 policy framework agreement, the European Commission has put forward an amendment proposal to the RED that would,

8 For more information on the EU 2030 Energy Strategy see https://ec.europa.eu/energy/node/163.
among other things, replace nationally binding 2020 renewables targets with an EU-wide target of 27 per cent renewable energy by 2030. Other amendments would seek to extend national renewable support mechanisms to projects in other member states (which the UK states may not be compatible with the principle of subsidiarity) and boost the proportion of renewable energy used for heating, cooling and transport. The RED amendment proposals are set to enter into force on 1 January 2021 (i.e., post the UK’s exit from the EU in early 2019) and as previously stated, until the Brexit Article 50 procedure is complete, the UK will continue to implement and observe EU law as normal. After the UK’s exit from the EU is effected, the entirety of EU legislation will be enshrined in national law by means of what the government calls a Great Repeal Bill. Renewables targets will, however, remain unaffected regardless of the final Brexit position as the UK’s national renewables and decarbonisation targets exceed those imposed at EU-level. However, the government’s focus on achieving industrial growth post-Brexit may render decarbonisation targets secondary to those of ensuring security of supply for large industrials. Not least, exit from the EU could potentially allow the UK to pursue an even more ambitious energy policy given that EU rules on state aid would cease to apply (however, the UK may still have to observe EU state aid rules to secure unrestricted access to EU markets).

**Contracts for Difference**

In the United Kingdom electricity sector, the main support for renewables is through Contracts for Difference (CfDs), which were introduced in 2013 by the Energy Act 2013 as part of the United Kingdom’s Electricity Market Reform programme. Prior to its introduction, the main support measures available for low-carbon generation were in the form of the Renewables Obligation (RO) for large-scale, and Feed-in Tariffs (FiTs) for small-scale projects. CfDs are 15-year contracts entered between a government-owned company, the Low Carbon Contracts Company, and the eligible low-carbon generators. The CfD mechanism works by setting a fixed price (strike price) thus reducing the generator’s exposure to electricity prices volatility and consequently the cost of capital of the investment. The first allocation round for CfDs took place in October 2014 and contracts were awarded to 27 projects in February 2015. The second allocation round for CfDs for the 2021/22 and 2022/23 delivery years was commenced in April 2017, with results being communicated around September 2017. The total budget for the second allocation round is around £290 million.

**Renewables Obligation**

Support for renewable generation via the RO scheme was introduced in England and Wales in 2002 and administered by Ofgem. The RO scheme imposes an obligation on electricity suppliers to source a fraction of their electricity from renewable generation, and compliance with this obligation is shown by obtaining RO certificates issued to generators accredited on

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the scheme (with the number of certificates issued varying depending on the technology and the value of each certificate being broadly maintained through terms, such as a buyout price, set from time to time by the electricity regulator).

While it was originally envisaged that the RO would close to new generation at the end of March 2017, the RO scheme has been gradually phased out through a series of legislative amendments, which imposed a cap on biomass, closed support to solar PV (large-scale on March 2015, and small-scale on March 2016) and closed support for onshore wind in May 2016. Early closures are subject to provisions of specific grace periods.

**FiTs**

The FiTs scheme was introduced to promote the deployment and use of small-scale (5MW and below) renewable and low-carbon generation. The FiTs scheme began operation on 1 April 2010 and is administered by Ofgem, which accredits generators, maintains the Central FiT Register of the accredited installations and monitors the reaching of deployment caps as well as compliance with the scheme.

Payments under the scheme are administered and performed by FiT licensees – suppliers that join the FiT scheme either compulsorily (those supplying more than 250,000 domestic users) or voluntarily – which then pass on costs to consumers. A fixed payment is made under the FiT scheme for electricity that is generated on-site, the ‘generation tariff’, and another payment for any unused electricity that the generator exports to the grid, the ‘export tariff’.

Major changes to the FiT scheme were introduced at the end of 2015, including a reduction of tariffs, the introduction of quarterly deployment caps coupled with a default degression mechanism and an overall FiT budget limit.

**ii Energy efficiency and conservation**

Until recently, the CRC Energy Efficiency Scheme was a mandatory carbon emissions reduction scheme that applied to large non-energy-intensive organisations. This was scrapped in March 2016 with effect from the end of the 2018/2019 compliance year.

The Climate Change Levy (CCL) is a tax on energy delivered to non-domestic consumers that aims to incentivise increased energy efficiency. The government has introduced a 100 per cent exemption from CCL for energy used in certain energy-intensive (metallurgical and mineralogical) industrial processes. Further, Climate Change Agreements are voluntary agreements that allow eligible energy-intensive sectors to receive up to 90 per cent reduction in the Climate Change Levy if they agree to meet certain energy efficiency targets.

Separately, the government has introduced the Renewable Heat Incentive (RHI) scheme aimed at promoting energy efficiency through encouraging renewable heat. The RHI is aimed towards levelling the cost of renewable heat with that of heating from fossil fuels. The RHI was first introduced in November 2011 for non-domestic heating and subsequently expanded to include domestic heating support. Duration of support is 20 years for the former and seven years for the latter category.

**iii Technological developments**

The electricity and gas sectors continue to attract much interest in the development of technologies. For several years, the UK government encouraged the development of industrial carbon capture and storage (CCS) and is funding a four-year co-ordinated research, development and innovation programme into CCS technologies. However, in late 2015,
the government announced it was cancelling funding for a UK CCS Commercialisation competition, which would have made available £1 billion capital funding for the design, construction and operation of the UK’s first commercial-scale CCS projects.

The UK government has also set up a Low Carbon Innovation Co-ordination Group to support innovation in energy technologies to meet the climate change goal of an 80 per cent reduction in greenhouse gas emissions by 2050. The group aims to maximise the impact of UK public sector support for low-carbon technologies.

The UK is emerging as a market leader and pioneer in the battery storage industry. According to a study carried out by Solar Media, the UK boasts a pipeline of 2.3GW of commercial and industrial and utility scale battery storage projects.11

VI THE YEAR IN REVIEW

The past year has been one of sea change for the GB electricity sector. The market has had to adjust to considerable uncertainty resulting from Brexit and changes to renewable subsidy policies coming into full effect. In this respect, the Hinkley Point C new nuclear build project is considering supply chain issues and is keen to ensure the talent and expertise required. The UK’s current pipeline of new interconnector projects is seemingly not hampered at the moment by the outcomes of Brexit. The UK is also keen to ensure continuity of trade with EU countries post Brexit. This is demonstrated by National Grid and RTE entering into contracts in April 2017 for the construction of the new England–France interconnector (IFA2), showing that market players are proceeding business as usual.

The closure of the Renewables Obligation scheme, coupled with volatile wholesale electricity trading prices, has accelerated new build renewables projects in the short term, but may cause a slowdown in the long term. Market players have now begun to pivot towards battery storage projects that can augment existing renewable projects’ revenue streams (through co-location) and allow them to access new ones such as National Grid’s Demand Turn-Up ancillary service launched in 2016. With over 200 storage projects in the pipeline, and a number of existing storage projects winning Capacity Market contracts, the focus on this technology has increased significantly.

Ofgem has launched consultations on the existing regime for embedded benefits and has issued a ‘minded to’ decision in March 2017 to reduce TNUoS Demand Residual (known as ‘triad’) payments from the current level of around £45/kW to around £2/kW given to generators connected to the distribution system during triad periods (being the three half-hour settlement periods each winter when electricity demand in Great Britain is highest, separated by 10 clear days). Also in March 2017, Ofgem launched a further consultation in relation to network charging as it suspects the current residual charges, smaller EG embedded benefits, and the charging treatment for storage have the potential to create distortions, adversely affect competition and increase costs for consumers. This latest consultation, coupled with Ofgem’s ‘Smart, Flexible Energy System’ Call for Evidence, highlight the increasing traction that energy storage is getting in the market. The industry, together with the government and regulator, are channelling efforts towards developing an appropriate and coherent regulatory regime (and definition) for this fast-emerging technology.

Investors are seeing further reasons for optimism in the OFTO and CATO transmission sector. The first CATO auctions are expected to start in 2019 and it is estimated that these

11 www.solar-intel.com/uk-battery-storage-project-database-report.
will attract around £1 billion of investment, representing an attractive opportunity for institutional investors seeking stable returns over long periods. Unlike the OFTO regime for which tenders begin after construction, the CATO auctions are expected to include the detailed design, procurement, construction and operation phases of the onshore transmission assets.

The past year has also seen an uptick in activity in the gas and electricity secondary markets. In the gas sector, the year’s highlights have been NGG’s disposal of a 61 per cent stake in its gas distribution business to a consortium backed by Macquarie and China Investment Corporation, among others, as well as SSE’s disposal of a 16.7 per cent stake in SGN to the Abu Dhabi Investment Authority. In the electricity sector, renewables (meaning wind, solar and hydro) made up around half of all M&A deals in the past year, a significant surge since the previous year and one that continues to grow. The need to recycle capital is pushing developers to sell operational renewable assets to funds and other institutional investors.

Lastly, in November 2016, the European Commission launched an ambitious and wide-ranging fourth energy package, which it is calling ‘Clean Energy for All Europeans’, to give effect to the EU’s Energy Union Strategy and to complete the implementation of the EU’s 2030 climate and energy framework. The main aims of the package are to improve energy efficiency, achieve global leadership in renewables and offer consumers a fair deal for their energy consumption. The package contains a vast legislative and non-legislative agenda and the UK government is in the main supportive of the Commission’s proposals but remains sceptical of certain measures such as binding energy efficiency targets. Under the proposals, the 2030 energy efficiency target would be raised from 27 per cent to 30 per cent and become binding rather than indicative. The European Commission is also concerned that although wholesale energy prices have fallen by 50 per cent since 2013, retail electricity prices have risen by around 3 per cent and gas prices by around 2 per cent annually since 2008. Therefore, the Commission is looking into rising network costs and government taxes and levies as key areas for action.

VII CONCLUSIONS AND OUTLOOK

As one would expect in a mature market that is coming to terms with changing market and geopolitical forces, the UK energy market is exceptionally stable in one sense, and yet still experiencing shifts in financial and business models arising from the need to keep pace with changing priorities and technologies. The general trend toward lowering costs for the government (and, implicitly, consumers) continues to affect the renewables industry, which is seeing an increase in M&A activity and a likely slowdown in new build projects in due course (although not immediately). The UK continues to remain an attractive market for investors wishing to invest in energy assets, and offshore and onshore transmission projects are an example where appetite is growing. Security of supply has been a cornerstone of the current government’s energy policy, sometimes at the detriment of decarbonisation efforts, and the Capacity Market will continue to incentivise investment in peaking technologies, with hope of new combined cycle gas turbine plants. It also appears that decarbonisation is becoming a secondary objective to that of ensuring security of supply, so as to assist the government in its drive for industrial growth (and Brexit may further emphasise this shift in priorities).

The star performer of the past year, and with increasingly positive prospects, is battery storage. With the continuing rapid decline in prices for lithium-ion batteries, ever more existing renewables projects will seek to co-locate batteries to improve returns and margins,
and standalone batteries are starting to become viable projects for demand side response and price arbitrage opportunities. One notable feature of the past year has been the exponential rise in the number of players in the UK’s electricity supply industry and this trend is not expected to slow down.

The gas market remains a stable investment with two large transactions in the distribution sector over the past year at significant premiums to the regulated asset values, and further M&A activity in the near to medium term is likely.

Finally, Brexit remains uncertain in shape and outcome for the UK’s economy and the energy sector is no exception. So far, the majority of downside risk caused by Brexit has been due to increased costs arising from the devaluation of sterling. To date, there have been no significant legislative or regulatory effects of Brexit for the simple reason that the UK continues to be a full member of the EU (with all associated rights and obligations) until the Article 50 procedure is complete in March 2019. The government has assured that EU law will continue to be in effect in the UK via a transposition of EU legislation into national law by way of a Great Repeal Bill, although the industry will expect to see clearer details of how that will be achieved before too long.
Chapter 36

UNITED STATES

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I OVERVIEW

Energy regulation in the United States is complex, broad and enforced by a variety of federal
and state governmental entities. Further, it is continually evolving in response to global,
national and regional events, supply/demand balance and other market shifts, political
dynamics and priorities, and technological advances. As such, this chapter is intended to be
an overview of the nature and scope of energy regulation and markets.

II REGULATION

i The regulators

Multiple federal and state agencies, departments and other governmental entities regulate
US energy development, and the ownership, control and operation of electric energy, natural
gas and oil production, gathering, transmission/transportation and distribution of energy
resources, including with respect to the rates, terms and conditions of wholesale and retail
services, as well as energy market rules.

The Federal Energy Regulatory Commission (FERC) is an independent federal
regulatory agency established by the United States Congress initially as the Federal Power
Commission to license hydroelectric facilities and regulate wholesale sales of electric energy
and natural gas and the transmission of electric energy or transportation by pipeline of
natural gas in interstate commerce. Subsequently, FERC’s authority was expanded to include
the regulation of interstate shipments of certain liquid fossil fuels via pipelines, including
crude oil, petroleum products and natural gas liquids, such as propane and ethane. FERC’s
authority is granted, and limited, by statutes, including the Federal Power Act (FPA), as
amended, the Natural Gas Act (NGA), as amended, the Natural Gas Policy Act of 1978, as
amended, the Interstate Commerce Act, as amended, the Energy Policy Act of 2005, and the

The Nuclear Regulatory Commission (NRC) is an independent federal regulatory agency
established by Congress to formulate policies and regulations governing nuclear reactor and
materials licensing and safety. The NRC’s authority is also granted, and limited, by statutes,
including the Atomic Energy Act of 1954, as amended, and the Energy Reorganization Act
of 1974, as amended.

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The Department of Energy (DOE) is an executive department created in 1977 whose current mission is to ensure America’s security and prosperity by addressing its energy, environmental and nuclear challenges through transformative science and technology solutions. The DOE is led by the Secretary of Energy, a member of the President's cabinet. FERC is within the DOE, and the DOE and FERC sometimes have overlapping and sometimes have separate authorities under their relevant organic statutes, including the FPA and the NGA. For example, under the NGA, the DOE is responsible for issuing authorisations to import and export natural gas to and from the United States, including liquefied natural gas (LNG). At the same time, under the NGA, FERC is responsible for issuing authorisations to construct and operate LNG import and export terminals.

Numerous other federal agencies and departments regulate certain aspects of the US energy industry, including the Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA), Environmental Protection Agency, the Commodities Futures Trading Commission, the Federal Trade Commission, and the United States Departments of Agriculture, Interior, State, Commerce and Justice. The production and gathering of crude oil and natural gas, the siting of energy facilities (except LNG facilities), and the distribution and retail sale of electric energy and natural gas are generally governed by individual state regulatory agencies. In many states, public utility regulation is carried out by public service commissions or public utility commissions (PUCs) or municipal agencies (or both). The jurisdiction of these state-based and locally-based regulatory agencies over energy companies is created by state constitutions and statutes and, like most state regulation in the United States, is also subject to the supremacy of the US government under the United States Constitution and federal statutes, except in certain limited circumstances.

**ii Regulated activities**

Many aspects of energy development, generation, production, transmission/transportation, and distribution in the United States are subject to some type of federal or state regulation.

FERC regulates the rates, terms and conditions of wholesale sales of electric energy in interstate commerce and the transmission of electric energy in interstate commerce. FERC also regulates the rates, terms and conditions of natural gas and oil pipeline transportation services. Entities making sales of FERC-jurisdictional products or services obtain rate approval from FERC. FERC rates for electric transmission and interstate natural gas transportation 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 charges and typically 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 upward adjustment). FERC also regulates entities subject to its jurisdiction with respect to matters that may affect rates, including with respect to accounting, record-keeping and reporting, and, with respect to companies regulated under the Federal Power Act, direct issuances of securities and direct and indirect transfers of control over FERC-jurisdictional facilities.

Under the NGA, FERC is authorised to approve the construction and operation of new interstate natural gas pipeline and storage facilities and, as discussed previously, LNG import and export terminals. Owners of natural gas facilities authorised by FERC (but not LNG terminals) may call on a federal power of eminent domain to condemn land on which to site approved facilities. As a condition to the construction of new natural gas pipeline
and storage facilities, FERC may require natural gas companies to conduct an ‘open season’, during which potential customers may subscribe to transportation or storage capacity on a non-discriminatory basis and existing customers may turn back capacity that may result in the downsizing or elimination of the new facilities. In exercising its rate jurisdiction over electric transmission facilities and oil pipelines, and in conjunction with its open access requirements, FERC has also required open seasons for some or all new or expanded capacity on certain electric transmission and oil pipeline facilities.

The NGA was amended in 2005 to expedite the licensing process for the construction of interstate natural gas pipelines and storage facilities, and to clarify and modify FERC’s review and approval of the construction and operation of LNG import and export terminals. The 2005 amendments prohibited FERC from regulating the rates, terms, and conditions of service for LNG terminals, but only until January 2015, at which time FERC’s authority over LNG terminals became the same as its authority over interstate natural gas pipelines; however, FERC has not yet exercised that authority and instead has continued to allow LNG import and export terminals to charge market-based rates and to operate without complying with FERC’s open access requirements. Under the FPA, FERC also has siting approval authority with respect to hydroelectric generating facilities to be constructed on navigable waterways. In 2005, Congress also gave FERC ‘backstop’ siting authority under the FPA to issue permits for the construction of transmission lines when the DOE designates important ‘national interest electric transmission corridors’ (NIETC) for geographical areas experiencing transmission constraints or congestion that adversely affects consumers, although the scope of FERC’s backstop siting authority and the DOE’s NIETC designation authority under the FPA remains unclear as a result of judicial decisions in the US Courts of Appeals.

Pipelines located in US waters on the Continental Shelf are subject to regulation by the US Department of Interior. Prior to the Deepwater Horizon oil spill in the Gulf of Mexico in 2010, the Department of Interior’s offshore pipeline responsibilities were carried out by the Minerals Management Service; however, in 2010, these responsibilities were transferred to a new agency, the Bureau of Ocean Energy Management, Regulation and Enforcement, and then transferred again in 2011 to two new bureaus: the Bureau of Ocean Energy Management and Bureau of Safety and Environmental Enforcement. 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 transportation of resources 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.

iv Ownership, market access restrictions and transfers of control
The Committee on Foreign Investment in the United States oversees foreign investment
in existing companies and assets in the United States, with the President having ultimate
authority to deny foreign investment that may adversely affect national security. Other than
with respect to nuclear energy, there is little restriction on foreign ownership of energy assets
in the United States under US energy-specific laws and regulations.

FERC approval is generally required for the direct transfer of natural gas facilities
subject to FERC’s jurisdiction. In reviewing the 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 is 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 services, including rates.

FERC also regulates the direct and indirect transfer of control over electric transmission
and generation facilities. In reviewing a proposed transfer of electric transmission or generation
facilities, FERC must determine whether the transaction is consistent with the public interest,
including the effect on competition, the effect on rates and the effect on regulation. FERC
also considers whether the transaction would result in the cross-subsidisation of a non-utility
affiliate of a public utility or the pledge or encumbrance of utility assets for the benefit of
a non-utility affiliate of a public utility.

PHMSA requires operators of regulated facilities to provide notice of certain transfers,
name changes, acquisitions and divestitures no later than 60 days after the event. New
operators must also be fully in compliance with PHMSA regulations, including recordkeeping
and operator ID requirements, upon owning or operating an active or idled pipeline.

Certain states also require that entities obtain PUC approval prior to the direct and, in
some jurisdictions, indirect transfer of assets subject to the jurisdiction of the PUC. While
many state statutes require PUCs to evaluate whether a proposed transaction is consistent
with the public interest, PUCs vary as to whether they interpret their jurisdiction as requiring
a showing that the transaction will not result in net harm to the public or a showing that the
transaction will provide net benefits to the public.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration, unbundling and open access
Over the past four decades, the federal government and many state governments have
sought to replace traditional forms of cost-based regulation of services provided by vertically
integrated monopolies with regulation designed to promote open access and competitive
market forces.

Prior to the mid-1980s, the natural gas industry was fairly rigidly structured into three
parts:

a producers that sold natural gas to pipeline companies;
pipeline companies that resold and delivered that natural gas to distributors on a ‘bundled’ basis (combining the commodity cost of the natural gas with the cost of transportation service); and
distributors that sold natural gas to retail customers.

Certain large industrial and electrical generating companies bought natural gas directly from producers or pipelines. In an effort to open natural gas markets to widespread competition, FERC initially voided contractual requirements that distributors purchase minimum quantities of natural gas from pipelines. These orders were followed by new open access rules requiring interstate pipelines to offer ‘unbundled’ transportation services (i.e., transportation services not tied to purchases of natural gas from the transporting pipeline or its affiliates) at tariff rates on non-discriminatory terms and conditions set by FERC for all pipelines, and requiring compliance with new standards of conduct that prohibit pipeline transportation personnel from communicating non-public, competitively sensitive information to marketing personnel. FERC also required interstate natural gas pipelines to establish internet-based information systems to facilitate reporting and use of available pipeline capacity, as well as 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. In 1989, Congress first deregulated sales of natural gas by producers and FERC then adopted rules that effectively deregulated the price of all other wholesale sales of natural gas. 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. The 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.

The electric sector in the United States was also dominated by franchised monopolies. Prior to the early 1990s, vertically integrated electric utilities with monopoly retail franchises owned and controlled most of the facilities used for the generation, transmission and distribution of electricity within their franchised service territories. Many vertically integrated utilities were widely traded stock corporations, although some were owned by the US or state governments. Numerous municipally owned or cooperatively owned utilities also distributed electricity at retail, although these publicly owned utilities were typically smaller and more likely to be dependent on investor-owned utilities for transmission services to access generation located outside their service territories.

In 1978, Congress enacted the Public Utility Regulatory Policies Act to encourage the deployment of renewable and energy-efficient technologies by requiring electric utilities to purchase electric power from generating sources using advanced technologies and eliminating all restrictions on the ownership of qualifying generating facilities. Non-utility companies demonstrated a high level of interest in building new power plants, which led in 1992 to Congress’s elimination of all ownership restrictions on facilities generating electricity for sale at wholesale. At the same time, both the federal government and many states began to liberalise their wholesale and retail electricity markets, including state efforts to have state-regulated public utilities divest some or all of their electric generation and federal efforts to make bulk power transmission facilities and distribution facilities available to others on an open access basis.
As part of the 1992 legislation, Congress amended the FPA to authorise FERC to order interstate transmission-owning public utilities to provide any electric utility, federal power marketing agency, or any other person generating electric energy for wholesale sales open and non-discriminatory access to their transmission facilities. As envisioned by Congress, such open access would allow bulk power consumers and suppliers to enjoy the benefits of competition in bulk power markets, as well as in those downstream retail power markets liberalised by states.

In 1996, FERC issued Order Nos. 888 and 889 to establish the foundation for the development of competitive bulk power markets by directing that bulk power transmission services be provided on an open access basis that is just, reasonable and not unduly discriminatory or preferential. Order No. 888 required that all FERC jurisdictional transmitting utilities in the United States file a *pro forma* open access transmission tariff (OATT) and functionally unbundle their wholesale power services from their wholesale and retail transmission services. Order No. 888 also encouraged transmitting utilities to convey operational control of their transmission facilities to independent system operators (ISOs) or other independent regional transmission organisations (RTOs), which led to the formation of ISOs and RTOs in regions including the large majority of electrical load in the United States.

The *pro forma* OATT requires transmitting utilities to provide open, not unduly discriminatory, access to their transmission system to transmission customers and addresses the terms of transmission service, including the terms for scheduling service, curtailments and the provision of ancillary services. Transmitting utilities are permitted to vary from the required *pro forma* terms of service if FERC finds that their proposed variations are equally or more conducive to the OATT’s open access objectives. Order No. 889 required codes of conduct governing how participants in the wholesale power markets should interact with transmission service providers and the establishment of electronic bulletin boards (open access same-time information systems) for the posting of details regarding available transmission capacity.

Since Order Nos. 888 and 889, FERC has issued a range of major orders updating and expanding its open access policies to address such matters as: the formation of and participation in RTOs; *pro forma* procedures and agreements for interconnection of generation to the bulk power grid; changes to the *pro forma* generator interconnection procedures and agreements to facilitate interconnection of wind generators; general rules to facilitate more open and transparent planning and use of wholesale transmission facilities; and most recently, general rules regarding transmission planning and cost allocation. FERC continues to consider whether reforms to its open access policies are necessary to eliminate possible barriers to the integration of wind, solar and other variable energy generation resources, as well as energy storage (e.g., batteries) and distributed energy resources, and to respond to market changes, including the growing deployment of small distributed generation resources, such as solar photovoltaic installations.

**ii Rates**

Economic regulation of most of the bulk power transmission system in the continental United States is administered by FERC, including regulation of the rates, terms and conditions for the transmission of electric energy in interstate commerce. Most FERC-regulated transmission services are provided at embedded cost-of-service rates that provide a return of investment
as well as a FERC-determined reasonable rate of return on common equity. FERC also has permitted ‘merchant’ transmission projects (i.e., transmission that is not included in a cost-of-service rate base) to charge negotiated rates for transmission service.

In 2005, Congress amended the FPA to direct FERC to develop rate incentives to encourage certain transmission development. In 2006, FERC issued regulations to provide on a case-by-case basis a variety of cost-of-service rate incentives for new transmission projects that improve reliability or reduce cost. These incentives include incentive rates of return on equity for new investment, use of a hypothetical capital structure during construction, full recovery of prudently incurred construction work in progress in rate base during construction, full recovery of prudently incurred costs of abandoned projects, and accelerated depreciation. To obtain one or more of these incentives an applicant must show that there is a nexus between the incentive being sought and the risks associated with the investment being made.

Since 2000, FERC has also permitted certain merchant transmission projects to charge negotiated rates for transmission service under OATT-based transmission service agreements. Initially, FERC required merchant transmission facilities to hold open seasons for the full capacity of a planned project. Beginning in 2009, FERC permitted certain merchant transmission project developers to allocate some portion of transmission capacity (generally not more than 75 per cent) through pre-subscription to ‘anchor customers’, who provide upfront or assured ongoing payments through long-term transmission service agreements to facilitate project construction. The remaining project capacity not committed to anchor customers will be made available to later customers selected through an open season process detailed in the project’s OATT and these customers will be entitled to obtain service under terms and conditions generally comparable to those available to anchor customers. Since 2013, FERC has permitted merchant transmission developers to avoid formal open season requirements and allocate up to 100 per cent of the capacity on a transmission project to a single customer, including an affiliate, if the developer broadly solicits interest in the project from potential customers and demonstrates to FERC that it has satisfied certain solicitation, selection and negotiation process criteria.

Rates for interstate natural gas transportation and storage are generally based on costs, including a reasonable return. Rates for service are established for new facilities when FERC certifies construction. Pipelines may change the rates based on a showing that a new cost-based rate is ‘just and reasonable’, and FERC or other affected parties may require prospective rate adjustments by showing that the existing rates are unjust and unreasonable. In 2009, FERC began a systematic and in-depth review of cost and revenue information that must be filed annually by pipelines, leading to the initiation of rate investigations of certain pipelines that appear to it to be over-earning. Pipelines and storage companies are also permitted to offer discounts from the maximum, cost-based rate discounts, as well as to negotiate rates with customers. Any rate discounts offered by an interstate natural gas company must be offered on a non-discriminatory basis to all similarly situated customers, and 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 if either they offer the customer the option to take service under a FERC-approved cost-of-service rate, known as a ‘recourse rate’, or they demonstrate to FERC that competition is sufficient to prevent the exercise of market power. Storage companies are often permitted to charge competitive market-based rates.
For interstate deliveries, FERC jurisdictional pipelines that transport fossil fuel liquids may charge cost-of-service rates, historical rates (where applicable) or market rates if adequate competition is proven to exist. FERC-regulated oil pipeline rates may change 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 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 pipelines if offered to all shippers and prospective shippers in an open season. FERC permits oil pipelines to offer priority service for part of the new capacity if open-season shippers pay a premium rate and all shippers have an opportunity to subscribe to capacity in an open season. FERC also permits pipelines to offer unreserved capacity at discounted rates through an open-season offering, and has also approved proposals to allow committed shippers who pay such discounted rates to receive priority service during periods of prorationing by paying a premium rate.

iii Security and technology restrictions

Prior to 2005, the United States relied on voluntary compliance by participants in the bulk power industry with reliability requirements for operating and planning the bulk power system coordinated through the North American Electric Reliability Corporation (NERC) and various related regional entities. In 2005, Congress responded to a widespread August 2003 blackout throughout the northeastern and midwestern United States (and parts of Canada) by amending the FPA to provide for a system of mandatory, enforceable reliability standards to be developed by a FERC-certified 'electric reliability organisation' (ERO), subject to review and approval by FERC. For purposes of approving and enforcing compliance with reliability standards, FERC has jurisdiction over the FERC-certified ERO, any regional reliability entities, and all users, owners and operators of the bulk power system, including public and governmental entities not otherwise subject to FERC jurisdiction under the FPA. FERC certified NERC as the ERO and in various subsequent orders has defined the bulk power system and approved a number of reliability standards proposed by NERC.

Federal law sets minimum safety standards for all natural gas and hazardous liquids pipelines, and provides for regulation of these facilities by PHMSA. PHMSA regulates pipeline facilities pursuant to its pipeline safety programme, which is implemented in cooperation with the states. Although PHMSA has the authority to regulate all interstate pipelines, it may allow a state to act as its agent, subject to certain limitations. Also, states adopting laws meeting or exceeding the federal minimum safety standards may obtain a certification from PHMSA to regulate intrastate pipelines. If a state's law does not meet the federal minimum safety standards, PHMSA may decertify the state or exercise backstop authority to inspect and enforce federal pipeline safety laws. States are permitted to adopt and enforce standards that are more stringent than the federal minimum standards, which in many cases are overseen by each state's PUC. The security of LNG waterfront facilities and deepwater ports is regulated by the US Coast Guard pursuant to a number of federal laws, including the Maritime Transportation Security Act, the Ports and Waterways Safety Act, the Magnuson Act and the Deepwater Port Act.

Federal law and agency-specific regulations require that owners and operators of energy facilities protect facility sensitive security and critical energy infrastructure information from disclosure to the public, including electronic copies of such information stored in company operating systems, databases and computers. The United States has not currently adopted
mandatory cybersecurity standards for pipelines, storage facilities or LNG terminals, although in response to growing concerns about cybersecurity and recently reported cyberattacks on major pipelines, new legislation and new rules are being considered. The 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 electric energy markets. FERC has prohibited any one set of market participants (including transmission owners) from controlling decision making within an ISO or RTO. FERC’s Order No. 2000 imposed significant regulatory requirements upon ISOs and RTOs regarding the independence of an energy market administrator, the performance of the energy markets and the elimination of discrimination. FERC left considerable discretion to market participants to determine an ISO’s or RTO’s governance structure, geographical scope and type of market services.

The following ISOs and RTOs are currently operating: PJM Interconnection, LLC (PJM), New York Independent System Operator Inc (NYISO), ISO New England Inc (ISO-New England), Midcontinent Independent System Operator Inc (MISO), Electric Reliability Council of Texas (ERCOT), Southwest Power Pool and California Independent System Operator Corp (CAISO). Of these RTOs, only ERCOT is not subject to FERC’s regulatory oversight, as ERCOT is deemed to be electrically isolated from the rest of the transmission grid in the continental United States.

Each ISO and RTO offers different energy products in its organised markets. While all of the existing ISOs and RTOs administer some form of bid-based markets for one or more energy products (i.e., where the highest price bid for the marginal quantity of supply that satisfies the quantity demanded in any relevant period sets the market price for the product within that applicable region, node or zone), some provide real-time and day-ahead markets, while others do not. In addition, some of the ISOs and RTOs offer forward markets for the sale of capacity (i.e., the ability to produce electric energy) separate from other energy products. Such forward capacity markets are structured differently in each RTO and ISO and the details associated with the ancillary service markets for these ISOs and RTOs differ as well. Each market has an independent market monitor, as FERC required by Order No. 719, but the nature and scope of the market monitors’ roles differ. RTOs and ISOs that are interconnected to one another have special joint operating arrangements relating to the ‘seams’ between them. Moreover, CAISO has established and made available to other electric grids in the western United States that are neither RTOs nor ISOs an energy imbalance market system that on a regional basis can automatically balance supply and demand and dispatch least-cost energy resources on a short-term basis. This system is intended to assist California and other states in the western United States to better manage and share their generation capacity reserves and integrate intermittent renewable generation resources. Electric grids in eight western states are active participants in this system.

ii Wholesale energy market rules and regulation

Each RTO and ISO develops its own market rules through the market participants’ stakeholder approval process. Market rules for all RTOs and ISOs must be filed with and
approved by FERC prior to implementation, except for ERCOT, which is subject to the exclusive jurisdiction of the Public Utility Commission of Texas. The independent market monitor within each RTO and ISO provides independent oversight over certain market issues, including with respect to market concentration issues.

iii Contracts for sale of electric energy at wholesale

The US electricity markets have a long history with bilateral power purchase and sale contracting at wholesale. Even where market participants are located within an applicable RTO or ISO (i.e., bidding or offering into the organised wholesale markets and scheduling flows through the RTO or ISO), market participants often enter into bilateral energy and capacity contracts as a means of hedging the volatility of market prices or providing a reliable source of supply. Bilateral contracts can be in the form of physical purchases and sales or financial settlements. Some contracting parties use standardised industry form agreements, such as those developed by the Edison Electric Institute or the International Swap and Derivatives Association, and others negotiate individualised contracts. Physical sales of energy, capacity and ancillary services products in the wholesale markets are subject to FERC jurisdiction and associated contracts must either be filed with FERC or reported through electric quarterly reports.

iv Natural gas and oil markets

Unlike in the electricity sector, there are no formal FERC-approved organised wholesale markets for oil and natural gas. Interstate natural gas pipelines are required to operate secondary markets for the transportation services they offer. Under FERC's rules, any shipper that has contracted for firm transportation service on a natural gas pipeline may release its contracted capacity to other shippers, either by publicly posting the availability of the pipeline capacity on an electronic bulletin board maintained by the pipeline and accepting offers for it, or, if certain criteria are met, in a privately negotiated, but publicly posted, transaction with prices capped at the pipeline's tariff rate. Also, to facilitate the development of natural gas markets, FERC has liberalised some of its rules designed to prevent shippers from capitalising on a pipeline's market power. Generally, FERC requires shippers to hold title to the natural gas they ship on interstate pipelines and prohibits shippers from buying natural gas at a receipt point and reselling the natural gas to the same company after transportation at the delivery point in a prearranged 'buy-sell' transaction. To allow brokers to aggregate transportation capacity and natural gas supplies, and to more efficiently use transportation services, FERC allows exceptions to its shipper-must-have-title rule under qualifying asset management arrangements. No similar rules, requirements or exceptions apply to pipelines that transport fossil fuel liquids.

v Retail energy market regulation

Retail energy markets are regulated at the state and local levels. Across much of the United States, retail consumers of electricity and natural gas buy electricity and natural gas from local utilities, many of whom remain vertically integrated, at rates and under terms and conditions set by local regulators. Beginning in the mid-1990s there was a move in some states to unbundle commodity generation or natural gas service from distribution services and allow retail consumers to purchase these commodity services from competitive retail suppliers. Between 1995 and 2002, a large number of states, including California, Texas and most of the states in the northeastern United States, introduced retail competition.
for electricity and natural gas, and in some instances required local utilities to divest or formally separate their electric generation, as part of industry reforms generally referred to as ‘electricity restructuring’. These restructuring efforts also included various mechanisms to provide short-term savings to retail consumers as well as mechanisms to protect consumers from market volatility in the wholesale markets and requirements that distribution utilities serve as a provider of last resort for retail consumers who cannot (or do not choose to) obtain commodity service from a competitive supplier. At the same time, in many states, distribution utilities were required to charge prices for commodity service at levels above projected market prices to create a competitive opening for other retail suppliers.

During 2000 and 2001, there was an extended period of extreme volatility in wholesale electricity and natural gas markets in the western United States, which had a severe negative impact on the financial conditions of the restructured utilities in California and ultimately compelled the state of California to become a significant buyer of last resort in the wholesale electricity markets and ended retail competition for most retail consumers in California. After the California electricity crisis, further efforts at electricity restructuring at the retail level in the United States largely came to a standstill and retail competition was suspended or rescinded in several states. As of early 2017, 14 states and the District of Columbia allow for retail competition. However, regulators in one of these states, New York, took action in early 2016 to limit retail competition for the majority of residential and small commercial customers by requiring retail suppliers to serve mass-market customers under contracts that either guaranteed certain customer cost savings or guaranteed a portion of retail supply from renewable energy sources. This action to limit retail competition was vacated by a state court. In late 2016, regulators in New York initiated a proceeding to determine if retail suppliers should be completely prohibited from serving their current product offerings to mass-market customers.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

The United States does not have comprehensive policies regarding the development of renewable energy. Rather, the federal government provides or has provided various targeted tax incentives and financing support programmes, while a large number of states have implemented renewable portfolio or clean energy standards and net metering, tax incentives and installation cost rebate programmes for distributed renewable generation resources. There have been a series of unsuccessful efforts by Congress to mandate a federal renewable or clean energy standard, most notably in the comprehensive greenhouse gas (GHG) cap and trade and clean energy legislation that passed in the House of Representatives in 2009. The Environmental Protection Agency also issued regulations regarding CO2 emissions from new and existing electric generating facilities (the latter referred to as the ‘Clean Power Plan’), which would limit the rate of emissions of CO2 per MWh of generation output, and the Clean Power Plan proposes in part increased generation output from renewable energy resources, as well as avoided fossil fuel-fired generation output from end-use energy efficiency measures, as compliance mechanisms. In February 2016, the US Supreme Court issued a stay, halting implementation of the Clean Power Plan pending the resolution of legal challenges to the programme in court. The new Trump administration took initial steps in early 2017 to reverse or revoke the Clean
Power Plan are expected to require regulatory actions that in and of themselves will take a year or more and are expected to be subject to legal challenges that may not be resolved before the next presidential election in 2020.

The federal government provides or has provided various tax incentives for renewable energy, including:

a. a production tax credit (PTC) (per energy generated) for wind, geothermal, biomass and some other renewable energy resources (not including solar and fuel cells) for a period of 10 years from the date the renewable energy facility is placed in service;

b. an investment tax credit (ITC) (based on qualified project costs) for a wide range of renewable energy resources (including solar and fuel cells) and for combined heat and power generation; and

c. special accelerated depreciation rules that provided five-year depreciation for a range of renewable energy resources placed in service from 2008 to 2012.

The PTC was first implemented under the Energy Policy Act (the EPAct) of 1992, and was most recently extended to include projects that commence construction prior to 1 January 2020, with a phase down in the credit amount for projects commencing construction after 31 December 2016. The ITC was first implemented under the EPAct of 2005 and was most recently extended until 2022, with a gradual step down of the credits between 2019 and 2022. The American Recovery and Reinvestment Act (ARRA) allowed taxpayers eligible for the PTC to take the ITC in lieu of the PTC for projects installed in 2009 through 2013 (2009 through 2012 for wind). ARRA also allowed taxpayers eligible for the ITC (including those taking the ITC in lieu of the PTC) to receive a cash grant from the US Treasury Department in lieu of the ITC for projects for whose construction commenced by the end of 2011, although projects not yet placed in service are subject to reduced cash grants under an automatic sequestration law that took effect in early 2013, affecting expenditures by the federal government. The federal government estimates that as of July 2012 it provided approximately $13 billion in cash grants for over 45,000 renewable energy projects, although the majority of the funding was awarded to larger wind projects.

The DOE operates various loan guarantee programmes for clean energy projects established under Title XVII of the EPAct of 2005 and ARRA, Sections 1703 and 1705. ARRA provided the DOE with guarantee authority under Section 1705 for commercial projects employing renewable energy systems, electric power transmission systems, or leading-edge biofuels, and appropriations to cover federal credit subsidy costs (i.e., loan loss reserves) of up to $2.5 billion for projects that commenced construction by 30 September 2011. Accordingly, the DOE issued approximately $16 billion in full or partial guarantees for 31 renewable energy projects (predominantly solar projects) between September 2010 and September 2011. The DOE has not closed on a loan or loan guarantee for a renewable energy project since September 2011, although the federal government reported that as of January 2013, the DOE had $2.3 billion in remaining loan guarantee authority for energy-efficiency and renewable energy projects, and was then considering using $2 billion of the remaining loan guarantee authority for loan guarantees requested by eight active applications. In December 2013, as part of the Obama administration’s Climate Action Plan, the DOE issued a solicitation making available up to $8 billion in loan guarantees under Section 1703 to support innovative advanced fossil energy projects that avoid, reduce or sequester GHGs. In February 2014, the DOE issued two loan guarantees under Section 1703 for approximately $6.2 billion to two entities involved in the development and construction of a nuclear power plant in Georgia.
July 2014, the DOE issued a solicitation making available up to $4 billion in loan guarantees under Section 1703 (made up of $2.5 billion in guarantee authority and approximately $170 million in remaining appropriations to cover credit subsidy costs) to support innovative renewable energy and efficient energy projects. In August 2015, the DOE issued supplements to this solicitation and another outstanding solicitation regarding advanced fossil energy projects to clarify both that the DOE will accept and consider applications for ‘distributed energy projects’ and that state-affiliated financial entities, including state green banks, may submit applications for eligible projects and participate in distributed energy projects as lenders or co-lenders, equity providers, or offtakers (i.e., entities purchasing the energy output of the projects).

More than half of all states and the District of Columbia have renewable energy portfolio standards or goals requiring retail electric utilities to deliver a certain amount of electricity from renewable or clean energy resources. These standards and goals vary greatly across the states, both in terms of their levels and target dates (generally between 10 per cent and 30 per cent by no later than 2020, though some states have higher target levels; e.g., 50 per cent by 2030 in California and New York, 100 per cent by 2045 in Hawaii) and what types of energy resources qualify (e.g., fuel cells, waste energy, combined heat and power (CHP), in-state versus out-of-state resources). Some states also have specific requirements or ‘carve-outs’ for specific energy resources such as solar or distributed generation. Many of these states also allow utilities to comply with their standards through the purchase of tradable renewable energy credits (though there are no national or regional markets for these credits in large part because of the significant differences among states’ standards).

More than 40 states and the District of Columbia have established net metering policies that allow retail electricity consumers who own or host distributed renewable generation resources (predominantly solar electric systems) to supply excess generation to their retail electricity supplier in exchange for credits against their retail electricity bills over 12-month and sometimes longer periods. Typically, generation resources eligible for net metering arrangements cannot be sized at levels greatly in excess of a retail consumer’s peak demand. In recent years, a number of states have taken steps to revisit or revise their net metering policies in response to concerns by retail electric utilities that crediting excess generation supplied back to them at their full retail rate did not accurately reflect the costs and benefits to their other retail customers of distributed solar electric systems being interconnected to their transmission and distribution systems. Notably, while regulators in California, the state in the United States with the largest market for distributed solar electric systems, in early 2016 retained most of the existing net metering tariff for new net metering customers, they also set in motion a process to redesign residential rates for electricity that is expected to reduce the economic attractiveness of distributed solar electric systems. In other examples, regulators in Hawaii closed the state’s largest electric utility’s net metering programme to new participants, while regulators in Nevada approved a new net metering tariff that lowered the existing retail credit and imposed higher fixed charges, including initially for existing customers, though they later restored the prior tariff for existing customers. A number of states also offer various tax incentive and rebate programmes for distributed renewable generation resources. Most notably, California provides a property tax exclusion for certain solar resources as well as installation cost rebates or performance-based payments for solar and certain other renewable resources (e.g., wind, fuel cells and CHP).

As discussed above, many of the federal tax incentive and financing support programmes have ended or will end no later than the end of 2021, though some of these
programmes could be extended by Congress, as has been the case in past years, and has been proposed in various pieces of legislation. However, given current fiscal concerns and related political disagreements over the nature and role of federal financial support for clean energy, the prospects for such legislation remain unclear. At the same time, state-based renewable portfolio standards, as well as net metering, tax incentive and rebate programmes for distributed renewable generation resources appear poised to remain in place, at least in part, for the foreseeable future (and as discussed in Section VI, infra, California not only strengthened its renewable portfolio standard during 2011, it also implemented its own GHG cap and trade programme beginning in 2012, which is intended, in part, to support greater deployment of renewable generation resources). Moreover, a number of states and local governments are actively considering establishing, and since 2011 three states and one local government, most notably the state of New York, have established, public–private partnership clean-energy financing entities, commonly referred to as ‘green banks’, to support deployment of renewable energy and energy-efficiency projects.

ii Energy efficiency and conservation

The United States has a limited set of comprehensive policies regarding promotion of energy efficiency for electric appliances and energy efficiency standards for federal buildings and properties. In addition, the federal government has various targeted grants and financing support programmes as well as tax incentives for energy efficiency investments. Moreover, as discussed above, the Environmental Protection Agency’s Clean Power Plan proposes in part avoided fossil fuel-fired generation output from end-use energy efficiency measures as a means to comply with proposed limits on CO2 emissions from existing generating facilities.

A large number of states have similar types of programmes (many of which are supported in whole or in part by funds provided by the federal government) and a large number of states have energy efficiency portfolio standards, similar in concept to a renewable energy portfolio standard, that require retail electric utilities to reduce their total retail sales, peak retail sales, or both, by certain amounts by target dates. Some states combine their renewable and energy efficiency portfolio standards. A number of states have also combined their energy efficiency portfolio standards with retail utility rate ‘decoupling’ policies to allow utilities to recover of and on their fixed costs regardless of reduced retail sales resulting from energy saving efforts. Certain states have implemented or will soon implement financing support programmes for end-use energy efficiency investments, including ‘on-bill’ financing or repayment programmes that allow retail utilities or third parties to finance the full cost of end-use efficiency investments for a retail utility customer and then recover of and on these investments through special charges included on the customer’s retail utility bill. A similar type financing arrangement is possible under federally authorised property-assessed clean energy (PACE) bonding authority for local governments, which use PACE bond proceeds to finance the upfront costs of energy efficiency investments in homes and small businesses and have the loans secured by an annual assessment on the home or business property tax bill, although this programme has so far generally been limited to commercial properties because of federal home mortgage insurance policies.
VI THE YEAR IN REVIEW

i Electricity

Over the past several years, the US electricity industry has evolved to become more dependent on natural gas caused by relative decreases in natural gas prices along with increasing environmental regulations under various federal laws leading to coal plant retirements. In addition, the increasing rate of penetration of intermittent renewable generation resources often requires natural gas fueled generation as a reliability backstop. The increasing reliance on natural gas for electricity generation, together with severe weather experiences across the United States in recent years, have continued to put pressure on the existing natural gas transportation infrastructure and highlighted several issues with respect to how the natural gas and electric industries interact. After several years of technical conferences and public comments on these issues, in April 2015, FERC issued Order No. 809, entitled 'Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities', adopting proposals submitted by an industry forum to modify the scheduling practices used by interstate natural gas pipelines to schedule natural gas transportation service and provide additional contracting flexibility to firm natural gas transportation customers through the use of multiparty transportation contracts and revised nomination timelines. FERC also directed each FERC-jurisdictional RTO and ISO to propose tariff revisions to coordinate its day-ahead energy market with the scheduling practices adopted in Order No. 809 or to show cause why its existing scheduling practices need not be changed.

As noted above, FERC’s Order No. 1000 adopted significant reforms of FERC’s transmission planning and cost-allocation rules established previously in Order No. 890. Order No. 1000 sought to address significant recent changes in the bulk power industry, including an increased emphasis on integrating renewable generation and reducing congestion, by implementing new policies to push transmission providers and planners to seek the most reliable, efficient and cost-efficient solutions. The major reforms of Order No. 1000 include:

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;
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. FERC required public utility transmission providers to begin making filings with FERC during 2012 that proposed revisions to their transmission planning processes under their respective OATTs to comply with Order No. 1000. Throughout 2013, FERC issued orders regarding some of these compliance filings in which it accepted and rejected various proposed revisions, including rejecting a number of proposals to retain certain types of rights of first refusal for incumbent transmission providers to build-and-own transmission projects eligible for socialised cost recovery. Various aspects of Order No. 1000, including its directives on cost allocation and rights of first refusal,
were appealed to the US Court of Appeals for the District of Columbia (DC Circuit). In August 2014, the DC Circuit issued a unanimous decision affirming Order No. 1000. FERC continues to face significant challenges regarding Order No. 1000, its cost allocation principles and the implementation of those principles.

FERC's Order No. 745 was adopted in 2011 to encourage demand responsiveness through market pricing mechanisms. In Order No. 745, FERC required that the RTO energy markets adopt market rules that treat demand reduction (i.e., ‘megawatts’) in the same way as generation supply alternatives (i.e., megawatts (MW)) for the purpose of bidding into the energy markets; however, the RTOs were still given flexibility as to how to implement these market incentives. 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 Order No. 745 exceeds FERC's jurisdiction under the FPA, as it seeks to regulate retail sales of electricity by requiring 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 Order No. 745 because demand response is part of the ‘retail market’, which is exclusively within the states’ jurisdiction to regulate. In January 2016, the Supreme Court issued a decision upholding Order No. 745 and FERC’s ‘affecting’ jurisdiction under the FPA to regulate demand response transactions in the wholesale markets. The Supreme Court held that RTOs' payments for demand response commitments directly affect wholesale rates and that in addressing demand response practices, FERC has not transgressed its jurisdictional boundary by regulating retail sales. The Supreme Court also approved a ‘common-sense construction’ of the FPA's language, previously adopted by the DC Circuit, that FERC’s affecting jurisdiction is limited ‘to rules or practices that “directly affect the [wholesale] rate”’ (emphasis in original).

Following severe weather in 2013–2014 in the eastern portion of the United States, when demand was high and generation supply was unavailable for a variety of reasons, both the ISO-New England and PJM sought to improve generator reliability during these periods by significantly revising their forward capacity markets. ISO-New England’s new capacity market rules, referred to as ‘performance incentive’ or ‘pay for performance’ were adopted in 2014, and PJM’s proposal, referred to as ‘capacity performance’, was adopted in June 2015. All capacity resources that clear ISO-New England’s market became subject to pay for performance requirements beginning with the delivery year that commences in June 2018. All capacity resources that clear the PJM market will be subject to capacity performance requirements beginning with the delivery that commences in June 2020. Both programmes eliminate most of the excuses for non-performance during a delivery year and increase the penalties for non-performance, as well as the financial assurances required to be posted by proposed generating facilities.

In October 2015, the Supreme Court agreed to hear a federal pre-emption case involving the effort by some states to subsidise the construction of new electric generating facilities through long-term power purchase arrangements mandated by the states. In those cases, the states’ load-serving entities were participants in PJM’s capacity market, and the subsidised generating facilities would receive the out-of-market compensation conditioned on their clearing the PJM capacity market. This issue came to the Supreme Court as a result of litigation in 2013 and 2014 before lower federal courts that held that procurement programmes in Maryland and New Jersey for the construction of new generation capacity
violated the Supremacy Clause of the US Constitution because they impermissibly intruded on FERC’s exclusive jurisdiction under the FPA over wholesale sales (i.e., sales for resale, including PJM’s capacity market). The case involving the Maryland procurement programme was decided by the US Court of Appeals for the Fourth Circuit (the Fourth Circuit), while the case involving the New Jersey procurement programme was decided by the US Court of Appeals for the Third Circuit (the Third Circuit). In April 2016, the Supreme Court issued a decision affirming the Fourth Circuit’s decision holding that ‘Maryland’s program sets an interstate wholesale rate, contravening the FPA’s division of authority between state and federal regulators’. The Supreme Court further provided that ‘States may not seek to achieve ends, however legitimate, through regulatory means that intrude on FERC’s authority over interstate wholesale rates, as Maryland has done here.’ At the same time, the Supreme Court provided that its holding was ‘limited’ and need not and did not ‘address the permissibility of various other measures States might employ to encourage development of new or clean generation, including tax incentives, land grants, direct subsidies, construction of state-owned generation facilities, or re-regulation of the energy sector’. Shortly after issuing its decision affirming the Fourth Circuit striking down Maryland’s programme, the Supreme Court declined to review the Third Circuit decision striking down New Jersey’s programme.

At the state level, during 2016 a few states continued efforts to consider the restructuring or transformation of the distribution and use of electricity at the retail level, including efforts to accommodate or encourage the greater deployment of distributed energy resources – distributed generation and storage, demand response, and end-use energy efficiency. Most notably, regulators in New York continued their efforts to implement their ‘Reforming the Energy Vision’ (REV) initiative, that calls for ‘animating markets’ at the distribution level so that retail customers and third parties (e.g., energy service companies, retail suppliers, demand-management companies) can monetise the economic values that distributed resources can provide to the overall electric system in New York. This initiative also tasks the electric distribution utilities in New York with acting as ‘distributed system platform’ providers, who together will furnish a state-wide platform that will deliver uniform market access to retail customers and distributed energy resource providers, and who will also act as an interface between customers at the distribution level and the NYISO. As part of this initiative, regulators also directed the electric distribution utilities to propose demonstration projects involving third-party market participants and demonstrating business models and customer engagement for distributed energy resources and to propose a ‘Distributed System Implementation Plan’. In a series of proceedings, regulators in New York are considering a wide range of issues relating to the REV initiative, including changes in their ratemaking practices for the electric distribution utilities, establishment of a new benefit–cost framework for electric distribution utility expenditures on investments in distributed system platforms, procurement of and compensation for distributed energy resources, and energy efficiency programmes, development of community distributed generation and retail choice aggregation, changes in net metering programmes, a reassessment of New York’s approach for encouraging the deployment of large-scale renewable energy generation, the development of a $5 billion ‘Clean Energy Fund’ that will in part support the New York Green Bank and a solar electric incentive programme, and the development of a ‘Clean Energy Standard’ to succeed New York’s RPS (which expired at the end of 2015) that requires that 50 per cent of the electricity consumed in New York to come from clean energy sources by 2030. Regulators have indicated that changes in their ratemaking practices for electric distribution utilities should result in utility earnings that depend on a utility’s success in creating value for its
customers and achieving regulatory policy goals, such as increased deployment of distributed energy resources and reduced emissions of GHGs, and they have pointed to the ‘RIIO’ or ‘revenue equals incentives plus innovation plus outputs’ framework used by regulators in Britain as a possible model.

Relating to the Clean Energy Standard, regulators in New York also established a ‘Zero Emission Credit’ (ZEC) compensation mechanism to subsidise the continued operation of certain existing nuclear generation facilities in New York that face competitive difficulties in the NYISO markets. Regulators in New York concluded that the continued operation of these facilities is necessary for New York to achieve its clean energy policy goals. Legislators in Illinois established a somewhat similar ZEC compensation mechanism directed at certain existing nuclear generation facilities in Illinois that face competitive difficulties in the PJM and MISO markets. Both the New York and Illinois programmes take into consideration the revenues that existing nuclear facilities receive in the energy and capacity markets in the determination of the ZEC payment. Legislators and regulators in other states in the United States are considering similar types of compensation mechanisms, though, as of early 2017, the compensation mechanisms in New York and Illinois are being challenged both in federal courts on constitutional grounds relating to federal pre-emption under the FPA and as being in violation of the dormant commerce clause and before FERC on grounds relating to the continuing lawfulness under the FPA of forward capacity market rules in the NYISO and PJM. FERC is considering mechanisms to include carbon pricing (or other mechanisms to implement state policy goals) in an RTO bid-based market.

On 1 June 2017, President Trump announced that he planned to have the United States withdraw from the Paris Agreement.

ii Natural gas and fossil fuel liquids pipelines, LNG terminals and rail transportation of crude oil

As gas production in the United States has grown dramatically in recent years, the interstate pipeline industry has proposed and constructed, with the approval of FERC, large amounts of new infrastructure to serve the new production and transport the gas to markets. In 2016, for instance, FERC certificated approximately 17.6 billion cubic feet per day of new pipeline capacity. Pipeline certificate proceedings have increasingly been heavily contested, with significant opposition to many projects from certain environmentalist organisations. These organisations have challenged projects at FERC and, in many cases, appealed FERC’s rulings to the courts.

In June 2014, the DC Circuit ruled that the FERC had violated the National Environmental Policy Act of 1970 (NEPA) by improperly ‘segmenting’ its review of four proposed expansions of the pipeline system of Tennessee Gas Pipeline Company in the northeastern United States. FERC regarded the proposed expansions as four separate projects because each resulted in a measurable increase in the pipeline’s overall capacity and therefore provided substantial independent utility. The individual proposed projects were reviewed individually by the FERC and then constructed in rapid succession between 2010 and 2013. The DC Circuit found that the projects were ‘physically, functionally, and financially connected and interdependent’ and should all have been reviewed by the FERC at the same time as ‘connected’ projects under NEPA, and that the FERC should have considered the ‘cumulative impacts’ of all four projects together before approving any one of them. The DC Circuit remanded the case, which involved one of the already built and operating segments, to FERC, but it did not vacate FERC’s order. This decision allowed the pipeline segment
to continue to operate while FERC supplemented its environmental analysis. On remand, FERC conducted a supplemental environmental review and reaffirmed its approval of the challenged pipeline project. The DC Circuit’s decision is significant in three respects: (1) although challenged many times, FERC had not previously lost an appeal of a natural gas pipeline case under NEPA; (2) the decision creates uncertainty as to when proposed pipeline projects must be reviewed together, as many proposed projects affect other proposed projects; and (3) the court allowed the pipeline to operate despite its finding that FERC had violated NEPA.

In recent years, FERC continued to approve new rights for committed shippers on new and expanded pipelines that transport oil and other liquid fossil fuels who participate in an open season process. FERC allowed these shippers to receive priority to subscribe to future available capacity or future expansion projects following the open season. FERC also approved tiered rates for shippers based on the size of their acreage dedications. Other FERC orders, however, reinforced the limits of FERC’s flexibility, such as orders denying priority service to shippers who enter into contracts after (but not during) an open season, and refusing to pre-approve uncommitted shipper rates for new and expanded pipelines unless pursuant to a formal rate filing made shortly before service commences. In 2015, FERC also determined that the transportation by pipeline of denatured fuel ethanol in interstate commerce is subject to its jurisdiction.

In July 2016, the DC Circuit issued a decision that could have broad rate implications for the interstate pipeline industry. In United Airlines v. FERC, 827 F3d 122 (DC Cir 2016), the DC Circuit sided with pipeline shippers who challenged FERC’s income tax allowance policy. FERC’s income tax allowance policy, which has been in place since 2005, allows partnerships and other pass-through entities that hold interests in regulated oil and natural gas pipelines to include in rates an income tax allowance if their partners or members have actual or potential income tax obligations on the partnership’s or other pass-through entity’s income. In United Airlines, the DC Circuit concluded that FERC had acted arbitrarily and capriciously when it permitted the pipeline in question to include an income tax allowance in its rates, because FERC had failed to demonstrate that its income tax allowance policy together with its use of a discounted cash flow methodology to determine return on equity would not permit the pipeline’s limited partnership owners to double-recover their income taxes through the pipeline’s rates. The DC Circuit vacated FERC’s orders authorising the pipeline’s rates, and remanded the case to FERC for further proceedings. In its decision, the DC Circuit made clear that FERC is free to continue to provide partnerships and other pass-through entities with an income tax allowance if it either provides a sufficient explanation that its current policy does not result in double-recovery of taxes for such entities, or takes another approach to assure there is no double-recovery. In response to the United Airlines decision, FERC issued a Notice of Inquiry in December 2016 seeking input from industry participants on how to address any double-recovery resulting from its current income tax allowance policy and policies regarding the derivation of return on equity. FERC has received two rounds of comments in response to the Notice of Inquiry. Depending on how FERC rules on the issue on remand, its decision could have a significant impact on the rates charged by interstate oil and natural gas pipelines that are organised as partnerships or other pass-through entities.

Since 2013, FERC has approved the construction and operation of 10 large-scale LNG terminals, nine for the export of LNG produced from natural gas originating in the continental United States and one for the import of LNG to the Commonwealth of Puerto Rico. One
of these projects completed its first phase of construction and commenced commercial operation in early 2016, making it the first facility to export LNG to overseas markets from the lower 48 United States. In total, six LNG export projects are under construction (including expansions of existing facilities or construction of new facilities). Three approved projects have yet to begin construction. In 2017, the Maritime Administration approved the first proposed floating liquefaction LNG export project pursuant to the Deepwater Port Act.

Several of the FERC orders approving these LNG projects were appealed to the DC Circuit. These appeals concerned both project-specific issues and common issues regarding FERC’s NEPA review as related to more general, ‘indirect’ and ‘cumulative’ environmental impacts asserted by some environmental non-governmental organisations. Among the common issues were claims that approval of new LNG terminals will induce additional US natural gas production for export, thereby increasing demand for natural gas and increasing its price in the US, resulting in the increased use of coal rather than natural gas to generate electricity. Environmental groups also asserted that approval of LNG exports would contribute to increased GHG emissions. 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 effects of the LNG exports, in part because the DOE has sole authority to authorise the export of natural gas and LNG. The DC Circuit also held that FERC adequately considered the environmental effects of the LNG terminals, together with any other past, present or likely future actions in the same geographic area. FERC was not obligated to consider the cumulative effects of other LNG terminals nationwide that either had been recently approved or whose applications for approval were still pending.

In early 2016, FERC denied the applications to construct the Jordan Cove LNG export terminal in southwest Oregon and the related Pacific Connector Pipeline. FERC found that the proponents of the Pacific Connector Pipeline had presented only general evidence as to natural gas demand in an effort to prove a need for the pipeline, but no evidence of subscriptions for its services. In the absence of more tangible evidence, FERC determined that the project was not in the public interest because the proven benefits of the project did not outweigh the detriment to approximately 630 landowners, including 54 intervenors, whose property would be disturbed by the pipeline. FERC also determined that the LNG export terminal is not feasible without the pipeline. The project’s proponents sought rehearing (essentially reconsideration) of FERC’s order, which FERC denied.

The DOE has authorised nine large-scale LNG projects to export LNG to all countries not specifically prohibited from receiving LNG from the United States (i.e., countries not subject to United States trade sanctions), including countries without free trade agreements to which the United States is a party, that require national treatment for trade in natural gas (non-FTA countries). DOE issued such a non-FTA export authorisation in April 2017 that followed its prior precedent, indicating that there was no change in policy with the new administration. Numerous other companies that have proposed to develop LNG export projects have applied to FERC and the DOE for similar authority and their applications are pending. Challenges to many of the DOE’s orders authorising exports of LNG to non-FTA countries are pending before the DC Circuit and should be decided in 2017.

In August 2014, the DOE announced a change in its policy regarding the processing of export applications to streamline its process by linking the timing of its final action on an application to follow the completion of environmental reports by FERC and other agencies. The DOE also issued reports supplementing the environmental analysis of LNG export
terminals, including an analysis of the effect of LNG exports on GHG emissions and a new study of the estimated economic consequences of LNG exports (up to the equivalent of 20 billion cubic feet of natural gas per day or approximately 168 million tonnes per year) that found that such additional exports would be marginally beneficial to the US economy. In September 2014, the DOE issued a notice of change in its procedures for changes in control affecting applications and authorisations to export or import natural gas. The new procedures allow for authorisation holders to file a notice or statement of a change in control within 30 days after such a change in control has occurred. For changes in control related to existing authorisations or pending applications for authorisations to export to non-FTA countries, the DOE will consider properly submitted protests of such changes in control but the DOE will take no action unless it determines that the change in control renders the underlying authorisation at issue inconsistent with the public interest.

Presidential Permits are required for the construction and operation of facilities that cross the international borders of the United States, including facilities for the transmission or transportation of electricity, natural gas, crude oil and petroleum products between the United States and Canada or Mexico. The authority to issue Presidential Permits has been delegated by the President to the Secretary of Energy for electricity, the FERC for natural gas and the Secretary of State for crude oil and petroleum products. Historically, there has been little controversy about the issuance of Presidential Permits, and more than 100 cross-border energy facilities were in operation as of 2015. FERC and the Secretary of Energy, acting through the DOE, have continued to receive and, after consultation with the Secretary of Defense and the Secretary of State, approve Presidential Permits for natural gas and electricity facilities in the ordinary course. At the Department of State, however, the Presidential Permit process for the Keystone XL pipeline has not followed a similar pattern. The Keystone XL pipeline is intended to transport heavy crude oil and diluted bitumen produced from Western Canadian oil sands and light crude oil produced in the Bakken shale formation (the Bakken) in the United States to refineries in the US Midwest. Much of this oil is transported by rail today. An application for a Presidential Permit for the Keystone XL pipeline was filed with the Department of State in May 2012; however, the application was strongly opposed by environmental groups and the Secretary of State in the Obama administration did not issue a decision on the then-pending application. In February 2015, Congress passed a bill approving the Keystone XL project and deeming all statutory environmental requirements to have been satisfied. However, President Obama vetoed the bill, and a vote to override that veto in the US Senate failed in March 2015. In November 2015, the Secretary of State in the Obama administration denied the application for the Presidential Permit for the Keystone XL pipeline, finding that the pipeline would only marginally benefit the US economy and energy security, but would ‘significantly undermine [the United States’] ability to continue leading the world in combating climate change’. In March 2017, the State Department in the new Trump administration reversed course and granted the application for the Presidential Permit for the Keystone XL pipeline, making a determination that issuance of the Presidential Permit ‘would serve the national interest’. Despite the State Department’s issuance of the Presidential Permit, many regulatory and legal steps remain for the Keystone XL pipeline. The Presidential Permit grants permission to ‘construct, connect, operate and maintain’ the pipeline facilities at the international border between the US and Canada, and therefore applies to only 1.2 miles of pipeline. The remaining miles of Keystone XL pipeline in the US have to be approved by various other regulatory bodies, including state regulatory bodies in Montana, South Dakota and Nebraska, before construction can commence. At the time
of publication, Montana and South Dakota have issued approvals for construction of their respective segments of the pipeline, but consideration of the Keystone XL pipeline by the Nebraska Public Service Commission is still under way, with fierce opposition from Nebraska farmers and landowners. Litigation is likely in connection with each of these regulatory decisions, and may potentially further delay the construction of the Keystone XL pipeline.

In January 2017, President Trump signed a Presidential Memorandum directing the Secretary of Commerce, in consultation with all relevant executive departments and agencies, to develop a plan under which all ‘new pipelines, as well as retrofitted, repaired or expanded pipelines, inside the borders of the US’, use materials and equipment produced in the US ‘to the maximum extent possible and to the extent permitted by law’. The Presidential Memorandum directed the Secretary of Commerce to submit such a plan within 180 days of the date of the memorandum. As of the date of publication, the Secretary of Commerce has not submitted such plan. In March 2017, the White House clarified that the Presidential Memorandum will not apply to the Keystone XL pipeline, because the Keystone XL pipeline does not constitute a ‘new’ pipeline under the Presidential Memorandum.

In response to a series of highly publicised accidents involving trains carrying crude oil from the Bakken, including the July 2013 derailment of a 72-car train carrying Bakken crude oil that resulted in 47 fatalities and extensive property damage in Lac-Mégantic, Quebec, US federal and state regulators have taken numerous steps to improve the safety of the rail transportation of crude oil. The North Dakota Industrial Commission issued new conditioning standards in December 2014 that among other matters established operating standards for crude oil conditioning equipment and prohibited operators from blending lighter hydrocarbons into crude oil before shipment. PHMSA and the Federal Railroad Administration (FRA) have proposed or undertaken a range of additional regulatory actions aimed at increasing the safety of rail transportation of hazardous materials, including the transportation of crude oil by rail. PHMSA and the FRA issued a comprehensive final rule in May 2015 that includes more stringent construction standards for rail tank cars built after 1 October 2015. Depending on the type of tank car, existing tank cars must be replaced or retrofitted within three or five years. The final PHMSA/FRA rule also includes mandates for using advanced braking and performing routing analyses, and makes permanent the provisions of an emergency order issued by DOT in April 2015 imposing a speed limit of 40mph in ‘high-threat’ urban areas for crude oil trains containing at least one older-model tank car. The speed limit for all other crude-by-rail service will be restricted to 50mph, in line with the speed limit railroads voluntarily adopted in 2013. The final rule requires sampling and testing programmes for all unrefined petroleum-based products, including crude oil, and certifications that hazardous materials subject to the programme are packaged in accordance with the test results, but does not require oil companies to process their products to make them less volatile before shipment, as has been proposed by certain safety advocates.

PHMSA also regulates the safety of pipelines and, following several pipeline accidents, has adopted more stringent safety standards for pipelines. Under agreements with certain state agencies, PHMSA allows the state agencies to administer federal safety standards for interstate pipelines. States are permitted to adopt stricter standards for state-regulated pipelines and several have done so in recent years. Effective as of 25 October 2013, PHMSA adopted new rules increasing the maximum administrative civil penalties for violation of the pipeline safety laws and regulations after 3 January 2012 to $2 million for a related series of violations. State agencies have imposed even greater penalties. In April 2015, the California Public Utilities Commission approved the largest penalty it has ever assessed
by ordering Pacific Gas & Electric Company (PG&E) shareholders to pay $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). The PG&E case was tried in federal district court during the summer of 2016. In August 2016, the jury in the federal district court case found PG&E guilty of five felony counts of violating the PSA and one felony count of obstructing a federal investigation. In sentencing proceedings in January 2017, the federal district court ordered the company to pay a maximum fine under the PSA of $3 million, placed the company on probation for five years, ordered the company to complete 10,000 hours of community service (including 2,000 hours by high-level personnel), and ordered the establishment of a court-appointed monitor. Congress passed legislation in 2016 amending the PSA and reauthorising PHMSA’s pipeline safety programme through 2019. However, the legislation did not revise the standard for criminal liability under the PSA for pipeline safety violations, despite some senior DOT officials advocating a lower liability standard – from ‘knowingly and wilfully’ to ‘recklessly.’

Meanwhile, PHMSA continues to review and revise its existing pipeline safety standards. Among its most significant recent regulatory proposals are two companion rules addressing pipeline safety and integrity, one applicable to hazardous liquid pipelines (which include crude oil and natural gas liquids pipelines) and another applicable to natural gas pipelines. The October 2015 proposal governing hazardous liquid pipelines would have extended existing integrity management requirements to previously-exempt pipelines and would have imposed additional obligations on hazardous liquid pipeline operators that are already subject to existing integrity management requirements. The proposal would also have required operators to evaluate annually the protective measures they have implemented on pipeline segments that operate in ‘High Consequence Areas’ where pipeline failures have the highest potential for human or environmental damage, would have established shorter repair timelines for critical pipeline repairs, and would have tightened the standards for pressure tests. PHMSA issued a final rule in January 2017, just prior to inauguration of the newly elected US president. The final rule modified certain aspects of the proposed rule to address concerns expressed by the regulated industries during the comment period, but retained key aspects of the rule regarding expanded inspection, leak detection, and reporting requirements. The rule was withdrawn in late January 2017.

In April 2016, PHMSA published proposed revisions to its pipeline safety regulations applicable to onshore natural gas transmission and gathering pipelines. The proposed rule would significantly broaden the scope and strength of PHMSA’s safety regulations by adding new assessment and repair criteria for natural gas transmission pipelines and by extending such protocols to pipelines located in newly designated ‘Moderate Consequence Areas’ where an incident would pose a risk to human life. In addition, the proposed rule would, among other things, modify assessment and repair criteria for pipelines inside and outside High Consequence Areas, provide additional direction to pipeline operators on how to evaluate internal inspection results, expand mandatory data collection and integration requirements for integrity management, and require a systematic approach for verifying a pipeline’s maximum allowable operating pressure (MAOP) and reporting of MAOP exceedances. The April 2016 proposal would also revise the definition of gathering lines, and repeal an exemption for natural gas gathering line reporting requirements. In January 2017, the Gas
Pipeline Advisory Committee convened the first of at least two meetings to discuss the proposed revisions, which would extensively modify Part 191 and Part 192 of the federal pipeline safety regulations applicable to gas transmission and gathering pipelines. The final rule is expected later in 2017.

Responding to the high-profile leak of methane gas from the Southern California Natural Gas Company’s Aliso Canyon/Porter Ranch underground storage field in October 2015 and calls from the Obama administration to act, PHMSA issued an Advisory Bulletin in February 2016 addressing the operation of underground storage facilities used for the storage of natural gas. In the Advisory Bulletin, PHMSA recommended that all operators of underground natural gas storage facilities have processes, procedures, mitigation measures, periodic assessments and reassessments, and emergency plans in place to maintain the safety and integrity of all wells and associated storage facilities, whether those facilities are operating, idled, or plugged. PHMSA specifically instructed operators to review their operations to identify the potential for leaks and failures caused by corrosion, chemical damage, mechanical damage or other material deficiencies in piping, tubing, casing valves, and associated facilities.

On 22 June 2016, the US Congress enacted the Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2016. Among other things, the act required PHMSA to issue, within two years, minimum safety standards for underground natural gas storage facilities. In addition, the PIPES Act allowed states to adopt more stringent safety standards for intrastate facilities, if such standards are compatible with the minimum standards prescribed in the Act. On October 14, a federal interagency task force convened to study the issue and released a final report and fact sheet on underground natural gas storage regulation. The task force was co-chaired by the DOE and PHMSA, and included members from numerous federal, state, and local government agencies. The report included 44 recommendations regarding well integrity, public health and environmental effects, and energy reliability. On 19 December 2016, as required by the Act, PHMSA published an interim final rule that revised existing federal pipeline safety regulations related to downhole facilities, including wells, wellbore tubing, and casing at underground natural gas storage facilities. The interim final rule also incorporated certain recommended practices of the American Petroleum Institute into PHMSA’s federal safety standards, including practices applicable to the design and operation of solution-mined salt caverns used for underground storage, and practices applicable to the functional integrity of natural gas storage in depleted hydrocarbon reservoirs and aquifer reservoirs. The interim final rule also requires that operators of underground natural gas storage facilities file annual reports, obtain operator identification numbers, and file incident and safety-related reports. The interim final rule also applies to intrastate storage facilities, and requires states to update their safety regulations to include the specified recommended practices. The interim final rule became effective on 18 January 2017, and owners and operators are expected to implement the new requirements by 18 January 2018.

The state of Texas and two natural gas and pipeline industry trade associations have filed separate petitions for review of PHMSA’s interim final rule, which are pending at the US Court of Appeals for the Fifth Circuit and the DC Circuit. Texas contends that the interim final rule impermissibly overrides the state’s authority to regulate intrastate underground natural gas facilities, while the trade associations challenge the timeframes for implementation
and certain technical aspects of the interim final rule. In April 2017, PHMSA announced the user fee requirements that will apply to operators of underground storage facilities in order to fund federal and state safety and oversight activities.

**VII CONCLUSIONS AND OUTLOOK**

Energy regulation in the United States remains complex and multilayered and will continue to evolve for the foreseeable future. Competing economic and political interests (including effects on ratepayers and taxpayers, and state policy initiatives aimed at increased deployment of clean energy resources and decreased GHG emissions) cause conflict surrounding jurisdictional issues, energy security, transmission system planning, cost allocation, renewable development and integration and many other issues. The variety of energy industry participants and regulators, as well as the geographical differences across the United States, can provide an opportunity for the development of innovative policies, but such heterogeneity may also lead to disjointed or overlapping regulatory obligations and may ultimately undermine the development of a uniform national energy policy.
Appendix 1

ABOUT THE AUTHORS

MASOOD AFRIDI
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Masood Afridi is a partner at Afridi & Angell specialising in the areas of infrastructure and project finance, corporate and commercial law, and energy law.

After working as an associate at the New York offices of the law firm of Sidley & Austin, he joined the Dubai office of Afridi & Angell in 1993. For several years, he has been a frontrunner in Pakistan’s energy sector, and has participated in the development of numerous thermal and hydroelectric power projects in the country. He has also been nominated from time to time to resolve other global issues with power purchasers on behalf of the industry.

Acting in the capacity of project developer’s lead counsel, Mr Afridi has concluded transactions with a cumulative value of over US$4 billion, spread over several project finance transactions.

Mr Afridi has an LLM in international business and trade law from Fordham University (1990) and an LLB from the University of Bristol. At Fordham University, Mr Afridi received the Edward J Hawke Prize for graduating with the highest grade point average in his class.

PASCAL AGBOYIBOR
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Pascal Agboyibor is a partner and a member of the Orrick, Herrington & Sutcliffe energy and infrastructure group. He currently advises lenders, governments and investors on major energy, mining and infrastructure projects in Africa.

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Rashi Ahooja is a senior associate in the Energy, Resources and Infrastructure team of Trilegal. Her principal area of practice is conventional energy projects. She has primarily advised conventional energy power generators on tariff-based competitively bid projects and related power purchase agreements. She has also advised on regulatory issues concerning coal linkages, land acquisition and acquisition of interest in existing power plants.
ADITE ALOKE
_Afridi & Angell_

Adite Aloke is an associate at Afridi & Angell. Her practice focuses on energy and infrastructure and project finance. She has extensive experience in advising on the development of renewable energy projects in India as well as on public-private partnerships. Ms Aloke was an associate with a leading law firm in India prior to joining Afridi & Angell in 2013. She spent two years at Afridi & Angell then rejoined the firm in 2016 after working with another leading law firm in India. Ms Aloke holds an LLB from Amity Law School, Guru Gobind Singh Indraprastha University, in India (2009).

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Ricardo Andrade Amaro joined the firm in 2002 and became a partner in 2015. He is a member of the corporate and commercial and capital markets team. He has extensive experience in corporate and commercial law and securities law, as well as in energy law.

In the area of corporate and commercial law, he has acted as legal adviser in several mergers, restructurings, acquisitions and sales of companies, on behalf of domestic and foreign clients.

He has also acted as legal adviser in the setting up of several initial public offers, including the largest initial public offer ever made in Portugal and the largest in Europe during 2008, and also in the structuring of several public share takeover bids.

In the area of energy law, he was involved in the reorganisation of the national energy sector in 2003 and 2004. Recently, he acted as a legal adviser in the setting up of securitisations made in Portugal regarding the right to receive amounts arising from tariff adjustments. He regularly acts as legal adviser in regulatory matters related to the energy sector.

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Ankur Arora is an associate in the Trilegal energy, resources and infrastructure team. His principal area of practice is renewable energy based power projects in various states in India. He has primarily advised renewable energy power generators on developing projects under various state and central policies, tariff-based competitively bid projects and related power purchase agreements.

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Pelumi Asiwaju is an associate in the law firm of G Elias & Co. She holds a degree in law from the University of Lagos, Akoka, and a first-class honours degree from the Nigerian Law School.

She has been involved in several of the firm’s oil and gas and energy deals, including advising syndicate of lenders on financing the development of wells in OMLs held by NNPC and Chevron Joint Venture. Her practice areas include energy, oil and gas, real estate and construction and capital markets.
FARIZ ABDUL AZIZ

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Fariz Abdul Aziz is an energy partner in the corporate department of Skrine. Fariz’s main area of focus is on cross-border mergers and acquisitions, energy, oil and gas, takeovers, private equity investments, and corporate restructurings. Fariz represents leading foreign multinationals on inward bound transactions and divestments. Fariz has also recently been advising Malaysian entities on their outward investment. Fariz was also appointed as facilitator for the Corridors and Cities Lab under the Performance Management and Delivery Unit (PEMANDU) of the Prime Minister’s Department, covering the manufacturing and oil, gas and petrochemical Entry Point Projects in Malaysia’s East Coast Economic Region. This project forms part of the government of Malaysia’s Economic Transformation Programme, which aims to make Malaysia a high-income nation by 2020.

DOUX DIDIER BOUA

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Doux Didier Boua is a senior associate in the Orrick, Herrington & Sutcliffe energy and infrastructure group. His practice focuses on corporate, finance, commercial and regulatory advice within the energy sector, including mining, oil and gas and power projects in Africa.

SALEM CHALABI

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Salem Chalabi, an Iraqi national and a lawyer, has been a corporate and projects partner at Stephenson Harwood LLP since June 2014.

Mr Chalabi is a graduate of Yale University (BA), Columbia University (MA) and the Northwestern University School of Law (JD). He has practised law with international law firms Morgan Lewis (in New York), Clifford Chance (in London) and DLA Piper (in Dubai). He is also a member of the New York Bar.

In 2003, Mr Chalabi was a deputy member of the Interim Governing Council of Iraq, and a member of the finance and legal committees. In such roles, he was responsible for drafting a large number of orders and laws, in conjunction with the Coalition Provisional Authority. In addition, in 2004, he was one of two Iraqis who drafted the Transitional Administrative Law (the Interim Constitution), which was the basis of the permanent constitution adopted in 2005.

Mr Chalabi represents various Iraqi government ministries, including the Ministry of Electricity. In this capacity, he has been very closely involved in various developments relating to the Ministry. Mr Chalabi also advises international oil companies in Iraq, as well oil services companies and Iraq’s largest private company (a licensed mobile telecoms operator).

KRZYSZTOF CICHOCKI

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Krzysztof Cichocki specialises in significant energy, natural resources, infrastructural and industrial projects. He also represents energy-sector companies before courts in regulatory and access-right matters. He has been with SK&S since 1998 and became a partner at the firm in 2009. He is a graduate of the Adam Mickiewicz University in Poznań, where he obtained
his Master of Laws degree in 1997. In the years 1997–1998 he completed postgraduate studies at the Asser Institute in The Hague and at the Central European University, where he obtained his Master of Laws (LLM) degree in international business law, accredited by the University of the State of New York. He practices as a legal counsel. He is fluent in English.

ANDREINA DEGLI ESPOSTI

Studio Legale Villata, Degli Esposti e Associati

Born in Bologna in June 1960, Andreina Degli Esposti graduated *magna cum laude* in law from the University of Bologna in February 1984. She also studied at the University of Münster and was admitted to the bar in 1986. She has been involved in research and lecturing in the Department of Constitutional Law at the University of Bologna and the Departments of Administrative Law at the Universities of Milan and Pavia, thus publishing various essays and contributing to entries in legal encyclopaedias.

Throughout the course of her practice – which covers both judicial (predominantly before the regional administrative courts and the council of state) and extrajudicial (stipulating agreements with public administrations and providing advice in the administrative areas of M&A and joint ventures) work – she has gained expertise in the sectors of energy, public procurement (also concerning the German legal system), environment, telecommunications and town-planning, including the drafting of general planning regulations. She also has extensive experience as member of arbitration panels. She is currently involved in the professional network of the online administrative law review GiustAmm.it.

*Chambers Europe* and *The Legal 500* place her among the most prominent Italian lawyers in the field of public law.

OKAN DEMIRKAN

Kolcuoğlu Demirkan Koçaklı Attorneys at Law

Mr Okan Demirkan currently leads the firm’s energy and dispute resolution practices.

Between 2004 and 2010, Mr Demirkan was heavily involved in all legal issues surrounding the Baku–Tbilisi–Ceyhan Crude Oil Pipeline Project (BTC), where he played a key role in real estate, corporate, employment, litigation and regulatory issues. In addition to BTC, Mr Demirkan advised clients in connection with the Nabucco gas pipeline and the Samsun–Ceyhan oil pipeline.

In 2011, Mr Demirkan took an active role in the Shah Deniz Stage 2 natural gas pipeline project, where he led the KDK team advising on the project’s legal structure in Turkey, including intergovernmental agreements, Turkey’s natural gas market legislation, the Transit Law and on related commercial and public international law matters. Mr Demirkan’s energy experience includes advice to an American energy company in its proposed bid in the privatisation of Turkey’s electricity distribution entities. He currently leads the KDK team in its legal advisory services to a Japanese company, in relation to the Sinop Nuclear Power Plant.

Between January and June 2012, Mr Demirkan led the KDK team in the firm’s key role in the Trans-Anatolian Natural Gas Pipeline (TANAP) project. In this multibillion-dollar project, the KDK team drafted the Host Government Agreement and negotiated it with the Turkish government, along with the IGA, which was signed in late June 2012. In 2013, 2014 and 2017, Mr Demirkan received the Client Choice Award for his work in energy and
natural resources projects. He is also the founding member and board member of INLA’s (International Nuclear Law Association) Turkey chapter.

Mr Demirkan has also been heavily involved in several international arbitration proceedings, concerning disputes arising from major infrastructure projects including build-operate-transfer model investments, share purchase agreements, shareholders’ agreements, EPC contracts, asset transfer agreements and licensing contracts.

NIGEL DREW
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Nigel Drew is a solicitor qualified in England and Wales and heads the firm’s successful energy and infrastructure finance team in London. He has led on some of the largest energy and infrastructure projects in Europe and Africa, and has acted for arrangers (bank and bond), sponsors, contractors and the public sector on international projects across a wide range of sectors. In his extensive experience in the energy sector, he has advised on renewable power projects throughout Europe and Africa, including the largest project financing in Poland.

Nigel has been listed in Expert Guide: Project Finance, Euromoney’s guide to the world’s leading project finance lawyers. His recent experience includes advising the sponsors of the multi-award-winning US$840 million Maamba coal-fired power project in Zambia.

GBOLAHAN ELIAS
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Professor Gbolahan Elias is the presiding partner of G Elias & Co, one of Nigeria’s leading business law firms. He is also a visiting professor of law at Babcock University, Ilishan where he teaches shipping, petroleum and arbitration law. He has published widely on a range of both historical and topical legal matters and served on numerous law reform committees, university administration boards and law journal editorial boards.

He read law at Magdalen and Merton Colleges, Oxford. He has DPhil, BCL (first-class honours), MA and BA (first-class honours) degrees from the University of Oxford. He was called to the New York Bar in 1990. Professor Elias was an associate at the Cravath firm in New York and has been a senior advocate of Nigeria since 2005. He is a member of the Chartered Institute of Arbitrators.

He has advised on numerous transactions in the Nigerian energy sector, including the largest acquisitions to date of electricity generation and distribution companies. He also advised on the development and negotiation of the precedent-setting power-purchase contracts and vesting contracts for the federal government-backed single buyer of grid electric power. He recently advised on a US$1.2 billion ‘gas-to-power’ project financing and a US$1.5 billion refinancing of NNPC petroleum product import receivables.

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Latham partner Gene Elrod has more than 35 years of experience representing companies across the oil and gas industry – including producers, pipelines, storage and local distribution companies – and large commercial end-users of natural gas. He is is ranked among the nation’s leading energy regulatory and litigation lawyers by Chambers Global, Chambers USA, The Legal 500 – United States, The Best Lawyers in America and Who's Who Legal. He was named

JORGE EDUARDO ESCOBEDO MONTAÑO
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Mr Escobedo has been with the firm since June 2015 in the corporate practice group. He is also a lawyer in the firm’s energy practice. From 2006 to 2009, he worked as a lawyer in Basham, Ringe & Correa, SC in the administrative practice group.

Mr Escobedo is a graduate of the South Mexico Anahuac University law school and has a master’s degree in government and public policy from the Panamerican University. He also holds a diploma degree in lobbying and legislative procedures from the Ibero-American University, and a diploma degree in energy law from the noted Mexican law school Escuela Libre de Derecho.

His experience includes advising in matters related to administrative procedures and regulatory compliance (in connection with federal, local and municipal authorities and legislation) in areas such as urban development, infrastructure, health and hydrocarbons.

He worked in the Mexican state oil company, Petróleos Mexicanos (Pemex), as a legislative adviser in the CEO’s office and took an active role in connection with the Mexican energy reforms of 2013.

FABRICE FAGES
Latham & Watkins AARPI

Fabrice Fages is a partner with a focus on litigation and arbitration, and he is chair of the Paris litigation department. He has also developed strong experience in regulatory and public policy, notably in regulated sectors such as the energy sector. Prior to joining Latham & Watkins, Mr Fages worked for the French Senate and the French National Assembly on various law drafts. He is a regular speaker at professional conferences on energy matters.

Mr Fages is also a lecturer at the Pantheon-Sorbonne University (Paris 1), the CentraleSupélec School of Paris and the Cairo University, Egypt.

DANIEL FAJARDO VILLADA
Holland & Knight

Daniel Fajardo Villada is an associate in Holland & Knight’s Bogota office. He practises in the areas of oil and gas and mining law, as well as litigation and dispute resolution.

Mr Fajardo Villada primarily represents oil and gas and mining companies as well as other types of corporations. He advises clients in contracting, due diligence, and mergers and acquisition matters, and also has experience with both litigation and arbitration.

He has served as assistant professor of general regime of obligations at Universidad del Rosario, and as an intern at the International Court of Arbitration at the International Chamber of Commerce (Paris, France).
LIDO FONTANA
Covington & Burling LLP
Lido Fontana is of counsel in Covington’s Johannesburg office. He has significant experience in international oil and gas, mining, power, including renewable energy, and large infrastructure development transactions, including public–private partnerships and the United Kingdom’s private finance initiative.

GABIN GABAS
Orrick, Herrington & Sutcliffe (Europe) LLP
Gabin Gabas is an associate in the Orrick, Herrington & Sutcliffe energy and infrastructure group. His practice focuses on projects in the field of energy and extractive industries, mainly within Europe and Africa.

BRUNO GAY
Orrick, Herrington & Sutcliffe (Europe) LLP
Bruno Gay is of counsel in the Orrick, Herrington & Sutcliffe energy and infrastructure group. His practice focuses on corporate, commercial and regulatory advice within the energy sector, in particular on mining and oil and gas projects in Africa.

MICHAEL J GERGEN
Latham & Watkins LLP
Latham partner Michael Gergen has extensive experience developing practical applications of economics, finance and regulatory law to assist clients in the electric, natural gas and other network industries to compete successfully in an environment of market-based, open-access competition. Mr Gergen is recognised as a leading energy lawyer by Chambers USA and by The Best Lawyers in America. Mr Gergen is an adjunct professor of law at the New York University School of Law.

NATASHA GIANVECCHIO
Latham & Watkins LLP
Latham partner Natasha Gianvecchio focuses her practice on the regulatory and regional energy market developments that impact clients in the electric and natural gas industries. Her representations involve a broad range of issues under various federal and state energy statutes and regulations and regional energy market rules affecting the domestic energy industry. Ms Gianvecchio is consistently recognised as a leading energy lawyer by Chambers USA and, in 2015, was named by Law360 as a ‘top energy attorney under 40’ and a ‘Rising Star’.

ANDREAS GUNST
DLA Piper International
Andreas is an energy, projects and finance practitioner qualified in England and Wales, and is a partner at DLA Piper based out of both the London and Vienna offices. His practice areas cover the entire energy value chain, including upstream oil and gas exploration, production, transportation and trading (both OTC and exchange); electricity generation projects from
conventional and renewable energy sources; electricity transmission, distribution, trading (both OTC and exchange) and supply; and emission reduction projects and environmental securities, allowance and certificate trading, as well as related regulatory advice.

Andreas takes an active role in the energy regulatory sector, serving as chairman of several working groups, including the drafting committee for the European Federation of Energy Traders (EFET), the RECS International Legal Task Force, the gas transportation committee of the Association of International Petroleum Negotiators (AIPN), and the Carbon Markets and Investors Association (CMIA) EU Emissions Trading Scheme working group, and he is member of the Renewable Energy Performance Platform advisory panel. Andreas additionally advised one of the participating governments up to and during the Paris Agreement negotiations in 2015.

Andreas has been named ACC/ILO European Counsel of the Year 2013 (Regulatory) and is listed in The Legal 500 for energy and projects.

MUNIR HASSAN

*CMS Cameron McKenna Nabarro Olswang LLP*

Munir Hassan is head of clean energy at CMS in London, helping to determine the firm’s strategy on renewables and clean generation. Munir has almost 20 years of experience advising the power sector on commercial arrangements, M&A transactions, electricity sector restructurings and reforms, price-regulated energy networks, regional trading arrangements, establishment of regulatory frameworks and wholesale/retail supply arrangements. He has advised on technologies across the power space, including on offshore and onshore wind, solar, tidal, biomass, energy from waste, tidal and tidal lagoon, wave power, CCGT and CHP, coal-fired projects, electricity transmission networks and electricity distribution networks. He has advised extensively on both the sector in the United Kingdom and power projects and market reforms across numerous jurisdictions around the world.

FABRÍCIA DE ALMEIDA HENRIQUES

*Henriques, Rocha & Associados*

Fabrícia de Almeida Henriques is a partner at Henriques, Rocha & Associados, member of MLGTS Legal Circle as Mozambique Legal Circle. At an early stage of her career, which she started at Morais Leitão, Galvão Teles, Soares da Silva, she participated in several privatisations involving Portuguese companies, as well as in transactions in the area of project finance. More recently, her activity has been primarily focused on assisting national and international clients in M&A operations, mainly in the energy sector.

Currently she is a non-equity partner at Morais Leitão, Galvão Teles, Soares da Silva & Associados, coordinating all matters pertaining to Mozambique.

Ms Henriques was a lecturer at the law faculty of the University of Lisbon from 2000 to 2011. Currently, she lectures at the Eduardo Mondlane University and the Higher Institute of Science and Technology of Mozambique, both located in Maputo.

She has participated in several conferences and seminars on securities, banking, e-commerce and internet law.
**WATARU HIGUCHI**
*Anderson Mōri & Tomotsune*

Wataru Higuchi is a partner at Anderson Mōri & Tomotsune. He studied at Hitotsubashi University (LLB) and Columbia Law School (LLM) and is admitted to the Bar in Japan (Dai-ni Tokyo Bar Association) and New York.

**HENRY HODA**
*Linklaters LLP*

Henry Hoda is a managing associate of Linklaters LLP and a corporate and energy lawyer in Berlin. He studied in Berlin, Paris (*license en droit*, Panthéon-Assas University (Paris II)) and London (LLM in competition law, King's College) and has been trained as a lawyer in Berlin and Shanghai.

Henry specialised in advising companies on regulatory matters, contract and corporate law in the energy sector, both on a stand-alone basis and in the context of M&A transactions and legal proceedings. He advised the German energy exchange EEX on its acquisition of a majority stake in the French energy exchange Powernext as well as EEX, Powernext, TenneT and Elia on the integration of the power spot exchange businesses of EPEX SPOT and the APX group. He also advised TenneT and TransnetBW on their cooperation with respect to the largest German HVDC transmission line, SuedLink. Henry regularly represents gas storage operators and energy suppliers in proceedings for adjustment of storage and supply agreements and recently advised several investors on legal requirements for construction and operation of power storage facilities in Germany.

**HACHEM EL HOUSSEINI**
*Abou Jaoude & Associates Law Firm*

Hachem El Housseini is a senior associate at Abou Jaoude & Associates Law Firm, practising in the areas of media, energy, corporate law and aviation.

Throughout his career, Hachem has advised key companies with respect to various aspects of their onshore and offshore business. In the energy sector, Hachem has a particular expertise in the oil and gas industry, and has worked on a number of major oil and gas projects in the region.

He also provides legal advice to the UNDP in the context of the Preparation of a Legislative Framework Study for the Transport and Energy Sectors in Lebanon, a component of the SODEL project.

Hachem holds a JD in private law from the Francophone Sector of the Lebanese University, and an MBA from ESA/ESCP (Ecole Supérieure des Affaires/Ecole Supérieure de Commerce de Paris). He is a lecturer at the American University of Beirut.

He is admitted to the Beirut Bar Association and the International Bar Association, and is an Associate Member of the Chartered Institute of Arbitrators, London. He is fluent in Arabic, French and English.
GÖKÇE İLDİRİ

Kolcuoğlu Demirkan Koçaklı Attorneys at Law

Ms Gökçe İldiri has been an associate at Kolcuoğlu Demirkan Koçaklı since August 2012. Ms İldiri is experienced in mergers and acquisitions and energy law. She has represented various energy sector international clients in connection with a wide range of agreements. She is also a member of the project team that provides legal advice to a Japanese company, in relation to the Sinop Nuclear Power Plant. She has also worked on a number of M&A transactions contemplating the transfer of power plants.

Ms İldiri is also the founding member and board member of INLA’s Turkey chapter.

ELENA IOANNIDES

Dr K Chrysostomides & Co LLC

Partner Elena Ioannides joined the firm as a senior associate in 2007, having previously trained and practised as a solicitor in London, at Schillings and Finers Stephens Innocent LLP.

Elena advises clients interested in entering the emerging domestic energy sector, from major multinational oil companies to service providers at different stages in the industry. She also assisted a major player regarding its acquisition of an interest in an exploration licence (for hydrocarbons) in one of the licensed blocks offshore Cyprus, as well as advising on the corresponding production-sharing agreement and other related agreements.

Furthermore, Elena has advised clients in the renewable energy sector, including in relation to construction of the Tafila Wind Farm in Jordan (a 117MW facility financed, inter alia by, institutions such as the EIB and the IFC) and another wind farm in Romania.

Other areas in which she practises, include banking and finance; corporate law and commercial law; commercial contracts; data protection and privacy.

Elena has been listed and recommended in the banking and finance, as well as the corporate and M&A sections of international legal directories including, recently, The Legal 500 – EMEA and IFLR1000.

MOCHAMAD KASMALI

Soemadipradja & Täher

Mochamad Kasmali, who has a Sarjana Hukum (LLB) and an LLM (energy and natural resources laws and policies), joined S&T in 1996. Since then, Kasmali has also worked for 10 years with Newmont’s Indonesian subsidiary companies and has undertaken a short internship with one of the leading environmental law firms in Colorado, United States, Temkin Wielga & Hardt LLP. Kasmali’s main practice areas include energy and natural resources, infrastructure, forestry, environmental, general corporate and foreign investment matters. He is a member of the Indonesian Advocates Association (Peradi).

RANA KATEB

Abou Jaoude & Associates Law Firm

Rana Kateb is a senior associate at Abou Jaoude & Associates Law Firm, practising in the areas of energy, pharmaceuticals, corporate law, and mergers and acquisitions.
Throughout her career, Rana has advised key companies with respect to various aspects of their onshore and offshore business. In the energy sector, Rana has particular expertise in the electricity industry, and has worked on a number of major power projects in the region.

Rana holds an LLB in both private and public law from St Joseph University, and a Diploma of Higher Specialised Studies (DESS) in arbitration and ADR from the Francophone Sector of the Lebanese University accredited by Panthéon-Assas University, Paris. She is recommended by The Legal 500.

She is admitted to the Beirut Bar Association, and is fluent in Arabic, French and English.

MOUHAMED KEBE
Geni & Kebe Law Firm

Mouhamed Kebe is the managing partner of Geni & Kebe, a full-service law firm based in Senegal with 10 affiliate offices across Africa, namely Benin, Burkina Faso, Cameroon, Côte d’Ivoire, Gabon, Ghana, Guinea, Mali, Mauritania and Niger. His practice focuses on natural resources (energy, hydrocarbons, mining) law with a concentration in west and central Africa, and the Francophone African subregion.

He is closely attuned to foreign investors’ concerns regarding doing business in Francophone Africa. He also oversees commercial transactions including joint ventures, banking and finance, corporate reorganisation and restructuring.

Recent work in the energy sector:

a advised Jindal Steel & Power, a company registered in India, on a BOT contract with SENELEC, the state Senegalese energy company. Through the agreement Jindal will build develop, finance, insure, own, operate and maintain a 300MW coal power station connected to the SENELEC grid. Jindal will also sell energy to SENELEC;
b advised the Abhijeet Group on an electricity equity investment in Senegal;
c advised Cairn Energy (Scotland) on legal aspects of oil and gas licence exploration under Senegalese law;
d advised ERDF (Senegal), on the regulatory framework of the electricity sector in Senegal; and
e advised Caterpillar (USA) on a Power Purchase Agreement with SENELEC, the state Senegalese energy company.

He holds a Master of Laws (UCAD, Dakar, 1997), an LLM with merit (University of Essex, United Kingdom, 2009) and a Certificate in International Commercial and Investment Arbitration (University of London, 2013). He is admitted to the Senegal Bar and is a member of the Senegal Bar Association, the Law Society of England and Wales (International Division) and the International Bar Association.

Mr Kebe’s languages are French, English and Wolof.

KARYN KHOR
Skrine

Karyn Khor is a projects and energy lawyer at Skrine whose practice encompasses energy M&A, project development, competition and oil and gas. Karyn Khor began to read law at King’s College London in 2008. In her third year at King’s, she was selected as one of five students to participate in a one-year intensive programme in international, comparative and
transnational law at the Center for Transnational Legal Studies, encompassing students and faculty from 23 world-class law schools in a study on the transnationality of law in theory and in practice. She went on to graduate in 2012 with an LLB in law and transnational legal studies. Upon graduation, she continued to do her Masters in King’s College London, obtaining an LLM in competition law in 2013. Karyn was called to the Bar of England and Wales in 2014, following which she joined Skrine as an associate.

NICOLAJ KLEIST
Brün & Hjejlé
Nicolaj Kleist has extensive experience in advising on regulatory matters and public law issues, especially within the energy sectors, where he advises energy and supply utilities in the areas of oil, gas, electricity, heating and renewables. He regularly assists in disputes before public authorities, complaints boards and the courts, and has assisted in a number of landmark cases regarding price issues.

MELIS ÖGET KOÇ
Kolcuoğlu Demirkan Koçaklı Attorneys at Law
Ms Melis Öget Koç is a senior associate in Kolcuoğlu Demirkan Koçaklı. Before joining the firm in 2015, she was a senior associate at another major Istanbul-based law firm for seven years.

Ms Koç has significant experience in energy law and M&A transactions. Her cross-border energy transaction experience includes a variety of deal types, ranging from joint ventures to M&A transactions involving companies in the energy sector. She has advised major companies both on renewable energy and non-renewable energy law matters, including regulatory matters relating to renewable energy generation activities, downstream and upstream oil and natural gas matters and licensing procedures. She has also worked on a number of M&A transactions contemplating the transfer of power plants.

She is a member of INLA’s Turkey chapter.

CHANG WOO LEE
Yoon & Yang LLC
Chang Woo Lee is a senior associate at Yoon & Yang LLC. Mr Lee’s main practice focuses on patent litigation, particularly in the energy and life sciences sector. He also has extensive experience in trademark and copyright matters.

KWANG-WOOK LEE
Yoon & Yang LLC
Kwang-Wook Lee is a partner at Yoon & Yang LLC. Mr Lee’s main areas of practice include antitrust law, telecommunications and energy, broadcasting and privacy law. Mr Lee represents a broad range of companies in the energy industry. He also has extensive experience providing legal advice concerning issues arising in the environment and clean-tech sector.
RUTH LOSCH

Linklaters LLP

Ruth Losch is a managing associate of Linklaters LLP and a corporate and energy lawyer in Berlin. She studied law in Osnabruck, Kingston upon Hull, Berlin, Brussels (LLM) and Heidelberg (Doctor Juris) and has been trained as a lawyer in Berlin and Gdansk.

Ruth is an experienced adviser of clients in the public domain on regulatory matters, specialising in energy and public procurement law. She advised several municipalities in awarding concessions for their gas, electricity or district heating grids.

She also specialises in legal knowledge management and regularly publishes and lectures on questions of energy law.

SOURAYA MACHNOUK

Abou Jaoude & Associates Law Firm

Souraya Machnouk is a partner at Abou Jaoude & Associates Law Firm, and lends her specialised knowledge and experience to several practice groups, including mergers and acquisitions, banking, finance, corporate law, telecommunications, and energy.

Throughout her career, Souraya has advised key companies with respect to various aspects of their onshore and offshore business. In the energy sector, Souraya has a particular expertise in the oil and gas industry, and has worked on major LNG-to-power projects in the region.

Souraya holds a JD in private and public law from St Joseph University, a master’s degree (DEA) in banking and financial markets law from the University of Paris II-Assas, and a joint master of laws degree (LLM) from George Washington and Georgetown Universities. She is recognised as a leading lawyer by The Legal 500, Chambers & Partners and IFLR1000.

She is admitted to the Beirut Bar Association and the International Bar Association, and is fluent in Arabic, French and English.

FIONA MEATON

Squire Patton Boggs

Fiona practises principally in commercial and corporate law with a focus on energy and resources transactions and projects. In particular Fiona advises Australian and international clients in relation to joint venture arrangements, acquisitions, risk management and due diligence associated with exploration and production activities within Australia. She also advises on corporate law and corporate governance issues, in particular in relation to Corporations Act compliance and ASX Listing Rules. Fiona is the Perth head of the Australian Young Energy Network and a member of the Australian Institute of Energy Young Energy Professionals and the Australian Mining and Petroleum Law Association (AMPLA). Fiona was a member of the team working on the Ichthys LNG transaction, which was named Energy and Resources Deal of the Year at the Asian Legal Business Japan Law Awards 2013.

CAROLINA QUEIROZ PEREIRA DANTAS DE MELO

Pinheiro Neto Advogados

Carolina Queiroz Melo is an associate at Pinheiro Neto Advogados, in the energy team. Her practice focuses mainly on electricity regulation and public law. She has a Bachelor of
Laws (LLB) from the Fluminense Federal University (UFF), Brazil and is a specialist with master’s degrees in public law and regulation, and infrastructure law from the Getúlio Vargas Foundation (FGV), Brazil. She was recognised in the 2014, 2015, 2016 and 2017 editions of *IFLR1000* as a ‘Leading Lawyer’ in Latin America for project development (power sector) within energy and infrastructure.

**NEERAJ MENON**

_Triblegal_

Neeraj Menon is a partner in the Trilegal energy, resources and infrastructure team. His primary areas of practice are energy and infrastructure project development and project financing.

In the renewable energy sector, he has extensive experience in advising financial and strategic investors and utilities on all aspects of investing, developing and financing wind, solar and hydropower projects across various states in India. He also has experience in advising conventional power generators on negotiated-route and competitive-bidding projects, including on all aspects of PPAs, fuel supply and transport arrangements, financing arrangements, EPC and O&M contracts and mine developer and operator contracts. He has assisted banks and financial institutions in the financing of power generation projects and transmission projects. In the infrastructure sector, he has advised clients on development of rail corridors, mass rapid transit systems, airport development projects and mega residential projects. He regularly advise industry associations on policy and regulatory issues in the energy and infrastructure sectors.


**TOMASZ MŁODAWSKI**

_Sołtysiński Kawecki & Szeląg_

Tomasz Młodawski joined SK&S as an associate in 2006. Tomasz specialises in energy law with special emphasis on law in relation to electricity, the oil and gas sectors, and heating infrastructure. He has advised in several energy projects and assisted energy enterprises in regulatory and court proceedings, including those relating to compensation for stranded costs and incentive schemes addressed to CHP and LNG terminal projects. He has also supported clients in negotiations regarding EPC contracts for generation units. He is fluent in English. He received his master’s degree in law from the University of Warsaw in 2007 and practises as a legal counsel.

**ANTONIO MORALES**

*Latham & Watkins LLP*

Antonio Morales is the deputy office managing partner and the responsible partner for the regulatory and litigation practice in the Spanish offices of Latham & Watkins, as well as being part of the environmental, land and resources practice group. Mr Morales’ practice focuses on projects and transactions relating to public and administrative law, including the energy, utility, water and telecommunications sectors.
In 1997, Mr Morales became a state attorney. During his time in the public administration, he worked at the Government Delegation in Madrid from 1998 to 1999 and from 1999 to 2002 at the Superior Court of Justice of Madrid. From 2002 and 2005 he served as Secretary General of the Spanish Nuclear Safety Council. Prior to joining Latham & Watkins, Mr Morales was a partner at Hogan Lovells. In 2008, Mr Morales obtained his PhD at the Autonomous University of Barcelona (UAB).

Mr Morales has been recognised as a leader in administrative and public law by Chambers Global for the past eight years and in the energy sector by Chambers Europe from 2008 to 2015. Additionally, he was recognised as a leading Iberian energy lawyer by Iberian Lawyer in June 2006 and, in 2007, he also received Iberian Lawyer’s ‘40 under Forty’ award. Mr Morales was commended by Chambers Europe in 2011 for being ‘a lawyer with tremendous expertise’ and for the ease with which he ‘explains the most complex legal issues to clients with staggering clarity and simplicity’ and ‘total dedication to the client’s needs’.

CHARLES MORRISON
DLA Piper International
Charles Morrison is a trade and project finance lawyer qualified in England and Wales, and is international group head of the finance and projects practice at DLA Piper. He has a particular focus on energy work, especially oil and gas, and his energy experience extends to upstream, midstream and downstream oil and gas, power projects, and the related financing. His clients include governments, oil companies, trading houses, banks and other financial institutions. Charles is a partner in the energy and infrastructure finance team, and was previously head of the Africa group, as well as head of the energy infrastructure finance and commodities team.

Charles appears regularly in the principal legal directories and awards. He has headed a number of teams in major international energy and infrastructure projects, and has significant experience throughout Africa. He was rated ‘leading individual’ in the 2013 The Legal 500 – United Kingdom awards, commended as a ‘respected practitioner’ and for ‘thorough commercial advice’, and was appointed by the British government (DFID) and Uganda’s central bank, the Bank of Uganda, as an inspector to review the sale of Uganda Commercial Bank to Stanbic Bank Uganda.

J PATRICK NEVINS
Latham & Watkins LLP
Latham partner Patrick Nevins has over 25 years of experience advising leading energy companies in the development of major infrastructure projects, administrative litigation and high-stakes regulatory matters. His clients have included companies in all segments of the natural gas industry including pipeline companies, LNG project developers, local distribution companies, producers, as well as oil and liquids pipelines and shippers. He is consistently recognised as a leading energy regulatory and oil and gas lawyer in Chambers Global, Chambers US, The Legal 500 – United States, Who’s Who Legal, Best Lawyers and Euromoney’s ExpertGuides.
LEAH O’CONNELL
*Squire Patton Boggs*
Leah is a law graduate at Squire Patton Boggs (AU) having graduated from the University of Western Australia in 2016. Leah’s area of practice is corporate energy and resources law and she has assisted with due diligence, drafting and research.

OKECHUKWU J OKORO
*G Elias & Co*
Okechukwu J Okoro is an associate in the law firm of G Elias & Co. He holds a Bachelor of Laws degree from Ebonyi State University.

He has been involved in several of the firm’s energy deals. He has been actively involved in the legal review of gas sale documentation and is currently advising on three embedded power projects. He was on the team that recently advised two distribution companies on the Central Bank of Nigeria’s Nigerian Electricity Market Stabilization Facility, and on the team that advised Africa Finance Corporation on its investment in and divestment from the acquirer of a 45 per cent participating interest in an OML. Okechukwu J Okoro was also on the team that advised on a US$1.2 billion ‘gas-to-power’ project financing and a US$1.5 billion refinancing of NNPC petroleum product import receivables.

JOSÉ ROBERTO OLIVA JR
*Pinheiro Neto Advogados*
José Roberto is a partner at Pinheiro Neto Advogados, in the energy team. He has more than 13 years of experience advising clients on matters related to the energy industry. His practice focuses mainly on energy regulation, project finance and M&A. He has extensive experience in assisting clients in domestic and international mergers and acquisitions, project development, financing, private equity investments, joint ventures, and a variety of other matters related to energy and infrastructure projects. He is consistently ranked among the nation’s top energy lawyers by the publications *Chambers Latin America* and *Chambers Global, The Legal 500* and *IFLR1000*. He holds a Bachelor of Laws (LLB) from the University of Rio de Janeiro and two master’s degrees – a Masters of Laws (LLM) from Insper (Institute of Education and Research), São Paulo and an LLM from the University of California, Berkeley. He is deputy general counsel for the Brazilian Association of Independent Power Producers (APINE), a member of the Energy Committee of the Brazilian Bar Association (OAB/RJ) and a member of the Brazilian Institute of Energy Law (IBDE).

MAX OOSTERHUIS
*Loyens & Loeff NV*
Max Oosterhuis, attorney at law, co-heads the Loyens & Loeff energy team. Max specialises in EU and national energy law, and is an expert on (corporate) energy and regulatory matters. He advises national and international energy, oil, gas and power companies, as well as national and local authorities in various upstream (exploration and production), midstream (LNG, gas storage, oil refinery) and downstream (transmission and distribution) transactions, project developments and joint ventures.
CATARINA LEVY OSÓRIO

*ALC Advogados*

Catarina Levy Osório is a partner with ALC Advogados. She previously worked at another law firm as a consultant in the tax department and as a senior tax consultant with a major international consulting firm.

Ms Osório is a consultant for Morais Leitão, Galvão Teles, Soares da Silva in all matters pertaining to Angola. She is a member of the Angolan and Portuguese Bar Associations and has relevant experience in Angolan law, having advised clients on private investment, tax and labour law in that jurisdiction.

DIMITRIS PAPAPOLYVIOU

*Dr K Chrysostomides & Co LLC*

Associate Dimitris Papapolyviou primarily practises in the areas of energy law, and corporate and commercial litigation.

Dimitris holds an LLM in oil and gas law from the University of Aberdeen and regularly advises clients on various issues pertaining to regulatory and commercial aspects of the electricity, hydrocarbons, and renewable energy markets in Cyprus, while he is also involved in drafting energy performance contracts. In addition to the above, he has also published articles in peer-reviewed journals and the press, in relation to the emerging hydrocarbons market of Cyprus, and he has also been invited to address energy related conferences.

Dimitris is involved in complex and high-profile commercial disputes before the Courts of Cyprus, with particular emphasis on corporate disputes and applications for the issuance of interlocutory relief.

CLARE POPE

*Squire Patton Boggs*

Clare is an experienced corporate energy and resources lawyer, acting principally for oil and gas, mining and independent power producers and sovereign governments. Her experience includes drafting and advising on sale and purchase agreements, farm-in and joint venture documentation, production-sharing agreements, state agreements, oil and gas supply agreements, royalty agreements, LNG offtake agreements, project development, power purchase agreements, commercial contracting, infrastructure access and sharing agreements, and other resources and infrastructure-related documentation.

Clare has advised clients in relation to their activities globally including in Latin America, Africa, South East Asia, Australia, the United Kingdom, Europe and former CIS states. She has worked in Perth, London, Tokyo, Singapore and Kuala Lumpur, and also spent 11 months on secondment at BP plc’s headquarters in London.

Clare’s expertise has been consistently recognised by leading legal directories, including *Doyle’s, The Legal 500 – Asia-Pacific* for corporate and M&A, and the *IFLR1000 Energy and Infrastructure* guide.
HELENA PRATA

*ALC Advogados*

Helena Prata is a partner with ALC Advogados, with expertise ranging from advisory to complex corporate and asset financing and restructuring transactions, incorporation of SPVs and structured security arrangements and labour law. She is highly experienced in corporate law, environment, oil and gas and has worked extensively with national and international clients in these areas.

She is the author of several articles published in specialised Angolan magazines and also teaches business law at the law faculty of the Agostinho Neto University. Ms Prata was recently elected a member of the Luanda Provincial Council of the Angolan Bar Association.

KAI PRITZSCHE

*Linklaters LLP*

Kai Pritzsche is a partner of Linklaters LLP and a corporate and energy lawyer in Berlin. He studied law and political sciences in Freiburg, Geneva, Bonn, Berkeley (LLM) and Cologne (Doctor Juris) and practised in Cologne, New York City and Berlin.

Kai Pritzsche has special expertise in M&A transactions, joint ventures, contractual work and dispute resolution, in particular in the energy industry. He has advised European Energy Exchange AG on its joint venture with the French energy exchange Powernext, and the establishment of EPEX European Power Spot Exchange in Paris as well as a group of exchanges and transmission system operators on the integration of the Dutch APX with the French EPEX, advised RWE and E.ON on the introduction of incentive regulation and unbundling in Germany, advised seven European transmission system operators and four energy exchanges on the introduction of the Central Western European market coupling regime, as well as GdF Suez in several cooperations with municipal utilities in Germany and in other transactions, represented GdF Suez E&P in farm-in transactions and the sale of oil and gas licences, advised Dow Chemical in the privatisation of the BUNA works and advised on several sales and acquisitions of chains of gasoline stations, advised Dow Chemical in the sale of its hydrocarbon resins business to Arakawa Chemical Industries, as well as BP on refinery and pipeline projects. Kai Pritzsche regularly publishes and lectures on questions of corporate law and energy law.

GEORGES RACINE

*Holman Fenwick Willan Switzerland LLP*

Georges Racine is a partner of Holman Fenwick Willan. He is a dual-qualified civil and common law lawyer with intimate knowledge of Switzerland, developing countries and emerging markets. He has wide-ranging experience in corporate, commercial and international business law, with particular emphasis on projects (energy, infrastructure, telecoms and transport), construction, licensing and concessions, privatisations, mergers and acquisitions, joint ventures, public-private partnerships (PPPs), foreign investment and public procurement. Mr Racine has acted as lead counsel in international projects and transactions in over 25 countries worldwide. He was a member of the expert group that advised the Secretariat of the United Nations Commission on International Trade Law (UNCITRAL) on its draft Legislative Guide on Privately Financed Infrastructure Projects. He has written several articles on energy, infrastructure, telecommunications, PPPs and other
subjects for international publications and attended several international conferences as a speaker. He has also acted for several international investment banks, international financial institutions (e.g., World Bank, IFC, EBRD), foreign governments, regulatory authorities, sponsors, developers, independent power producers, utilities, trading firms, contractors, service providers, suppliers, investors and consulting, engineering and accounting firms.

FILIP RADU
CMS Cameron McKenna Nabarro Olswang LLP
Filip Radu is an associate at CMS in London, practising in the firm’s energy projects and construction department, focusing on the power sector. Filip has advised on both conventional and renewable power projects around the world, acting for UK and international utilities, developers, financiers, governments and regulators. He also has experience advising on market reform, helping enshrine international best practice into national energy rules, regulations and legislation. Filip’s experience also spans M&A transactions within the energy sector, advising on corporate, regulatory and commercial matters.

PAULA DUARTE ROCHA
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Paula Duarte Rocha is a partner at Henriques, Rocha & Associados, member of MLGTS Legal Circle as Mozambique Legal Circle. Engaged as a legal assistant, she had started her career even before completing her law degree. She then became a legal assistant to a partner at Pimenta, Dionísio & Associados. From 2000 to 2002 she provided multidisciplinary legal consultancy at the tax and legal services department of PricewaterhouseCoopers, cooperating with national and foreign investors. She was also an associate lawyer and senior legal adviser at MGA Advogados & Consultores.

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Julia advises international clients on M&A transactions and joint ventures in the energy sector as well as on various regulatory matters of European and German energy law. She has advised, among others, Macquarie European Infrastructure Fund 3 in connection with the indirect sale of their shares in the German gas transmission operator Thyssengas GmbH, L1 Energy on the acquisition of RWE Dea from RWE, and several European gas storage operators on the regulatory aspects of gas storages, regulatory compliance of new trading models and on adjustment of long-term contracts. Moreover, she has prepared an opinion for the German energy regulator analysing the activities of an energy supplier and its group companies. In addition, Julia regularly publishes and gives presentations in the field of energy law.

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David Schwartz is a partner in the finance department of Latham & Watkins’ Washington, DC office. He serves as global chair of the energy regulatory and markets practice, is a member of the project finance group, and is co-chair of the firm’s global power industry group. He has extensive experience representing entities involved in electric generation, transmission and distribution, electric and gas marketing and trading, and gas transportation and distribution.

Mr Schwartz has been active in the formation of the developing electricity markets in the United States; led transactional and regulatory teams in mergers and acquisitions and divestitures of energy companies and assets; litigated contract, rate and transmission access disputes; and drafted federal and state energy legislation. He also has extensive experience in negotiating power purchase and sale agreements, electric transmission agreements, natural gas transportation agreements, energy management agreements, and electric and gas interconnection agreements.

Mr Schwartz regularly advises clients on energy matters before the Federal Energy Regulatory Commission, various state public utility commissions, the US Department of Justice, the Federal Trade Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission and the Department of Energy.

Mr Schwartz is regularly named as a leading energy lawyer in *Corporate Counsel* magazine, *The Best Lawyers in America, The Legal 500 – United States* and both the global and the US *Chambers & Partners* guides to leading business lawyers. Mr Schwartz is a member of the American Bar Association and has held leadership positions in the Energy Bar Association.

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He is recognised as a ‘Leading Lawyer’ for Latin America by *IFLR1000’s Energy and Infrastructure Guide*, and is ranked in *Chambers Latin America* 2015 edition as a leading lawyer in corporate, energy and natural resources, mergers and acquisitions, and real estate practices.
Juan Carlos Serra Campillo was also named one of the world’s leading lawyers in *Who’s Who Legal: Mining* in 2014, and in *Who’s Who Legal: Energy* in 2012, 2013, 2014 and 2015. His specific experience includes joint ventures, mergers and acquisitions, reorganisations, investments, acquisitions, and solid experience participating in national and international public bidding, as well as advising extensively in energy and mining issues.

He is an active member of the Mexican Bar Association, the Institute for Energy Law, the Rocky Mountain Mineral Law Foundation, the Association of International Petroleum Negotiators (AIPN) and the International Bar Association (IBA).

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Samantha specialises in advising in relation to public and private mergers and acquisitions, the development of independent power projects, joint venture and farm-in arrangement structuring and secondary capital raisings. Samantha also regularly provides advice to clients on a broad variety of corporate law issues and corporate governance risk mitigation, including directors’ duties, continuous disclosure requirements, company secretarial matters and general regulatory compliance issues involving the Corporations Act and the ASX Listing Rules.

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Since February 2016, Shaghayegh Smousavi has been the managing director of CMS Pars. Her work focuses on cross-border transactions and financing, in the energy sector in particular. She has special, local know-how and experience in advising international companies both on taking up operations in Iran and on re-entering the Iranian market.

Shaghayegh started her legal career with an international accountancy firm in Frankfurt and Paris, and then worked for a tax consultancy in Niamey in Niger, as well as for the European Commission in Brussels. She subsequently joined Clifford Chance, where she worked as a counsel in her final post there. Shaghayegh has been a CMS partner since 2013.

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Codou Sow-Seck is a partner at Geni & Kebe Law Firm.

Her practice areas are transport, corporate and public-private agreements.

Recent energy-sector work includes:

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- advised the Abhijeet Group on an electricity equity investment in Senegal;

- advised Chemtech Solar, an Italian company, to assist them in the sale of three PV projects located in Senegal; and
advised Thesan in a potential acquisition of a 10MW PV project located in Senegal owned by WSS Suarl, a company incorporated under Senegalese law.

She holds an LLM (Paris-Sorbonne University, France) and an LLB (the University of St Louis, Senegal). Her academic qualifications are Master of International Transport Law (Paris-Sorbonne University, France), and Master of Economic and Business Law (University of St Louis, Senegal). She has been admitted to the Senegal Bar since 2006, and is a member of the Senegal Bar Association.

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Throughout his career, Chadi has advised key companies with respect to various aspects of their onshore and offshore business. In the energy sector, Chadi has a particular expertise in the electricity industry, and has worked on a number of major power projects in the region.

Chadi holds an LLB in both private and public law from the Holy Spirit University of Kaslik (USEK), and a Diploma of Higher Specialised Studies (DESS) in international agreements from USEK accredited by the University of Montpellier I.

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Monica Sun, part of Herbert Smith Freehills’ global energy practice in Beijing, has experience of advising on oil and gas (including LNG), power, renewables, mining projects and transactions around the world, in particular advising major PRC companies on their outbound investment. Her clients include major Chinese state-owned enterprises such as Sinopec, CNOOC, CNPC, State Grid, Huaneng, Huadian, Shenhua and Minmetals. Her practice covers M&A, joint venture, project development and project finance, private equity investment, corporate and corporate finance. She also has considerable experience in advising foreign clients on doing business in China. Monica has advised on acquisitions and projects in jurisdictions including China, Australia, Indonesia, Africa, the former Soviet Union, South America and the United Kingdom.
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His relationship with the Portuguese energy sector dates back to the early 1990s. During the past 15 years, he has been involved with enterprises in the energy sector and given support to the Portuguese government on some of the most important transactions to have occurred in the country’s energy sector.

He has advised and assisted several companies and banks with a focus on M&A and capital markets operations. During recent years he has played an active role in key M&A transactions in Portugal or carried out overseas by Portuguese companies.

Mr Teles has led the team of lawyers responsible for some of the major privatisation transactions in Portugal, in the energy, pulp, motorway and cement industries.

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