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THE LAW REVIEWS

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EDITOR’S PREFACE

Our fifth year of writing and publishing The Energy Regulation and Markets Review has been marked by significant efforts to reduce greenhouse gases (GHGs), important infrastructure development needs and continued low oil and gas prices. We have also seen divergent positions on existing and future nuclear power generation, and further liberalisation of the energy sector.

I  CLIMATE CHANGE DEVELOPMENTS

With respect to climate change efforts, 177 countries signed the Paris Agreement and 17 countries have ratified the Paris Agreement, which will enter into force after at least 55 countries representing at least 55 per cent of the global greenhouse gas emissions ratify the Agreement. Even prior to the effectiveness of the Paris Agreement, we are seeing significant carbon reduction efforts, such as increased development of renewable resources, as well as energy efficiency and demand reduction measures.

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. The United Kingdom announced its energy goals, which includes increasing reliance on renewables and imposing strict ‘carbon budget’ requirements. France adopted new energy legislation that seeks reductions of fossil energy consumption by 30 per cent, reductions of GHGs by 40 per cent by 2030 (and by 75 per cent by 2050), reduction of energy consumption by 50 per cent by 2050, and increased reliance on renewables to eventually reach 40 per cent of electricity production. Denmark established a goal of having renewable energy meet all electricity demands by 2050. The Netherlands has made significant efforts to reduce GHGs, including the shutdown of some older coal-fired power plants. Italy enacted new legislation encouraging energy efficiency, biomass, biogas and bioliquids. Germany undertook significant steps to increase reliance on renewable energy resources.

In the United States, the Environmental Protection Agency’s Clean Power Plan, which is currently stayed pending further judicial proceedings, would require 32 per cent
reductions in CO2 emissions from 2005 levels by 2030. Last year, China set out a goal to peak CO2 emissions by 2030 and to increase reliance on non-fossil fuels to 20 per cent by 2030. Japan, Korea, 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, increase energy efficiency, reduce existing energy subsidies and to develop greater renewable energy infrastructure. Dubai has established a Dubai Green Fund to assist in the development of renewable energy and energy efficiency. South Africa is looking to procure significant new renewable resources. India has set a target of 175GW of renewable energy to be installed by 2022. India’s Renewable Energy Certificate programme has largely failed because of non-enforcement of Renewable Purchase Obligation goals.

II INFRASTRUCTURE DEVELOPMENT

For many countries, reliable energy supply is the key concern, regardless of fuel source. Coal still plays a dominant role in meeting energy supply for Poland, India, Turkey and China. Indonesia’s primary challenge remains to reach its goal of 90 per cent electrification by 2020. The primary concern for India’s energy sector remains the challenge of providing reliable, uninterruptible electricity to its population and India has begun to employ a variety of creative measures (including a transitional state financing programme) to allow distribution companies to expend greater resources on investment in procurement and infrastructure over the next five years. To meet electrification needs in Central and West Africa, the Regional Initiative for Sustainable Energy identifies over 100 generation power sector projects in countries that are members of the West Africa Economic and Monetary Union that are targeted for development prior to 2030. Mozambique similarly continues to face significant infrastructure needs to meet electricity and natural gas demand. As a result of its civil war, Angola desperately needs to rebuild infrastructure (generation, transmission and distribution). Ukraine’s main focus is building infrastructure and reducing gas dependence on Russia following Russia’s annexation of Crimea.

III IMPACTS OF LOW OIL AND GAS PRICES

Low oil and gas prices continue to have adverse impacts for the United Arab Emirates, Mexico, Angola and Nigeria. Exploration and production activity has slowed in the United States because of current oil and gas prices, and low gas prices have led to increases in coal plant retirements. Since the relaxation of certain US and international sanctions against Iran, Iran is now looking to attract US$200 billion in investment in its oil and gas industries over the next five years, which may be challenging with today’s low oil and gas prices. China is also looking for assistance with shale exploration in the Sichuan Basin, with mixed levels of interest from potential investors. Mexico has also sought to eliminate some of its regulatory uncertainty as a way to attract new investors.

IV NUCLEAR POWER GENERATION

We have seen divergent positions with respect to nuclear power. Following the Fukushima disaster, Japan has shut down all 48 of its nuclear power stations pending new detailed safety reviews. Germany has targeted 2022 as the date for phasing out all nuclear generation.
France is seeking a reduction of nuclear power generation by 30 per cent by 2030. On the other hand, Turkey is continuing with development of a nuclear power plant (expected to be operational in 2023), and the United Arab Emirates is still proceeding with construction of the Barakah nuclear power plant, which is expected to be operational next year. The United Kingdom has stated that nuclear energy will remain an important part of the country’s energy future. In the United States, the early retirement of certain nuclear plants has been driven by cost considerations, rather than safety concerns.

V LIBERALISATION OF THE ENERGY SECTOR

We have seen significant energy sector regulatory reforms in many countries. Italy has opened up distribution systems to retail competition and trading, and has seen the widespread introduction of smart meters. Portugal will complete its transition to competition in the energy markets by the end of 2017. South Africa is liberalising its generation sector through a massive procurement programme from independent power producers. Australia is in the midst of restructuring its electricity sector through retail competition. Japan is seeking full retail competition this year, as well as the unbundling of the transmission sector from the generation sector, and is seeking to achieve similar reforms (retail competition and unbundling) in the gas sector. Korea announced a new energy plan to deregulate energy markets and mitigate the monopoly power of the majority state-owned utility company by, among other things, encouraging customer-side generation projects. Brazil saw an increase in retail competition as a result of higher prices, which was an indirect result of the reduced availability of inexpensive hydroelectric power due to the drought from last year. Turkey is focused on privatising state-owned generation companies. There are proposals in Norway to separate transmission grid companies from supply.

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 fifth edition of The Energy Regulation and Markets Review.

David L Schwartz
Latham & Watkins LLP
Washington, DC
June 2015
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, 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, 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: (1) non-discriminatory conditions for trade and provisions on reliable cross-border energy transit, (2) protection of direct foreign investment and protection against key non-commercial risk, (3) a dispute resolution system between participating states and between investors and host states, and (4) the promotion of energy efficiency.

The Energy Community is an international organisation joining the European Union with a number of countries from the Southeast Europe and Black Sea regions, with the primary aim of extending the European acquis communautaire on energy, environment,
competitions and renewables to the parties. The Energy Community Treaty additionally sets up a regulatory mechanism for the regional network energy markets. The implementation of the European internal energy market in contracting states is a measure that facilitates potential membership of the European Union, as demonstrated by Bulgaria and Romania in 2007 and Croatia in 2013.

Most recently, the Paris Agreement sets ambitious targets for the parties to mitigate and adapt to climate change and contribute to the decarbonisation of the global economy, and if ratified will create 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’: (1) energy security, solidarity and trust, (2) a fully integrated European energy market, (3) energy efficiency contributing to moderation of demand, (4) decarbonising the economy, and (5) 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 on the concept of solidarity in matters of energy supply as introduced by the Treaty of Lisbon.

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,2 the Electricity Directive3 and the Gas Directive,4 and the Electricity Access Regulation5 and the Gas Access Regulation.6 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

5 Regulation (EC) No. 714/2009 on conditions for access to the network for cross-border exchanges in electricity.
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 Regulatory (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.

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, 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.

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.

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.
Furthermore, the Regulation 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.

iii Network codes

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

Currently 10 electricity network codes have been specified, which are grouped into three categories: (1) connection codes, which set requirements for the connection of both generators and large customers to the transmission grids; (2) 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 (3) 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, two electricity network codes have entered into force. The network code on Capacity Allocation and Congestion Management (CACM) designates Nominated Electricity Market Operators as coupling operators, 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.

Network code Requirements for Generators provides requirements for newly constructed generators, as well as notification procedures and compliance provisions. The network code Forward Capacity Allocation is expected to enter force in July 2016, and the remaining seven network codes are currently at various stages of development or evaluation.

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

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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.
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, the designation of storage and liquefied natural gas system operators, and 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, four gas network codes have been adopted.

The network code on Capacity Allocation Mechanisms 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, interruptible capacity, and tariffs and capacity booking platforms.

Gas Balancing in Transmission Networks\textsuperscript{14} sets out detailed provisions for a gas balancing system, trade notifications and allocations, operational balancing procedures, and on nomination and renomination procedures. The balancing procedures include provisions on short-term standardised products and the establishment of a trading platform for their procurement, as well as incentives for TSOs to undertake efficient balancing actions.

Congestion Management Procedures\textsuperscript{15} is fundamentally a set of 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\textsuperscript{16} 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 odourisation.

Tariff Harmonisation is currently undergoing development, with the aim to homogenise gas transmission tariffs within the European Union, promoting fair and objective tariffs. The current draft provides reference price methodologies, including postage stamp and capacity weighted distance methodologies, as well as equalisation, benchmarking, and storage adjustment provisions.

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.

\textbf{iv Gas Security of Supply Regulation}

The Gas Security of Supply Regulation\textsuperscript{17} aims to prevent a disruption of natural gas supply to the European Union and to ensure a coordinated response if necessary. It regulates the 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, 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.

\textsuperscript{14} Commission Regulation (EU) No. 312/2014 establishing a Network Code on Gas Balancing of Transmission Networks.

\textsuperscript{15} Annex 1 to the Gas Access Regulation.

\textsuperscript{16} Commission Regulation (EU) 2015/703 establishing a network code on interoperability and data exchange rules.

\textsuperscript{17} Regulation (EU) No. 994/2010 concerning measures to safeguard security of gas supply.
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.

V PETROLEUM

i Oil and Gas Licensing Directive

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

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

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

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

ii Oil Stockholding Directive

The stocks of crude oil and petroleum products 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 Central Stockholding Entities 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

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

19 Directive 2009/119/EC imposing an obligation on Member States to maintain minimum stocks of crude oil or petroleum products.
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)\textsuperscript{20} 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 (1) accelerated and more efficient permit granting procedures, (2) improved regulatory treatment on the national level, (3) streamlined environmental assessment procedures, (4) increased public participation via consultation, and (5) access to grants from the Connecting Europe Facility. In 2015, a total of €650 million in grants was granted to 35 PCIs. Furthermore, receiving PCI status increases the attractiveness to external investors.

An applicant project must meet a series of criteria to be considered a PCI: it has to (1) have significant benefits for at least two Member States, (2) contribute to market integration and further competition, (3) enhance security of supply for the European Union, and (4) 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 for this. 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\textsuperscript{21} 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

\textsuperscript{20} Regulation (EU) No. 347/2013 on guidelines for trans-European energy infrastructure.

\textsuperscript{21} Directive 2009/28/EC on the promotion of the use of energy from renewable sources.
energy action plans. To achieve these targets, the Directive provides for statistical transfers, joint projects between Member States or third countries, and joint support schemes between Member States.

Member States are required to provide information and training on support measures and details on the benefits, 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, which is a system to ensure that the origin of electricity produced from renewable energy sources can be guaranteed.

The Directive furthermore regulates on 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.

VIII ENERGY EFFICIENCY DIRECTIVE

The Energy Efficiency Directive22 aims to promote energy efficiency across the European Union to meet the European Union 2020 goal of energy savings of 20 per cent through energy efficiency, and in doing so remove 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, and provide final consumers with meters, cost-free access to metering and billing information, and information on energy, as well as 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 small and medium-sized enterprises, and are permitted to set up an energy efficiency national fund and other financing and technical support to increase energy efficiency in different sectors.

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IX DECARBONISATION

i Emissions Trading Directive

The European greenhouse gas emissions allowance trading scheme was established by the Emissions Trading Directive\textsuperscript{23} 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, 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,\textsuperscript{24} such as the Registry Regulation,\textsuperscript{25} 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.

\textsuperscript{23} Directive 2003/87/EC establishing a scheme for greenhouse gas emission allowance trading within the Community.


X CARBON CAPTURE AND STORAGE (CCS) DIRECTIVE

The CCS Directive\(^{26}\) 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.\(^{27}\)

Along with the Third Energy Package and REMIT,\(^{28}\) this legislation has introduced additional obligations for energy markets, including reporting obligations, transparency requirements, the treatment of certain types of energy or emissions allowances as financial instruments or derivatives, organisational requirements for markets, the introduction of new trading venues, the mandatory use of regulated markets for certain products, and a clearing obligation for certain trades.

XII FUTURE DEVELOPMENTS

There is currently a large amount of European secondary legislation expected in the near future as the European Union prepares for the period from 2020 to 2030. This will likely

\(^{26}\) Directive 2009/31/EC on the geological storage of carbon dioxide.
\(^{27}\) These include Directive 2004/39/EC on markets in financial instruments (MiFID), Directive 2014/65/EU on markets in financial instruments (MiFID II), Regulation (EU) No. 600/2014 on markets in financial instruments (MiFIR), Regulation (EU) No. 648/2012 on OTC derivatives, central counterparties and trade repositories (the European Market Infrastructure Regulation), Directive 2014/57/EU on criminal sanctions for market abuse (the Market Abuse Directive), and Directive 2013/36/EU on access to the activity of credit institutions and the prudential supervision of credit institutions and investment firms (the Capital Requirements Directive).
\(^{28}\) Regulation (EU) No. 1227/2011 on wholesale energy market integrity and transparency.
include regulations on security of supply of gas and electricity, a new renewable energy
directive, additional network codes for electricity and gas, and further legislation as part of
the European Union Framework Strategy.

As described previously, two main external factors will likely 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 that are in line with the target of the
Paris Agreement. Should the Paris Agreement be ratified, this would likely see a further
increase in commitment from the European Union and its Member States to decarbonise
the economy.
Chapter 2

OVERVIEW OF CENTRAL AND WEST AFRICA

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

I OVERVIEW

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,3 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;

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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, Gabon, Guinea, the Ivory Coast, the Republic of the Congo, 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.
the power infrastructure is in a state of disrepair, which leads to significant energy losses; and
growing demand colliding with a persistent shortfall in production and poor quality of services is causing chronic power cuts and slowing industrial development.

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

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

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);\(^4\)
- the Protocol dated 18 October 1983 on cooperation in energy between the members of the Economic Community of Central African States (ECCAS);\(^5\)
- the A/P4/1/03 Energy Protocol, adopted by the Economic Community of West African States (ECOWAS)\(^6\) 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).\(^7\)

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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, the Ivory Coast, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leone and Togo.

\(^7\) The WAEMU is composed of eight Member States: Benin, Burkina Faso, the Ivory Coast, Guinea-Bissau, Mali, Niger, Senegal and Togo.
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.

New power regulations are now in force in the Ivory Coast and the Democratic Republic of the Congo, and have been included in this overview (see below).

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.

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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,\(^9\) all the states have legislation providing for the creation of a regulation authority in the electricity sector.\(^10\) Some of these national authorities may have only been set up very recently,\(^11\) or may even not be effective yet.\(^12\)

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

- monitoring that operators comply with the applicable regulations;
- intervening in the setting or approval of electricity tariffs;
- ensuring compliance with competition rules in relation to power production, transport and distribution;
- preserving customers’ interests;
- 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 players (between operators or between operators and customers).

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9 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.

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

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

12 As is the case in Chad.
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.

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.

For example, the Authority for the Downstream Petroleum Sector Regulation (Chad), 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 to 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.

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

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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 as 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.
Overview of Central and West Africa

19

the purpose, extent and duration of the relationship;
b the investment plan;
c the conditions relating to the maintenance of the infrastructure;
d the quality of the service;
e accounting and financial aspects;
f tariffs;
g the conditions of remuneration of the operator;
h the applicable tax regime; and
i 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 mere authorisations, in particular when production facilities have a capacity below a certain threshold. The situation in Chad is, in fact, very specific, as the legislation provides that producing and selling electricity outside the framework of the public service is possible without formalities, other than a mere declaration.

Oil and gas sector

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

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

21 For instance, in Benin, with the Société Nationale de Commercialisation des Produits Pétroliers (SONACOP), which is wholly owned by the state and acts in the procurement, storage, transport and marking 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 the Ivory Coast, with the Société Nationale des
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.\(^{22}\) 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.\(^{23}\)

Opérations Pétrolières de Côte d’Ivoire (PETROCI); and the Société Ivoirienne de Raffinerie (SIR), which is 45.74 per cent owned by PETROCI and 1.54 per cent by the state and acts in the refining and importation of crude oil as well as the importation of refined products; and the Société de Gestion des Stocks de Sécurité (GESTOCI); in the Democratic Republic of the Congo, with the Congolaise des Hydrocarbures, which is wholly owned by the state; in Gabon, with the Gabon Oil Company (GOC), which is wholly owned by the state; 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; in Senegal, with the Société des Pétroles du Sénégal (PETROSEN), which is wholly owned by the state; the Société Africaine de Raffinage, which is 46 per cent owned by PETROSEN; and with the Sénégalaise de Stockage (SENSTOCK), which is 66 per cent owned by PETROSEN.

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

Hydrocarbons rights and titles

Hydrocarbons titles are either exploration or exploitation titles.\textsuperscript{24}

These titles are granted by the state\textsuperscript{25} through administrative acts (generally ministerial orders or presidential decrees) to companies that demonstrate the technical and financial capacities required to carry out the necessary petroleum operations.\textsuperscript{26}

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

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

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

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

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

\begin{itemize}
  \item[] cover the perimeter of the hydrocarbons titles to which they refer (exploration title and, as the case may be, exploitation title);
\end{itemize}

\textsuperscript{24} The term of exploitation titles range 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.

\textsuperscript{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.

\textsuperscript{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.

\textsuperscript{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.

\textsuperscript{28} Temporary authorisations to exploit are, for example, provided in the legislation of Benin, Cameroon, the Central African Republic and the Ivory Coast.
are concluded for the term of the exploration title (and, as the case may be, exploitation title to which they apply);

c set the minimum work obligations of the holder during the various phases of the project, as well as the conditions in which exploration and exploitation will be carried out;

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

e set the tax and customs regime applicable to the holder;

f set the obligation for the holder to respect local content;

g 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, and

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

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

Legislation also envisages (without necessarily regulating 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.

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.

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.

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’.
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.\(^{34}\)

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.

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34 This is the case in the Republic of the Congo, Mali and Senegal.
35 Some states also refer to the continental shelf (the 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.
Oil and gas sector

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

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 the transfer; 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 (SENELEC) 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 the Ivory Coast, the Société Nationale d’Électricité (SNEL) in the Democratic Republic of the Congo, Électricité de Guinée (EDG) in Guinea, the Société Nigérienne d’Électricité (NIGELEC) in Niger or the Société Nationale d’Électricité (SNE) in the Republic of the Congo.

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 the 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 regulation 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 regulation authority.

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 a 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, the 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 the Ivory Coast, Liberia, Sierra Leone and Guinea; between Ghana, Burkina Faso and Mali; and between Guinea and Mali.

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43 The Regional Electricity Regulatory Authority (RERA).
Oil and gas sector

Besides the Chad-Cameroon pipeline, the most significant example of cross-border interconnected infrastructure in relation to hydrocarbons is the Western African Gas Pipeline, which was created by international treaty and crosses four states including Benin and Togo, and the operation of which, although managed by a private company, is regulated by a regional regulator instituted by the treaty: the Western African Pipeline Authority.

The 258km Abidjan-Yamoussoukro pipeline will expand to Burkina Faso, with a view to redistributing hydrocarbons to Mali and Burkina Faso. Finally, in November 2013 the Ivory Coast and Burkina Faso authorities signed agreements intended to provide a general framework for the future construction of a gas pipeline linking the Ivory Coast to Burkina Faso for it to benefit from a natural gas supply.

Lastly, a Niger-Chad pipeline is expected to be built, from where the existing Chad-Cameroon pipeline will carry Niger’s oil (from the Agadem fields) to the coast of Cameroon. This project will allow the new oil-producing country to become an exporter of crude oil. A bilateral convention was signed to this effect in Yaoundé on 30 October 2013, which stipulates the conditions under which Niger’s oil will transit through the Chad-Cameroon pipeline.

RENEWABLE ENERGY AND CONSERVATION

Development of renewable energy

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

THE YEAR IN REVIEW, CONCLUSIONS AND OUTLOOK

Electricity sector

Current projects

Almost two dozen power plant projects are currently ongoing in Central Africa among the CEMAC, including a gas plant in Cameroon (345MW, Limbé) and several hydroelectric dams in Cameroon (420MW, Nachtigal and 201MW, Memve’ele), in Gabon (70MW, Ngounié

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44 This pipeline has been jointly operated since October 2003 by two transportation operators: COTCO (Cameroon Oil Transportation Company SA, which is jointly owned by private investors and the states of Chad and Cameroon) and TOTCO (Tchad Oil Transportation Company SA, which is jointly owned by private investors and Chad).

45 Taking into account the existence of significant oil and gas resources in the subregion, and with a view to fostering the satisfaction of power requirements, the ECOWAS published a call for expression of interest in July 2013 to assess the possibility of expanding the WAGP to the coastal countries of the Community.

46 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.
and 52MW, Woleu-Ntem), and in the Central African Republic (200MW, Ndjimoli). These projects are part of the CEMAC Vision 2025 programme, which is aiming for 10,000MW of additional capacity within the CEMAC region.

Moreover, the Regional Initiative for Sustainable Energy identified more than 100 projects directly related to the power sector, and that are to be achieved by 2030, all within the framework of 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. Production capacity should ultimately be multiplied by three. As part of these initiatives, a number of power plants are currently ongoing, including several hydroelectric dams in Senegal (120MW), which is expected to provide energy in Gambia, Guinea-Bissau and Senegal, in Niger (130MW, Kandadji) and in Mali (140MW, Gouina), as well as a thermal plant in Burkina Faso (50MW). A hydroelectric dam (240MW, Kaléta) was commissioned in 2015 in Guinea.

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

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

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

Regional electricity market
The directive N°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. In June 2015, the heads of state and government of the ECOWAS Member States gave their support for pooling their electric resources to implement a regional electricity market that can stop the power outages that Member States have suffered for decades.

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.

47 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.
Oil and gas sector

New legislation

Democratic Republic of the Congo

In the Democratic Republic of the Congo, Law No. 15-012 dated 1 August 2015 establishing a general regime applicable to hydrocarbons entered into force on 1 August 2015.

This new law aims to enhance the state’s hydrocarbon resources and to meet the growing energy needs for the well-being of the population and the development of economic activities.

This legislation governs upstream recognition, exploration, exploitation, production and marketing of hydrocarbons and downstream refining activities, transportation, storage, supply of oil products, import and marketing of petroleum products to the petrochemical industry.

This code innovates by (1) establishing a regime mainly based on production sharing contracts and, alternatively, on service contracts; (2) establishing a specific tender procedure for the attribution of hydrocarbon rights different from the procedure organising public procurement; (3) creating the national oil company; (4) creating a fund for future generations; (5) strengthening local content requirements in hydrocarbon activities; (6) improving the protection of the environment and cultural heritage; and (7) strengthening the state’s obligation to invest in geological, geophysical and geochemical research to evaluate its hydrocarbon resources.

In addition to the above, the new hydrocarbons code introduces the principle that the state is the sole owner of hydrocarbon resources in the Congolese soil and subsoil, and of the scientific and technical data gathered from the hydrocarbon activities.

The activities related to the hydrocarbon resources of the Democratic Republic of the Congo, contained in particular in the coastal basin, the central basin and the western branch of the East African Rift, are now governed by this new code.

Republic of the Congo

A new hydrocarbons code was adopted by the government in 2015 in the Republic of the Congo.

This code reiterates most of the provisions of the old code dating from 1994. It contains some innovations including (1) the granting of mining titles on an exclusive basis to the national oil company; (2) the establishment of a national environmental risk prevention fund; (3) the strengthening of sanctions against oil companies, in cases of breach of legal and contractual provisions; (4) the establishment of a unique tax and customs regime; (5) the setting of the state’s minimum share of profit oil to 35 per cent; (6) the definitive ban of gas flaring; and (7) the establishment of a minimal participation of 15 per cent for private companies in production sharing contracts.

Mali

In Mali, Law No. 2015-035 relating to the organisation of research, exploration, exploitation and transport of hydrocarbons was adopted on 16 July 2015.

This law (1) replaces concession contracts with production sharing contracts; (2) introduces reconnaissance contracts for geological work before the conclusion of a production sharing contract; (3) introduces a service contract by which the state entrusts specific exploration works to authorised mining companies; (4) establishes a minimum quota of Malian employees to be recruited by petroleum companies operating on the national
territory; (5) implements the obligation for petroleum companies to contribute to an escrow account to guarantee the funding of the rehabilitation plan; and (6) strengthens the state’s revenues in the case of farm-out and transfer transactions by setting additional tax on the transfer of capital gains.

Projects based on regional initiatives
An oil refinery with high capabilities is expected to be built over the next 15 years within the CEMAC region, as part of the CEMAC Regional Economic Programme and the CEMAC Vision 2025 programme.

The rationale of this project is to provide additional capacity to the three existing refineries (in Gabon, Republic of the Congo and Cameroon) and to the fourth, expected in Chad, which all have small capacities and are not profitable.
Chapter 3

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

John A Trenor and Anna S Holloway

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.

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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.

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

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

ii Flexibility rights

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

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

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terms becoming prevalent for LNG sales. Some contracts may contain an express provision for incremental limited extension of the term for a number of years (either by agreement, or at the election of one party).

iv Pricing provisions

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

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

Over the past decade, following the emergence of gas trading at physical or virtual hubs in certain markets (like the NBP in the United Kingdom and the TTF in the Netherlands), the parties to some contracts have agreed to include (to varying degrees) hub pricing in the price 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.


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.
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:

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

(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

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, infra.

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.

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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 Westlaw). Other published language of price dispute clauses is seen in ICC Final Award No. 9812 (extract), dated August 1999, ICC International Court of Arbitration Bulletin Vol. 20 No. 2 (2009), and ICC Case No. 13504 (2007), 20(2) ICC Bull. 93 (2009), at p. 94.
Over time, many countries have made efforts to liberalise their natural gas markets, although the results of these efforts vary by country. For example, the European Union has taken a variety of steps to liberalise gas markets in the Member States and across the EU, commencing with the First EU Gas Directive in 1998 and continuing through the Third EU Gas Directive in 2009. These liberalisation efforts coupled with other factors facilitated the emergence and increased liquidity of gas trading hubs, noted above, on which buyers can purchase certain volumes of gas at a market price. This ‘gas-to-gas’ competition has led a number of buyers to argue for the introduction of hub pricing in the contract price formulae of their long-term GSPAs.

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

Buyers reacted in a number of ways. Some sought to minimise their offtake under their existing contracts to the extent permissible under their take-or-pay obligations. And some commenced price reviews, seeking a variety of revisions to reduce the contract price. The revisions sought have reportedly ranged from basic price discounts to revisions that would modify the contract price formulae to achieve a contract price that includes hub-based elements or, in some instances, is entirely hub-based. Sellers also responded in a variety of ways, with some proposing reductions in flexibility terms or introduction of seller’s optionality.

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

IV THE ANATOMY OF A GAS PRICING DISPUTE

Although the provisions of any given price review clause must be construed on 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

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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

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12 See Section II.v, supra.
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:

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

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

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13 See Section II.v, *supra*. 
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;

c 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);

d 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;

e 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.
In the relatively short history of the world’s efforts to address global climate change, 2015 is likely to be recorded among the most monumental of years. More than 100 nations came together in Paris to sign the most comprehensive agreement to reduce greenhouse gases (GHGs) globally, the United States promulgated a landscape-changing regulation to reduce fossil fuel power generation, and courts around the world intervened to push their governments towards more aggressive measures at home to address climate change.

But despite these landmark accomplishments in 2015, the developments of 2016 and beyond have the potential to more directly and significantly impact energy development around the world. On the heels of the Paris Agreement, advocates for addressing climate change are reinventing their playbook for 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 turning the focus to the pursuit of economic damages, compensation and other remedies directly against energy companies, not only for current and future GHG emissions, but also for a 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 the ‘2.0’ era of climate change issues, 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 that are likely to bar the award of remedies, 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 2016 and beyond.

I CLIMATE CHANGE 1.0: 2015 MARKS MILESTONES FOR LIMITING GREENHOUSE GAS EMISSIONS

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.

For more than a generation, the focus for the proponents of climate change action has been to do just that: to cap the increase in the planet’s temperature by a certain amount (usually 2°C or less) by in turn capping emissions of 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 (and thus reducing GHG emissions) or capping GHG emissions to some extent. The best known examples of such programmes are various fuel efficiency standards for motor vehicles, Europe’s EU ETS cap-and-trade system, the US Clean Power Plan regulation of fossil fuel utilities, California’s AB 32 cap-and-trade programme, and a cap-and-trade programme in the northeast United States called the Regional Greenhouse Gas Initiative.

These programmes differ widely in form and scope but share the common goal of regulators acting to limit GHG emissions from various specified sectors. Several of these programmes arose originally from either environmental advocate intervention or court decisions, but what they share in common is that the focus has been primarily on regulators to determine how to reduce GHGs to address climate change, and then to translate those decisions to regulations and standards imposed on industry, whether they be efficiency requirements or GHG caps.

Indeed, in 2015, the three most significant developments share this theme of deferring GHG reduction goals to regulators, who in turn develop plans to implement the goals. First, the Paris Agreement provided for some 177 nations to sign ‘intended nationally determined contribution’ pledges to reduce or address GHGs through regulatory mechanisms. Second, the Obama administration finalised the Clean Power Plan, the most expansive GHG regulation in the United States, which aims to reduce GHG emissions from the fossil fuel power sector through promoting renewable energy and energy efficiency. Third, in a decision captioned ‘Urgenda’, which is being cited as precedent for a wave of new judicial decisions 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).

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 (*AEP v. Connecticut*); has limited the scope of regulations that could reach beyond industrial sources of GHGs (*UARG v. EPA*); and has recently 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 regulators authority and would cause irreparable harm to the nation’s energy grid. Beyond the US Supreme Court, other courts 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  CLIMATE CHANGE 2.0: THE EFFORTS AND CHALLENGES IN SEEKING ACCOUNTABILITY FOR CLIMATE CHANGE

In upcoming years, the efforts to reduce GHG emissions globally will intensify. 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 focus GHG controls and limits on power generation and other sources, with increasing efforts to ‘decarbonise’ economies around the world. But 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 commitments through additional programmes and lawsuits that aim to achieve separate and additional goals.

In the post-Paris 2.0 stage of climate change issues, these groups – activist environmental groups and 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, increasingly are shifting their targets in a new direction. The emerging efforts are aimed beyond just limiting GHG emissions, but also seeking remedies against individual emitters of GHG emissions for their alleged historic accountability for climate change and its impacts. These actions take several different forms and claims but share a set of commonalities and challenges.

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, these groups share a common study, referred to as the Heede study, that purports to present a historical 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 relative trifle of the world’s nearly infinite GHG emitters. 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 fuels, 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. These efforts, while different in form, share certain commonalities beyond just reliance on the study. 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. 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, unjust enrichment, other human rights regimes, and advertising and consumer protection laws.

Although groups have indicated that they plan to bring such 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 – a reluctance for 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. But, 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 defences and issues such as causation, redressibility and standing, which, given the infinite amount of GHG emitters in the world, provide obstacles to such claims that are likely to be insurmountable.
Chapter 5

ANGOLA

Catarina Levy Osório and Helena Prata

I OVERVIEW

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

Despite the prominent public presence in the energy industry, the country is progressively widening entry to private players, creating the necessary mechanisms to allow private companies to take part in the industry’s activities alongside and in close cooperation with the relevant public 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 Policy and Strategy for the National Energetic Security, 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 public companies;

b developing a strategic and regulatory framework for renewable energies;

c reinforcing powers of the Regulatory Institute of the Electrical Sector (IRSE);

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.

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2 Put into force by Presidential Decree No. 256/11 of 29 September.
In the oil and natural gas industry, the focus is on:

a. ensuring the ‘Angolanisation’ of upstream activities by defining a plan for upgrading Sonangol's management and integration capacities on deep-water projects;
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.

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 IRSE.

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3 Mainly composed by 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 between 35kV and 60kV, the MV networks between 35kV and 1kV and the LV networks below 1kV.
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.

II REGULATION

i The regulators

The IRSE, 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 IRSE 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

7 Decree No. 48/04 of 1 September governs the Rules and Procedures for Public Tenders in the Oil Sector.
The concession for exploration and production, after the public tender procedure, is granted by concession decree, issued by the Angolan government, awarding the national concessionaire Sonangol⁸ the right to develop a specific oil concession.

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

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 facilities⁹ 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 sector¹⁰ 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.

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⁸ Sociedade Nacional de Combustíveis de Angola, EP, the exclusive concessionaire for mining rights in Angola.

⁹ Meaning generation, transmission or distribution facilities.

¹⁰ At present, the Ministry of Energy and Water.
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.

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, 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.

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11 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.
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\(^{12}\) 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).

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 IRSE’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.\(^{13}\) 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.\(^{14}\)

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12 Considering an adequate return on the investment made.
13 Or 120 days, in the case of a hydropower generation unit.
14 Except for localities 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.
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 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.15

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 controlled16 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

via concession agreement, under the terms of Article 5 of the Electric Power Distribution Regulation (Decree No. 45/01 of 13 July).

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

16 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, hold the 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.
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 Ministers’ Council, concessionaires for generation, transmission or distribution activities may assign, sell or encumber their contractual positions 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 public 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 chain of business. Its activities include exploration, production, development, marketing, transportation and refining of hydrocarbons and its 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\(^\text{17}\) 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.

\(^{17}\) Currently developed by Sonangol Logística, EP.
In 2007, an agreement was made to develop the Angola LNG Project,\(^\text{18}\) 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.

This reorganisation stemmed from the Policy and Strategy for the National Energetic Security, 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.\(^\text{19}\) As part of the reform, the government envisaged:

\[a\] a public company exclusively dedicated to the management of generation assets, resulting from the merger of ENE and GAMEK, resulting in the incorporation of PRODEL;

\[b\] a public 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

\[c\] a public 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.

\(^{18}\) More information about this project can be found at www.angolalng.com/project/default.htm.

\(^{19}\) Today, only around 30 per cent of the Angolan population has access to electricity.
ii Transmission/transportation and distribution access

*Oil and gas*

Under the Law for the Transport and Storage of Oil and Natural Gas, operators of oil and gas pipelines have an exclusive right to explore 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 licence authorisation to generate electric power under the terms of the Electric Power Generation Regulation;
- entities who are not tied to the PES and hold a concession agreement or a licence to generate electric power;
- tied customers under the terms of the Electric Power Supply Regulation;
- non-tied customers who are recognised as such under the Commercial Relations Regulation; and
- self-producers or producers for private supply who intend to exercise their right of providing electric power through access to PES networks, as well as the entities that are supplied by these.

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

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

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

iii Terminalling, processing and treatment

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

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20 Enacted by Law No. 26/12 of 22 August.
21 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.
Investment, however, has been limited (the main investment in the industry is the Angola LNG project), mainly because of great legal and regulatory uncertainty. To address these uncertainties, Presidential Decree No. 256/11 of 29 September sets the development of the legal and regulatory framework for these activities as a primary goal for the strategic orientation of the oil and natural gas industries.

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

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

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

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

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

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

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

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

24 Presidential Decree No. 4/11 of 6 January.
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, \textit{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 respective concession agreements, taking into account the rules to be set in a separate regulation (the latter to be approved by the Minister of Energy and Water).

v Security and technology restrictions

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

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

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

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

IV ENERGY MARKETS

i Contracts for sale of energy

As previously mentioned, only non-tied agents use a market-based approach. Accordingly, the Commercial Relations Regulation allows 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, 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 public 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 sectorial 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 awareness towards the use of environmental technologies in Angola, mainly by (1) developing information campaigns using the existent social media, (2) implementing information campaigns in schools and local communities, (3) creating a platform to share information between entities related with the environmental technologies industries, and (4) promoting the country’s adherence to an international sustainability index.

The sectorial perspective focuses on promoting and implementing tailored measures and actions by 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.
Technological developments

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

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

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

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.

VI THE YEAR IN REVIEW

The main issue facing the Angolan energy market in 2016 continues to be the lowering of oil prices due in part to the shale gas boom and the end of sanctions imposed on Iran. 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.

Partly in response to the low oil prices, the government has decided to restructure the oil and gas institutional framework, and while this is known to focus in particular on Sonangol, further details have yet to be revealed.

Another aspect of this new conjuncture is the cutting of petrol subsidies (because of decreased government revenues), a measure that has sparked some unrest.

Also noteworthy, from a legislative standpoint, was the enactment of the amendment to the General Electricity Law, which has, among other aspects, eased requirements for non-tied generation of electricity, created a Rural Electricity Fund (aiming to provide electricity to rural areas) and reinforced the rights and obligations of electricity consumers.

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 public 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 Tim O’Shannassy

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 paper.

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 2017, 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.

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1 Clare Pope is a partner, Samantha Smart is of counsel, Fiona Meaton is an associate and Tim O’Shannassy is a law graduate at Squire Patton Boggs.

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
- 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, 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 energy regulation in the context of solar and wind electricity generation facilities.

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.\textsuperscript{6}

The ERA is established under the Economic Regulation Authority Act 2003 (Cth) 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\textsuperscript{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.\textsuperscript{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’\textsuperscript{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.\textsuperscript{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.\textsuperscript{11}

\section*{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:
\begin{itemize}
  \item[a] construct or operate generating works;
  \item[b] construct or operate a transmission system of a voltage of 66kV or higher;
  \item[c] construct or operate a distribution system of a voltage of less than 66kV; or
  \item[d] sell electricity to customers.\textsuperscript{12}
\end{itemize}

\begin{itemize}
\item[10] Note 7, supra.
\item[12] Electricity Industry Act 2004 (WA) Section 4; Economic Regulation Authority, Licence Application Guidelines and Form (February 2015), 2.
\end{itemize}
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:

a 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

b where the sale of electricity is to a person who is not the end-use customer; for example, a generator who sells electricity solely to retailers is not required to hold an electricity retail licence.

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

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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.
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

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 can often trigger the need for FIRB approval. Once FIRB is notified, the board will consider the proposed transaction and assess whether it is against the ‘national interest’. 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.18 The FIRB approval process generally takes 40 days from the time the application is made; however, FIRB may extend this period for complex applications.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

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.19 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.

18 Foreign Acquisitions and Takeovers Act 1975 (Cth) Section 17.
However, in the most recent WA budget announced on 12 May 2016, the WA government has disclosed that it is considering privatising Western Power (or at least certain aspects of its business) to reduce government debt and to encourage private sector investment in the industry.

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.\(^{20}\) As a network provider, Western Power is responsible for approving the connection of new ‘embedded’ generation systems to the SWIS. A system can only be connected once all of the applicable connection eligibility criteria have been met, as a means of ensuring that the quality and reliability of supply is of an appropriate standard. The connection of new generation systems may also be subject to the completion of overall network upgrades or the installation of new infrastructure to ensure network capacity is large enough to service the additional generation capacity and community and industrial demand. Therefore, the approval process depends on the size of the system to be embedded and the capacity of the network in the region where it will be installed.\(^{21}\)

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.\(^{22}\)

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.

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The objectives of the REBS are 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.\(^{23}\)

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.\(^{24}\)

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

iv Security and technology restrictions

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

The scale and changing nature of electricity networks now dictates that security is of greater significance. The roles of key electricity sector stakeholders are changing with a gradual shift toward a shared responsibility for network security, with customers becoming generators that use distributed generation technologies, and vendors assuming new responsibilities to


\(^{24}\) Ibid.

\(^{25}\) Above n 20, 2.9.1.
provide advanced technologies as well as their own security mechanisms. With these changes, all stakeholders are becoming responsible for ensuring the continued overall security and resilience of the broader grid, including through:

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

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 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.  

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 (STCs) and large-scale generation certificates (LGCs). 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.  

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

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

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

Bilateral contracts are agreements formed between wholesale market suppliers and wholesale market consumers (i.e., retailers and directly connected loads) for the provision of energy and serve to provide the holders with certainty over their settlement position with respect to that transaction. Once a bilateral contract submission is accepted, the energy is ‘scheduled’ and the ensuing demand forecast. The AEMO report allows market participants to revise their bilateral contract positions.30

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 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.

b Institutional arrangements: this involves six broad projects including transferring system management functions and market operation functions to the Australian Energy Market Operator, creating a new market rule change committee, establishing a WA reliability panel, investigating the merits of replacing the five Market Objectives with the singular National Electricity Objective, and replacing the Western Australian Energy Disputes Arbitrator and Western Australian Energy Disputes Board with more cost-efficient dispute resolution bodies and procedures.

c 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. The reforms to energy market operations and processes potentially include introducing security-constrained dispatch, a shorter gate closure period and dispatch cycle, facility bidding and the development of co-optimised energy ancillary services.\(^{31}\)

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.

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. 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.

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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:

- 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
- 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, functioned to improve the competitiveness of renewable energy technologies and increased the supply of renewable energy in Australia. ARENA has a $2.5 billion budget to invest in supporting renewable energy projects until the year 2022 to:

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

Consequently, ARENA is currently funding 100 solar energy projects nationwide, a contribution totalling over $585 million.

**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 (set to come 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

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 model included a new tariff option for consumers and had the potential to be replicated in future residential developments across Australia because of its centralised lithium ion battery storage capabilities. 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. 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

40 Note 37, supra.
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.\textsuperscript{41}

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.

\textbf{VI \hspace{1em} THE YEAR IN REVIEW}

In March 2015, the Minister for Energy, Dr Mike Nahan, outlined the state government’s reform programme for the electricity industry in response to recommendations made in an options paper prepared by a review committee. Consequently, the Liberal National government sought to begin taking the necessary steps to limit future electricity price increases for households and businesses, and reduce the requirement for subsidy of the industry that is forecast to cost the state more than $500 million in 2014–2015.

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 also transferred the once state-based regulation of the Western Power electricity network to the national regulator, the AER. This 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, Dr Nahan announced that the government would not split the state-owned electricity business Synergy and that WA would not join the national electricity market.\textsuperscript{42}

In April 2016, the state government also announced important changes to Western Australia’s electricity market, which is expected to reduce the cost of supplying electricity by up to $130 million every year. The changes, which are to take effect from 2017–2018 in the SWIS, formed part of the government’s Electricity Market Review, aimed at keeping electricity prices as low as possible for Western Australians.

The reforms included:

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

\textsuperscript{41} Note 37, supra.

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.\textsuperscript{43}

\section{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.

\textsuperscript{43} Government of Western Australia, Electricity reforms ensure fairer system for all (7 April 2016), https://www.mediastatements.wa.gov.au/Pages/Barnett/2016/04/Electricity-reforms-ensure-fairer-system-for-all.aspx.
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.

1 Marcos Chaves Ladeira is a partner, José Roberto Oliva Jr is a senior associate and Carolina Queiroz Pereira Dantas de Melo is a mid-level associate at Pinheiro Neto Advogados.
More recently, the sector has undergone some regulatory changes, particularly in the trading segment. Most of these changes have the stated purpose of enhancing reliability and safety in the sector’s transactions.

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:

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

b the Committee for Monitoring of the Electricity Sector, 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 among 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, organised into technical divisions and charged with performance of administrative functions in different areas such as economic regulation, market studies, supervision, mediation and the granting of concessions or 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

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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.
Brazil

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.

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 in the regulated market (the remainder may be sold at 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 in 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, and a capacity of up to 3MW for 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:

<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 3MW 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 3MW</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.

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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.
Ownership and market access restrictions

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

a foreign companies shall organise a special purpose company under Brazilian laws to have the regulatory licence granted; and

b if foreign companies bid jointly with a Brazilian company in a consortium, the leadership shall always be exercised by the Brazilian company.

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

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 to 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.

Transfers of control and assignments

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

In general terms, the regulation in force (ANEEL Resolution 484/12) sets forth that the prior consent of the regulatory agency is required for transfer of controlling interests of public service providers, hydropower companies and nuclear fuelled energy companies, as well as in any companies, regardless of the power source, whose intended controlling company makes up the corporate group holding or which, with the intended transaction, become the holder of ‘a significant share of the power generation market for the safety of the regulated market’ – a concept yet to be ruled 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 thereupon to date.

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

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. The 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.

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

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, which may choose their power generation supplier, need to have a demand higher than 3MW (former consumers also need to comply with a voltage requirement). 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); and

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.

iii Contracts for sale of energy

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

The contracts’ effective terms depend on each type of auction and power source, and may vary from 15 years to 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

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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.
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.\(^\text{11}\)

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.

iv Market developments

Some developments have been attained recently. Free and special consumers and small generation participants are now eligible for representation in their transactions before the CCEE by a ‘retail trading company’, under the terms established by ANEEL’s regulations. This is intended to benefit small companies acting in the market. Consumers within the free market 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 the possibility of having distribution companies overcontracted (to serve the relevant market demand) and about the struggle of generation companies to comply with their construction schedules, ANEEL has reinitiated discussions and recently issued new regulations on mechanisms for contracting-level adjustments by way of bilateral agreements.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

One of the most important regulatory policies adopted to encourage the development of renewable power was Proinfa, an incentive programme to encourage the use of alternative power sources, created by Law No. 10,438/2002. This programme was based on feed-in mechanisms to contract wind, biomass and SHPP projects for a 20-year period. According to information provided by the EPE,\(^\text{12}\) a total of 3,300MW was successfully contracted under Proinfa.

Recent information provided by the EPE, in its 2024 Energy Plan,\(^\text{13}\) 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

\(^{11}\) 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.


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.

In addition, investors have been analysing the integration of solar energy into wind power plants (or even hydropower plants), hence profiting from the efficiency that would result from using (1) the same land to set the solar energy business, and (2) existing transmission facilities to export production into the grid.

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, at the beginning of 2015, the government signalled its intention to allow the setting of more realistic power rates, sending consumers a significant signal through prices. In this respect, apart from the end of subsidies and other costs being transferred to consumers, 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.14

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 in Group B16 consumers. These

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

After the recent water-shortage crisis, which threatened the country with the prospect of renewed rationing, the PLD started to decline over the course of the second half of 2015 and decreased even further at the beginning of 2016.\(^{18}\) Following the significant reduction in consumption, hydropower plant reservoirs recovered to a great extent, which led the government to reduce the dispatching of thermal power plants.

Nevertheless, the market is still experiencing the negative effects of the drought, especially since several participants, having suffered because of the shortage of hydropower generation, filed lawsuits to limit their liability and have been granted injunctions that entail losses for other participants in relation to the market’s default. This caused an avalanche of lawsuits to prevent, by means of favourable injunctions, those participants from being held liable for the others’ default, which in turn forced CCEE to temporarily suspend financial settlement of the short-term market as it became unfeasible to comply with the different contradictory decisions (i.e., the market lacked funds to have all creditors paid). Some hydrogen companies gave up on their lawsuits on account of an agreement offered by ANEEL, following the enactment of legislation on the subject, to mitigate the hydrological risks they faced.

A notable auction was conducted in November 2015 to grant new concessions for the operation of former hydropower plants, the concessions for which, under the terms of Provisional Measure No. 579/2012 (later converted into Law No. 12,783/2013), had not been renewed. In addition, renewable energy sources continued to enjoy great success in the auctions in the regulated market in 2015. In auction A-3, 19 wind, seven SHPPs and two biomass projects were successfully contracted; in the first back-up energy auction, exclusively for solar, 30 projects were contracted at the average price of 301.79 reais/MWh; and in the second back-up energy auction, 20 more wind projects and 33 solar projects were contracted.\(^{19}\)

Some of the sector’s mergers and acquisitions transactions included:

- \(a\) the acquisition of wind power plants from Casa dos Ventos by Votorantim;
- \(b\) the acquisition of hydropower plants from EDP Energias do Brasil by a company belonging to the Brookfield Group;
- \(c\) the acquisition by China Three Gorges of interest in Rio Verde Energia, Rio Canoas Energia and Triunfo Negócios de Energia;


\(^{18}\) The PLD for the northeast submarket has not lowered as much, mainly because of worse hydrologic conditions there. Information on PLD prices was provided by CCEE on its website: www.ccee.org.br. Accessed on 19 April 2016.

\(^{19}\) All the information on projects contracted and price was provided by EPE on its website: www.epe.gov.br. Accessed on 19 April 2016.
The acquisition of wind power plants from Casa dos Ventos by Cubico Sustainable Investments, a company owned by Santander and two Canadian pension funds; and the acquisition of wind power projects from Bioenergy by Omega Energia.

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. While the recent drought has left several issues as yet unaddressed, the market is likely to adjust to the new scenario. In addition, the captive market has been subject to more realistic and higher rates, which has prompted an increasing number of consumers to migrate to the free market.

The market is currently anticipating the privatisation of Celg Distribuição, the first of several distribution companies belonging to state-owned Eletrobras that are expected to have their controlling interests auctioned in the near future.

The government has tried to send positive signals to investors in relation to auctions. In addition to a number of generation auctions – including one back-up energy auction exclusively for solar projects and an alternative energy auction for biomass and wind power projects – it has established more attractive conditions for new transmission concessions by increasing the length of the construction period and the capital return, as evidenced in the auction that took place on 13 April 2016. For the first A-5 auction of 2016, conducted on 29 April 2016, the government has taken into consideration current economic conditions and established more attractive price caps. Two back-up energy auctions are expected this year. Furthermore, in the near future, if environmental issues are settled, a large hydropower plant, São Luiz do Tapajós, located at Pará State with 8,040MW of installed capacity, is expected to be put up for auction.20

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 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.

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

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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.\textsuperscript{21}

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

Chapter 8

CHINA

Monica Sun, Hao Su and James Zhang

I OVERVIEW

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

China, as one of the largest economies globally, is 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 May 2016.

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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 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 plan (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 State Electricity Regulatory Commission (SERC) 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 (SAWS): 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 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.
China

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.


e The Regulation on Sino-foreign Cooperation in the Exploitation of Onshore Petroleum Resources (1993, amended 2001 and 2007) is the basis for foreign companies to participate in the exploration and exploitation of onshore blocks in China through PSCs.

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

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

Power

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

b 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).


d 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.

e 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.

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

g 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.

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

a The Energy Conservation Law (2008) is aimed at promoting energy conservation.

c The NDRC Notice on Feed-in Tariff for Offshore Wind Power (2014) provides for the feed-in tariff for offshore wind farms.

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 SERC. Electric power business permits are divided into three categories depending on the type of business:

\[ a \quad \text{a power generation permit for power generation companies}; \]

\[ b \quad \text{a power transmission permit for power transmission companies; and} \]

\[ c \quad \text{a power supply permit for power supply companies}. \]

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:

\[ a \quad \text{distributed generation projects registered or approved by the NEA}; \]

\[ b \quad \text{small hydropower stations with single-station generating capacity below 1MW}; \]

\[ c \quad \text{new-energy generation projects such as solar, wind, biomass, ocean power and geothermal power with generating capacity below 6MW}; \]

\[ d \quad \text{power projects with comprehensive use of heat and pressure by-products; and} \]
v 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).

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 recently revised 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 PSC regime.

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 2013 CNPC annual report shows that it operates nearly 80 per cent of the natural gas pipelines and 70 per cent of the crude oil pipelines in China. 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
China

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 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 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, infra, 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 Huagneng 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;
c. construction and operation of power stations with large air-cooled generation units with single unit power of 600,000kW or more in regions suffering from water shortage;
d. construction and operation of projects of power generation via integrated gasification combined cycle and other clean coal power generation projects;
e. construction and operation of power generation projects with single unit power of 300,000kW or more that use fluidised bed boilers and coal gangue, middling, and coal slurry;
f. construction and operation of hydropower stations for the primary purpose of power generation;
g. construction and operation of nuclear power stations (the Chinese party must hold a controlling interest);
h. construction and operation of new-energy power stations (including solar energy, wind energy, geothermal energy, tidal energy, wave energy and biomass energy); and
i. 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 to small grids:
a. power plants utilising coal-fired and steam condensation thermal generator sets whose single generator capacity is 300,000kW at most; and
China

thermoelectric 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 connected to large grids fall into the prohibited category for foreign investment.

v 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:

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

b the specified minimum input for exploration has been fulfilled;

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

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

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

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 SERC. The SERC 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. This reform is now carried out in pilot provinces including Anhui, Guizhou, Hubei, Inner Mongolia, Ningxia, Shenzhen and Yunnan.

Since 2009, the user-generator direct trading system has been put on trial in seven 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.

Power

A grid operator must ensure non-discriminatory and fair opening of their grid to qualified power plants and disclose the following information to power plants within their 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;
b enter into grid connection agreements with qualified RPG enterprises; and
c purchase all the on-grid power generated by these RPG projects at a higher feed-in tariff.

iii Rates

Oil and gas
Pipeline transportation fees are regulated by the NDRC. A national price will apply for earlier pipelines, while for newly constructed pipelines the NDRC will issue a separate notice on transportation fees.

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, the current pricing regime is expecting reform towards a market-oriented pricing mechanism this year or next year.

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:

a. have a foreign trade business qualification;
b. satisfy the requirements published by MOFCOM; and
c. register with MOFCOM.

Both state trading enterprises and non-state trading enterprises must obtain an import licence issued by MOFCOM. However, non-state trading enterprises shall be subject to import quotas. This quota has increased from 37.6 million tons in 2015 to 87.6 million tons in 2016. 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, 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. Twelve refineries have obtained a permit from 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 use–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 SERC, are met.

iii Contracts for sale of energy

Oil and gas
There are two types of government regulated prices:

a. government fixed price; and
b. government guidance price.
The former is fixed and there is no flexibility, while the latter is more flexible. Government guidance price can be in the form of:

- a benchmark price with a float range;
- maximum price;
- minimum price;
- the rate of price difference; and
- 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:

- 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
- 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, and liquefied natural gas are determined freely by suppliers and consumers.

**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.

<table>
<thead>
<tr>
<th>Electricity source</th>
<th>FITs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind (Onshore)</td>
<td>Four tiers ranging from 0.47 yuan/kWh to 0.60 yuan/kWh, depending on project locations (for projects approved after 1 January 2016 and projects approved before 1 January 2016 but not in construction at the end of 2017). Four tiers ranging from 0.44 yuan/kWh to 0.58 yuan/kWh, depending on project locations (for projects approved after 1 January 2018). Offshore projects: 0.85 yuan/kWh or 0.75 yuan/kWh depending on the distance to shore.</td>
</tr>
<tr>
<td>Biomass</td>
<td>0.75 yuan/kWh.</td>
</tr>
<tr>
<td>Solar</td>
<td>Three tiers ranging from 0.80 yuan/kWh to 0.98 yuan/kWh, depending on project locations.</td>
</tr>
</tbody>
</table>

Other incentives include:

- surcharges collected from end users, which are used to subsidise the difference between feed-in tariffs and the benchmark price for desulfurised coal generators, operations and maintenance for independent public power systems, and costs for connecting renewable energy generators to power grids;
- favourable loans with financial discounts for renewable energy projects listed in the Guidance Catalogue for renewable energy Industry Development;
- subsidies for renewable energy development in areas such as new-energy vehicles, building-integrated solar photovoltaic systems, wind turbines and biomass power generation; and
- 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 (CNNC) and China General Nuclear Power Corporation (CGN) on taking stakes in domestic nuclear projects, as part of its efforts to diversify into cleaner forms of energy.
VI  THE YEAR IN REVIEW

In June 2015, China submitted its Intended Nationally Determined Contribution (INDC), setting out its goal to peak carbon dioxide emissions by 2030 and increase energy supplied from non-fossil fuels to at least 20 per cent by 2030. In addition, China signed the Paris Agreement, a treaty dealing with greenhouse gases emissions mitigation, on 22 April 2016, and aims to finalise the domestic legal procedures by September 2016.

In line with China’s above commitment to the international community, the State Council released the 13th Five Year Plan for National Economic and Social Development (2016 to 2020) in March 2016 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 4.8 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 by 2020.

China also continues to push its goal to achieve the marketisation of energy supply. The ongoing power price reforms, as mentioned above, reflect the government’s intention to open up the energy market. This can be considered as part of China’s efforts in promoting ‘supply-side structural reform’ to boost economic development. A pilot project started in Shenzhen and Inner Mongolia has been expanded to seven additional provinces. With more entities allowed or encouraged into the energy market, new opportunities may open for foreign and private investment.

The trend towards opening up the energy market is in line with the SOE ownership overhaul since 2013. In response to the hybrid ownership reform, and to the low oil-price environment, in November 2015, CNPC sold its 50 per cent stake in Trans-Asia Gas Pipeline Co to China Reform Holdings Corp, a state-owned company established for the SOE ownership reform. This is also considered as a transition towards a separate pipeline monopoly. The industry expects to see more divestment of assets by the big NOCs, partly because of the low oil price, and partly because of the government’s determination to reform the energy giants.

In the power sector, the merger between China Power Investment Corporation and State Nuclear Power Technology Corporation was completed in July 2015. The new nuclear giant formed from this merger, State Power Investment Corporation, has total assets of $116.3 billion and installed generating capacity of 98GW. The merger is considered a good combination of the two companies’ technology, capital strength and operating licences, and ultimately a step towards a better position to compete in the global market.

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 PSC for shale gas exploration, development and production in the Neijiang-Dazu block in the Sichuan Basin with CNPC in March 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
China

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

Cyprus is not currently producing any primary sources of energy and it is considered to be a heavily energy receiving country as over 90 per cent of its energy comes from imports. It has no electrical or natural gas interconnections with other countries and, therefore, has an isolated energy system. The country’s dominant source of energy in all sectors, including transportation and electricity generation, is imported petroleum products, which contribute over 91 per cent to the country’s gross final energy consumption.

The Cyprus electricity market is currently dominated by the state-owned Electricity Authority of Cyprus (EAC), which supplies 100 per cent of the electricity in Cyprus. The EAC generates 91.5 per cent of its electricity from imported petroleum products and only around 8.5 per cent\(^2\) from renewable energy sources (RES), which basically relates to energy produced from wind farms, solar energy plants and biomass plants, which are all privately owned and which sell the energy they produce to the EAC.

The accession of Cyprus to the EU in 2004 has meant that the monopoly of the EAC in Cyprus should legally come to an end. In 2004 a part of the electricity market was liberalised (35 per cent) for certain non-domestic consumers. In 2009 the electricity market was fully opened in relation to all non-domestic consumers (65 per cent), with a view for full liberalisation for all consumers by 2014. Since January 2014, the electricity market has been fully liberalised to allow all consumers (both domestic and non-domestic) to choose their electricity supplier. Despite the above liberalisation no electricity company has broken into the market yet and the EAC remains the sole supplier of electricity, thus enjoying a de facto monopoly.

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1 Michael Damianos is the founder and managing partner of Michael Damianos & Co LLC and Electra Theodorou is an associate of the firm.
2 In accordance with statistical data provided for the year 2015 by the TSO (as defined below).
As far as gas is concerned, the legal regime is there, but there is currently no production or imports to supply the market (and there is no infrastructure for this). The most significant development in Cyprus’s energy history, however, is the fact that in December 2011 it discovered large natural gas reserves in its exclusive economic zone (EEZ). Despite the natural gas discoveries, according to commentators, natural gas from the Cyprus EEZ will not be available to the Cyprus market at least until 2020 and exports are not expected to commence before 2024. The Council of Ministers of the Republic of Cyprus has, therefore, decided to import natural gas for the production of (mainly) electricity (to decrease the cost of production), and any power station or unit of considerable capacity is to be fuelled with natural gas as soon as this is feasible. As will be seen in this chapter, however, the supply of gas to the Cyprus market will also be a clear monopoly for a number of years.

Finally, the current economic and financial developments in Cyprus and its current commitments to its lenders mean that the government should proceed with the denationalisation of certain profit-making state-owned organisations. Legislation was passed in March 2014 to allow for this, and the Council of Ministers subsequently approved a government plan for the period from 2014 to 2016, dealing, inter alia, with the denationalisation of the EAC. Even though the denationalisation of the EAC is likely to have a significant impact on the unbundling of the Cyprus electricity market (as is further discussed in this chapter) this is not expected to occur before the end of 2017. The Cyprus parliament has recently approved a draft bill that postpones the entry into force of the denationalisation legislation in relation to the EAC until 31 December 2017.

II REGULATION

i The regulators

The Cyprus Energy Regulatory Authority (CERA) is the sole regulator for the electricity and (emerging) gas market in Cyprus. It was established by the Law on Regulating the Electricity Market of 2003 (as amended) (the Electricity Market Law), which was enacted for the purpose of harmonisation of Cyprus law with the (now repealed and replaced by EU Directive 2003/54/EC, which itself was repealed and replaced by EU Directive 2009/72/EC) EU Directive 96/92/EC concerning common rules for the internal market in electricity.

CERA was established aiming to liberalise the electricity market (which has been, at least legally, fully liberalised since January 2014), and is the body responsible for ensuring that electricity prices determined by (the current monopoly of) the EAC reflect the actual costs of the services provided with a reasonable profit.

In addition to the above, by virtue of the Law Regulating the Natural Gas Market of 2004 (as amended) (the Natural Gas Market Law), which transposes EU Directive 2003/55/EC (now repealed and replaced by EU Directive 2009/73/EC) concerning common rules for the internal market in natural gas into Cyprus law, CERA is also responsible for regulating the Cyprus gas market.

CERA is legally separate from and operationally independent of any other public or private body. Its main objective is to effectively regulate and monitor the electricity and (emerging) gas market. It is required to ensure that the energy market as a whole operates on the basis of sound competition, that the various participants are acting with transparency, that high-quality services are provided, and that the interests of consumers are protected. It is entrusted with various statutory powers and duties that mainly derive from the Electricity Market Law and the Natural Gas Market Law.
One of CERA’s main powers is to investigate any infringement of the law, breach of the terms of any authorisation granted (i.e., a licence, order, prior permit or exemption), or breach of any regulatory or other decision issued by it. It has the power to issue orders to remedy any such infringement or breach by an authorisation holder, and if the relevant authorisation holder fails to remedy the infringement or breach, CERA has the power to impose administrative fines on it, depending on the nature, seriousness and duration of the infringement or breach, and even revoke an authorisation granted to the relevant authorisation holder.

CERA has also been granted extensive powers to protect competition. The highest authority in Cyprus in relation to the protection of competition, however, is the Commission for the Protection of Competition (the Commission), which was established in accordance with the provisions of the Law for the Protection of Competition of 1989 to 2000 (now repealed and replaced by the Law for the Protection of Competition of 2008 to 2014). This basically means that although CERA has the power to protect competition itself, its actions must be aligned with the competition law provisions and with the practice of the Commission.

ii Regulated activities

Under both the Electricity Market Law and the Natural Gas Market Law, it is prohibited to carry out a licensable activity without an authorisation. Authorisations can take the form of either a licence or an exemption. Licences are issued by CERA in accordance with the relevant law, the regulations issued by CERA, and any government policy guidance published by the Minister of Energy, Commerce, Industry and Tourism, from time to time. Licences may be granted to both physical and legal persons.

Article 34 of the Electricity Market Law provides that CERA may issue a licence with regard to the following activities:

- a constructing a generating plant or generating electricity;
- b supplying electricity to eligible consumers;
- c supplying electricity to non-eligible consumers;
- d discharging any of the functions of the transmission system operator;
- e discharging any of the functions of the distribution system operator;
- f discharging any of the functions of the transmission system owner; and
- g discharging any of the functions of the distribution system owner.

CERA considers certain criteria when evaluating an application for a licence under the Electricity Market Law, including the safety of the system, the protection of the environment, the location of the generating plant (if the application relates to a generating licence) and the protection of public health and public safety.

Article 35 of the Electricity Market Law provides that CERA has the power to grant exemptions, following a relevant application, from the requirement to hold a licence to carry out any of the activities in (a) and (b) above. Any person who auto-generates electricity of a capacity of less than 1MW can be granted an exemption. CERA may also grant exemptions in relation to electricity generation from RES of a capacity of less than 5MW and electricity supply by a specific person of a total capacity of less 0.5MW per generating plant.

In exercising its powers, CERA may take regulatory decisions setting out how it shall regulate the different segments of the electricity market and which authorisation holders shall be bound by these regulatory decisions. A regulatory decision was issued by CERA in
2013, pursuant to which CERA is not currently accepting applications for a licence or an exemption regarding the construction of a generating plant that will use conventional fuels or RES to generate electricity (excluding any licences that fall under any government-backed or European support scheme). CERA based its decision, principally, on the need to amend certain regulations and market rules and to reconsider the country’s national plan on RES before proceeding with the acceptance of any applications of new generating plants. This decision effectively means that, in practice, a big part of the production segment of the electricity market is, currently, not open to competitors and that the EAC is still a monopoly.

The Natural Gas Market Law is structured along the same lines. Article 8 of the Natural Gas Market Law 2004 provides that CERA may issue a licence with regard to the following activities:

- building and operating, or only operating, natural gas facilities, storage facilities, pipeline networks or combinations thereof, and pipelines and associated equipment;
- discharging any of the functions of the owner of natural gas facilities, storage facilities or pipeline networks, or combinations thereof, and pipelines and associated equipment;
- discharging any of the functions of the network operator;
- supplying natural gas to, among others, wholesale customers;
- supplying natural gas to eligible customers;
- supplying natural gas to non-eligible customers;
- discharging any of the functions of the operator of natural gas importation, storage, transmission or distribution; and
- discharging any of the functions of the owner of the natural gas importation, storage, transmission or distribution network.

As far as natural gas is concerned, it should be noted that despite the transposition of EU Directive 2009/73/EC into Cyprus law, Cyprus, being an isolated and emerging market, has obtained derogation from a number of its provisions. As a result, it is planned that the supply of natural gas to the Cyprus market will be a clear monopoly for a number of years. The Natural Gas Public Company (NGPC), which is fully controlled by the state, was established to become the body responsible for the development of the internal gas market and network. The NGPC is responsible, among others, for the import, storage, distribution, transmission, supply, and trading of natural gas, as well as the management of the distribution and supply system of natural gas in Cyprus. It will, once Cyprus is able to import natural gas as mentioned in the introductory section of this chapter, be the sole importer and distributor of natural gas in Cyprus, therefore making it a monopoly. The NGPC has to proceed with securing the necessary natural gas quantities, at the most favourable commercial terms, to cover Cyprus’s needs for electricity power generation (phase A) and supply industries, hotels and households (phases B and C) with natural gas. It has to develop an efficient gas network, which will initially (phase A) consist of three pipelines that will themselves be connected to the gas import hub and to the three existing downstream power stations (all owned and controlled by the EAC). The estimated cost for phase A is approximately €65 million and a €10 million grant has been secured from the European Economic Programme for Recovery. Phases B and C, which will connect the receiving terminal to industries, hotels and households, are expected to cost over €500 million.

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3 Regulatory Decision of the Cyprus Energy Regulatory Authority 856/2013.
iii Ownership and market access restrictions

As mentioned above, it is currently legally impossible to enter the natural gas market. As far as the electricity market is concerned, a person is eligible to apply for a licence only if:

a being a natural person, he or she is a citizen of the EU and resides in an EU Member State; or

b being a legal person (which includes a company, partnership, municipality, club, foundation, or any other union or any other union or association of persons with or without legal personality), it is established in an EU Member State, and, if a company, it has been incorporated in accordance with the laws of an EU Member State and it has its statutory place of establishment, central management or main place of establishment within the EU.

iv Transfers of control and assignments

Under the Issue of Licences Regulations (Electricity Market) of 2004, a licence holder who wishes to transfer or assign his, her or its licence to a third party, needs to make an application to CERA at least three months before the proposed transfer or assignment takes place stating who the transferee or assignee is and the reason for making the transfer or assignment. The transferee or assignee then needs to follow an almost identical procedure to that required when applying for a new licence.

The Issue of Licences Regulations (Electricity Market) of 2004 also provides that a company that has obtained an electricity production licence must immediately notify CERA of any (proposed) change of control in that company and request CERA’s written consent for that. The licensee shall also notify CERA of any intention to sell, transfer or create a charge against any of its electricity generation assets (at least one month prior to the sale, or transfer of the asset, or creation of the charge) and request its written consent for that. Similar restrictions apply to any company that has obtained an electricity supply licence.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

The Cyprus electricity market has long been dominated by the vertically integrated EAC. The EAC is currently engaged in all segments of the Cyprus electricity market. It is the sole supplier of electricity, it owns and operates the distribution network and also owns the transmission network (i.e., the only segment of the electricity market that is independent from the EAC is the operation of the transmission network). For this reason the EAC is required under the Electricity Market Law to keep separate accounts for its electricity production, supply, transmission and distribution processes.\(^4\) CERA issued a number of regulatory decisions requiring the EAC to do this. In accordance with CERA, steps have been taken by the EAC to implement the accounting separation, but the EAC has yet to fully comply with these regulatory decisions.

\(^4\) Article 108(1) of the Law on Regulating the Electricity Market of 2003 (as amended).
It should be noted that Cyprus has been one of the last EU Member States to transpose the unbundling provisions of the EU Third Energy Package into national legislation, and having a small isolated system it has obtained certain exemptions, as discussed below:

**Unbundling of distribution system operators**

Cyprus decided to opt out from the provisions of the EU Directive 2009/72/EC on the unbundling of distribution system operators on the basis that its integrated electricity undertaking serves a small isolated system. It has, therefore, maintained its existing distribution system regime and the function of the distributor system operator (DSO) is still within the network business unit of the EAC. The DSO is provided with all of its employees from the EAC and it is not an independent body. The DSO is required to safeguard third party access to the distribution network and equal treatment of all users of the said network.

**Unbundling of transmission systems**

Cyprus has obtained an exemption from Article 9 (unbundling of transmission systems) of the EU Directive 2009/72/EC and has, therefore, maintained its existing regime on transmission unbundling. Under the current regime, the transmission system operator (TSO), which was established pursuant to a decision of the government of the Republic of Cyprus for harmonisation with EU Directive 2003/54/EC (which was repealed and replaced by EU Directive 2009/72/EC), acts independently in terms of organisation and decision-making from the EAC, which is the transmission system owner and distribution system owner and operator. Under the Electricity Market Law of 2003 (as amended), the TSO is legally unbundled and is prohibited from being engaged in production, distribution or supply activities in the Republic of Cyprus.

The TSO’s main functions and responsibilities are to secure the operation of the electricity transmission system and to manage the electricity market on an objective, non-discriminatory basis in a competitive environment, while at the same time supporting and promoting electricity generation from RES. It ensures access and equal treatment of all users of the transmission network. Both CERA and the TSO have a significant role to play and their role will be even more significant if electricity companies do break into the Cyprus market in the next few years.

As mentioned in the overview of this chapter, if the denationalisation of the EAC proceeds, it will have an impact on the unbundling of the Cyprus electricity market. In accordance with the denationalisation plan, which was approved by the Council of Ministers in March 2014, the activities of the EAC (electricity production, transmission, distribution and supply) should have been unbundled into separate legal entities by 30 June 2015 (first stage of the denationalisation process). The second stage of the denationalisation process was to involve the transformation of the EAC, by 31 December 2015, from a body governed by public law to one or more companies limited by shares, of which the Cypriot government would be the sole shareholder. By 31 March 2016, a decision should also have been reached in relation to the percentage of share capital that would be offered to employees of the EAC on an individual or collective basis (provident or pension fund) in the company, or companies. The next stage of the denationalisation process was to involve the search for one

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5 Article 26 of EU Directive 2009/72/EC.
6 Article 64(1).
or more strategic investors in respect of one or more of the above-mentioned activities of the EAC by 30 September 2017. As mentioned above, however, the denationalisation and the unbundling of the EAC has recently been put on hold and none of the aforementioned time frames have been adhered to. It remains to be seen, therefore, whether the plan will be brought back to the table at a later stage (if at all).

ii Rates
As far as rates and terms of access to the transmission and distribution network are concerned, these are regulated by CERA, which may require the TSO and the DSO to amend the methodologies they use for determining their tariffs. As mentioned above, given the fact that the electricity market is currently dominated by the EAC, CERA must protect consumers from being adversely affected by any abuse of the EAC’s dominant position in the electricity market. It shall, therefore, ensure that the electricity prices determined by the EAC reflect the actual costs of the services offered plus a reasonable profit.

IV ENERGY MARKETS

The monopolies of the EAC and NGPC mean that there are no real or actual energy markets operating in Cyprus. Despite that, there are certain energy market rules and regulations that are worth mentioning for future reference, as follows:

i Electricity Transmission and Distribution Rules
Pursuant to the Electricity Market Law, CERA has the power to issue regulatory decisions instructing the TSO and the DSO to draft and publish certain transmission (as far as the TSO is concerned) and distribution (as far as the DSO is concerned) system rules. The publication of these rules is subject to CERA’s consultation with an advisory committee on transmission and distribution (which has not yet been formed) and CERA’s prior approval. The Transmission and Distribution Rules of 2004 (as amended) set out the technical conditions and constrains that will apply to licensees who wish to connect to the transmission or distribution network, or both, or use these two networks for electricity transportation. The imposed conditions should not be discriminatory. The said rules also ensure that the transmission and distribution system will be used and developed in an efficient and reliable manner.

ii Electricity Trading and Settlement Rules (Market Rules)
Under the Electricity Market Law, CERA instructs the TSO to draft and publish certain electricity market rules. The publication of these rules is subject to CERA’s consultation with an advisory committee on market rules and the written approval of CERA and the Minister of Energy, Commerce, Industry and Tourism. The Trading and Settlement Rules (Market Rules) of 2009 set out the mechanisms, tariffs and various terms and conditions subject to which licensees buy or sell electricity, in accordance with arrangements made by the TSO, and ensure that market participants who buy or sell electricity pursuant to these arrangements should not be subject to discrimination. The said rules also promote energy efficiency and energy saving and facilitate competition in the electricity market.
It should be noted that CERA has recently undertaken a study on the reorganisation of the Cyprus electricity market and the amendment of its regulatory framework. The current Market Rules will need to be amended, among other things, to be in line with the market reorganisation proposed by CERA.

V RENEWABLE ENERGY AND CONSERVATION

RES contribute only marginally to Cyprus’s energy mix, as they (currently) have a share of less than 10 per cent of the country’s gross final energy consumption. They are, however, now more significant in the country’s energy mix than they were 10 years ago (when their contribution was not much above zero). RES are used in Cyprus, as follows:

- **Solar energy:** solar energy is used by domestic and industrial solar thermal systems. Cyprus ranks first in the world in terms of the use of solar energy for domestic heating (through solar thermal systems). Photovoltaic grids are also used and they are either connected (currently) to the EAC, or are stand-alone and used in other ways.

- **Wind energy:** there are currently six wind farms in operation and they all generate electricity that they sell in its totality to the EAC. Wind energy is also used through wind turbines for water pumping.

- **Biomass:** the total capacity of biomass plants is insignificant, generated through manure and organic animal waste and, again, sold to the EAC.

Cyprus’s energy policy is aligned with the energy policy of the EU. The three main goals set by Cyprus are (1) the development of indigenous energy resources, (2) the enhancement of security of energy supply and competitiveness, and (3) the protection of the environment. In this respect, Cyprus has recently transposed the Renewable Energy Directive 2009/28/EC into Cyprus law by enacting the Law for the Promotion and Encouragement of the Use of Renewable Energy Sources of 2013. In accordance with the above, Cyprus is bound to achieve certain targets by 2020, such as a share of 13 per cent of RES in its gross final energy consumption (after adjustment for aviation consumption) and a share of 10 per cent of RES in the final energy consumption of transportation.

To achieve the above-mentioned 2020 targets, the Ministry of Energy, Commerce, Industry and Tourism has issued certain support schemes. The support schemes aim to provide financial incentives in the form of government grants for the promotion and penetration of RES into the market, and both individuals and companies or organisations are eligible for participation. The support schemes cover investments for thermal insulation on existing residential buildings, heating and cooling from RES, and electricity generation from RES. They address mature technologies rather than technologies currently under research and development and are being reviewed and, if required, updated on an annual basis, so that the incentives provided ensure the viability of RES systems. Furthermore, any support scheme revision is done taking into account any changes in the energy policy of the country.

In 2013, the government announced and implemented certain support schemes for the promotion of electricity generation using RES. One of these schemes involved the provision of state grants to vulnerable households for the installation of 2,000 photovoltaic systems of 3kW each and their connection to the grid of the EAC via net metering. The electricity consumption of the household is offset by the electricity generated by its photovoltaic system into the grid, with the household being billed for the difference. This is estimated to save each participating household 80 per cent on its electricity bill. A second
scheme for the installation of a further 3,000 photovoltaic systems of 3kW each (but without a grant) was also announced and implemented in 2013 and similar schemes are expected to be announced soon. In 2014, the Ministry of Energy, Commerce, Industry and Tourism announced similar support schemes for the installation of photovoltaic systems of 3kW each by vulnerable households (with a state grant) and by non-vulnerable households and local government authorities (without a state grant). Another support scheme was announced in 2014 for auto-generating photovoltaic systems of 500kW each to be installed on commercial and industrial units.

As far as energy efficiency is concerned, measures have been implemented to promote the energy efficiency of buildings, such as minimum energy performance requirements, energy performance certificates, and regular inspections of heating and air conditioning installations.

VI THE YEAR IN REVIEW

As mentioned above, the commitment of the Cyprus government to denationalising the state-owned EAC is currently on hold and the Cyprus parliament recently approved a draft bill postponing the entry into force of the denationalisation legislation in relation to the EAC until 31 December 2017. If it is eventually denationalised, this will definitely have an impact on the Cyprus electricity market as it will almost certainly result in the end of the EAC monopoly. If this is the case, the activities of the EAC will be unbundled into separate legal entities to be offered to potential investors. It is, therefore, likely that different investors will acquire different activities of the EAC, which will result in the actual disintegration of the electricity market.

Although discussion of this is beyond the scope of this chapter, the government of Cyprus is rapidly moving towards exploiting the country’s natural gas reserves, despite current global economic conditions and oil prices. The discovery of natural gas in the Cyprus EEZ will surely affect the country’s energy policy. However, natural gas from the Cyprus EEZ will, according to commentators, not be available to the Cyprus market before 2020 at the earliest.

VII CONCLUSIONS AND OUTLOOK

One can conclude that Cyprus is a heavily energy receiving country with a monopolised electricity market and a (currently) inexistent gas market. The EAC’s monopoly in the electricity market is likely to end in the years to come with the EAC’s proposed denationalisation, while the gas market, once this actually evolves, will be a monopoly of the NGPC for a good few years.

For the electricity market to be practically liberalised (as it is only legally fully liberalised to date) electricity companies need to enter the market. Although the legal and regulatory framework is there, this has yet to attract any new players, but it is anticipated that this will change in the next few years.
Chapter 10

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,2 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,3 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

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1 Nicolaj Kleist is partner at Bruun & Hjejle.
2 Act No. 960 of 13 September 2011 on the Use of Danish Subsoil.
3 Act No. 1329 of 25 November 2013 on the Supply of Electricity.
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.

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). 4 Part of the Ministers authority has been delegated to the Danish Energy Agency (DEA). 5 The DEA is responsible for the entire chain of tasks linked to energy production and supply, transportation and consumption, including energy efficiency and savings as well as national carbon dioxide targets and initiatives to limit emissions of greenhouse gases. The DEA prepares, in cooperation with the Minister, 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) 6 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. 7 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. 8 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 be mandatory.

The Energy Supplies Complaints Board is a private board established by the energy industry and the Consumers’ Council. The Energy Supplies Complaints Board handles complaints about the purchase and delivery of energy from supply undertakings. As a principal rule, the board only accepts complaints from consumers. Decisions of the board cannot be appealed to any administrative authority, but can be brought before the courts.

4 www.kebmin.dk.
5 www.ens.dk.
6 www.energitilsynet.dk.
7 www.ekn.dk.
8 Act No. 1307 of 11 November 2014.
The main legislation for energy regulation is the Continental Shelf Act, the Act on Raw Materials, the Subsoil Act, the Pipeline Act, the Natural Gas Supply Act, the Heat Supply Act and the Electricity Supply Act.

ii Regulated activities

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

A permit is required for the establishment of plants and for expansion or changes to such plants causing increased pollution. Permits are issued by the relevant city council or regional council depending on the size of the plant. Permits for major plants require a prior public hearing, and for major plants there may be a duty to complete an environment impact assessment under the Planning Act. Offshore plants are primarily subject to approval under the Subsoil Act and Continental Shelf Act. Offshore installations are subject to approvals and permits issued by the DEA. These include operation permit, manning and organisation plan approval and approval for the contingency plan. To obtain an operation permit, there must be an evaluation of safety and health conditions for the installation and the operational conditions (health and safety review/safety case) and other relevant information regarding health and safety conditions (e.g., certificates). Offshore installations operating in Denmark must have a workplace assessment system.

iii Ownership and market access restrictions

The Danish state has a general right to all hydrocarbons in the subsoil of the Danish territorial jurisdiction area. The state can grant licences for preliminary investigation, exploration and production of hydrocarbons. Licences are granted through tender procedures or under the ‘open door’ procedure.

The main part of the natural gas on the Danish market is produced in the Danish North Sea. Through the Danish North Sea Fund, the Danish state participates in concessions for exploration and production of hydrocarbons. Licences are granted through tender procedures or under the ‘open door’ procedure.

Partly state-owned DONG Energy owns upstream pipelines and operates the gas treatment plant at Nybro. The establishment and operation of upstream pipeline networks

9 Act No. 1101 of 18 November 2005.
10 Act No. 1585 of 10 December 2015.
11 See footnote 2, supra.
14 See footnote 8, supra.
15 See footnote 3, supra.
16 See also Section III.iii, infra.
17 Act No. 1317 of 19 November 2015.
require a licence issued by the DEA. Any interested party is entitled to access an upstream 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{19} 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 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{20}

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.

\textbf{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.

\textsuperscript{19} There are 98 municipalities (city councils).
\textsuperscript{20} Act No. 1161 of 20 November 2008 on the Procedure for Compulsory Sale of Real Property.
In the electricity and natural gas industries, there is a requirement for legal unbundling in relation to the parts of the value chain of monopolistic character. The Natural Gas Supply Act requires a company with a licence for transmission, distribution, storage, LNG business or universal service obligations to conduct only activities allowed under the licence.

As a general rule, the Electricity Supply Act does not allow grid and transmission licences to be issued to the same company. Undertakings producing electricity by means of waste incineration are not allowed to carry out other types of electricity production or trading activities. The requirement for unbundling of activities does, however, not preclude the use in combined waste incineration plants of other types of fuel (e.g., straw, chipped wood or natural gas) together with waste suitable for incineration.

The requirements are supplemented by demands for managerial unbundling in the Electricity Supply Act and in the Natural Gas Supply Act. To prevent conflicts of interest, executives and managers of a distribution undertaking must not directly or indirectly participate in the operation or management of an associated undertaking selling or producing natural gas or electricity, or participate in an associated undertaking that indirectly owns such an undertaking. Members of the board of directors of distribution undertakings must not directly or indirectly participate in the operation or management of associated undertakings selling or producing natural gas or electricity.

### ii Transmission/transportation and distribution access

Danish law allows full access on a non-discriminatory basis to the transmission and distribution systems in both the natural gas and electricity sectors.

**Natural gas**

The transmission network for natural gas is connected to the natural gas transmission networks in Germany and Sweden. The transmission network is connected to the distribution network to which the end-users are connected. There is a general right to use the transmission network against payment of applicable fees. Access can be denied if the transmission undertaking cannot meet the capacity requirements, cannot ensure the quality of the natural gas, cannot ensure security of supply, cannot ensure sufficient quantities of natural gas, or if a natural gas undertaking has severe economic and financial difficulties with fulfilling contracts (including take-or-pay commitments). Access can also be denied if a natural gas undertaking does not comply with the access requirements laid down by the transmission undertaking. Reasons must be given for denial of access, and a denial of access can be brought before the DERA.

**Electricity**

The transmission grid for electricity is the part of the electricity grid that transports electricity to local grid undertakings, which then distribute the electricity to end-users. The transmission grid also transports electricity to and from other countries. The transmission grid is owned and operated by Energinet.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.

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21 Act No. 1097 of 8 November 2011 as amended.
Each owns and operates a distribution grid within a local supply area. Grid undertakings have a monopoly on the distribution within their area. However, the grid undertakings must ensure that players have access to the grid on objective, fair and transparent terms.

iii Terminalling, processing and treatment
The storage facilities for natural gas are currently situated at two locations in Denmark: Stenlille and Lille Torup. 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 Supplies\(^ {22} \) ensures emergency supply in the event of disruptions or threats in the oil sector, including keeping reserves of crude oil and petroleum products, and collecting data on the oil conditions in Denmark. The Danish emergency oil management system is primarily handled by the Danish Central 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.

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\(^ {22} \) Act No. 354 of 24 April 2012 on Emergency Oil Supplies.
The liberalisation of the gas market on 1 January 2004 meant that all natural gas customers would have a free choice of supplier. Any party can establish a natural gas undertaking supplying natural gas, provided that it enters into agreements with the relevant transmission, storage (if needed) and distribution undertakings. An undertaking trading in natural gas can sell its products on market terms. Natural gas suppliers may be licensed as a supply-committed undertaking in areas designated for natural gas pursuant to the Heat Supply Act, with the effect that the undertaking has the right and duty to supply natural gas to all customers within the area that have not used their right to choose an alternative gas supplier. The undertaking may deny supply of natural gas to a customer that does not pay for the deliveries.

Sale and delivery of electricity to end-users are made by electricity suppliers, which are either supply-committed undertakings or undertakings supplying electricity on commercial terms. Supply-committed undertakings deliver electricity to consumers who have not exercised their right to choose an alternative supplier.

iii Contracts for sale of energy
Most power in the Nordic and Baltic region is traded on Nord Pool Spot. Natural gas, on the other hand, is still primarily traded through bilateral contracts, although an increasing quantity is traded at the market exchange Gaspoint Nordic. Danish energy legislation generally only regulates end-user contracts.

iv Market developments
There are a large number of new energy policy initiatives seeking to accelerate the transition to green energy. The four critical focus areas are: energy efficiency, electrification, expansion of renewable energy and research, and development and demonstration.

V RENEWABLE ENERGY AND CONSERVATION
i Development of renewable energy
Denmark has a long tradition of active energy policy, initiated by the first oil crisis in 1973. When oil prices accelerated in 1973, Denmark was among the OECD countries most dependent on oil in its energy supply, with more than 90 per cent of all energy supply deriving from imported oil. Denmark launched an active energy policy to ensure the supply and enable Denmark to reduce its dependency on imported oil. In combination with oil and gas production from the North Sea, Denmark went from being a net importer of oil in 1973 to being more than self-sufficient in energy from 1997 and beyond.

In the Kyoto period 2008–2012, Denmark committed itself to a greenhouse gas reduction target of 21 per cent. Today, renewables account for more than 40 per cent of Danish electricity consumption and, through expanded offshore wind production and use of biomass, the government expects that renewables will reach almost 70 per cent of Danish electricity production in 2020. A new political agreement between the government and all the major opposition parties was reached in March 2012. The agreement covers the period 2012–2020 and sets out the following goals: more than 35 per cent renewable energy in final energy consumption, approximately 50 per cent of electricity consumption to be supplied by wind power, 7.6 per cent reduction in gross energy consumption in relation to the 2010 level and 35 per cent reduction in greenhouse gas emissions in relation to the 1990 level.
Energy taxes on electricity and oil were introduced in 1977, and since then taxes have been increased several times and have also been extended to coal and natural gas. In 1992, the taxes were supplemented by carbon taxes.

Other means of achieving renewable energy are heat savings initiatives in buildings, use of renewable energy in buildings, municipal heat planning, energy-efficient electricity and district heat production, and use of renewable energy in electricity and district heat production, plus energy savings and use of renewable energy in industry and transportation.

Wind turbines have been supported politically for many years, including through state subsidies, feed-in tariffs, orders to the electricity utilities to build wind turbines, tenders for offshore wind farms and orders to the municipalities to allocate suitable areas for new onshore wind turbines. Approximately 40–45 per cent of electricity is currently produced by wind turbines (and this is expected to exceed to 50 per cent in 2020).

In 2009, the Promotion of Renewable Energy Act\textsuperscript{23} 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.

\section*{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:

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

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

\begin{enumerate}
  \item energy and carbon taxes on domestic and public sector energy consumption;
  \item carbon taxes on industrial consumption;
  \item carbon emission allowance trading scheme;
  \item voluntary agreements for industry;
  \item energy labelling for large and small buildings;
  \item energy labelling of appliances and lighting;
  \item norms for energy efficiency and voluntary agreements; and
  \item reduction of standby consumption.
\end{enumerate}

\section*{iii Technological developments}

The Danish strategy for energy-efficient technologies provides a framework for prioritisation and development of research and development efforts to achieve the greatest possible impact by public funds used in the field.

\textsuperscript{23} Act No. 122 of 6 February 2015 on the Promotion of Renewable Energy.
VI  THE YEAR IN REVIEW

i  Energy Commission
On 31 March 2016 the government launched the Energy Commission, a body intended to prepare recommendations for the objectives and direction of Danish energy policy from 2020 to 2030. The Energy Commission’s overall task is to analyse and assess trends in the energy sector and make recommendations for a cost-effective Danish energy policy for the period 2020 to 2030. The commission will contribute to Denmark’s aim of meeting its international obligations on climate change in a cost-effective and market-based manner.

ii  Recommendations for new gas sector regulation
In 2014 the government set up an interdepartmental working group to examine the regulation of the gas supply sector. The working group’s task was to rethink regulation to encourage a more competitive gas sector and ensure the efficient and competitive distribution of gas in Denmark. On 8 February 2016 the working group submitted its seven main recommendations to the government. The working group found that the future structure of natural gas distribution should be organised to ensure effective and clear regulation for the benefit of the industry, businesses and consumers. Further, regulation should ensure that the challenges that the gas sector is facing can be solved in a cost-effective manner. The committee’s recommendations will be part of the government’s plans for the future regulation of the gas sector.

iii  New subsidy scheme for electricity-intensive businesses
On 10 September 2015 a new subsidy scheme for electricity-intensive businesses came into force, which offers companies financial support to cover part of the public service obligation (PSO) fee for electricity consumption. The scheme establishes a pool of 185 million Danish kroner per year for 2015–2020, for which eligible companies can apply to cover part of their PSO payments in connection with electricity use. The scheme’s main objectives are to ensure that electricity-intensive businesses are not burdened with a PSO payment such that their competitiveness suffers noticeably, and to promote energy efficiency in electricity-intensive businesses.

iv  DONG Energy’s initial public offering
In connection with a capital injection in February 2014 in the Danish majority state-owned energy company, DONG Energy, it was agreed between the main shareholders and the company to pursue an IPO. DONG Energy, which is currently the world’s largest offshore wind farm operator, is expected to make the IPO in the summer of 2016.

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 11

ECUADOR

Ariel López, Gina Ludeña, Joan Proaño, Daniela Buraye and Paulette Toro

I OVERVIEW

Ecuador is an oil-exporting country, which has a high impact on the national economy and also dominates the energy matrix.

The Ministry of Electricity and Renewable Energy (MEER), created on 9 July 2007, is the governing body of the Ecuadorian electricity sector, operating through sectoral development plans and policies for the efficient use of our renewable resources.

The institution has specialised units for the implementation of projects, such as the Undersecretary of Energy Generation and Transmission, coordinating the development of strategies to ensure the expansion of electricity nationwide.

To strengthen and take advantage of Ecuador’s renewable natural resources, the Ministry has developed important power generation projects such as Coca Codo Sinclair, Toachi Pilatón, Minas San Francisco, Delsintanisagua, Manduriacu, Sopladora, Quijos, Mazar Dudas and Villonaco; with the launch of these hydroelectric projects, Ecuador will supply domestic demand and will be able to export energy to countries in the region.

Also, these mega constructions will double Ecuador’s installed power capacity, allowing advances in both the country’s energy potential and its productive transformation through environmentally friendly generation projects that promote the use of renewable resources and reduce CO2 emissions.

This year, one of the biggest projects, the Coca Codo Sinclair hydroelectric plant, commences operations. This hydroelectric plant will initially generate 750MW and within the following months will be working at full power, with eight turbines producing 1,500MW. It will comply with all the environmental regulations, preventing pollution and promoting...

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sustainable development with clean and renewable energy providing lighting throughout Ecuador. Thanks to hydroelectric power, we are exporters of energy produced in our rivers and in 2016 we expect the value of these exports to reach US$200 million.

II REGULATION

i The regulators

The main source of law is the Constitution of Ecuador and the Organic Law of Public Electricity Service (LOSPEE), which cites MEER as the highest authority in the field of energy regulation, and under which is the Regulation and Control of Electricity Agency (ARCONEL).

MEER, created on 9 July 2007, is the governing body of the Ecuadorian electricity sector and renewable energy. This entity is responsible for meeting the electrical power needs of the country through the formulation of relevant legislation, development plans and sectorial policies for the efficient use of resources. It further provides that any power generation or distribution and marketing companies can be managed and operated by international state companies that reach an agreement with the Ecuadorian state.

The main functions of MEER include:

a increasing the supply of electricity generation and transmission;
b increasing efficiency to meet the demand for electricity;
c increasing the efficiency of the distribution companies;
d increasing the service quality for electrical power;
e increasing overall safe use of ionising radiation and application of atomic and nuclear energy; and
f increasing the electrical service coverage in the country.

There are different regulators for the different segments of the energy industry, each serving under the MEER regime. These are:

a ARCONEL, the technical administrative body responsible for exercising state power to regulate and control activities related to the public electricity service and the service of general lighting, thereby safeguarding the interests of the consumer or end user;
b the National Electricity Operator (CENACE), a specialised technical body that protects the security and quality of operation of the National Interconnected System (SNI); and
c specialised institutes.

ARCONEL

The main functions of ARCONEL include:

a regular technical-economic and operational aspects of activities related to the public service of electricity and public lighting service;
b issuing regulations to which utilities and users, whether public or private (and including CENACE and consumers or end users), must conform, including observing energy efficiency policies (for which they are obliged to provide the information required);
c verifying the compliance of electrical companies with the relevant regulations and obligations required for certification and other conditions set by MEER;
d establishing the schedule of rates of electricity for the public lighting service.
performing operational planning for the short, medium and long term for the supply of electricity at the lowest possible cost, and optimising electricity transactions at the national and international levels;

managing and settling commercial transactions in the electricity sector wholesale market;

managing technical and international commercial electricity transactions on behalf of participants in the electricity sector;

coordination of the planning and execution of energy generation and transmission maintenance; and

supervising and coordinating the supply and use of fuel for the electricity generation sector.

ii Regulated activities

Through MEER, the state can authorise public, mixed or state enterprises, created under the Organic Law on Public Enterprises, to carry out the activities of generation, transmission, distribution and merchandising; import and export electricity; and general lighting service. To fulfil these activities, public companies may conclude any agreements or contracts for procurement of goods, works execution or provision of services deemed necessary.

MEER is responsible for processing and issuing operating permits and concession contracts.

The process to obtain such authorisations is initiated by a public selection procedure that allows the company that developed the project under the most favourable conditions to national interests to be chosen. Energy requirements are also determined, and the process also considers unregulated demand, term conditions and price. The bidder who is selected using this public process has the right to be granted the authorisation certificate concerned, and in turn this bidder is obliged to sign the corresponding contracts, based on the price submitted in the tender. Once obtained, the authorisation and any information relating to operating authorisations and concession contracts in the electricity sector must be registered with the National Registry of Authorisation certificates, which is in charge of MEER. It is the responsibility of electricity companies, at their own expense, to record the authorisation certificate in accordance with the provisions laid down for that purpose in the general regulations of law.

iii Ownership and market access restrictions

The public and mixed electrical companies, responsible for the provision of a public and strategic electricity service and the service of general lighting, have the right of free use of roads, poles, ducts, sidewalks and similar infrastructure that belongs to the state, is regional, provincial or municipal property, or belongs to other public companies that are exempted from payment of taxes and contributions for these items. The electric company will have ownership of these facilities, transforming stations of lots and housing developments.

Public companies providing the public service of electricity and mixed capital companies have the right to build transmission lines and other electrical distribution and electric service facilities within the limits of the terms of their employment. These rights allow entry and occupation of the land through which the transmission lines pass and distribute. They do not constitute prohibition to transfer the affected property, but merely an easement, unless by product of this easement the property turns unusable. It should then be declared
a public utility and the landowner should be compensated. MEER, or public companies providing the public service of electricity, may provide easements for the infrastructure of transmission lines and other electrical distribution and owned facilities for electric service.

iv Transfers of control and assignments
To transfer rights or private contracts, or agree to the transfer of one or more rights, or for the sale of stocks, shares, share certificates or other securities involving a change in the partners of a private, popular or solidarity economy, it is necessary to have permission from MEER.

According to Article 50 of the Organic Law of Public Service Electric Power, if the activities of generation, transmission, distribution or sale are concentrated in a public company, the transfer costs between the activities of generation, transmission, distribution or merchandising must be registered, using the same principles as for contracts covered, and be subject to regulation by ARCONEL.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES
i Vertical integration and unbundling

Electricity
National electricity transmission is performed by the state through the corresponding public company. The electricity sector is considered a strategic area of the Ecuadorian state. This important sector has undergone significant changes in recent times, and has been very vulnerable given current political management and the lack of responsibility of past administrations.

The electricity sector has undergone several changes. The first was in 1961, when the Ecuadorian Institute of Electrification was created to control all activities in this sector. Subsequently, in 1996, the Electrical Sector Regime Law was published to meet the sector’s needs, and also creating CENACE. This legislation was superseded in January 2015 with the publication of the Organic Law of Public Service Electric Power, which established ARCONEL as the sector regulator.

Gas and oil
The main entity involved in hydrocarbon activities is Petroamazonas EP, the state company that has been in charge of managing the phases of exploration and exploitation since 2013 pursuant to Executive Decree 1351-A (November 2012). Petroamazonas also took the majority stake (70 per cent share) of Operaciones Río Napo, a mixed capital company that has achieved oil production of 144.9 million barrels, equivalent to a daily average of 397,000 thousand barrels. EP Petroecuador, the public company formerly in charge of all of these phases, now manages only the transportation, refining, storage and commercialisation of hydrocarbons.

The oil and gas sector is regulated by the Hydrocarbon Operations Regulation, enacted on 26 September 2012 in Ministerial Agreement No. 389, and the Environmental Regulation of Oil and Gas Operations, enacted in 2010 in Executive Order No. 1215. These key laws regulate oil and gas activity throughout all phases of exploration, production, transportation, refining, storage and commercialisation, as well as establishing environmental criteria to be met in relation to these activities.
ii Transmission/transportation and distribution access

Pursuant to the LOSPEE, electricity transmission activity at the national level is conducted by the state through the relevant public companies.

Operation of this activity is subject to general constitutional rules and law, and to specific legal provisions applicable to these public transmission companies; the companies have sole responsibility for the observance of these provisions, and for observing principles of transparency, efficiency, continuity, quality and accessibility.

The public transmission companies have a duty of responsibility for the transmission service and for the expansion of the National Transmission System, based on plans drawn up by MEER.

On the other hand, the distribution and marketing of electricity is conducted by the state through legal persons duly authorised to exercise such activities.

iii Rates

Within the first semester of each year, ARCONEL determines the costs of generation, transmission, distribution and merchandising, and general lighting, to be applied in the electricity transactions. This is used as a basis for determining tariffs for consumers or end user for the subsequent year. In cases not expressly provided for in the relevant regulation, the rates approved for the year of validity may be reviewed.

After the corresponding study, ARCONEL may set rates that promote and encourage the development of basic industries, taking into consideration the effect of the use of renewable and environmentally friendly energies at competitive and stable prices, or subsidies, if necessary.

Also, ARCONEL may establish rates to achieve efficient use of energy. The adjustment, modification and restructuring of the tariff schedule entail the automatic modification of supply contracts for the public electricity service, including publicly provided general lighting.

The tariff schedules shall be prepared by ARCONEL, observing the principles of solidarity, equity, coverage costs and energy efficiency. The same principles should be developed in the corresponding regulation. The fee will be unique throughout the national territory according to consumption and voltage levels. Additionally, the principles of social and environmental responsibility should be considered.

The cost of public and strategic electricity services include costs related to the stages of generation, transmission, distribution and marketing; and the service of general lighting, the same to be determined by the ARCONEL.

iv Security and technology restrictions

CENACE is a strategic technical body of MEER. In performing its duties, it should safeguard the security and quality of operation of the SNI, subject to the regulations issued by ARCONEL.

The LOSPEE established the following as serious offences:

\[ a \] failure to implement expansion plans for transmission and distribution; and

\[ b \] maintenance programmes affecting the safety of persons, and the safety and reliability of systems.
Plant operators have obligations to the environment and to the owners of properties to which they are providing a service. They must have prior authorisation to operate, and have the obligation to compensate for any damage incurred to third parties. Owners are also obliged to give easy access to areas that provide for the proper functioning of facilities.

At the moment, there are no cybersecurity measures in place in the electricity sector; however, the country has instituted measures to protect governmental infrastructure from cyberattacks, including Decree 166 requires that all the technology of the Central Public Administration meets safety standards.

Law No. 2002-67 provides the general framework governing cybercrime and the government is seeking support from multiple stakeholders to institute reforms to the Criminal Code to address cybercrime more adequately.

IV ENERGY MARKETS

i Development of energy markets

According to Article 10 of the LOSPEE, in the field of business, the electricity sector will act through:

- public enterprises;
- mixed economy companies;
- private companies;
- consortia or partnerships; and
- companies belonging to a popular or solidarity economy.

The law provides that international interconnections are to be permitted in accordance with the availability and needs of the electricity sector and subject to the Constitution, treaties and international instruments and regulations as may be provided for the purpose. MEER is responsible for defining policies regarding international interconnections.

ARCONEL is responsible for coordinating regulatory actions with the corresponding regulatory agencies of other countries, while CENACE coordinates the operation of electricity interconnections with neighbouring countries and is responsible for applying the rules on international energy transactions.

ii Energy market rules and regulation

As mentioned above, the electricity company will provide an electricity supply to natural or legal persons meeting ARCONEL's regulatory requirements.

To have the electric company provide a power supply, the consumer or end user must enter into an electricity supply contract with the company, the stipulations, conditions and other applicable rules for which are set by the relevant regulation.

Merchandising activity includes the purchase of blocks of electricity for sale to consumers or end users, and all the commercial management associated with these transactions for buying and selling. This includes the installation of mediation systems, meters, billing and collection of consumption readings. Electrical distribution and merchandising companies have coercive jurisdiction for the collection of receivables related to the provision of a public electricity service and the service of general lighting.
iii Contracts for sale of energy

The law (Article 44 LOSPEE) establishes that large consumers will be those legal persons duly qualified as such by the competent authority, whose consumption characteristics entitle them to act through bilateral contracts. Consumption characteristics will be defined by the corresponding regulation.

The power block transactions may be held only by purchase and sale of energy through contracts signed by the participants. They are commercially settled by CENACE, depending on the prices agreed in the contract.

For commercial close of business transactions through contracts, settlement of transactions may be made in the short term. International transactions of electricity will be settled by CENACE, depending on the trade agreements with other countries.

The scope and conditions of the contracts of the purchase and sale of energy, as well as short-term transactions, are established by ARCONEL using appropriate regulations.

CENACE performs the programming operation of long, medium and short-term contracts to achieve the minimum operating cost for the country considering the technical constraints.

Participants who perform activities of generation, auto generation, transmission, distribution and merchandising; huge consumers; and those enabled for international transactions of electricity will be required to provide to CENACE all economic information, technical and operational, to be used for programming.

Purchases and sales of electricity that are made between electricity sector participants through contracts, as well as short-term transactions, will be settled by CENACE within the scope of its powers, on the basis of regulations issued for this purpose by ARCONEL.

CENACE determines the values to be paid and perceives each participant. Likewise, CENACE liquidates appropriate values for the service of electricity transmission and international electricity transactions.

Legal entities affianced to generation activities are required to sign contracts with legal persons engaged in distribution and merchandising activities, in a form proportional to their regulated demand.

iv Market developments

This year one of the country’s biggest energy projects, Coca Codo Sinclair, became operational. This hydroelectric facility and other ongoing projects help fulfil the objective of growth in the energy sector. Other hydroelectric projects are expected to be implemented shortly, and other projects using renewable energy sources such as geothermal, biomass, wind and solar are being considered.

The 10-year Electricity Master Plan (PME), prepared by MEER, identifies priority projects for the electricity generation sector. The PME also identifies expansion and improvement programmes in generation, transmission, distribution and energising in isolated rural areas.

The PME will ensure that the coverage of electricity in isolated rural areas gradually increases. MEER will select, from that plan, those that will be developed by the state and those that could be given to private companies and popular and solidarity economy, previous to the public selection process established in this law.

The investment by institutions and public companies required to implement the PME generation, transmission and distribution projects will be conducted under the general state budget, or through those bodies’ own resources, or both.
Alternatively, for project financing, public companies may contract loans with their own guarantees or through the state.

Investments funded through the general state budget will be considered as equity contribution by public companies; and as capital contributions to corporations, while these remain.

V  RENEWABLE ENERGY AND CONSERVATION

i  Development of renewable energy

Renewable energy is energy that is obtained from virtually inexhaustible natural sources, either through the immense amount of energy they contain, or because they are able to regenerate by natural means. Among the renewable energy sources are wind, geothermal, hydropower, tidal, solar, wave, biomass and biofuels.

Ecuador has made progress in renewable energies. This is ratified by wind generation projects in some sectors of the country, and solar power in others. However, national commitment also focuses on the harnessing of its water potential, with big projects and investments. The main changes in renewable energy have been consolidated in Galapagos, with advanced projects in wind, solar and biofuel energy. This marks the beginning of a change in the Ecuadorian energy matrix, which should show results in 2020.

MEER has developed policies and projects that promote the rational use of energy, and strategies to improve energy efficiency in different parts of the country. One that is considered most innovative for Latin America is the programme for induction cooking and heating water with electricity (PEC). Initiatives like these seek to modify the energy matrix, supported by the use of clean and environmentally friendly energy.

With Coca Codo Sinclair commencing operations, Ecuador has become an exporter of energy and it is expected to export energy worth US$200 million in 2016.

The realisation of eight hydroelectric projects – Coca Codo Sinclair, Sopladora, San Francisco mines, Delsinantisagua, Manduriacu, Mazar Dudas, Toachi Pilatón and Quijos – will strengthen Ecuador’s energy sovereignty, replacing thermal generation, reducing CO2 emissions, replacing imported energy sources and creating direct employment.

Some of these hydroelectric projects have already begun operations, with great success. According to MEER, in 2016, more than 90 per cent of the energy produced in Ecuador will be from hydroelectric sources, providing renewable, pollution-free energy to meet domestic demand for electricity. In addition, these projects will transform the energy matrix that underpins the system, and will result in changes such as processes to switch from gas cookers to electricity. Moreover, the production of energy from these new hydroelectric facilities will save the state about US$800 million by eliminating the need for gas subsidies for end users.

ii  Energy efficiency and conservation

In Ecuador, energy efficiency has been developed through different programmes and projects promoted by the current government at the level of technological substitution (such as the Spotlight Saver scheme, the Renova programme, etc.), management and the transformation of the cultural habits of the population.
MEER has developed policies and projects that promote the rational use of energy, as well as the development of standards or regulations that promote the use of efficient appliances, and additional strategies to improve energy efficiency in the different sectors of the country (e.g., residential, public and industrial sectors).

LOSPEE has established the obligation to enact policies to achieve energy efficiency and environmental responsibility. This must be observed by electric companies during all phases of the service.

The Improvement Plan for Power Distribution Systems is a set of projects that run on all electrical distribution companies in the country, with the aim of ensuring the availability of electricity to satisfy current demand and future customers under conditions of adequate quality and safety. It is based on improving standards, increasing electricity coverage and strengthening the distribution system with a view to the National Programme for Efficient Cooking and updating the energy matrix.

MEER is working on modernisation and comprehensive approval of sub transmission systems, distribution and merchandising, through technological upgrades.

To achieve this objective, it is developing the Integrated System to Improve Electricity Distribution Management, whose main objective is to support the strengthening of the management of distributors through standardisation and approval of processes, procedures, semantics, computers and smart devices, adoption of a Common Information Model and establishing unique data centres.

iii Technological developments

In 2014, the PEC was implemented to contribute to changing the energy matrix of the country through the substantial reduction in demand for LPG in the residential sector. For this purpose, the PEC seeks to replace the use of LPG with electricity for cooking and heating water for domestic use in the residential sector of the country. This will be achieved by the introduction of high efficiency induction cookers to approximately 3 million households. Also, electric water heating equipment will be introduced to approximately 0.75 million households up to 2016, taking advantage of the increasing availability of electricity generated mainly from renewable sources.

The PEC includes two major components:

a strengthening the national electricity system through the improvement of the distribution network, with an investment of US$485.5 million (headed by the MEER Secretariat for Energy Distribution and Merchandising); and

b introduction of induction cookers and high-efficiency electric water heating equipment, with an investment of around US$903 million. Additionally, there will be mass media campaigns and a set of tariff measures and taxes to promote the implementation of the programme.

VI THE YEAR IN REVIEW

In Ecuador, electricity distribution companies are responsible for the sale of electricity to end users. Two of eight major generation projects in the electricity sector have become operational and, with the resulting addition of 2800MW to the SNI, this is expected to effect a change in the country’s energy matrix.

The creation, construction and operation of these major projects allows Ecuador not only to have energy sovereignty, but also to be an exporter of renewable, clean energy.
Among the main events of 2015/2016 have been the following:

- the implementation of the 65MW Manduriacu hydroelectric facility;
- 10 per cent reduction on electricity losses, resulting in savings of US$1.2 billion dollars in the period 2007–2015;
- the operation of Coca Codo Sinclair’s first four turbines, allowing Ecuador to export energy to countries in the region, starting with Colombia; and
- the implementation of the Renova energy efficiency programme and the changeover to induction cookers; all users migrating from gas to electricity for cooking and water heating receive free, until August 2018, the following:
  - up to 80kWh/month of power for users who replace their gas cookers with electric cookers; and
  - up to 20 kWh/month of power for users who replace their gas water-heating equipment with electric water-heating equipment.

**LOSPEE**

LOSPEE provides a new legal framework governing the participation of the public and private sectors, related to public electricity service activities as well as the promotion and implementation of plans and projects with renewable energy sources, establishing mechanisms for energy efficiency.

This law gives electric power the characteristic of a strategic public service, involving the definition of public policies and planning of the electricity sector in coordination with the National Plan for Good Living by MEER.

A flat rate has been set at national level for each type of consumption and enhanced rural electrification financed by state power. This new law allocates 30 per cent of operating surplus to utility generation projects, and 12 per cent of the value of private generation projects for the implementation of spatial development plans. Similarly, it determines the state’s responsibility for service delivery through public enterprises.

**VII CONCLUSIONS AND OUTLOOK**

Currently, Coca Codo Sinclair and Manduriacu, two of eight major hydroelectric projects, have begun operations. Thanks to these important developments in the energy sector, 2016 marks a significant change in the energy history of the country, with Ecuador establishing one of the principal axes of public policy on electricity, making optimum use of the country’s natural resources while respecting nature and the right of communities to be the main beneficiaries of public works.

The emblematic 65MW Manduriacu hydroelectric power project (which uses water from the Guayllabamba River, with an annual average flow of 168.9m3/s usable for generation, resulting in 0.14 tonnes per year of avoided CO2) has, up to December 2015, contributed 143.05GWh of energy to the SNI.

Furthermore, the Coca Codo Sinclair is the largest hydroelectric project in the country’s history and, at the beginning of 2016, the project commenced the operation of its fourth turbine. This hydroelectric facility, with its eight turbines, will have the capacity to supply 30 per cent of Ecuador’s energy requirements and to export surplus power to neighbouring countries (this year Ecuador began exporting energy to Colombia). The launch of Coca Codo Sinclair will be beneficial because the country will not spend on buying fossil fuels required for the operation of thermal power plants, which will be held in reserve as
emergency mechanisms only. The hydroelectric schemes are environmentally responsible, in conception and development, using water as fuel and with most of the works underground, so they do not affect the environment and the energy produced is clean and renewable. The eight hydroelectric schemes will save the country in the region of US$1 billion.

During 2015, the National Transmission System was expanded and strengthened, with the addition of 169km of high-voltage lines at the level of 230,000V, 1,085MVA capacity in new transformer substations and reinforcement of existing ones.

In the distribution system, which allows energy reaches each Ecuadorian households, 2015 was characterised by increased coverage, improved street lighting and an intensive programme of strengthening networks, construction and operation of new substations and introduction of the modern control systems necessary to incorporate electric induction cookers. With the implementation of both modern marketing systems and the programme to strengthen the national electricity distribution system, users are receiving a better service on a daily basis.
Chapter 12

EGYPT

Mariam Fahmy and Mostafa El Zeky

I OVERVIEW

The energy sector in Egypt is heavily dominated by the government and the public sector. The electricity sector is monopolised by the Egyptian Electricity Holding Company (EEHC), which owns most of the electrical power generation and distribution companies in Egypt.

According to the EEHC’s annual report for the financial year 2013–2014, only 8.6 per cent of the generated electrical power is produced by companies with a concession to generate electrical power by virtue of a BOOT (build-own-operate-transfer) or similar model. In an effort to liberalise the electricity sector and incentivise private investment in all aspects of the energy sector in Egypt, Law No. 87 of 2015 (the New Electricity Law) has been enacted.

Egypt is one of the wealthiest countries in terms of renewable energy resources, notably solar and wind. Coupling such potential with the current energy crisis provides for a very strong need for drastic reform in the energy sector. Accordingly, the New and Renewable Energy Authority (NREA), which is a governmental entity, recently began implementing solar and wind energy projects, in addition to more projects that are currently in the pipeline. These projects are offered through tenders by the NREA and are implemented by local and foreign investors with the required expertise. Further, there are several ongoing projects that have been tendered by the Egyptian Electricity Transmission Company (EETC) for the establishment of power generation plants generating electricity using renewable energy resources. In addition, the EEHC and the NREA are working towards using renewable energy resources to generate 20 per cent of gross generated energy by the year 2020.2

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In addition, although the government has approved the use of coal as a source of energy for industrial production, this decision has been heavily criticised because of its hazardous implications for the environment. Currently, the EEHC is developing the Ayoun Moussa coal-fired power project, which is the first coal-fired project to be developed in Egypt.

II REGULATION

i The regulators

The Egyptian Electric Utility and Consumer Protection Agency (ERA) was established by virtue of Presidential Decree No. 326 of 1997, which was then abrogated by the New Electricity Law; this Law also reorganised the ERA. The ERA is affiliated with the Ministry of Electricity and Renewable Energy (MoEE).

The ERA’s main purpose is organising and monitoring all aspects relating to the electricity sector (i.e., generation, transmission, distribution and consumption of electric power) to ensure the availability and continuity of electricity provision in return for fair prices, all while guaranteeing environmental protection, free competition and consumers’ rights.

The ERA’s mandate and authorities include, *inter alia*, the following:

a setting general principles and rules governing electricity sector stakeholders, securing their interests and the interests of consumers and enhancing free competition;
b setting proper economic rules and principles for the calculation of the electricity sale tariff for unqualified subscribers, electricity exchange prices in the organised market and the consideration for utilising the transmission and distribution networks within a framework of justice and transparency;
c setting principles to ensure technical quality and other standard measures for the performance of the various electricity sector services;
d granting licences for construction, management, operation and maintenance of electric power production, distribution and sale projects;
e setting rules and procedures as required for developing and encouraging the production and use of electricity obtained from renewable sources; and
f imposing the penalties set forth under the New Electricity Law in the event of violations of any free competition rules or transparency and equal opportunity principles.

Oil and gas

The oil and gas sector is regulated by the Egyptian General Petroleum Corporation (EGPC). EGPC is affiliated with the Ministry of Petroleum.

EGPC regulates the upstream sector, including entering into concession agreements, granting the necessary licences (which differ depending on the activity), in addition to regulating midstream and downstream sectors. In doing so, EGPC has, *inter alia*, the following powers and authorities:

a establishing and operating petroleum entities;

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4 Article 2 of Law No. 167 of 1958, as amended.
undertaking exploration activities, in addition to refining, purchasing, selling, transporting, storing and distributing oil in Egypt. EGPC has the right to undertake such activities by itself or through third parties;

c importing oil and its products and exporting any excess by itself or through third parties;

d determining the standards of petroleum products alongside the competent authorities; and

e determining the prices of petroleum products alongside the competent authorities.

ii Regulated activities

Electricity

According to Law No. 12 of 1976, as amended, establishing the Egyptian Electricity Authority, the predecessor of the EEHC, the EEHC is mandated, inter alia, to implement and supervise projects relating to the generation, transmission and distribution of electricity and to offtake the electricity generated by electricity power stations constructed by local or foreign investors.5

In doing so, the EEHC has the right to establish companies solely or with other private or public sector entities or individuals. In addition, the EEHC has the right to grant concessions to local or foreign investors allowing such investors to construct, manage, operate and maintain electricity power stations. This is carried out by virtue of a concession agreement entered into between the EEHC and the investor for a period of not more than 99 years after a fair and transparent bidding process.6

The concession agreement, and any amendments thereto, are issued by virtue of a Ministerial Cabinet Decree upon the suggestion of the Minister of Energy and Renewable Energy (i.e., the approval of the Minister of Energy and Renewable Energy is also required).

In addition to the above, the construction, management, operation and maintenance of electric power production, distribution and sale projects require a licence from the ERA. Any entity undertaking electric power production, distribution or sale must be in the form of a joint-stock company.7

The licence is issued for a maximum period of 25 years and can be renewed. The applicant must follow the procedures issued by the ERA in this regard. Such procedures include the payment of the relevant fee, which depends on the activity to be carried out by the applicant, and submitting all the required documents set out in the application form.8

Oil and gas

According to Law No. 66 of 1953, for an entity to explore and produce oil and gas, the entity must be granted a concession.9 Concessions in Egypt are granted by virtue of a specific law empowering the Minister of Petroleum to sign the relevant concession agreement with either EGPC, the Egyptian Natural Gas Holding Company (EGAS) or Ganoub El Wadi

5 Article 2 of Law No. 12 of 1976.
6 Article 7 of Law No. 12 of 1976.
7 Articles 6(16) and 13 of the New Electricity Law.
8 Article 16 of the New Electricity Law.
9 Article 32 of Law No. 66 of 1953.
Petroleum Holding Company (Ganope), depending on the subject matter of the exploration and production (i.e., whether oil or gas) and the contractor being declared as a successful bidder for the tender issued by the Ministry of Petroleum.

Further, for an investor to establish a plant for producing oil and gas derivatives, a licence from EGPC in addition to a licence from the Industrial Development Authority must be obtained.

Moreover, with regard to the natural gas activities, EGAS has the right to establish companies with third parties to produce or liquefy natural gas (i.e., EGAS must be a shareholder in any company operating in the production or liquefaction of natural gas; however, there is no minimum or maximum shareholding percentage requirement).

iii Ownership and market access restrictions

Electricity
Generally, there are no ownership and market access restrictions. However, there is a market monopoly by the EEHC, which owns approximately 90 per cent of the electricity generating capacity in Egypt in addition to its affiliated generation and distribution companies.11 The EETC, which is no longer affiliated with the EEHC pursuant to the New Electricity Law, is the sole entity undertaking transmission and operation of the national grid.12 However, given that current projects in the pipeline include significant private sector contributions, this governmental monopoly is subject to gradual change.

As stated above, the EEHC has the right to establish companies solely or with other private or public sector entities or individuals in relation to the generation, transmission and distribution of electricity, in addition to granting concessions to local or foreign investors allowing them to construct, manage, operate and maintain electricity power stations.

Further, any company operating in the electricity sector, whether construction, management, operation or maintenance of electricity generation, transmission, distribution and sale, must obtain the relevant licence from the ERA. Moreover, there are no constraints on aggregate holdings.

Oil and gas
There are no ownership and market access restriction in the exploration phase of oil or gas. However, once a discovery occurs, the contractor and EGPC or EGAS, as the case may be, will have to establish a joint venture where the contractor owns 50 per cent and EGPC or EGAS owns the other 50 per cent.

With regard to midstream and downstream oil activities, there are no ownership restrictions. However, the necessary licences and approvals mentioned above must be obtained.

With regard to natural gas, EGAS must hold shares in any company producing or liquefying natural gas. There is no minimum percentage for this shareholding. Further, there are no constraints on aggregate holdings.

10 Article 4(6) of Ministerial Decree No. 1009 of 2001 establishing EGAS.
12 Article 26 of the New Electricity Law.
iv Transfers of control and assignments

Electricity

Usually concession agreements state that any assignment or change of control by the concessionaire is permitted provided that the concessionaire obtains the prior written approval of the EEHC.

Further, in relation to licensed activities, the licensee must obtain the prior written approval of the relevant entity, which is usually the ERA, before any assignment or change of control; the licence itself includes the process and procedures for obtaining the prior approval for assignment or change of control. Additionally, a licensee is prohibited from undertaking any change in the ownership or control of its assets in a way that would lead to lack of competition or to monopolistic practices.13

Oil and gas

All concession agreements for the exploration of oil and gas include a provision by which the concessionaire cannot transfer or assign, whether directly or indirectly, the concession except after obtaining the prior written approval of EGPC or EGAS, as the case may be. Further, some concessions allow the concessionaire to assign the concession to its affiliates without obtaining the prior written approval of EGPC or EGAS.

Further, usually the concession agreements include a right of first refusal provision, whereby EGPC or EGAS has a pre-emption right in the event of assignment by the contractor.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Electricity

The electricity sector is monopolised by the EEHC, which is a state-owned joint-stock company. The EEHC owns six electricity generation companies and nine electricity distribution companies.14 This structure was adopted in the late 1990s, following the growth in demand, when the Egyptian Electricity Authority was converted into a joint-stock company, the EEHC.

This was supposed to be a step towards the liberalisation of the electricity sector in Egypt, as after the structure was implemented, investors began engaging in production and distribution of electricity according to the regulations, tariffs and fees mandated by the ERA (as detailed in Section IV, infra). Further, the Public-Private Partnerships (PPP) Unit, which is affiliated with the Ministry of Finance, announced that there is one project in the pipeline relating to generation of electricity from waste. This means that the state is currently looking for more private investors to invest in the electricity generation sector and, in fact, we have recently encountered noticeable concrete steps towards liberalisation of the market.

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13 Article 21 of the New Electricity Law.
Oil and gas
In the exploration and production of oil and gas, EGPC or EGAS must be a party to all concession agreements. Further, as stated above, once a discovery occurs, the contractor and EGPC or EGAS, as the case may be, will have to establish a joint venture where the contractor owns 50 per cent and EGPC or EGAS owns the other 50 per cent.

In addition to EGPC and EGAS, the main players in the oil and gas sector are the Egyptian Petrochemicals Company (working in all activities relating to petrochemicals, including monitoring the implementation of petrochemicals projects and attracting investments in the petrochemicals field) and Ganope (working in the oil and gas field, including exploration and production, in the South Valley region), which are wholly-owned by EGPC. Further, the oil sector has a lot of foreign investors whether in the upstream, midstream or downstream sectors including BP and Apache. This structure is not expected to change in the near future.

ii Transmission/transportation and distribution access

Electricity
Electricity transportation and distribution companies may be required to serve a particular geographical area in accordance with the licence granted by the competent authority, namely, the ERA, and their articles of incorporation. For example, the nine electricity distribution companies and six electricity generation companies owned by the EEHC are each mandated to serve different regions; however, the EETC serves all of Egypt. The New Electricity Law has further deregulated the power distribution sector.

It should be taken into consideration that the New Electricity Law prohibits transportation and distribution companies from undertaking monopolistic acts within their licensed geographic area.15

The EEHC is mandated to offtake all electrical power generated by the privately owned power generation stations for its affiliate companies and privately owned distribution companies to distribute electricity to all consumers.

Further, electricity must be distributed to all of Egypt based on the determined rates without discrimination between consumers.

iii Rates

Electricity
The MoEE is the entity mandated to determine the rates regarding the distribution and sale of electricity for all voltage levels.16 There are no regulations, however, setting out the method according to which these rates are determined. Further, electricity rates in Egypt are uniform as they are subsidised. The subsidy differs according to the nature of the beneficiary (i.e., residency, commercial, etc).

The method of calculating the distributors and transporters’ profits is determined in the concession agreement or the licence, as there are no regulations setting out a particular method.

15 Article 13 of the New Electricity Law.
16 Article 1(2) of Presidential Decree No. 1103 of 1974 organising the MoEE.
Security and technology restrictions

The ERA is mandated to make sure that all laws and regulations related to the electricity sector in Egypt are strictly adhered to by the different stakeholders. Further, the MoEE is mandated to control and supervise all activities relating to the electricity sector.

Moreover, the EEHC is responsible for providing electricity power to all consumers at reasonable prices.

In addition, the concessionaires and licensees have to abide by all provisions included in the concession or the licence; otherwise, the concessionaire or licensee will be subject to the sanctions stipulated for in the concession, licence and the relevant laws and regulations.

IV ENERGY MARKETS

i Development of energy markets

Egypt’s recently enacted New Electricity Law has implemented steps to liberalise the sale and distribution of electricity in Egypt and create a competitive free market for electricity. It has embarked on a promising renewable energy feed-in-tariffs (FiT) programme, under which qualified developers will build and operate a solar or wind power station and sell the power generated to end users directly. However, until the New Electricity Law is fully implemented and the FiT programme matures, the supply and sale of energy remains primarily controlled by the state through state-owned enterprises. Further, the prices of different sources of energy are fixed by the state. Since 1996, the activities of production and distribution of electricity were opened to the private sector while maintaining a state monopoly over electricity transmission. Investors can engage in production and distribution of electricity under the regulations and using the tariffs and fees mandated by the ERA.

Egypt, so far, has three privately owned production plants operating under a BOOT agreement with the government and 15 private companies that have a production licence, as well as a total of 24 companies that have an electricity distribution licence. The markets for other sources of energy remain a complete state monopoly.

ii Energy market rules and regulation

There are different rules governing the different sources of energy. The production and sale of natural gas is managed through the exploration concessions regime with the state-owned enterprises as sole purchaser of production and sole distributor of gas to end-users. However, for electricity, private production and distribution companies are entitled to sell to the end-user while observing the regulations of the ERA.

iii Contracts for sale of energy

Electricity producers and distributors are permitted to have individual contracts for the sale of electric power, while the rates and other charges are mandated by the government. Power producers and distributors are subject to the supervision of the ERA.

iv Market developments
The New Electricity Law was enacted in July 2015. The Law aims at liberalising the electricity production and distribution market and encouraging private investment in the energy sector, including renewable energy. The New Electricity Law provides for a transitional period of eight years in which to develop a more liberal market.18

V RENEWABLE ENERGY AND CONSERVATION
i Development of renewable energy
Egypt recently passed Law No. 203/2014 for the Enhancement of the Production of Electricity from Renewable Energy Resources, known as the Feed-in Tariff law (the FiT Law). The FiT Law introduces, for the first time, a feed-in tariff programme for renewable energy in Egypt. The main features are:

- a feed-in tariff scheme for the development of wind farms, reducing project risks through signing a long-term power purchase agreement (PPA) for 20 to 25 years;
- a sovereign guarantee of all financial obligations under the PPA and;
- the exemption of renewable energy equipment from customs and tariffs.

The first round of qualified FiT investors has been announced by ERA with a targeted capacity of 2,000MW for solar (500kW–50MW) and 2,000MW for wind between 2015 and 2017.

Renewable energy in Egypt falls under the competencies of the NREA. The government aims at boosting contribution of renewable energy sector to be 20 per cent of total power generation by 2020, 12 per cent of which will be generated by wind energy. Given the need to reduce dependence on gas, it is anticipated that Egypt will place greater emphasis on its considerable solar and wind potential. Egypt’s overall power generation is expected to increase by an annual average of 4.5 per cent during the period 2011–2016. This includes annual increases of more than 9 per cent from renewable sources. Further, the government is looking to attract US$110 billion of investment into its power sector by 2027.

ii Energy efficiency and conservation
Egypt has adopted a national plan for enhancing energy efficiency by 5 per cent from 2012 to 2015. The plan includes: (1) renovation of old electric power stations, (2) implementing a programme for transforming gas-based stations to operate on a twin turbine to reduce fuel consumption, and (3) renovating electricity transmission networks. Further, on the side of consumption Egypt is undertaking several initiatives including:19 (1) introducing energy-efficient lighting for consumers at low cost, (2) implementing energy-efficient quality standards for white goods, and (3) using an energy-efficient street lighting system including solar-based lighting.

iii Technological developments
There have been technological improvements in the area of renewable energy sector. With respect to solar energy, it is expected that its cost will decline sharply within the next five to

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18 Article 63 of the New Electricity Law.
seven years. Egypt aims to develop a competitive market for solar energy. Egypt has not fully implemented smart grid technologies, but as the energy market moves toward more liberalisation and with the international grid connections projects contemplated by Egypt it is expected to see more technological developments in the energy sector.

VI THE YEAR IN REVIEW

Egypt has enacted the FiT Law, which established the FiT programme for power generation from renewable resources. The New Electricity Law has also been enacted and this has implemented steps towards a more liberalised market in the electricity sector. The government’s medium and long-term plan is to increase the electricity generated from all sources of power supply by 5 to 7 per cent.

In terms of projects, the NREA recently signed a contract with Gamesa Olica to implement a 220MW wind power plant in Gabal El Zeit on the west coast of the Gulf of Suez, worth a total amount of about €220 million, and the implementation period of this plant is 32 months.

In addition, on 19 April 2015 the EETC received the bids for a build-own-operate wind power project, located in the Gulf of Suez area in Egypt for a plant up to 250MW.

VII CONCLUSIONS AND OUTLOOK

The past year has seen the introduction of the FiT programme with a higher than expected turnout from investors (a total number of 93 qualified investors for the first round).

It is expected that once the New Electricity Law and its implementing regulations are fully implemented, many of the grey areas in the current laws and regulations governing the electricity sector will be resolved, resulting in a more suitable climate for investment and the creation of a free market in this sector.

In addition, there are calls for the restructuring of the electricity tariffs and rates on the basis of geographical areas, the level of consumption and the nature of the consumers. Although the current government is denying that the electricity tariffs and rates restructuring will be implemented in the near future, it seems that such a restructuring is inevitable as it is required to deal with the increasing demand.

The state is focusing on exploiting Egypt’s huge renewable energy resources in the next few years through private investors and it is taking steady steps towards creating a safe and stable environment for foreign investment in the renewable energy sector.

In light of the above, it is safe to say that Egypt’s main priority at the moment is the development of the electricity sector and exploring alternative methods for generating electrical power, and in doing so the state is working on attracting private investors to invest in this critical sector.

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21 www.nrea.gov.eg/download/%D8%AE%D8%A8%D8%B1%20%D8%A5%D8%B9%D9%84%D8%A7%D9%85%D9%89%20%D8%A5%D9%86%D8%AC%D9%84%D9%8A%D8%B2%D9%89.pdf.
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.

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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 Floriane Cruchet, law clerk.


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 2007.4

Although significant progress had been made, the European Commission adopted the Third Energy Package to further liberalise the energy market, which included two new directives5 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’.6 In addition, Law NOME led to the removal of obstacles of the development of competition on the French electricity market. Greater price liberalisation for industrial and residential customers has been achieved, 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 states ambitious objectives, notably in terms of reduction of gas emissions and energy consumption, and increase of the percentage of renewable energy. It also establishes new rules supporting renewable energy production.

II REGULATION

i The regulators

Compliance with the new energy market regulations is mainly controlled by the Commission of Regulation of Energy (CRE), the sectoral regulator, which was created by the Law dated 10 February 2000.7 Its overall mission is to ‘contribute to the proper operation of the electricity and natural gas markets, to the benefit of final customers’.

The CRE is principally in charge of:

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;


Law No. 2005-781 of 13 July 2005 setting out the guidelines for energy policy regarding professionals and Law No. 2006-1537 of 7 December 2006 for individuals completed the transposition of these directives.


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

7 The legal framework applicable to the CRE is defined in Articles L131-1 to L135-16 of the French Energy Code.
France

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 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 anti-competitive practices in any economic sector, including electricity and 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 anti-competitive 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.

\section{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 (see Section II, infra). 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. 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.\(^12\)

\(^8\) Article L134-16 of the French Energy Code.

\(^9\) Law No. 2004-803 of 9 August 2004 concerning the electricity and gas public service. Law No. 2010-1488 of 7 December 2010 on the new organisation of the electricity market.

\(^10\) 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.
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 Engie\textsuperscript{13} (to protect the French national interest, the state may benefit from specific shares within the capital of Engie).\textsuperscript{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:\textsuperscript{15}

\begin{enumerate}[(a)]
\item worldwide aggregate turnover of all the parties to the concentration exceeds €150 million; \\
\item turnover in France of each or at least two parties concerned exceeds €50 million; and \\
\item the transaction does not meet the EC Merger Regulation thresholds.
\end{enumerate}

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.\textsuperscript{16}

In addition, the French government issued a new 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 pursuant to Article L151-3 of the French Monetary and Financial Code.

\textsuperscript{13} Articles L111-67 and L111-68 of the French Energy Code.


\textsuperscript{15} Articles L430-1 and L430-2 of the French Commercial Code.

\textsuperscript{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 a regulated tariffs as a tactic to win customers on the open market.
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 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 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.

18 Articles L111-91 et seq. of the French Energy Code.
19 Articles L134-25 et seq. of the French Energy Code.
20 Articles L111-93 (for electricity) and L111-102 et seq. (for gas) of the French Energy Code.
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, near Marseille, and Montoir-de-Bretagne, near Saint-Nazaire (both of these are owned by a subsidiary of Engie (Enelgy)) and Fos Cavaou, near Marseille (owned by Enelgy and Total). Tariffs for the use of natural gas terminals are regulated. They are decided at ministerial level on the basis of proposals from 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 (e.g., security, continuity of natural gas supply from 1 November to 31 March of each year). 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

Pursuant to Articles L341-2 and L452-1 of the Energy Code, 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.

v Security and technology restrictions

Security of electricity and gas supply is an essential public service obligation. 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. Such measures mainly concern production, imports, exports,
storage, acquisition, and transportation. In the event of a serious energy market crisis, threat to the safety or security of the networks and of people, the Minister of Energy may take protective measures to grant or suspend licences for the operation of power generating facilities.\textsuperscript{30} In times of war or serious international tension, the government may regulate or even suspend oil import or export completely.\textsuperscript{31}

\section*{IV ENERGY MARKETS}

\subsection*{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).\textsuperscript{32}

The participants of the wholesale market are:

\begin{itemize}
  \item[a] the producers who trade and sell their production;
  \item[b] the suppliers who trade and supply gas or electricity before selling gas or electricity to the final client; and
  \item[c] brokers or traders who purchase gas or electricity for resale and thus favour market liquidity.
\end{itemize}

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),\textsuperscript{33} 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).

\subsection*{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.\textsuperscript{34}

\begin{flushright}
\textsuperscript{30} Article L143-4 of the French Energy Code.
\textsuperscript{31} Article L143-7 of the French Energy Code.
\textsuperscript{32} Article L331-1 of the French Energy Code.
\textsuperscript{33} Commission de Régulation de l’Energie, Electricity and gas market report, fourth quarter of 2011.
\textsuperscript{34} Articles L333-1 (electricity), L443-1 and L443-2 (gas) of the French Energy Code.
\end{flushright}
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).35

Finally, free competition is limited with respect to pricing practices since, in certain circumstances, ‘regulated tariffs’ may be chosen by buyers. This is the case for customers having contracted for less than 36kVA (‘blue’ tariffs).36 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 (‘yellow’ and ‘green’ tariffs) by 31 December 2015.37 The removal of these tariffs should bring more competition, with new participants entering the wholesale market.

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’ (Articles L121-86 to L121-94; future Article L224-1 to 224-5 from 1 July 2016). These provisions apply to contracts concluded by consumers and professionals for less than 36kVA (electricity) or less than 30,000kW (gas).

According to Article L121-92 of the Consumer Code (future Article L224-8 from 1 July 2016), the energy supplier ‘must give the client an opportunity to sign a single contract dealing with both the supply and the distribution of electricity or natural gas’. This contract, which should at least last for one year, thus creates a tripartite relationship between the supplier, the distributor and the consumer, even though the supplier often remains the consumer’s main interlocutor.

The supplier must mention several specific provisions both in the offer and the contract. Failure to do so is subject to sanctions.38 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.39

36 Article L337-7 of the French Energy Code.
38 Articles R121-14 to R121-21 of the French Consumer Code.
Market developments have taken place in different areas, and in particular on the cost of electricity with the Law NOME. Moreover, the renewal procedure of hydraulic concessions has been launched and is ongoing.\textsuperscript{40} Finally, various reports were submitted at the beginning of 2012, aimed at clarifying what should be the investments to ensure the security of supply.

## 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,\textsuperscript{41} 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.\textsuperscript{42} These laws were codified in a separate section dedicated to renewable energy in the Energy Code.\textsuperscript{43} More recently, Law No. 2015-992 of 17 August 2015 on energy transition substantially modified the applicable legal framework on renewable energy.

To enhance the development of renewable energies, public authorities can use two economic instruments.\textsuperscript{44} First, feed-in tariffs require the historical operator to buy energy produced from renewable sources, for a regulated tariff over a long period, which can be changed and is slightly higher than the market price. Second, calls for tender can be used to determine \textit{ex ante} the quantity of renewable energies benefiting from the public support. A third system was introduced by Law No. 2015-992 of 17 August 2015, known as ‘Supplementary Remuneration’.\textsuperscript{45} Pursuant to this new system, EDF is obliged to enter into a contract with renewable energy producers, according to which an additional remuneration shall be paid to the relevant renewable energy producer. The duration of the contract shall not exceed 20 years. The Supplementary Remuneration system should become the new main support mechanism for renewable energy. A decree setting out the conditions for access to this mechanism is under discussion.

Finally, a landmark decision regarding the French wind feed-in tariff was issued by the European Court of Justice on 19 December 2013 in the \textit{Vent de Colère} case. Following

\textsuperscript{40} www.developpement-durable.gouv.fr/Les-concessions-hydroelectriques.html.
\textsuperscript{41} Law No. 2009-967 of 3 August 2009 relating to the implementation of the Grenelle Environment Forum and Law No. 2010-788 of 12 July 2010 relating to national commitment for the environment.
\textsuperscript{43} Articles L211-1 to L271-1 of the French Energy Code.
\textsuperscript{44} www.cre.fr/operateurs/producteurs/appels-d-offres.
a request for a preliminary ruling by the French Council of State, the European Court of Justice ruled that the French wind feed-in tariff implemented by a ministerial order dated 17 November 2008 falls within the concept of an intervention by the state through state resources. On 28 May 2014, the Council of State decided that the tariff conditions set out by the above-mentioned order constitute illegal state aid and cancelled the order. A new ministerial order was adopted on 17 June 2014 and sets out the feed-in tariff for wind power.

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.

Article 8 of this Directive, stating that enterprises must be subject to an energy audit by 5 December 2015 and at least every four years thereafter, has been transposed by French Law No. 2013-619 dated 16 July 2013.

In addition, the Directive served as a basis for a national debate on energy transition launched on 29 November 2012 by the government (see below).

iii Technological developments

Directive 2012/27/EU 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. This decree was specified by a ministerial order dated 4 January 2012.

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.

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47 Ministerial order of 17 November 2008 fixing the purchasing conditions for plants using the mechanical energy of wind.
48 CE, 28 May 2014, req. No. 324852.
50 Articles 6 and 3 of the Decree No. 2010-1022 dated 31 August 2010.
VI THE YEAR IN REVIEW

2015 and the beginning of 2016 were characterised by several developments in the energy sector.

i Energy transition law
Following the national debate on energy transition launched on 29 November 2012, Law No. 2015-992 on energy transition for green growth was adopted on 17 August 2015.

The Law notably sets ambitious targets including:

- reducing final energy consumption of fossil energies by 30 per cent from 2012 levels;
- reducing greenhouse gas emissions by 40 per cent by 2030 (from 1990 levels) and by 75 per cent in 2050;
- reducing the proportion of nuclear power and fossil fuels in French electricity generation by 30 per cent in 2030 (from 2012 levels);
- reducing final energy consumption by 50 per cent in 2050 (from 2012 levels);
- increasing the share of renewables in final energy consumption to 23 per cent in 2020 and 32 per cent in 2030; and
- increasing the share of renewable energy sources to 40 per cent of total electricity production.

The adoption by the French Parliament in 2015 of Law No. 2015-992 on energy transition and concerning renewable energies will modify many provisions of the French Energy Code.

ii Decree No. 2016-141 dated 11 February 2016
Pursuant to the energy transition law, Decree No. 2016-141, dated 11 February 2016, introduced a new status for electro-intensive users to allow them to benefit from a reduced electricity transport tariff.

The Decree specifies the conditions necessary to qualify for this status, and reduction caps to preserve consumers' interests.

iii Contribution to the Public Electricity Service reform
The Contribution to the Public Electricity Service aims at compensating public service charges assigned to EDF in particular, and is collected directly from the end user.

The French national budget law of 2015 introduced a special budget item called ‘Energy Transition’, which will be funded in 2016 by the domestic consumption tax on electricity for end users.51

In addition, the scope of the contribution has been enlarged to cover more expenses (such as the purchase of renewable energy and biogas).

iv National Energy Efficiency Action Plans
Pursuant to the Energy Efficiency Directive (establishing a set of binding measures to help the EU reach its 20 per cent energy efficiency target by 2020), transposed in France

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51 **Taxe intérieure sur la consommation finale d’électricité** – TICFE.
by Law No. 2013-619 dated 16 July 2013, on 24 April 2015 France submitted to the European commission its report on its energy efficiency target. The report sets out several objectives, notably:

\[a\] a final energy consumption of 131 Mtoe in 2020 (against 155 currently); and

\[b\] a primary energy consumption of 236 Mtoe in 2020 (against 260 currently).

The report details what policy measures will be implemented to reach the targets, including measures to stimulate building energy efficiency retrofitting projects, to improve energy efficiency in the transportation and agriculture industries.

v The suppression of gas and electricity regulated tariffs

Pursuant to Law No. 2014-344 of 17 March 2014 relating to consumption, the suppression of gas-regulated tariffs for all non-domestic consumers has been effective since 1 January 2016. If no new contract was signed by this suppression date, the client is deemed to have accepted the terms and conditions of the supplier, resulting in the inception of a new six-month contract, terminable by the client at any time.

Provisions relating to information obligations and to contract renewal conditions also apply to electricity suppliers in relation to the suppression of regulated tariffs by the NOME law.

vii The Paris Climate Conference (COP 21)

From 30 November to 12 December 2015, Paris hosted and presided over the 21st session of the Conference of the Parties to the United Nations Framework Convention on Climate Change. It was one of the largest international conferences ever held in France, as 195 countries were present. The Conference resulted in the Paris Agreement, which ‘aims to strengthen the global response to the threat of climate change’. Notably, the parties agreed: (1) on limiting the rise in global temperatures to less than 2°C Celsius and limiting its increase to 1.5°C Celsius; (2) on reducing greenhouse gas emissions; (3) and considering that it will take much more time for developing countries to meet those requirements, on ‘adaptation of enhancing adaptive capacity, strengthening resilience and reducing vulnerability to climate change’, as well as providing support for adaptation to developing countries; (4) on the importance of ‘realizing technology development and transfer to improve resilience to climate change and to reduce greenhouse gas emissions’; and (5) on establishing flexibility that takes ‘into account Parties’ different capacities and builds upon collective experience’.

The Paris Agreement has been lodged at the United Nations in New York and has been opened for signature for one year from 22 April 2016. The Agreement will enter into force after 55 countries that account for at least 55 per cent of global emissions have ratified the agreement.

viii Creation of a capacity market
In accordance with the NOME law, France has put in place a capacity market. 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.

The terms were defined by Decree No. 2012-1405 of 14 December 2012 and were confirmed by a ministerial order of 22 January 2015.

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 year, notably so with the end of regulated tariffs and the adoption of the Law on energy transition on 17 August 2015.
Chapter 14

GERMANY

Kai Pritzsche, Sebastian Pooschke and Henry Hoda

I OVERVIEW

The German energy sector continues to evolve dynamically. The government continues to pursue the reform of the German energy market (the ‘energy transition’), meaning a phase-out of nuclear energy, substantial reduction of carbon dioxide emissions and a shift of electricity generation to renewable energies. However, the side effects of the 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. To further guarantee security of supply the government has decided to introduce a capacity reserve of conventional power without creating a separate capacity market (energy-only market). In addition, investment conditions for distribution system operators shall be improved by amending the current system of incentive grid fee regulation. 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, is 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

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network extension measures. The BNetzA also enforces EU Regulation No. 1227/2011 on wholesale energy market integrity and transparency (REMIT) at national level. 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. The regulators 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.

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 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 last amended in February 2016. A number of ordinances set out further details, such as the Incentive Regulation Ordinance and the Electricity and Gas Grid Fee Ordinances. The Renewable Energies Act (EEG) and the Combined Heat and Power Generation Act (KWKG) set out the priority network access and remuneration for the generation of electricity from renewable and cogeneration sources. 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 administrative decisions of the BNetzA, addressed to individual parties or to groups of network operators, constitute another important source of law. 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.

**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 case, the BNetzA requested Baltic
Germany

Cable AB, operator of the Baltic Cable merchant electricity interconnector between Germany and Sweden, to obtain certification as a TSO. However, Baltic Cable AB is challenging its qualification as a TSO.

When using public roads, network operators must enter into concession agreements with the municipality owning the roads. These concession agreements have to be tendered by the municipalities every 20 years in a non-discriminatory procedure. In recent years, courts have annulled a number of tender procedures in which municipalities had unduly favoured their own utilities. In 2016, the German government plans to amend the regulation of concession agreements in the EnWG. Municipalities shall be allowed to take into account the interests of the local community in the tender procedure. The consideration for the transfer of the network assets to a new concessionaire shall be determined on the basis of the capitalised earnings value of the grid.

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 March 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. By November 2015, power generation units with a total capacity of 14.3GW had been reported for decommissioning with the BNetzA, and it had approved the designation of power generation units with a total capacity of 3.7GW as relevant for system security. Until 2019, a further approximately 4.1GW of generation capacity will probably be decommissioned resulting in a gap of 1GW of generation capacity in southern Germany.

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.
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 because of 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 and gas storage operators 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.

At the level of the DSOs and gas storage operators there remains a large degree of vertical integration. DSOs typically belong to municipal utilities or to one of the incumbent energy suppliers.

**Transmission/transportation and distribution access**

Connection to networks and network access is regulated. Network operators have to ensure a reasonable, non-discriminatory and transparent connection and access to their grids for all third parties, including extension of the network if required and reasonable (regulated third-party access). By way of exception, priority will be given to network connection and access of operators of renewable energy facilities.

Costs for network connection are in general borne by the network customer, except for 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 electricity 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). Access to gas networks is granted on the basis of a standard access agreement developed by the network operators and approved by the BNetzA.

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. Re-dispatch measures of TSOs to relieve bottlenecks increased fivefold between 2010 and 2014 and doubled again in 2015. The resulting costs for compensation of generators are socialised. Hence construction of additional electricity transmission lines is one of the key priorities of German energy policy but meets rising opposition at the local level in affected municipalities.

TSOs have to establish separate annual 10-year network development plans for electricity, gas and for connection of offshore wind farms. 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.

As of 2016, there is a preference for all high-voltage direct current (HVDC) transmission lines to be constructed as underground cabling to limit public resistance to network extension. Overhead HVDC lines will only be approved in exceptional cases (e.g., if existing transmission lines can be used and upgraded). This change will result in a considerable cost increase for network extension, in particular for the urgently required new north-south transmission lines.

iii Rates

Grid fees are subject to revenue cap incentive regulation. Two years prior to the beginning of each five-year regulatory period, the competent regulatory authority determines a grid operator’s allowed cost and asset base by analysing its costs of the preceding financial year (photo year). The cost and asset base in the photo year is the basis for the network operator’s allowed revenues in the next regulatory period. The regulatory authority sets the grid operator’s individual annual revenue cap for each year of the five-year regulatory period, taking into account individual and sector-specific efficiency targets and an allowed rate of return on equity set by the BNetzA. The allowed rate on equity (capped at 40 per cent equity) for the current regulatory period (2013–2017 for gas, 2014–2018 for electricity) is 9.05 per cent for new assets and 7.14 per cent for old assets (commissioned before 2006). 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.

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.

In recent years the German Federal Supreme Court has clarified many previously disputed items around grid fee regulation. For example, the court confirmed the methods of assessing efficiency and quality targets as applied by the BNetzA, the methodology for setting the rate of return on equity and for calculating the regulated asset base.

2016 will see a reform of the incentive regulation to adjust it to the challenges the network operators face in the energy transition. According to a first draft from March 2016, investment conditions for DSOs will be improved by recognising capital costs for investments into the distribution grid in the network operators’ asset base without time lag. Very efficient
DSOs shall receive an efficiency bonus and inefficiencies shall be eliminated within three years instead of one or more regulatory periods, as is the case now. Moreover, the regulatory period for all grid operators shall be shortened to four years.

iv Security and technology restrictions
There are no specific restrictions on technology transfer for the energy sector.

On the basis of 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. Since 2015, the IT Security Act has required operators of critical infrastructure, such as network operators, to ensure adequate protection against threats to their telecommunications and IT systems, and to report disruptions to their systems to the competent authorities.

IV ENERGY MARKETS

i Development of energy markets
Gross energy consumption in 2015 increased by 1 per cent compared with 2014. The share of renewable energies in primary energy consumption increased to 12.5 per cent (from 11.5 in 2014) and to 32.6 per cent (from 27.4 per cent in 2014) in gross electricity consumption. These figures illustrate that despite an increased share of renewable energy sources, conventional energy sources are still the backbone of the German energy supply.

Germany has liquid electricity and gas wholesale markets. The European Energy Exchange AG (EEX) in Leipzig operates organised markets for trading in electricity, coal, carbon dioxide emission allowances and guarantees of origin. The electricity spot market for the joint power market area Germany/Austria is operated by EPEX SPOT SE in Paris. The German gas futures and spot market is operated by Powernext, also seated in Paris, where short-term and long-term gas contracts are traded for delivery, inter alia, in the two German market areas GASPOOL and NetConnect Germany.

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). Because of 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 – because of 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 (OTC) trades.

The spot and futures markets are energy-only markets (i.e., there are no capacity payments). The increase in generation from renewable energies led to depressed wholesale prices and pushed conventional generation capacity out of the merit order, in particular flexible gas-fired power plants. To guarantee security of supply, in 2014 the German government reviewed options for the introduction of capacity mechanisms. In November 2015, however, the government adopted a draft bill to further develop the German electricity-only market, which does not include a capacity market. Instead a ‘capacity reserve’ of 5 per cent of the average annual maximum load (approximately 4GW) shall be auctioned as a backup for intermittent generation from renewable sources. In addition, the ‘network reserve’, introduced in 2013 to counter network congestion, in particular towards the south of Germany, shall be extended.
To achieve Germany’s greenhouse gas emission reduction targets, lignite power plants with a capacity of 2.7GW shall be temporarily taken off line but kept available, for remuneration, for system security for four years, after which they will finally be decommissioned. Further measures shall increase market transparency and reduce costs for network expansion and balancing energy.

ii Energy market rules and regulation

The energy market operated by EEX is subject to the Exchange Act. Under the authority of the State Ministry of Economy, Labour and Transport in the German state of Saxony, an independent market surveillance body continuously supervises trading activities to prevent market manipulation.

Under the EU REMIT Regulation, market participants are required to publish inside information in an effective and timely manner. REMIT also prohibits market abuse in wholesale energy markets in the form of market manipulation and insider trading. As of 7 October 2015, market participants must report details of wholesale energy transactions executed at organised market places to the Agency for the Cooperation of Energy Regulators (ACER). As of 7 April 2016 market participants also have to report wholesale energy transportation contracts and OTC contracts to ACER.

Since February 2014, all EU-based entities that enter into derivatives transactions have been required to report details of these transactions to a trade repository under the European Marketing Infrastructure Regulation (EMIR). Furthermore, EMIR establishes 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. On the basis of this provision, the BKartA has taken action against several suppliers and enforced price reductions.

In recent years, price increases for final customers based on the passing-on of input costs (e.g., increase in fuel costs 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 judgments of the European Court of Justice, the German Federal Supreme Court in October 2015 held that the price adjustment clauses in the Basic Gas Supply Regulation are invalid as they violate European law. Nevertheless, suppliers are entitled to pass on cost increases to customers that cannot be offset by cost reductions, provided that network operators let customers benefit from cost reductions the same way they pass on cost increases. Network operators also have
iv Market developments

The reform of the electricity market is intended to further develop the existing energy-only market without introducing a capacity market (see Section IV.i, supra). Despite the technical progress in the field, the electricity storage market is still largely undeveloped because of existing regulatory hurdles. The reform of the grid fee incentive regulation aims at improving investment conditions for DSOs, but leaves the status quo for TSOs mostly unchanged (see Section III.iii, supra).

The market share of the four largest utilities in Germany in electricity generation has further decreased to 67 per cent in 2014, compared with 73 per cent in 2010. The large utilities are looking for new business opportunities as conventional power generation facilities are driven out of the market by renewable energy sources. E.ON has transferred its conventional generation and trading business into a new company, called Uniper, to focus on renewable generation, energy grids and customer solutions. RWE has announced to follow suit by spinning off its renewable, sales and network business. EnBW is shifting its generation portfolio to renewables. Vattenfall has announced to divest its German lignite business (power plants and open-cast mines) and to focus in Germany on district heating, supply and distribution grids.

Law suits by E.ON, RWE and Vattenfall against the decision of the German government to immediately shut down eight nuclear power plants following the nuclear incident at Fukushima in March 2011 are still pending before the Federal Constitutional Court. However, the outcome of these proceedings does not call into question Germany’s decision to phase out nuclear energy by 2022.

In an opinion published in September 2015, ACER suggested the introduction of congestion management at the German-Austrian border, which would lead to a split of the joint German-Austrian price zone. An action for annulment of this opinion, brought by the Austrian regulator E-Control, is pending before the European General Court.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

EEG 2014

In 2014, a major reform of the EEG, the law governing the development of renewable energy sources, entered into force. However, the principles of priority network access and priority offtake of electricity from renewable energy sources continue to apply. The general aim of the EEG 2014 is to control the growth of the cost for renewable energy production, and to move away from 'produce-and-forget' guaranteed feed-in tariffs towards market-based mechanisms for their remuneration.

The EEG 2014 defines binding corridors for the deployment of renewable energies, thereby lifting the total share of renewable energy sources in the gross electricity consumption to 40 to 45 per cent by 2025, to 55 to 60 per cent by 2035 and to 80 per cent in 2050. For this purpose, feed-in remuneration for new facilities is limited to a certain maximum capacity
added per year: 2,500MW per year for photovoltaic, 2,500MW per year for onshore wind, 6,500MW for offshore wind until 2020 (15,000MW until 2030) and 100MW per year for biomass. Additional capacity of geothermal energy and hydropower will not be restricted.

In the interest of better market integration of renewable energy sources, the former system of fixed statutory feed-in tariffs and market premiums has been replaced for larger facilities by mandatory direct marketing of electricity by plant operators. Direct marketing is compulsory for new facilities with a capacity of more than 500kW as of 1 August 2014 (reduced to more than 100kV as of 1 August 2016). In addition to the proceeds from direct marketing, plant operators receive a market premium, which amounts to the difference between an average spot market price and a reference remuneration set out in the law.

Energy-intensive industries continue to benefit from a reduction of the EEG surcharge, which is an extra charge on top of an end consumer’s electricity bill socialising the cost of the EEG support scheme. However, the EEG 2014 tightened the eligibility criteria and limited the scope of the reduction bringing it in line with EU state aid rules. The former exemption of consumers of self-produced electricity from the EEG surcharge has been replaced by a reduction of the EEG surcharge to 30 per cent (40 per cent as of 1 January 2017) for consumers of electricity from renewable energy sources or highly efficient cogeneration plants.

Until 2017, the BNetzA will auction an annual average of 400MW from free-standing photovoltaic facilities as a pilot scheme.

EEG 2016
In April 2016 the BMWi started stakeholder consultation on a draft bill to amend the EEG. It is planed that from 2017 the level of remuneration for electricity from onshore wind and photovoltaic facilities above 1MW shall be set by way of auctions. For onshore wind the capacity to be auctioned shall be determined with regard to the targeted share of 45 per cent renewables in 2025, but not less than 2,000MW per year. For photovoltaic, the annual capacity to be auctioned is set at 500MW. Of the annual capacity to be auctioned, 5 per cent shall be open for renewable facilities in other Member States. The BNetzA will conduct three to four pay-as-bid auctions per year to award these capacities to the bidders offering the lowest remuneration (subject to a maximum price).

Offshore wind farms that are commissioned up until 2020 will continue to benefit from the EEG 2014 feed-in tariff regime. Thereafter, suitable locations for offshore wind farms will be investigated and auctioned off by a central authority with a view to installing a capacity of 800MW per year. The details will be set out in a new Offshore Wind Energy Act.

ii Energy efficiency and conservation
In its 2014 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 with 2008. In December 2014 the German government therefore adopted a number of immediate and long-term measures to increase energy efficiency in its National Action Plan Energy Efficiency (NAPE). As part of NAPE, inter alia, 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 own energy efficiency shall be increased.

In January 2016 a new Combined Heat and Power Generation Act (KWKG) entered into force. It is intended to further increase power output from cogeneration facilities.
However, remuneration for cogeneration units above 2MW will be reduced if the total costs for the remuneration of cogeneration plants exceed an amount of €1.5 billion per year. Operators of highly efficient facilities may receive a bonus depending on the capacity of their facilities. The bonus is increased if the new unit replaces a coal-fired plant.

As of 2016, the energy-efficiency requirements for new buildings under the Energy Saving Ordinance have been tightened by 25 per cent with respect to the primary energy consumption and by 20 per cent with respect to thermal insulation.

iii Technological developments

In 2015 a number of pilot power-to-X facilities have been commissioned. Power-to-X means technologies for the storage or conversion of surplus electricity from renewable energy sources into other forms of energy, such as power-to-gas, power-to-heat or power-to-liquid.

Another technological trend are virtual power plants, which are clusters of small distributed generations 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 2014 requires all generation facilities to be remotely controllable.

As part of the planned grid expansion measures, new HVDC technologies are researched and deployed, both offshore and onshore. Because of opposition to new transmission lines at local level, underground HVDC cabling will play an important role in increasing acceptance of the required grid expansion measures.

In November 2015, the German government adopted a draft bill on the ‘digitalisation of the energy transition’. The Act stipulates the introduction of smart meters, including rules on data protection, data access, roll-out and financing of the roll-out. It is planned that smart meters will have to be installed by consumers with a consumption above 10,000kWh per year as of 2017 and with a consumption above 6,000kWh per year as of 2020. Costs for installation and operation of a smart meter are capped depending on annual consumption (e.g., €130 for consumption from 10,000 to 20,000kWh, €100 from 6,000 to 10,000kWh). Roll-out to consumers with an annual consumption of less than 6,000kWh is optional as of 2020.

In April 2015, the German government adopted a draft legislative package on hydraulic fracturing of conventional and unconventional gas (fracking), which has not yet been put to the vote. According to the draft package, any form of fracking shall be prohibited in conservation and drinking water protection areas. Fracking shall always require an environmental impact assessment. Unconventional fracking above 3,000 metres shall be prohibited with the exception of exploratory drillings using non-water-hazardous fracking fluids.

VI THE YEAR IN REVIEW

The discussion on the reform of the electricity market design turned against the introduction of a capacity market in Germany. Instead, security of supply shall be achieved by redispatching and by way of a capacity and network reserve, accompanied by additional measures to increase market transparency and to reduce costs for network expansion and balancing energy.

A pilot auction scheme for the promotion of the market integration of photovoltaic energy from free-standing facilities proved successful; it will serve as a blueprint for the further market integration of renewables. The existing promotion of renewable energies further increased their share in the gross electricity consumption to about one third, but
drove down market prices for electricity to a historic low. This induced the large German utilities to accelerate the restructuring of their generation portfolios and the two largest German suppliers to separate their conventional generation from the renewable generation and most of their other business.

Onshore network expansion faced strong public and also partly political opposition. As of 2016, therefore, onshore HVDC transmission lines mostly have to be constructed as underground cables. Even though this reform is intended to increase public acceptance of network expansion, the necessary replanning of transmission lines is likely to further delay the expansion of the high-voltage transmission network. The commissioning of offshore grid connections and of offshore wind farms has further progressed, however, thanks to the stabilised regulatory framework and revived investor interest.

VII CONCLUSIONS AND OUTLOOK

In 2016, key reforms for the electricity market will enter into force that set the stage for market developments in the years to come.

The next reform of the EEG, in 2016, will introduce auctioning as the principle means to determine the level of remuneration of renewable energy sources, and thus to develop renewable energy expansion within the corridor set by the government. Together with a partial opening of the promotion of renewables to operators from other Member States, this will be the next step towards a comprehensive market integration of renewable generation.

A successful reform of the electricity market and accelerated network expansion will be the requirements for a further increase of the renewable share that remains affordable to consumers while not endangering security of supply. The reform of incentive regulation will be key for the improvement of investment conditions at the distribution system level.

The reform of the EnWG will strengthen the energy-only market, but it will also introduce a capacity mechanism to ensure security of supply. The legal framework for the smart-meter and smart-grid roll-out will be established by the Act on Digitalisation of the Energy Transition.

Low wholesale market prices, a competitive retail market and the financing obligations with regard to the dismantling of nuclear power plants will put further financial strain on the large German utilities. They will continue to restructure their business models and to seek new business opportunities to adjust to the changing market conditions.

The speed of the development of the markets for power-to-X technologies and smart customer solutions will depend on whether the legislator succeeds in addressing the existing regulatory hurdles.

In April 2016, a commission of experts established by the German government handed down proposals for the long-term financing of the decommissioning and dismantling obligations of operators of German nuclear power plants (NPPs). According to the proposal, intermediate and final storage of nuclear waste shall be the sole responsibility of the state. It is proposed that the NPP operators are released from these obligations against transfer of €23.3 billion into a new public law fund that will manage the disposal. Decommissioning and dismantling of NPPs remains the sole responsibility of the operators. It is expected that these recommendations will be implemented in laws in 2016. The government has also adopted a draft bill, expected to enter into force in 2016, that shall prevent the large utilities operating NPPs to transfer or limit their dismantling obligations through corporate restructuring. At the same time, the large utilities continued to challenge before the Federal Constitutional
Court the lawfulness of the immediate shutdown of eight nuclear power plants in 2011 after the Fukushima accident. It is to be decided whether the upcoming decision of the Federal Constitutional Court on this matter will result in further compensation payments to plant operators. At any rate, it is unlikely that the decision will call into question Germany’s decision to phase out nuclear energy by 2022.
Chapter 15

INDIA

Neeraj Menon and Riyaz Bhagat

I  OVERVIEW

The Indian economy is undergoing large-scale transformation across various key sectors, and energy security has emerged as one of the key thrust 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 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 alarming increase in 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. For the second year running, India has significantly exceeded its solar and wind energy capacity addition targets.

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

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central level (the Central Electricity Regulatory Commission (CERC)) and state level (the state electricity regulatory commissions (SERCs)) and the setting up of the Appellate Tribunal for Electricity. The relevant SERCs exercise jurisdiction over intrastate electricity regulatory matters (including tariffs), whereas the CERC exercises jurisdiction over all interstate electricity regulatory issues (also including tariffs). In January of this year, the revised Tariff Policy was announced 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 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. Recently, significant amendments have been proposed 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.

The Department of Atomic Energy\footnote{Which is directly under the Prime Minister’s charge.} 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. The coal sector is still recovering after the Supreme Court, in September 2014, 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. The Coal Mines Act now governs coal block allocations, with a view to ensuring coordinated and scientific development and the utilisation of coal resources. The Coal Mines Act lifted end-use restrictions on the coal mined from some of the re-allocated blocks to enable the sale of coal on the open market, in other words, allowing for the commercial mining of coal. However, the government’s stance continues to indicate that it is unlikely that a free pricing regime and export of coal will be allowed through commercial mining until such time as the domestic coal requirement of the country is met in full, which the government aims at meeting in full by 2017. Recently, the Union Cabinet approved a proposal that allows flexibility in utilisation of domestic coal with an aim to reduce the cost of power generation. This decision aims at improving the efficiency of coal-based thermal power plants by reducing cost of coal transportation and allowing coal swapping among plants. The Central Electricity Authority has been tasked with devising a methodology for implementing the use of coal assigned to particular states, in power generating plants in the respective states.

The Ministry of Petroleum and Natural Gas (MoPNG) deals with issues relating to petroleum, natural gas, coal bed methane, shale gas and other petroleum products. Along with exploration and production, the MoPNG also monitors its supply, distribution,
marketing and pricing. The Directorate General of Hydrocarbons (DGH), which is under the administrative control of the MoPNG, regulates the upstream segments for issues relating to exploration and production of oil and gas. The Petroleum and Natural Gas Regulatory Board (PNGRB) is the midstream and downstream regulator that regulates the refining, storage, transportation, distribution, marketing and sale of petroleum, petroleum products and natural gas.

ii Regulated activities

Electricity generation, including captive generation, is a delicensed activity. While generation activities can be freely undertaken without a licence, approvals and procedures under other laws for land acquisition, environmental, corporate 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 awards 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 stipulates 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 has given notification of the Domestic Natural Gas Pricing Guidelines 2014. These guidelines provide for the prices to be fixed on the basis of the annual average of the price of gas at specified international hubs, and requires notification of the prices determined by the government to be issued on a biannual basis with effect from 1 November 2014.

The coal bed methane (CBM) policy 2009 offered blocks for exploitation of CBM through biddable revenue-sharing based on production-linked payment. In 2014, a comprehensive note was prepared for the Cabinet Committee on Economic Affairs, proposing amendments to the CBM policy to, among other things, solve the controversial issue of exploiting CBM at already allotted coal blocks belonging to CIL and private entities. Currently, the government is in the process of obtaining stakeholder comments and suggestions and is expected to issue amendments to the CBM policy later this year. The new policy is likely to permit both government and private entities to participate in the bidding process to attract increased investment.

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. 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 on the basis of their revenue-sharing commitment with the government. 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 also introduces 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. While the potential shale gas reserves overshadow those of conventional gas, India has a long way to go in identifying shale gas-rich basins and acquiring the necessary technology and experience to extract shale gas, specifically in the absence of private participants.

Petroleum, natural gas and city gas distribution (CGD) networks can be developed either through an expression of interest to the PNGRB or under competitive bids invited by the PNGRB. Under the expression-of-interest route, the PNGRB must publicise upon receipt such an expression of interest, to receive proposals or comments from different entities, and may invite competitive bids or allow for the proposal (with or without modification).

iii Ownership and market access restrictions

Over the past decade, the government has progressively liberalised the energy sector, although government companies continue to be active players. Up to 100 per cent foreign direct investment (FDI) is permissible in generation (except nuclear power), transmission, distribution of electricity and power trading, as well as in the oil and gas sector and up to 49 per cent in power exchanges without prior regulatory approval. Such investments are 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 (PGCIL), 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 systems.

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3 In investments in petroleum refining undertaken by public sector entities, only up to 49 per cent FDI is permitted.
networks. Electricity distribution is largely in the control of government distribution utilities, with privatisation being slow largely on account of the huge legacy liabilities of the state distribution utilities. 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, for generating stations set up pursuant to certain renewable energy policies or by competitive bidding (for thermal or hydroelectric projects), there is a shareholder lock-in period for the developer. The Ministry of Power’s revised standard bidding documents for long-term (seven to 25 years) and medium-term (one to five years) procurement of power from thermal power projects (Revised SBDs), provides 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 will be 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 agreements for long-term procurement under 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, notification of which was issued in 2013, and which provide for two modes of bidding and supply of electricity. Under the DBFOO\(^4\) 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\(^5\) model, one or multiple distribution licensees may collectively invite bids for setting up projects 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).

The Revised SBDs have prescribed higher normative availability, single-variable bidding, restrictions on usage of concessional fuel (i.e., fuel procured at subsidised rates from government fuel suppliers), pass-through of variable charges (including cost of fuel) to the consumers, detailed construction and operations and maintenance (O&M) standards and appointment of a mandatory independent engineer for each project.

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. While the pass-through mechanism of fuel costs is likely to lead to an increase in the power tariffs for consumers, it appears to be a necessary evil to ensure that commissioned generation capacity is not stranded. In 2015, the government further amended the guidelines for procurement of power through the DBFOO route. Some of the key amendments include changing the minimum tenure of long-term procurement contracts from 25 years to seven to 25 years from the date of power supply. Additionally, power producers are also given the option of a five-year extension. Pursuant to the amendments, distribution licensees are only allowed to make deviations to the SBDs with the prior approval of the SERC or CERC and not the government, as was the case earlier, allowing more flexibility for procurement by the distribution licensees.

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

\( ^4 \) 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.
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 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 and has issued Revised SBDs for medium-term procurement of one to five years (from coal, gas or hydro-based stations) and on a short-term basis (i.e., for a period of more than one day and up to one year). The revised guidelines introduce tariff determination through an e-auction, with an overall aim of reducing power procurement costs in the short term for distribution licensees.

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 envisages 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. A target of 30 per cent plant load factor has been set, which was to be achieved towards the end of 2015–2016. This is a much needed move to revive ailing gas-based thermal power plants in India.

On the distribution front, the major problems plaguing the power sector in India are the abysmal credit ratings of the state distribution utilities and their persistent failure to honour payments to generators under PPAs or extensive delays in doing so. Distribution utilities have borrowed heavily to finance losses in their businesses, and are facing major hurdles in repaying their debt. The government recently launched the Ujwal Discom Assurance Yojana (the UDAY scheme) with the objective of improving the operational and financial efficiency of state-owned distribution utilities. 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. The states may then 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 distribution licensee’s debt, and will waive off unpaid overdue interest, including penal interest. For financing future losses and working capital of distribution utilities, state governments will take over and fund future losses in a graded manner until the financial year 2020/2021. One of the much praised aspects of the UDAY scheme is its greater acceptability to the relevant state governments, as the debt proposed to be absorbed will not affect their fiscal deficit and in turn will not affect their central government budgetary allocation. This should in turn lead to distribution utilities significantly increasing their procurement of power. However, the UDAY scheme has been criticised in some quarters for a perceived lack of explicit central government support as part of the transitional financing mechanisms, and a lack of operational control measures in terms of automatic fuel and power purchase price adjustments. While, on one hand, the industry is hopeful that the UDAY scheme will provide a much needed shot in the arm to the distribution segment in the country, the response of states in the country will invariably determine its success or failure. To date, 10 states have signed up for the UDAY scheme, with more states likely to follow in the coming months.

The government has also constituted a committee to propose a PPP framework for mining of coal. While a model concession agreement has been developed by the Ministry of Coal, this document is yet to be formally adopted by CIL. Media reports suggest that the
proposed PPP framework will move away from the existing mine-developer-operator model, and mining contracts will be awarded on a turnkey basis to bidders, who will be responsible for all stages of development ranging from production to loading and transportation.

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)).

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 utilities. These RECs can be bought by certain obligated entities (such as electricity distribution licensees and captive power consumers) to fulfil their RPOs.

With the introduction of HELP, the government seeks to revive the ailing gas market. HELP has introduced market and pricing freedom for gas discoveries in blocks that have yet to commence commercial production as of 1 January 2016. In addition to HELP, with the introduction of the new domestic gas pricing guidelines, the underlying principle is 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.

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, which commenced in February 2015. Out of an initial 110 coal blocks available for auction or allocation, the government subsequently proceeded to auction or allocate 50 coal blocks last year. Of these coal blocks, 35 belong to Schedule II of the Coal Mines Act, in which mines are currently operating or ‘ready to operate’. The key incentive offered to bidders was a speedy transfer or grant of all applicable permits and approvals that would enable mine operators to commence production at the earliest. However, pursuant to the auctions, the government has faced criticism for a failure to provide timely permits and approvals, thereby affecting bidders who bid aggressively on this assumption. Additionally, market participants have also criticised the government for capping capacity charges in the electricity tariff to not allow the cost of mining and mine infrastructure. Therefore, bidders are currently not allowed to pass on mining costs to power procurers and are also required to pay the government an additional premium.

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 utilities 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. 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. Wind-power projects can claim either accelerated depreciation of up to 80 per cent or generation-based incentives (i.e., a monetary entitlement per unit of electricity fed into the grid).

The government 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. The criteria for selection of developers has also been set out in the policy, which includes various factors such as tariff, total cost of project, sharing of production benefits or revenue and rate of lease of land, etc. In addition to allocation of blocks, NIWE is also required to carry out the initial wind resource assessment and assist the project developers in obtaining clearances. As a part of the planned off-take arrangement, NIWE or the respective state distribution utilities will sign power purchase agreements. Transmission utilities owned by the government will provide the onshore infrastructure required to evacuate power generated from these projects. Offshore power evacuation infrastructure up to the first onshore substation will have to be constructed by developers at their own cost. Currently, offshore wind power projects with a capacity of approximately 300MW are planned to be set up in two states as demonstration projects.

Solar energy
Solar plants can be set up under the Renewable Energy Ministry's National Solar Mission (NSM, previously the Jawaharlal Nehru National Solar Mission), as well as under state policies. Important incentives such as accelerated depreciation of 80 per cent continue to be allowed on solar assets.

After successfully implementing both batches of Phase I, and Batch I and II of Phase II of the NSM, the Renewable Energy Ministry has issued final guidelines for Batch III of Phase II of the NSM, which propose to add capacity aggregating 2,000MW in solar parks to be purchased by the respective states. In a departure from Batch II Phase II (but similar to Batch I Phase II), solar power in Batch III 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. Like Batch II of Phase II, solar capacity under this batch is sought to be installed, within solar parks to be delineated by state governments, who will independently invite tenders under the NSM. Solar parks are essentially tracts of land delineated for the
purpose of setting up the plants of multiple developers along with appropriate evacuation infrastructure, which aims to solve two of the most pressing concerns in the solar sector: the availability of land and the setting up of evacuation infrastructure. The solar park concept has gained traction in the country with various states signing up to the government’s solar park scheme.

In addition to issuing notification of the guidelines for Batch III of Phase II, 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 has introduced the concepts of deemed generation payments (if the evacuation grid is unavailable for more than 175 hours in a year) and termination compensation. Termination compensation amounting to six months of generation payments is payable by the procurer and, in certain cases of termination, the power procurers are required to repay the balance of the debt due from the project developer, and take over the project. The government’s decision to put forward these concepts is reassuring for the developer and lender community, which has been demanding these provisions in the PPAs. However, it remains to be seen whether these provisions will be included as is when notification of the final guidelines is issued.

On the domestic manufacturing front, the sector suffered a setback earlier this year 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 meet the twin objectives of promoting local manufacturing capability and attracting efficient and advanced technology. In response, the United States raised a dispute at the WTO following failed consultations regarding the domestic content requirements 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 has, however, decided to appeal the WTO’s decision before the WTO Appellate Body.

While there is a view that the government’s aim of developing domestic manufacturing capacity can also be achieved by other means such as providing specific subsidies to domestic solar manufacturers and providing low-cost financing, others believe that a fair balance of the content requirements strikes a safe middle ground. Further, while tariffs for purchase of solar power currently offered under the NSM are inching towards grid parity, the tariffs announced by certain state governments (e.g., Rajasthan, Karnataka, Punjab and Gujarat) continue to be more attractive. 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.

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 recently launched a US$750 million subsidy scheme for rooftop solar projects, which aims to provide close to 30 per cent of the capital
subsidy required. Solar Energy Corporation of India, which is a central government company under the administrative control of the Renewable Energy Ministry, is in the process of concluding the award of rooftop solar projects to developers with a cumulative capacity of 750MW. In a further boost to the sector, the government is currently in talks with various multilateral funding agencies with a view to tying up close to US$3 billion in financing for the sector. Additionally, recent trends show that state governments are promoting the installation of such systems by introducing enabling legislation, such as net metering regulations. 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.

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, the government is trying to promote schemes to encourage cities and municipalities to take up waste-to-energy projects in PPP mode (such as the Pune Municipal Corporation’s project of producing energy by utilising unsegregated waste). As a protective measure, stringent regulations allow use of only those technologies that are duly approved by the Central Pollution Control Board.

**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. For instance, the UDAY scheme, if implemented successfully, could be a game changer as it seeks to manage the burgeoning debt of various distribution utilities and enforce 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 has been received positively in the market. This decision 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. Additionally, the Reserve Bank of India (RBI) issued a notification last year allowing relief for projects that were stalled primarily because of the inability of existing promoters to develop projects effectively and in which the promoters’ shareholding was subsequently transferred. In such situations, the RBI has decided to allow lenders to extend the date of commencement of commercial operations by a further period of up to two years, which is expected to provide considerable relief to projects in the pipeline that have been facing delays. Further, the RBI has also fine-tuned its scheme for long-term flexible finance structuring for infrastructure 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. This scheme is also commonly known as the RBI 5-25 Scheme and has been introduced to provide more flexible loan restructuring options to debt-heavy power projects in the country.

In the transmission sector, as well as 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 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.

In the nuclear power sector, President Obama’s visit to India last year resulted in meaningful progress in resolving the concerns of suppliers and manufactures of nuclear material and equipment in both countries 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, foreign suppliers continue to treat the sector, and particularly India’s nuclear liability laws, with suspicion. The government has recently issued notification of the Nuclear Liability Fund Rules, 2015. These rules contemplate the creation of a fund through levies paid by operators to the tune of 0.05 paise per unit of electricity sold. However, the collection of levies from operators will stop the moment the fund reaches a corpus of 2,000 crores (20 billion Indian rupees) and will subsequently resume when any withdrawals are made.

One of the major developments of the year came when the government announced the new Tariff Policy in January 2016. The announcement on exemption from payment of interstate transmission charges and losses for solar and wind energy generators will give
the sector a further boost. Additionally, fixing the solar RPO to 8 per cent by 2022 and introducing the renewable generation obligation on thermal power plants has been well received in the renewables market.

The year saw the reinstatement of key incentives, such as extension of the prescribed 10-year income tax holiday to those undertakings that begin generation, distribution and transmission of power by 31 March 2017. Production was also sought to be increased through advanced technology by proposing installation of ‘supercritical ultra-modern thermal power projects’ and ‘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 also proposed feeder separation to augment power supply to rural areas and for strengthening subtransmission and distribution systems.

On the renewable energy front, 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. The proposed introduction of renewable generation obligations as part of the amendments to the Electricity Act have the potential to shore up the REC market. Further, the promotion of solar rooftop projects by various state governments is a discernable 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. According to media reports, various states are in the process of issuing intrastate scheduling and forecasting regulations to complement the interstate regulations.

On the natural gas front, welcome signs for beleaguered gas-based power plants include the second revision of gas prices under the new domestic gas pricing guidelines, leading to a significant fall in the price of gas from 1 April 2015 onwards, and the diversion of gas from fertiliser plants to standard power stations in coastal states. The government also announced that it would lay an additional 15,000km of natural gas pipelines on a PPP basis, which presents a key value proposition for private entities going forward. Additionally, the government has also launched a scheme for gas-based plants that involves importing spot regasified LNG for stranded and partly stranded gas-based plants. The scheme also provides for financial support from the Power System Development Fund (PSDF). The government held the auctions on PSDF support in May and September 2015, with over 22,000MW of gas-based plants able to secure gas allocation.

One key development revolves around the Appellate Tribunal for Electricity’s (APTEL) 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 APTEL in its judgment has 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. Therefore, the CERC has been asked to decide if any relief can be granted on account of the force majeure, if any.

With the Supreme Court cancelling almost all coal blocks allotted between 1993 and 2010, it remains to be seen whether the regulators or courts will allow any relief to developers who may claim that the Supreme Court verdict is in the nature of a change in law or force majeure under their PPAs.

In the oil and gas sector, the dispute between the government and the Reliance group (an oil and gas major) on the pricing of gas from the KG-D6 block – 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 utilities, revising the DBFOT SBDs, and introducing a new pricing regime for natural gas coupled with the shift to OALP. 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 judicial authorities are also taking a serious look at irregularities and inconsistencies in government policies, which is evidenced by landmark judgments by the Supreme Court, including in the coal block deallocation cases.

However, there are persisting concerns, such as a lack of certainty over the power procurement regime, with the DBFOT SBDs being revised just two years after their introduction and the NSM alternating between the VGF model and the bundling scheme. While the policy reforms have led to an initial spurt in capacity addition, achieving India’s aim of energy security is quite a way from being accomplished. That said, although the government seems to gaining some ground, it will require continuous and persistent reforms over the coming year to ensure that India achieves its ambitious targets in the energy sector.
Chapter 16

INDONESIA

Mochamad Kasmali

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 501 regencies and municipalities. Each sub-national government has its own executive (governors, regents and mayors) and legislature (regional DPR).

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¹ Mochamad Kasmali is a partner at Soemadipradja & Taher. The author would like to thank associates Bilma Rachmadi Ganie and Anandianty Febrina 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.
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. As such, there are both national and regional laws and regulations.

Indonesia has a civil law system, with the following hierarchy of laws:

- the Constitution;
- MPR decrees;
- laws or government regulations in lieu of law;
- government regulations;
- presidential regulations;
- provincial regulations; and
- 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. 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.

Indonesia’s energy policy is established under the Energy Law, which applies to both renewable and non-renewable energy.

Each energy sector is subject to different laws and regulations:

- Electricity: the Electricity Law, with regulations including:
  - the Electricity Business Regulation.

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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.
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.
• the Electricity Supporting Business Regulation;\textsuperscript{12} and
• the Electricity Business Licences Regulation.\textsuperscript{13}

\textit{b} Geothermal: the Geothermal Law,\textsuperscript{14} with regulations including the Geothermal Business Regulation.\textsuperscript{15}

\textit{c} Mining: the Mining Law,\textsuperscript{16} with regulations including the Mining Regulation.\textsuperscript{17}

\textit{d} Nuclear: the Nuclear Law,\textsuperscript{18} with regulations including the Nuclear Regulation.\textsuperscript{19}

\textit{e} 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.

\textit{i} 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:
\textit{a} electricity (DGE);\textsuperscript{24}
\textit{b} minerals and coal (DGMC);\textsuperscript{25}

\textsuperscript{12} Government Regulation No. 62 of 2012 on Electricity Supporting Businesses.
\textsuperscript{13} Minister of Energy and Mineral Resources Regulation No. 35 of 2013 on Procedures for Electricity Business Licences (as amended by Minister of Energy and Mineral Resources Regulation No. 12 of 2016).
\textsuperscript{14} Law No. 27 of 2003 on Geothermal, as later revoked and replaced by Law No. 21 of 2014 on Geothermal.
\textsuperscript{15} Government Regulation No. 59 of 2007 on Geothermal Business Activities (as amended by Government Regulation No. 70 of 2010).
\textsuperscript{16} Law No. 4 of 2009 on Mineral and Coal Mining.
\textsuperscript{17} Government Regulation No. 23 of 2010 on the Implementation of Mineral and Coal Mining Business Activities (as amended by Government Regulation No. 24 of 2012, Government Regulation No. 1 of 2014 and Government Regulation No. 77 of 2014).
\textsuperscript{18} Law No. 10 of 1997 on Nuclear Energy.
\textsuperscript{19} Government Regulation No. 2 of 2014 on Licensing of Nuclear Installations and the Utilisation of Nuclear Materials.
\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/.
Other energy regulators include:

a. The National Energy Board (NEB): the Energy Law provides for the establishment of the NEB, which is responsible for formulating and implementing energy policies.

b. 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.

c. Oil and Gas Downstream Regulatory Agency (BPH Migas): BPH Migas’s responsibilities include licensing and regulating downstream oil and gas activities.

d. National Nuclear Power Agency (BATAN): BATAN is responsible for research and development, exploration and exploitation of radioactive materials and management of radioactive waste.

e. 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).

ii 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.

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 fulfill 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 company.

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26 www.ebtke.esdm.go.id/.
27 www.migas.esdm.go.id/.
28 Article 11(2) of the Electricity Law.
29 Articles 8-9 of the Electricity Law.
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, and 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. 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.

**Coal mining**

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
   - obtain from the relevant authority (the Minister of MEMR or governor, depending on the location of the mining area) an IUP; or

b. a coal contract of work (CCoW): CCoWs were entered into between the government and companies under the previous mining law. 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.

**Oil and gas**

To conduct upstream activities (namely, exploration and exploitation), an entity must:

a. succeed in a tender process held by DGOG for an oil and gas block; and

b. enter into a PSC with SKK Migas.

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30 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.

31 MEMR Regulation No. 35 of 2013 on Procedures for Electricity Business Licences (as amended by MEMR Regulation No. 12 of 2016).

32 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.

33 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.

34 Law No. 11 of 1967 on the Basic Provisions of Mining, later revoked and replaced by the Mining Law.
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:

- a processing business licence;
- a transportation business licence (and a special right from BPH Migas to transport gas via a pipeline);
- a storage business licence; or
- a trading business licence.

**Renewable energy**

An entity is permitted to generate renewable electricity for sale to PLN. An entity is permitted to generate renewable electricity for sale to PLN. Under the Geothermal Law, geothermal resources can be utilised for:

- an indirect purpose, which involves electricity generation. This will require a Geothermal Licence issued by BKPM; or
- 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.

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:

- succeed in a public auction for the award of a geothermal work area;
- obtain a Geothermal Licence from the Minister of MEMR; and
- 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 remain to be specifically regulated.

**General**

Energy and natural resources projects and proponents may also need to obtain appropriate approvals and licences in relation to:

- land; for example, a right to own, right to build or right to use;
- the environment: principally an environmental licence and environmental impact analysis approval or environmental management and monitoring efforts approval; and
- forestry: principally a borrow-to-use forest area licence.

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36 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.
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.

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

37 Law No. 25 of 2007 on Investment.
38 Law No. 40 of 2007 on Limited Liability Companies.
39 BKPM Regulation No. 14 of 2015 on Guidelines and Procedures for In-Principle Licences on the procedure and requirements for an investment application.
40 The Negative List identifies the business sectors that are closed to foreign investments or are open subject to conditions.
41 Presidential Regulation No. 44 of 2016 on the List of Business Fields Closed to Investment and Business Fields Open to Investment with Conditions.
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.

This requirement applies to production operation IUP holders who do not carry out
their own processing or refining, or both, while there are exceptions for the amount
of required divestiture for production operation IUP holders who: (1) conduct
processing or refining activities, or both; (2) perform underground mining activities;
or (3) perform underground and open-pit mining activities.42

However, under a MEMR regulation, if:43

- a non-PMA company holding an exploration IUP applies to become a PMA
  company, the maximum permitted foreign ownership is 75 per cent;
- a PMA company holding an exploration IUP or production operation IUP seeks
to transfer its shares to a new foreign investor, the maximum permitted foreign
ownership is 75 per cent and 49 per cent (respectively); and
- a non-PMA company holding a production operation IUP applies to become
  a PMA company, the maximum permitted foreign ownership is 49 per cent
(regardless of whether five or 10 years of commercial production have passed).

In addition, CCoW companies that have been in commercial production since at
least 14 October 2009 (that is, for at least five years):

- were required to divest to Indonesian parties 20 per cent of their foreign capital by
  14 October 2015; and
- and are required to so divest the relevant further percentages of their foreign capital
  (based on their mining activities and the divestment percentage as stipulated in
  the Mining Regulation) by 14 October 2019.

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.

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42 Government Regulation No. 77 of 2014 on the Third Amendment to Government
Regulation No. 23 of 2010 on the Implementation of Mineral and Coal Mining
Business Activities.

43 MEMR Regulation No. 27 of 2013 on Procedures for Divestment and Share Pricing and
Changes to Capital Investment in Mineral and Coal Mining Businesses.
Any merger, acquisition or transfer of shares will require at 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:

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.44

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.45

44 Article 11(2) of the Electricity Law.
45 Articles 4 and 8 of MEMR Regulation No. 1 of 2015 on Cooperation of Electricity Supply and Joint Use of Electricity Grids.
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.

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 2013.46 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 is sometimes permitted (e.g., renewable energy generation). The price payable by PLN is subject to MEMR approval, except with regard to certain types of electricity generation (e.g., mine-mouth steam power, coal power, gas or gas machine power and hydropower).47 There is no transmission/transportation, distribution or retail competition.

46 BPH Migas Regulation No. 8 of 2013 on Tariff Determination for Gas Transportation via Pipelines.
47 MEMR Regulation No. 3 of 2015 on Procedures and Benchmark Prices of Purchase of Electricity from Mine-Mouth Steam Power Plants, Coal Steam Power Plants, Gas or Gas Machine Power Plants and Hydropower Plants by PT PLN (Persero) through Direct Election and Direct Appointment.
The government’s objective is to increase energy security by relying on domestic supply. In this context, large coal mining companies are subject to an annual domestic market obligation. In 2015, these companies were required to sell 23.4 per cent of their coal production domestically, principally to support power generation.

Similarly, in relation to oil and gas, PSC contractors are required to sell 25 per cent of their production domestically. 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, vary depending upon the consumption purpose (residential, industrial, etc.). There are additional regulations for renewable energy electricity tariffs. 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 there are PLN guidelines on the content of PPAs, the terms and conditions vary from project to project.

48 Government Regulation No. 79 of 2014 on the National Energy Policy.
49 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. 31 of 2014 on Electricity Tariffs offered by PLN, as amended by MEMR Regulation No. 9 of 2015.
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. 19 of 2013 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 of up to 10MW.
54 Dr Ir Santosa Gotosusatro, Experience and Management of Private Electricity: Independent Power Producer (PLN, 2010).
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 recently allocated 1.89 trillion rupiah in the 2016 State Revenue and Expenditure Budget (APBN) to develop new and renewable energy. It has been indicated that this allocation will be focused mainly on the development of solar energy.

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55 Article 26, Upstream Regulations.
56 Government Regulation No. 79 of 2010 on Recoverable Operational Costs and Income Tax Treatment for the Upstream Oil and Gas Business Sector.
57 Government Regulation No. 79 of 2014 on National Energy Policy.
60 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.
61 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).
62 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).
63 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.
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).\(^65\)

MEMR has established a non-binding efficiency target to reduce electricity use by 20 per cent.\(^66\) 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).\(^67\) 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.\(^68\) 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.

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.\(^69\) 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.\(^70\) 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.\(^71\) A carbon tax charges emitters based on the amount of carbon they emit, with the intention that emitters will substantially reduce their emissions. Indonesia plans to have a carbon tax imposed by 2017 at the earliest.\(^72\) However, there have been no relevant policies or regulations promulgated to date.\(^73\)

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66 MEMR Regulation No. 13 of 2012 on Saving on Electricity Consumption.
70 www.reuters.com/article/2013/11/12/indonesia-carbon-climate-idUSL4N0IX4S920131112.
VI THE YEAR IN REVIEW

i Summary of new regulations

Laws, regulations and policies released in the past year include:

a Presidential Regulation No. 3 of 2016 on the Acceleration of Strategic National Project Development;

b Presidential Regulation No. 4 of 2016 on the Acceleration of Electricity Infrastructure Development;

c Presidential Regulation No. 44 of 2016 on the List of Business Fields Closed to Investment and Business Fields Open to Investment with Conditions;

d MEMR Regulation No. 19 of 2015 on the Purchase of Electricity by PT PLN (Persero) from Hydropower Plants of up to 10MW;

e MEMR Regulation No. 43 of 2015 on the Re-evaluation of Mineral and Coal Mining Business Licences;

f MEMR Regulation No. 9 of 2016 on the Procedures for Coal Supply for Mine-Mouth Power Plants and the Determination of Benchmark Prices;

g MEMR Regulation No. 12 of 2016 on the Amendment to MEMR Regulation No. 35 of 2013 on Procedures for Electricity Business Licences;

h MEMR Decree No. 2805 K/30/MEM/2015 of 2015 on the Determination of the Minimum Needs and Sales of Coal for Domestic Purposes in 2015;

i Minister of Public Works and Housing Regulation No. 09/PRT/M/2016 of 2016 on the Procedures for the Utilisation of Water Supply Infrastructure Facilities for the Development of Hydropower Plants/Mini-Hydropower Plants/Micro-Hydropower Plants through Public–Private Partnerships;

j Ministry/Head of National Development Planning Agency Decree No. KEP.82/M. PPN/HK/05/2015 on the List of Infrastructure Project Plans of 2015; and

k BKPM Regulation No. 14 of 2015 on Guidelines and Procedures for In-principle Licences.

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 37 draft laws prioritised to be passed this year, including proposed amendments to laws regulating the oil and gas, coal and mineral mining, and construction services industries.

To widen the impact of the Prolegnas, the government recently identified 196 draft government regulations and 91 draft presidential regulations that will be prioritised to be issued in 2016. The regulations of relevance to the energy sector include a government regulation on new and renewable energy that covers, among other things, related sale

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74 The decree stipulating the Minimum Needs and Sales of Coal for Domestic Purposes in 2016 has not yet been issued.


76 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.
and purchase, feed-in electricity tariffs and power plants; and a presidential regulation on the inventory of national greenhouse gases that will regulate, among other things, the government’s national greenhouse gas emissions targets.

iii Increasing supply

At the end of 2013, Indonesia’s total power generating capacity (including captive and off-grid capacity) was around 44,000MW, of which 36,897MW was owned by PLN and the rest procured by PLN from contracted IPPs. At that time, most of Indonesia’s electricity production was from coal (44 per cent), followed by fuel oil (23 per cent), gas (21 per cent), hydropower (7 per cent) and geothermal (5 per cent).77 Demand was increasing by approximately 8 to 9 per cent per annum,78 which meant new infrastructure was required.

In recognition of this, the government recently stated that it aims to construct an additional network of power plants with a combined generating capacity of 35,000MW, as is recorded in the PLN Electricity Supply Plan for 2015–2024;79 and address the failure of the government’s ‘First and Second Fast Track’ programmes.80 It is expected that most of the new generating capacity will derive from coal-fired power plants (56 per cent), followed by gas (36 per cent), hydropower (4 per cent), geothermal (2 per cent) and other energy sources (2 per cent).

To achieve the 35,000MW goal, the government has issued regulations mandating the acceleration of the development of strategic national projects (SNPs), including power projects.81 These regulations are expected to enable business entities to obtain the requisite licences within days of complying with all requirements, and ease the process of securing business viability guarantees for SNPs.

Indonesia’s Ministry of National Development Planning Agency (Bappenas) has a ‘Master Plan for the Acceleration and Expansion of Indonesian Economic Development for 2011 to 2025’, which contemplates eight main programmes (including energy) and foreshadows six economic corridors, with energy centres in three of them (Kalimantan, Papua-Moluccas and Sumatra).

79 www.energy-indonesia.com/0150130plan35.pdf. This additional generating capacity pledge has been described as the Third Fast Track Programme. It does not incorporate the commitments made under the First and Second Fast Track Programmes and should be completed by 2019.
80 The First Fast Track programme was introduced in 2006, mandating that PLN (in coordination with IPPs) develop 10,000MW of coal-fired power plants across Indonesia, while the Second Fast Track programme was subsequently introduced in 2010, aiming for the acceleration of the development of another 10,000MW of power plants focusing on renewable energy and enhanced cooperation with IPPs.
www.pln.co.id/eng/?p=63 and www.thinkgeoenergy.com/indonesia-opens-fast-track-program-for-private-sector-power-producers/.
81 Presidential Regulation No. 3 of 2016 on Acceleration of Strategic National Project Development; Presidential Regulation No. 4 of 2016 on Acceleration of Development of Electricity Infrastructure.
In addition, Bappenas recently published a list of 38 prioritised infrastructure projects that were to be developed in 2015–2016. The projects consist of six tendered projects (which do not include any power plants), eight prospective projects (including the 450MW Karama hydroelectric power plant) and 24 potential projects (including the 2x200MW Tebo steam power plant).

Dubbed as one of the largest power plants using renewable energy sources, the Karama hydroelectric power plant has been a priority of the government since 2012. It was initially expected to produce electricity for distribution across the entire island of Sulawesi. The investment allocated for this project was estimated to be in the region of US$1.3 billion and the power plant was expected to be operational by 2017. However, to date, this project has yet to reach financial close (perhaps because of complex licensing procedures, land acquisition challenges and local environmental concerns).

Indonesia still needs to continue to develop plans for, and laws and regulations to better facilitate and accelerate, the development of new power infrastructure.

iv Fuel and electricity subsidies

Electricity and fuel subsidies must be managed appropriately, lest Indonesia fails to reach its goal of 90 per cent electrification by 2020. In 2013, the government’s electricity subsidy was 99.8 trillion rupiah. In 2014, the government approved increased electricity tariffs and budgeted for the subsidy to fall to 80 trillion rupiah. In 2015, the government’s electricity subsidy fell to 38.4 trillion rupiah.

As this much lower figure suggests, from 2014 to 2015, the government embarked on a series of subsidy reforms, such that the electricity subsidy is now only available in poor and remote areas. The subsidy will continue to be phased out gradually, until all but the poorest households must pay the market price by 2018.

Even more significant is the fuel subsidy. In 2013, it was 211 trillion rupiah. In October 2014, the government determined that the allocation for subsidies (both electricity and fuel) for 2015 would be 414.68 trillion rupiah.

The government then further reduced the allocation for these subsidies for 2015 to 212.1 trillion rupiah. It has been indicated that the main reason for this reduction was

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82 Head of Bappenas Decree No. 82/M.PPN/HK/05/2015 on Stipulation of a List of Infrastructure Project Plans for 2015.
87 Law No. 27 of 2014 on State Revenues and Expenditure Budget for 2015, as later amended by Law No. 3 of 2015.
88 Law No. 3 of 2015 on Amendment to Law No. 27 of 2014 on State Revenues and Expenditure Budget for 2015.
a push to reduce the fuel subsidy. In 2016, the government’s fuel subsidy is only 63.7 trillion rupiah. However, there is an indication that the 2016 APBN will be amended, which may alter the allocation between fuel and electricity subsidies.

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.

Chapter 17

IRAN

Munir Hassan and Shaghayegh Smousavi

I  INTRODUCTION

This is the first time a chapter on Iran has been included in The Energy Regulation and Markets Review. This is because with the opening up of Iran for foreign investors and companies, Iran is at the start of a potentially transformational period for its energy sector. The closed and insular state of the Iranian sector for the past decades means that many of the industry structures in other jurisdictions are not as developed in Iran. To ensure that this chapter remains a practical and useful business tool, it 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. Nevertheless, Iran remains a huge player in the energy sector. Both the size of the Iranian energy sector and its influence in the region is expected to grow.

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 will have to deal with issues arising from that transformation. Not least the issue of cross-subsidisation

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and artificially depressed energy prices. However, the prize is large. Energy prices in Iran are significantly lower and energy consumption significantly higher than international and regional averages.

Largely because of sanctions, Iran has developed a strong home-grown power industry that is able to develop and operate assets largely independently of foreign and global players. However, this has come at a price, with stranded assets and failed projects being commonplace over the years. The pressure to achieve greater and more cost-effective delivery is therefore strong and increasing.

This, together with the recent relaxation of sanctions against Iran, opens up opportunities in a potentially significant market for Western power and renewables companies. There is a need to tread carefully, however, in view of the sanctions that remain in place, most notably sanctions imposed by the United States, with US companies (including UK subsidiaries of US corporates) remaining broadly prohibited from engaging in transactions involving Iran.²

### 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. The agreement has been concluded with 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). Pursuant to this agreement, 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 most financial and economic sanctions against Iran have now been lifted, 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.

EU and UN nuclear-related economic and financial sanctions have been terminated. This includes the delisting of many UN and EU entities and individuals. The major sectors that will be affected by this initial phase of sanctions relief include the energy sector.

It remains important to conduct due diligence and ensure compliance with sanctions regimes before signing business contracts in or relating to Iran. Companies with activities in the United States should be aware of the US sanctions that remain in place as, in particular, those considered to be a US person or a UK subsidiary of a US company could be impacted. 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.

European Union companies that are owned or controlled by US corporations will fall under US jurisdiction and will therefore continue to be subject to US primary sanctions. However, the US Treasury Department’s Office of Foreign Assets Control through the

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issuing of General License H authorises non-US entities to engage in business with Iran, subject to certain exemptions and restrictions including strict limitation on the extent of the involvement of the parent company.

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 118th (2015–2016), 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.

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 is looking for something close to US$200 billion over the next five years in investment to capitalise on the opportunities presented by the opening up of the sector following Implementation Day. The timing is perhaps unfortunate, with oil prices languishing without immediate evidence of an imminent recovery. Nevertheless, the costs of production in Iran are estimated to be significantly lower than the international average, and well below the low current oil price. In these circumstances, Iran is 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).3 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. It is currently set out as a series of principles, and a form of contract is anticipated during the course of the summer of 2016. The IPC bill would need to be endorsed by both government and parliament and by the Guardian Council.

There has been some controversy about the exact status of the IPC, with suggestions that the cabinet’s executive decision defines the general terms of a future contract to be signed between Iran and a foreign party, but does not allow it to be used automatically to contract with foreign investors. 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).4

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.

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.

Many aspects of the IPC remain uncertain, such as formulae for determining economic viability to develop a field, and a number of mechanisms are provided for (such as a cap on windfall profits for the IOCs) without sufficient detail to assess their impact. It is also not clear how bidders will be qualified, assessed and ultimately be successful. Furthermore, the

4 See www.al-monitor.com/pulse/originals/2016/02/iran-new-oil-contract-ipc-petroleum.html#ixzz4A8gZjgL.v.
question of technology transfer, in spite of its purported importance under this model, has not been clearly dealt with. Also, IPCs will be governed by Iranian law, although international arbitration may be provided for (see Section VII, infra, on international arbitration in Iran). This is also important as a 20–25-year term contract will need to ride through no doubt further major changes in the Iranian political and economic landscape.

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.

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’. According to this decision, the Ministry of Energy was authorised to make the necessary modifications in its organisational chart to perform the aforesaid decision. For the execution of policies drawn up by the Ministry of Energy, the Renewable Energy Organization of Iran (SUNA) was

established in 1995 to be specifically in charge of renewable energy matters. SUNA operates in close cooperation with the Renewable Energy Headquarters of the Vice Presidency for Science and Technology.8 The key responsibilities of SUNA are as follows:

- fostering grounds for study and implementation of pilot projects;
- design and construction of power plants with participation of public and private sectors; and
- preparation of access to diverse renewable energy resources.9

To start the operation of a renewable energy power plant in Iran, applicants must register and obtain an approval from SUNA.10 Having received permission for the grid connection and land use, and environment-related licences, applicants sign a power purchase agreement (PPA) with SUNA and can then start the construction works.11 Key points in the PPA include:

- the purchaser has no responsibility for the facility being connected to the grid or for the generating facilities: any expenditure in connection with these rests with the seller;
- while the PPA provides for a conditional purchase price, this price may be decreased if the project is delayed in commissioning;
- 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 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 must provide a revolving letter of credit (LC) from an Iranian bank, with a validity period not less than six months and a value equivalent to the amount to be paid by the purchaser. The expenses associated with the LC shall be shared between the purchaser and the seller;
- 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;
- 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;
- 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).

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.12

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8 Ibid.
9 Ibid.
12 For further information on the power sector, see www.igmc.ir.
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.\(^\text{13}\) 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 power exchange is excluded from the day-ahead market. On a longer-term basis, generators and purchasers of power can also contract long-term power purchase agreements at negotiated price. Trades are then notified to the system operator, IGMC.

Iran has significant hydroelectric capacity; however, recent droughts have affected the effectiveness of the hydroelectric contribution to baseload power.\(^\text{14}\) Iran remains significantly reliant on thermal generation, although 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)\(^\text{15}\) with about 2GW expected to be wind power. 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. For example, in May 2016 it was reported that Tavanir had signed a memorandum of understanding with Korea Electric Power Corporation using approximately US$10 billion of Chinese financing to update the power system to reduce losses, improve efficiency and implement a smart-grid programme.

On renewables, interest is high following successive feed-in tariffs being announced guaranteed for projects starting in the next five years, including further feed-in tariffs for solar PV in 2016 of between €0.082 to €0.12/kWh (3,200 rials to 4,900 rials/kWh) for 20 years.\(^\text{16}\) These feed-in tariffs are adjusted for inflation, exchange-rate fluctuation and if the project fails to deploy within 18 months of the agreed deadline. Implementation remains

\(^{13}\) For further information on the IEM and power exchange and trading arrangements, see further on www.igmc.ir.

\(^{14}\) www.mei.edu/content/article/iran%20%E2%80%99s-renewable-energy-potential.

\(^{15}\) Fifth-Year Development Plan; www.wipo.int/edocs/lexdocs/laws/fa/in/ir038fa.pdf.

low and slow. A key question will be the availability of project finance. Linked to that, will be the 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 President Hassan Rouhani and his administration in office since 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 recope the role of NIOC and bring in substantial foreign investment and technology. President Rouhani must seek to bring the various sides of the debate together and achieve a level of consensus if implementation of reforms in both power and oil and gas are to be successful.

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, power purchase agreements offered by Iran would need to be long term, 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. Existing power purchase agreements in Iran currently do not provide such a framework and so an updating of the form of contracts for future projects is required if international investment is to materialise. Further, while competitive procurement of new 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.

VII  ESTABLISHING AN ENERGY BUSINESS IN IRAN

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 (such as a corporation, limited partnership, partnership, co-ownership, joint-stock company or limited liability company). 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 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, Kish and 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. Primarily, the difference is geographic: FTZs are established in border regions while SEZs can be set up anywhere on the mainland.

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 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.

There is no restriction on foreign ownership in Iran, no requirement for Iranian involvement or sponsorship for establishing in Iran and no limitations relating to foreign participation in the board of directors of companies. 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 as 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, and

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17 See www.freezones.ir.
18 Ibid.
19 Ibid.
20 Ibid.
21 Article 2 FIPPA.
22 Article 3 of Implementation Regulation of FIPPA.
23 Article 15 of Implementation Regulation of FIPPA.
24 Article 8 FIPPA.
25 Article 4 of Implementation Regulation of FIPPA.
expropriation,\textsuperscript{26} government intervention and breach of contract by government.\textsuperscript{27} As to the major questions of expropriation and nationalisation of foreign investors’ assets, FIPPA recognises the right to receive immediately compensation based on the fair market value of the expropriated assets on the day before expropriation takes place.\textsuperscript{28} Besides, foreign investors have direct access to and possibility of withdrawal of export proceeds out of escrow accounts established in banks outside Iran.\textsuperscript{29} Foreign investors may export their goods and services without any commitment to reintroduce export proceeds to the country.\textsuperscript{30} Also, travel for foreign investors, directors, experts and their immediate family in relation to the investment covered by FIPPA is made easier by the grant of a three-year multi-entry visa, a residence permit, a work permit for each individual with a right of entry and a three-month residence permit on each occasion.\textsuperscript{31} Furthermore, all bilateral investment treaties concluded with other countries contain a provision whereby they are only applicable to investments for which the FIPPA licence is acquired.

According to statements from OIETAI officials, foreign investment applications are processed within 15 days, although, in practice, such a process can take up to 30 days to complete.\textsuperscript{32}

The FIPPA licence validity can be extended upon request by the foreign investor (for example, if the foreign investor fails to bring in the investment capital within the determined period and needs an extension). Otherwise, the licence will be considered null and void.\textsuperscript{33}

In the renewable energy sector, applications for foreign investment licences are submitted to OIETAI, once the necessary permits have been obtained from SUNA.

More generally, it should be noted that Iranian contract law is contained in the Iranian Civil Code, which is broadly comparable to other civil law jurisdictions, while preserving the influence of Islamic law. The Iranian Commercial Law is based on the French Commercial Law and was enacted in May 1932. Iranian courts recognise the sanctity of contracts provided that they are not contrary to the explicit provisions of law, and particularly those cited under Article 90 of the Civil Code (i.e., the essential conditions for validity of contracts). Specific performance is the preferred remedy for breach of contract under Iranian law, and the courts can order the parties to the contract, or a third party, to perform, with damages awarded if that is not possible.

Iranian law applies as the default law for contracts between Iranian companies and foreign companies if the contract is signed in Iran, unless the parties have chosen the law of another jurisdiction. According to the Iranian Civil Code, ‘Obligations arising out of contracts are governed by the law of the place where they are concluded, unless the parties thereto are foreign nationals and have subjected it, expressly or impliedly, to another law’\textsuperscript{34}.

\textsuperscript{26} Article 9 FIPPA.
\textsuperscript{27} Article 17 of Implementation Regulation of FIPPA.
\textsuperscript{28} Article 9 FIPPA.
\textsuperscript{29} Articles 13–18 FIPPA.
\textsuperscript{30} Articles 13–18 FIPPA.
\textsuperscript{31} Article 20 FIPPA and Article 35 Implementation Regulation of FIPPA.
\textsuperscript{32} Article 6 FIPPA.
\textsuperscript{33} Article 32 of Implementation Regulation of FIPPA.
\textsuperscript{34} Article 968 of the Civil Code.
This conflict-of-law rule has been the subject of long discussions among Iranian legal experts, particularly in relation to the possibility of opting for a foreign law for contracts concluded in Iran between an Iranian party and a foreign party.

The civil courts in Iran are divided into three categories: (1) the court of first instance (its judgment is final and binding); (2) the appellate court of first instance; and (3) the Supreme Court. There is no time limitation for bringing civil claims under Iranian law and proceedings are typically lengthy. The most common forms of interim measures, as with some other jurisdictions in the Middle East, are an interim writ of attachment and protection. State entities do not enjoy immunity from civil proceedings, although state property is exempt from seizure and confiscation. A judgment issued by a foreign court can only be enforced by way of an Iranian court order, which will only be granted if it meets certain requirements.

However, 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 the provisions of Article 139 of the Iranian Constitution. This 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.

Accordingly, where the subject matter concerns public and governmental property, or if a party is foreign, the approval of the Consultative Assembly (the parliament) is also required.

VIII CONCLUSIONS AND OUTLOOK

Now that sanctions have been eased, the Iranian energy market offers potentially enormous opportunities for investment, development and growth. EU sanctions under the JCPOA were eased on 16 January 2016 (Implementation Day), and the government’s current plans make significant involvement in Iran’s energy market realisable and potentially very attractive for foreign investors. The Iranian market is also itself well placed to become a regional hub and a key international participant.
However, these outcomes are not without political and financial challenges. The coming year will be a defining year for President Hassan Rouhani’s administration. Success will be measured by the government’s ability both to manage the competing political interests in Iran and to successfully deliver on its aspiration for economic and social benefits arising from large-scale foreign investment, capital and know-how being applied to the Iranian energy sector.
Chapter 18

IRAQ

Salem Chalabi

I OVERVIEW

1. 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.

1 Salem Chalabi is a partner at Stephenson Harwood Middle East LLP. The information in this chapter was correct as of June 2015.
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.

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 (the 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 these 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.

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.

### Developments in 2014

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 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.

### THE IRAQI ELECTRICITY SECTOR

#### The Ministry of Electricity – Baghdad

The role of the Iraqi Ministry of Electricity (MOE) 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 to 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. The following is a brief summary of the latest draft:

- 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.

- 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.

- 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). In an effort to carry out the above, the draft electricity law keeps more or less the same central departments within the ministry (generation, transmission, distribution, etc.) but then converts 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 draft law proposes that these companies would be converted into publicly owned companies (listed on the Iraq Stock Exchange).

The draft 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 the companies and for the MOE. In early 2015, the MOE announced the introduction of higher tariffs to be paid by the consumers. (Currently, a small percentage of consumers pay what they actually consume in electricity, principally because of old and vandalised meters, corruption in the collection of electricity bills (which are manually collected) and rewiring of home electricity lines.) This 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. 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.

The draft law has the right intentions, but it suffers from having, in part, 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, in Iraq, Law No. 43 of 1976 provides that the government or any governmental entity must obtain judicial decisions prior to attaching private assets if it is seeking to recover 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 financial institutions and investors to feel comfortable doing business in Iraq generally.

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, 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, because of certain structural difficulties, in particular to do with the supply of fuels (the MOE did not want to assume the risks of supply and requested that the developers enter into separate supply agreements with the MOO), there was little or no international interest in these tenders. Accordingly, only local companies bid (with some international participation in the consortiums) and, with one exception, these bidders had no experience of the IPP sector. Shortly after the bids were analysed by the MOE’s IPP team, a new minister was appointed who was not in favour of these projects. He therefore cancelled the tendering process, and ran tenders to award these as engineering, procurement and construction contracts.

In late 2013, the Iraqi cabinet instructed the MOE to commence negotiations with three independent Iraqi companies to develop independent power plants in Iraq. In February 2014, the Iraqi cabinet passed resolution 90 of 2014, authorising the MOE to enter into power purchase agreements with these three companies, pursuant to which these companies were to develop up to 9,000MW. Some of the locations were allocated in the cabinet resolution. In particular, one of the developers was to develop a 3,000MW power plant in the Al-Rumailah area of the Basra Governorate, while another developer was to develop a 1,500MW power plant in the Besmaya area south of Baghdad (adjacent to a new real estate development project). 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.

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 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 Ministries of Oil and Electricity 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 because of the security situation in certain parts of Iraq.

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 have not been issued and therefore may delay the implementation of one or more of 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 these two new projects are path-mark 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. At the time of writing, 12 companies (mainly international companies with long track records) have been prequalified for the tender process, which should be announced in the spring of 2015. There is a pipeline of other projects, 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 because of 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). Coupled with this, the lack of natural gas and, because of 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 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 doubled.

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, 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, at the time of writing, there is an arbitration between Dana Gas and the KRG in London over unpaid past costs. In addition, because of 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 ENERGY MARKETS

i 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, because 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. Because of 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, the international oil companies effectively constitute a third limited producer of electricity in federal Iraq, and these 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 fields 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.

ii 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 because of the fact that there are large tracts of land not under government control.

Additional borrowing

In light of the budgetary constraints in 2015, 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, because of 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 has announced a request for information to develop, on a build-own-operate basis, three renewable energy projects – two solar and one wind. The initial energy produced by these projects is 15MW, but is intended to be expanded to 50MW. The technical staff at the MOE have informed the author that they have identified the sites for these projects, and have obtained significant data on temperatures, hours of light and, with respect to the wind project, appropriate weather data.

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.
Chapter 19

ITALY

Marco D’Ostuni, Luciana Bellia and Giuliana D’Andrea

I OVERVIEW

In Italy, energy markets are almost entirely liberalised, but they are subject to strict regulation and public service obligations. Regulation closely mirrors the legislation adopted by the institutions of the European Union (EU) with a view to fostering the creation of a single energy market for electricity and gas, and to ensuring security of supply throughout the EU.

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2 The liberalisation of the Italian electricity and gas markets was driven by the EU electricity and gas directives. The process started with the adoption of Legislative Decree No. 79/1999 (the Bersani Decree), transposing Directive 96/92/EC for the electricity industry and Legislative Decree No. 164/2000 (the Letta Decree), transposing Directive 98/30/EC, for the gas industry. The main focus of the EU legislator was that of ensuring effective and non-discriminatory third-party-access (TPA) on the ‘network services’ (i.e., services operated through a grid that constitutes a natural monopoly – electricity transmission, dispatching and distribution; gas storage, transportation, dispatching and distribution). For this reason, rules on unbundling of network operators (legal, accounting, information, functional and even ownership unbundling) have been issued. Moreover, rigid conditions for refusing access to networks and now even to solve congestions managements have been established at EU and national level.

Transmission and distribution of both gas and power are fully regulated and subject to non-discriminatory third-party access (TPA) rules. Gas production is operated under public concessions; electricity production is an open market activity, but power plant construction generally requires an authorisation and may be subject to public service obligations (e.g., with a view to ensuring security of supply). Gas imports based on agreements of a duration exceeding one year also require an authorisation, and may attract public service obligations. Supply of electricity and gas is fully liberalised at the wholesale and retail level. However, domestic customers and small businesses are still entitled to benefit from a safeguarded service, under reasonable tariffs set by the Authority for Electricity Gas and Water (AEEGSI). There is an increasing trend to switch from the safeguarded service to the free market.

Electricity consumption has dropped over the past five to six years because of the economic crisis (with the ensuing drop in production activities), a mild climate and a wider dissemination of more efficient electric devices in houses and firms. The drop in demand has significantly reduced the amount of electricity generated from non-renewable sources (which is granted priority access to the transmission and distribution grid). Imports still account for the vast majority of Italian electricity consumption (76 per cent in 2014). Like electricity, Italian gas supply largely depends on imports. Domestic production only covered (approximately) 10 per cent of Italian gas consumption in 2015. Because of the economic crisis, energy efficiency, the mild climate and competitive pressure exerted by renewable sources (which receive state incentives), gas consumption in Italy has diminished significantly over the past five years compared with 2008. In 2015, gas consumption increased by 10.5 per cent compared with 2014, but it still remained well below the 2008 level.

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4 Bersani Decree, Articles 3 and 9, and Letta Decree, Article 8.
5 Bersani Decree, Articles 1 and 4–7.
6 Bersani Decree, Article 8.
7 Letta Decree, Article 3.
8 Traders of natural gas must be included in a list compiled by the Ministry of Economic Development before selling gas to final customers.
9 AEEGSI, 2015 Annual Report, pp. 65–66. At the end of 2014, the safeguarded service was still provided to 10,794,000 customers for gas and 25,408,000 for electricity.
10 AEEGSI, 2015 Annual Report, p. 54. In 2014 electricity consumption dropped to 309TWh, about 3 per cent less than 2013 electricity consumption (318.5TWh). 2015 data are not available to us.
12 The electricity imports in 2014 came mainly from Switzerland (54 per cent), France (33.9 per cent) and Slovenia (11.6 per cent) (AEEGSI, 2015 Annual Report, p. 46).
13 Gas imports in 2014 originated mainly from Russia (47 per cent), Algeria (12.3 per cent) and Libya (11.7 per cent) (AEEGSI, 2015 Annual Report, p. 124).
15 AEEGSI, 2015 Annual Report, pp. 158–159. In 2014 gas consumption fell down to 61.9G (m³), about 11.6 per cent less than the 2013 natural gas consumption (70.1G (m³)).
16 According to the Ministry of Economic Development, gas consumption amounted to 61,912 million m³ in 2014, and 67,522 million m³ in 2015; whereas it amounted to 84,883 million m³ in 2008 (see http://dgsaie.mise.gov.it/dgerm/bilanciogas.asp).
The drop in demand for gas and power, in conjunction with the development of gas import infrastructures (e.g., the entry into operation of new liquefied natural gas (LNG) regasification terminals and the expansion of gas pipelines) and the increase in domestic production of electricity, has made the Italian energy markets more liquid during the past six years.

The tariffs for natural gas paid in 2014 by domestic customers in Italy were higher than the average price in the EU, except for the highest consumption class (>5,253.60 m³ per year), which were 2 per cent lower. Following the trend of the past years, industrial customers in Italy paid higher tariffs for the lowest consumption classes (<263,000 m³ per year) and lower tariffs for the higher consumption classes.17

Following the past years’ trends, in 2014 domestic consumers in Italy paid lower electricity tariffs than the average prices applied in the EU for the lower consumption classes (<2,500 kWh per year) and higher than the average prices applied in the EU for the higher consumption classes (>2,500 kWh per year). In the same year, industrial customers in Italy paid higher electricity tariffs for all consumption classes than the average price paid by industrial customers in the EU, by about 25 per cent.18

II REGULATION

i The regulators

The energy sector is regulated through primary (both national and regional)19 and secondary legislation, the latter being adopted by the Ministry of Economic Development or the AEEGSI.

The Ministry of Economic Development defines the strategic lines and sets out general principles for the organisation and functioning of the electricity and gas markets (e.g., new capacity generation, energy efficiency measures and security of supply).20 It also defines certification systems for energy efficiency and promotes agreements with the Italian regions with the aim of granting minimum quality levels for the supply of electricity and gas within the entire national territory. In March 2013, the Ministry published the National Energy Strategy, a very long document discussing the objectives for 2020 and 2050.21

The AEEGSI, which is an independent body, governed by a committee of five members elected for seven years, regulates, controls and monitors the electricity and gas markets in Italy. It was established under Law No. 481/1995 for the purpose of protecting consumers’ interests, promoting competition and ensuring quality, efficiency and

19 Article 117 of the Italian Constitution defines whether the cases in which the national or the regional legislator is entitled to adopt relevant rules in the energy sector. For more details, see D Diaco, ‘Produzione, trasporto e distribuzione nazionale dell’energia nei giudizi di legittimità costituzionale in via principale, (2002–2015)’, Constitutional Court, Research Department, available at www.cortecostituzionale.it/documenti/convegni_seminari/stu_281.pdf.
20 Legislative Decree No. 93/2011.
cost-effectiveness of energy services. The AEEGSI is entrusted with the task of establishing a transparent tariff system, which must balance the economic interests of operators against general social objectives. Furthermore, the AEEGSI has an important role in the promotion of environmental protection and efficient use of energy. It advises the government and Parliament and provides observations and recommendations concerning issues in the regulated sectors of electricity and gas. The AEEGSI issues general regulations applicable to the energy markets’ operators, and resolutions or orders applicable to single operators, for which it must provide comprehensive reasoning. Under Article 2 of Law No. 481/1995, the AEEGSI determines its costs, which are entirely recovered from the companies it regulates. The AEEGSI may also issue fines.22

ii Regulated activities

Regulation in the energy markets may be more or less pervasive depending on the activities involved. In a nutshell:

a for the electricity market:

- import, export, supply (wholesale and retail), and metering services are liberalised in compliance with the EU legal framework,23 but they remain subject to public service obligations descending from EU and national legislation;24
- generation is an open market activity, but there are still limitations descending from public service obligations. Moreover, pursuant to Article 8, Paragraph 1 of the Bersani Decree, a single operator cannot generate or import, directly or indirectly, more than 50 per cent of the total amount of electricity produced and imported in Italy. Furthermore, construction of thermoelectric power plants with power-production capacity above 300MW requires a single licence issued by the Ministry of Economic Development with the consent of the region concerned, following a procedure that involves all of the administrative entities concerned. The licence recognises the plant as a work of public interest;25
- transmission and dispatching services are reserved to the state and operated under a concession regime by the publicly owned company Terna SpA (which is also the owner of the national transmission grid). These activities are fully regulated (e.g., conditions for access, unbundling rules, applicable tariffs and network code);26 and
- distributors operate under concession regimes (DSOs) at the local level. Distribution activities are fully regulated (e.g., conditions for access, unbundling rules, applicable tariffs and network code); and27

b for the gas market:

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22 Law No. 481/1995, Article 2, Paragraph 20, Letter (c).
24 Law No. 239/2004, Article 1, Paragraph 2, Letter (a) and (b).
26 AEEGSI, Resolutions No. 268/2015/R/eel, 296/2015/R/com, and 654/2015/R/eel, as subsequently amended.
Italy

- production is operated under farming concessions;\(^{28}\)
- import and sales are open market activities subject to the EU legal framework,\(^{29}\) but operators must comply with public service obligations descending from EU and national legislation.\(^{30}\) Moreover, pursuant to Article 3 of the Letta Decree, imports of gas based on agreements exceeding one year are subject to prior authorisation by the Ministry of Economic Development; imports of gas based on agreements shorter than a year must be communicated to the Ministry of Economic Development at least 30 days before the import takes place. Furthermore, Legislative Decree No. 130/2010 establishes thresholds concerning the maximum volume of gas that can be placed into the Italian gas transmission system or sold therein by a single operator.\(^{31}\) Finally, pursuant to Article 17 of the Letta Decree, companies willing to sell gas to final customers must request the Ministry of Economic Development to include them in the ‘List of operators licensed for the sale of gas to final customers’;
- storage is operated under a concession issued by the Ministry of Economic Development for a 20-year maximum period to operators meeting the necessary technical, economical and organisational requirements;\(^{32}\) storage activities are fully regulated (e.g., conditions for access, unbundling rules, applicable tariffs and network code);\(^{33}\)
- all the operators meeting the technical requirements may engage in transportation activities. Snam Rete Gas SpA (Snam) and SGI SpA coordinate gas transportation operators at national level. Snam, as a ‘major transportation operator’ is also entrusted with the balancing and dispatching service.\(^{34}\) Transportation, balancing and dispatching activities are fully regulated (e.g., conditions for access, unbundling rules, applicable tariffs and network code);\(^{35}\) and
- distributors (DSOs) operate under concession regimes at the local level. Distribution activities are fully regulated (e.g., conditions for access, unbundling rules, applicable tariffs and network code).\(^{36}\) Concessions must be awarded through public tenders.\(^{37}\)

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\(^{28}\) See, \textit{inter alia}, Letta Decree, Articles 1 and 4–7.


\(^{30}\) Law No. 239/2004, Article 1, Paragraph 2, Letter (a) and (b) and Letta Decree, Article 22.

\(^{31}\) The Italian Antitrust Authority is entrusted with the task of monitoring the implementation of the threshold set by Legislative Decree No. 130/2010 and issuing fines for failure to comply.

\(^{32}\) Letta Decree, Article 11.

\(^{33}\) AEEGSI, Resolutions No. 77/2016/R/gas, and 296/2015/R/com.

\(^{34}\) AEEGSI, Resolution No. ARG/gas 45/11.


\(^{36}\) AEEGSI, Resolutions No. 108/06, 296/2015/R/com, and 173/2016/R/gas, as subsequently amended.

\(^{37}\) Letta Decree, Article 14. The forthcoming wave of new tenders will dramatically change the landscape of the Italian gas distribution market. Pursuant to Article 46 \textit{bis} of the Decree Law No. 159/2007, the ongoing concessions that are granted by single municipalities should be
iii Ownership and market access restrictions
There are no restrictions on ownership of (new or existing) energy assets, service providers or licence holders, nor market access restrictions other than technical, economic and organisational requirements for the operation of services awarded through tenders or subject to authorisation. However, certain mechanisms can apply to monitor the transfer of ownership of certain energy ‘strategic assets’ (see Section II.iv, infra).

iv Transfers of control and assignments
Any transaction that may result in a transfer of ownership or control of a company holding energy assets of national interest, such as the gas transportation network, plants for sourcing from other states, or the electricity transmission grid, is subject to prior notification to the government, which has the power to veto such a transfer insofar as it would represent an exceptional threat to the national interests of the security and continuity of supply.

The acquisition by a non-EU person of a controlling stake in companies holding the above-mentioned strategic energy assets is subject to prior notification to the government, which has the power to veto or attach conditions to the acquisition (in the event that it constitutes a serious prejudice to essential national interests).

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling
The former de facto monopolistic structure of the Italian electricity and gas markets, which were managed by ENEL and ENI respectively, underwent significant changes following the liberalisation process and the introduction of unbundling obligations on vertically integrated energy operators at the beginning of 2000.
Unbundling obligations on energy companies are now regulated by Legislative Decree No. 93/2011. For electricity transmission, Legislative Decree No. 93/2011 imposed ownership unbundling (OU) on Terna. Terna was then certified compliant with the OU model on 5 April 2013. For natural gas transportation, Legislative Decree No. 93/2011 left open the possibility to certify gas transmission companies according to the OU, the independent transmission operator (ITO) or the independent system operator (ISO) model. Since at

43 Legislative Decree No. 93/2011 transposes Directives 2009/72/EC (the Third Electricity Directive) and 2009/72/EC (the Third Gas Directive) for the internal electricity and gas markets respectively.

44 The ownership unbundling model requires a full separation of transport activities (including both the ownership and management of gas or electricity transportation infrastructures) from the production and sale of natural gas or electricity. In particular, the following conditions have to be met: 1) on the one hand, a person or a legal entity, directly or indirectly exercising control or any voting or appointment right (i.e., rights to appoint members of the supervisory board, the management board or other bodies legally representing the undertaking) over an undertaking that is active in the production or supply of natural gas, or generation or supply of electricity, cannot directly or indirectly exercise control or any voting or appointment right over a TSO or a transport infrastructure; (2) on the other hand, a person or a legal entity, directly or indirectly exercising control or any appointment or voting right over a TSO or a transport infrastructure, cannot directly or indirectly exercise control or any voting or appointment right over an undertaking that is active in the production or supply of natural gas or generation or supply of electricity. Undertakings active in the supply or production of natural gas, or generation or supply of electricity, can keep a merely financial, direct or indirect, minority shareholding in a TSO or transport infrastructure. In other words, such a shareholding can only provide financial rights (i.e., the right to receive dividends) but cannot confer any right to take part in the decision-making process of, or exercise any influence on, the TSO or transport infrastructure.

45 AEEGSI, Resolution No. 142/2013/R/eel.

46 Under the ITO model, the functions of TSOs are performed by a company (namely, the ITO) belonging to the vertically integrated undertaking. However, the ITO company should neither control, nor be controlled by, or have any participation in, or be participated in by, any other company belonging to the vertically integrated group and active in the production or supply of natural gas or generation or supply of electricity. In other words, the supply company within the vertically integrated undertaking and the ITO shall be positioned under a common parent company and shall not be in a (direct or indirect) parent–subsidiary relationship, nor shall it hold any cross-holding. The ITO must comply with tight functional unbundling obligations (as well as with accounting and information unbundling obligations).

47 The ISO model requires full separation between the ownership of the transport infrastructure (which remains within the vertically integrated undertaking) and the management of the infrastructure, which shall be carried out by a company, namely the ISO, which is ownership-unbundled (within the above meaning) from the vertically integrated undertaking, which has kept the ownership of the transport infrastructure. The ISO acts as TSO of the relevant transport system, and is subject to all the obligations and duties that the Third Gas Directive and Third Electricity Directive impose on TSOs.

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that time Snam belonged to a vertically integrated undertaking (VIU),\textsuperscript{48} it was originally certified as an ITO.\textsuperscript{49} Upon implementation of the OU model,\textsuperscript{50} Snam obtained a new certification as OU.\textsuperscript{51}

DSOs belonging to a VIU have to be organised under different legal entities with independent decision-making mechanisms.\textsuperscript{52} DSOs are also required to implement functional and accounting unbundling with the aim of promoting competition, granting neutrality in the management of distribution facilities, avoiding discrimination in the access to commercially sensitive information and avoiding cross-subsidisation among the different segments of the gas or electricity chain.\textsuperscript{53} Less stringent rules apply to DSOs that serve a negligible amount of clients (fewer than 100,000 supply points).

\textbf{ii Transmission/transportation and distribution access}

Third-party access to transmission and distribution networks is the core of the European and Italian rules on electricity and gas.

In particular, the electricity transmission grid operator (i.e., Terna SpA), and electricity distributors must grant access under equal terms and conditions to every operator requesting it (provided that it complies with technical requirements),\textsuperscript{54} without prejudice to the continuity of the service and in compliance with technical and economic conditions for access. Grid operators must also provide sufficient information to ensure the efficient and safe functioning of the grid.\textsuperscript{55}

Likewise, gas transmission and distribution operators must grant access under equal terms and conditions to undertakings requesting it when the system has sufficient capacity and the connection is economically and technically feasible.\textsuperscript{56} In cases of illegitimate refusal

\textsuperscript{48} According to Article 9 of the Third Gas Directive, Member States were entitled to opt for an unbundling model different from OU if at the date of the entry into force of the Third Gas Directive (i.e., September 3, 2009) the TSO was part of a vertically integrated undertaking (if this was not the case, the TSO will have to comply with the ownership unbundling requirements). The same rules apply in the electricity sector (see Article 9 of the Third Electricity Directive).

\textsuperscript{49} AEEGSI, Resolution No. 403/2012/R/gas.

\textsuperscript{50} See Prime Minister Decree of 25 May 2012, enacting Law Decree No. 1/2012, Article 15.

\textsuperscript{51} See AEEGSI Resolution 515/2013/R/gas.

\textsuperscript{52} Letta Decree.

\textsuperscript{53} Legislative Decree No. 93/2011. See also the Integrated Text for Functional Unbundling (TIUF), Annex A to AEEGSI Resolution No. 296/2015/R/com, and the Integrated Text for Account Unbundling (TIUC), Annex A to AEEGSI Resolution No. 231/2014/R/com.

\textsuperscript{54} Technical requirements for access to the transmission grid are fixed in the Prime Minister Decree of 11 May 2014.

\textsuperscript{55} Bersani Decree, Articles 3 and 9.

\textsuperscript{56} Law No. 239/2004, Article 1, Paragraph 17, provides for the possibility of an exemption from TPA rules in cases where significant investments are needed for the construction (or the expansion) of certain gas infrastructures. Pursuant to Article 1, Paragraph 20, of Law No. 239/2004, and Article 35 of the Third Gas Directive, exceptions are also allowed when
of connection, the AEEGSI may force the network operator to connect other operators. Network operators must also provide sufficient information, to ensure the efficient and safe functioning of the grid.  

iii Rates

The AEEGSI is entrusted with the task of setting transmission, dispatching, transport and distribution tariffs both for electricity and gas. Tariffs must be transparent and based on predetermined criteria to safeguard competition, and ultimately the interests of customers.

The tariffs set by the AEEGSI are maximum tariffs not including taxes, and have to allow for a fair remuneration of the invested capital and full coverage of system costs (operational costs). The tariffs must strike a balance among a number of potentially conflicting interests (e.g., network viability, promoting investments, general social and environmental protection objectives, as well as efficient use of energy sources, customers and, ultimately, consumers’ interest not to pay excessively burdensome prices).

Tariffs are determined according to a methodology that is established by the AEEGSI for a certain time frame (and, typically, revised every four years). TSOs and DSOs must submit the tariffs determined on the basis of the above-mentioned methodology for the AEEGSI’s prior approval.

In a nutshell, electricity tariffs are based on a price-cap mechanism, which applies to the operation costs (see Law No. 290/2003) and takes into account the following objectives and variables: (1) remuneration of inputs (e.g., return on investments, computed on the weighted average cost of capital); (2) incentives linked to efficiency and investments; and (3) performance objectives. The AEEGSI Resolution No. 654/2015/R/eel also introduced a 50 per cent profit sharing mechanism, which applies to foster efficiencies.

The same methodology also applies to the gas sector (i.e., price cap, return on investments, profit-sharing mechanism, etc.). In addition, tariffs are charged based on an entry-exit mechanism and operational costs are allocated only to the capacity component. The tariff structure for the transmission of natural gas is likely to change when the Network Codes on Harmonised Transmission Tariff Structures for Gas are adopted by the European Commission.

TPA rules prevent an LNG terminal from carrying out its public service obligations. Finally, based on Article 26 of the Letta Decree, natural gas operators may refuse access to the system where it would cause serious economic and financial difficulties with take-or-pay contracts.
iv Security and technology restrictions

Legislative Decree No. 61/2011 transposed into national law Directive 2008/114/EC on the identification and designation of European critical infrastructures and the assessment of the need to improve their protection. Legislative Decree No. 61/2011 sets the criteria for the identification of the European critical infrastructures. For the energy sector, those infrastructures are then identified by the Ministry of Economic Development. Legislative Decree No. 61/2011 also sets out the criteria for the assessment of the security level of such infrastructures and establishes the rules for their protection from threats both of human (accidental and voluntary, even by means of technology tools) and natural origin. In sum, network operators must appoint a safety and security representative; they are also required to prepare an operator security plan, identifying the assets that are part of the European critical infrastructures as well as appropriate solutions for their protection, considering all potential (even technological) threats and risks that could affect their functionality.

IV ENERGY MARKETS

i Development of energy markets

The Bersani Decree has outlined the architecture of the electricity market providing for an organised wholesale market (the Italian Power Exchange or IPEX) for the sale and purchase of electricity and entrusting the company Gestore dei mercati energetici SpA (GME) with its organisation and management.62

The Italian Power Exchange is divided into three segments:

a a spot electricity market, which consists of: a day-ahead market (MGP), organised on an auction model, where transactions are concluded for the following day; an adjustment market (MA), which allows the parties to update their purchase and sale offers for the same day; and a market for the dispatching service where Terna SpA, as central dispatching operator, purchases the necessary resources for the management and control of the dispatching system;

b a platform for physical delivery of derivative contracts concluded on the IDEX,64 and

c the forward electricity market, where the parties negotiate future supplies of electricity over a longer time horizon than the day ahead.

The wholesale market for natural gas is organised and managed by GME, which plays the role of central counterparty.

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62 Bersani Decree, Article 5.
63 The company GME acts as central counterparty, purchasing from sellers and selling to purchasers in electricity negotiations for the following day. The majority of electricity wholesale transactions are carried out on this market.
64 The Italian Derivatives Energy Exchange, which is a segment of the Italian Derivatives Market managed by Borsa Italiana SpA, is the market of derivatives whose underlying value is the spot price of electricity.
GME also supervises the markets of:

- the spot gas market (MP-GAS), comprising the gas day-ahead market (MGP-GAS),\(^{65}\) which is structured in a single trading session, and the intra-day market (MI-GAS);\(^{66}\) and
- the forward gas market (MT-GAS), operating on a continuous trading basis.

The GME also operates: (1) the platform for trading imported natural gas and royalties on natural gas extracted under domestic concessions (P-GAS);\(^{67}\) and (2) the platform for the balancing of natural gas (PB-GAS).\(^{68}\)

### ii Energy market rules and regulation

The Italian Power Exchange is regulated by the amended Integrated Text for the Electric Power Market approved by the Ministry of Economic Development on 19 December 2003 on the basis of the proposal submitted by GME. Wholesale (both spot and forward) gas markets are regulated by the Regulation approved by the Ministry of Economic Development on 6 March 2013, as subsequently amended.\(^{69}\)

Rules for the P-GAS and PB-GAS markets are set out respectively in the Regulation of the Natural Gas Market approved by the Ministry of Economic Development on 23 April 2010 on the basis of the proposal submitted by GME, as subsequently amended, and in the Regulation approved by AEEGSI with Resolution No. ARG/gas/145/2011.

Market rules include criteria and procedures for the accreditation of the parties on markets and platforms, guarantee requirements and the rules for trading, delivery and invoicing, as well as for sanctions for infringements of the rules.

### iii Contracts for sale of energy

At the wholesale level, the purchase and sale of electricity and gas may occur ‘over the counter’ (i.e., by means of bilateral non-standard contracts concluded outside organised markets).

For the purchase and sale of natural gas, the parties may also enter into spot bilateral contracts through the virtual trading point,\(^{70}\) which is managed by Snam.

Wholesale bilateral contracts are not subject to restrictions, apart from compliance with technical requirements stated in the regulations issued by GME.\(^{71}\)

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65 In the MGP-GAS market the operators submit purchase and sale offers regarding contracts to be executed the following gas-day.

66 In the MGP-GAS market the operators submit purchase and sale offers regarding contracts to be executed in the same gas-day.

67 See the Regulation approved by the Ministry of Economic Development on 23 April 2010.

68 See the Regulation approved by AEEGSI with Resolution No. ARG/gas/145/2011.

69 The text is available at www.mercatoelettrico.org/En/MenuBiblioteca/documenti/20150924_DISCIPLINA_GAS_en.pdf.

70 The virtual trading point is a virtual area located between the entry points and the exit points of the national pipeline grid. See AEEGSI, Resolution No. 137/2002, and 22/2014/R/gas, as subsequently amended.

71 See the Regulation of the Natural Gas Market approved by the Ministry of Economic Development on 23 April 2010, and the Integrated Text for the Electric Power Market approved by the Ministry of Economic Development on 19 December 2003, as subsequently amended.
At the retail level, final customers\(^{72}\) may freely enter into individual contracts for the supply of natural gas and power with energy traders,\(^{73}\) who are subject to transparency and information obligations, but are free to define the rates and the contractual terms.\(^{74}\) Household customers and small businesses not having entered into any contract on the free market are still granted the safeguarded service. In the electricity sector, Acquirente Unico SpA (AU, a subsidiary of the Gestore dei Servizi Energetici GSE SpA Group) is entrusted with the task of procuring reasonably priced electricity supply for households and small business customers that wish to remain with the safeguarded service. In particular, AU buys electricity on the market and resells it to distributors or retailers for supply to small consumers who have not switched to the free market. In addition, the AEEGSI sets the regulated tariff that applies to those customers\(^{75}\) that are still supplied with the safeguarded service. In the gas sector, the AEEGSI merely sets a gas tariff for households and small business customers and customers can choose to remain with the safeguarded service and pay the tariff set by the AEEGSI or to buy natural gas in the free market.

iv Market developments

An important development in the energy retail market is likely to occur following the approval by the Parliament of the annual bill on competition and market liberalisation, which provides for the elimination of the safeguarded service and the full liberalisation of the electricity and gas markets at retail level starting from 1 January 2018.\(^{76}\)

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

According to the target set by the Italian legislator, 17 per cent of gross energy consumption should be produced by renewable energy sources by 2020.\(^{77}\)
The Italian incentive system for energy generated by renewable sources comprises a variety of mechanisms.

In particular:

- **a** the Cip 6/92 mechanism, which is a feed-in tariff updated over time. This mechanism is available only for plants falling within the scope of the Cip 6/92 resolution while it was still in force;
- **b** the Energy Account system (feed-in premium) for electricity produced by photovoltaic plants that had come into operation before 26 August 2012 and by thermodynamic solar plants;
- **c** green certificates, which are certificates awarded by GSE in proportion to the amount of energy produced by renewable sources and by cogeneration plants that had come into operation by 31 December 2012. The number of green certificates awarded depends on the type of plant used for the energy generation. Starting from 2016, the green certificates system is being replaced by a new incentive system in the form of extra tariffs granted by GSE to operators entitled to green certificates;
- **d** feed-in tariffs for electricity conveyed into the grid by plants fed by renewable sources (except for photovoltaic plants) not exceeding 1MW power (200kW for wind plants) and that had come into operation by 31 December 2012; and
- **e** tariff incentives for electricity conveyed into the grid by plants fed by renewable sources (except for photovoltaic plants) that came into operation on or after 1 January 2013 (in the form of a feed-in tariff for plants not exceeding 1MW in power and in the form of a feed-in premium for other plants).

The economic incentives in 2014 concerned more than 64 TWh of electricity produced by renewable sources. The costs for incentives to renewable energy were about €12.7 billion in 2014, €12 billion of which were covered by the tariff component A3 of electricity and gas bills.

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78 A feed-in tariff includes an ‘incentive’ component and a component for the remuneration of electricity conveyed into the network.

79 A feed-in premium consists of an incentive granted exclusively for the electricity produced, not including remuneration for the sale of that energy, which might even be self-consumed by the producer.

80 The Energy Account system consists of a standard premium related to the amount of energy produced. The premium for energy produced by photovoltaic plants was most recently updated by the Ministerial Decree of 5 July 2012.

81 Each energy operator had the obligation to obtain a certain amount of green certificates, and could sell extra green certificates to other operators over the counter or through a trading platform managed by GME, thus obtaining further remuneration for ‘green’ energy produced.

82 Ministerial Decree of 6 July 2012.


84 Ministerial Decree of 6 July 2012.

Apart from purely economic incentives, there are other important benefits for operators producing electricity from renewable sources. In particular:

- **a** the construction of new plants for the generation of electricity from renewable sources is subject to a single licence issued by the relevant region or the delegated province or by the Ministry of Economic Development for plants of power equal to or above 300 MW, following a procedure involving all the administrative entities concerned.\(^{86}\) A further simplified procedure applies to the construction of new plants below the mentioned thresholds;\(^ {87}\) and, even more important,

- **b** electricity generated from renewable sources is granted priority access to the transmission and distribution grid.\(^ {88}\)

### ii Energy efficiency and conservation

The 2020 energy efficiency target for Italy is a reduction in the primary energy consumption by 20 million tons of oil equivalent (TOE) starting from 2010, corresponding to a reduction in the final energy consumption by 15.5 million TOE.\(^ {89}\)

The Italian efficiency incentive system comprises a variety of mechanisms. In particular, the main incentive mechanisms are:

- **a** white certificates,\(^ {90}\) which are tradable certificates issued by GSE to distributors or Energy Service Companies (ESCOs) that achieve savings in the final use of energy by means of energy efficiency interventions and projects. Electricity and gas DSOs must obtain a minimum amount\(^ {91}\) of white certificates to avoid sanctions by the AEEGSI. DSOs can also purchase white certificates with bilateral contracts or on the market for white certificates operated by GME. The legal framework for the white certificates system\(^ {92}\) has been subject to continuous evolution and it was most recently amended by the Ministerial Decree of 28 December 2012, which entrusted GSE (instead of the AEEGSI) with the task of evaluating energy efficiency projects. The Ministerial Decree of 28 December 2012 established that white certificates can no longer be issued in conjunction with other incentives granted by the Italian state and are now attributable only for energy savings achieved by means of new projects (or projects in progress). Pursuant to Legislative Decree No. 102/2014, starting from July 2016, the white certificate system will be limited to operators certified according to specific standards.\(^ {93}\) In 2015, GSE issued about 5 million white certificates (31 per cent for energy efficiency projects related to electricity savings, 58 per cent for energy efficiency

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\(^{86}\) Article 12 of Legislative Decree No. 387/2003.

\(^{87}\) Article 6 of Legislative Decree No. 28/2011.

\(^{88}\) Article 3, paragraph 3, and Article 11, paragraph 4, of the Bersani Decree, transposing Article 16 of Directive 2009/28/EC.

\(^{89}\) Article 3 of Legislative Decree No. 102/2014, transposing Directive 2012/27/EU.

\(^{90}\) White certificates must grant at least 60 per cent of the energy savings target for the period from 1 January 2014 to 31 December 2020 (see Article 7 of Legislative Decree No. 102/2014).

\(^{91}\) The amount of white certificates is subject to review every year.

\(^{92}\) The system was introduced in Italy by the Ministerial Decrees of 20 July 2004.

\(^{93}\) Article 12, paragraph 5 of Legislative Decree No. 102/2014.
projects related to natural gas savings and 11 per cent for energy efficiency projects in the transport sector not related to electricity and natural gas savings), corresponding to total savings in primary energy of 1.7 million TOE;\textsuperscript{94}

\textit{b} incentives for small-sized energy efficiency measures (thermal insulation of walls, replacement of heating devices with condensing boilers, replacement of in-house lighting systems with more efficient ones, installation of shielding and shading systems and building automation), which are financed by gas tariffs;\textsuperscript{95} and

\textit{c} tax deductions for energy requalification projects on buildings (65 per cent until 31 December 2016 and 36 per cent starting from 1 January 2017).\textsuperscript{96}

### III  Technological developments

Italy is a leader in the research and development of smart grid technologies. Since 2011,\textsuperscript{97} many grid pilot projects have been implemented and concluded by private operators.\textsuperscript{98} On the basis of the results of the grid pilot projects already implemented, the AEEGSI is currently studying possible incentive mechanisms for electricity distribution operators to convert the current electricity distribution grids into an integrated smart distribution system conveying distributed generation.\textsuperscript{99} The AEEGSI is currently assessing the possibility of launching new experimental projects in areas not already tested under the pilot projects already concluded.\textsuperscript{100}

Another important technological development in the energy sector is the recent approval by the AEEGSI of the technical requirements of new generation meters (second generation meters or 2G), which allow a real-time monitoring of electricity consumed and consequently real-time pricing, and which will in the next year replace the first generation meters.\textsuperscript{101}

### VI  THE YEAR IN REVIEW

Some of the key developments in legislation in the energy sector in 2015 and 2016 include:

\textit{a} Law No. 208/2015: (1) provides new incentives for operators managing biomass, biogas and bioliquid power plants; and (2) grants tax deductions for energy requalification projects on buildings (65 per cent until 31 December 2016 and 36 per cent starting from 1 January 2017);

\textit{b} Law-Decree No. 210/2015, converted by Law No. 21/2016, has postponed the term for the publication of calls for tenders for the service of gas distribution at ATEM
level, including for ATEMs for which the term has already expired; the criteria to be followed in tenders for the award of the gas distribution service have been reformed by Decree of the Ministry of Economic Development No. 106 of 20 May 2015;

c the Decree of the Ministry of Economic Development of 16 February 2016 has redefined the incentives for small-sized energy efficiency measures and for the production of thermal energy from renewable sources; and

d AEESGI Resolution No. 209/2016/E/com has established the procedure for mandatory mediation before the Mediation Service as a condition for legal action in disputes between customers or final consumers and operators in sectors regulated by the AEESGI.

Some of the key corporate transactions in the energy sector include:

a 18 April 2016: Edma Srl sold to Estra Energie Srl its 59.59 per cent shareholding in Prometeo SpA, which is active in the sale of electricity and gas at retail level, thus obtaining sole control over Prometeo SpA

b 21 December 2015: merger of Società Elettrica Altoatesina SpA, holding company of the SEA group, which was active in the generation of electricity (mainly from hydroelectric sources), in the distribution of electricity and gas, in the supply of heat and of green certificates, and Azienda Energetica SpA, holding company of the AE group and active in the generation of electricity (mainly from hydroelectric sources), in the distribution of electricity and gas, in the supply of heat and of green certificates, in the management of public lighting plants and in the transmission of electricity. Alperia SpA is the new company resulting from the merger;

c 9 December 2015: Terna – Rete Elettrica Nazionale SpA, the national electricity transmission grid operator, acquired a 100 per cent shareholding in SELF – Società Elettrica Ferroviaria Srl, controlled by the Ferrovie dello Stato group and active in the transportation and transmission of electricity on the high and very high-voltage grid that belonged to Ferrovie dello Stato SpA; and

d 30 November 2015: ERG Power Generation SpA, belonging to the ERG group and active in the generation and sale of electricity and related products, acquired a branch of E.On Produzione SpA consisting of 16 plants for power generation from hydroelectric sources.

VII CONCLUSIONS AND OUTLOOK

The Italian energy sector has undergone significant changes in recent years, implementing important reforms towards liberalisation and environmental sustainability. The reform process will no doubt continue in the next few years.

Among the most positive developments concerning the energy sector in Italy is the implementation of measures to ensure full neutrality of DSOs towards retail traders. New measures include standardised network codes regulating the obligations and rights of DSOs and traders, the introduction of smart meter systems, which provide consumers with real-time invoicing, and the development of smart grids, which will increase the reliability and quality of power supplies, integrate renewable power sources and increase energy efficiency by balancing electricity consumption and supply.
On the other hand, some aspects need greater attention by the regulator, such as incentives for renewable energy, energy efficiency projects and e-mobility, which appear underdeveloped in the current scenario. Tariff systems should also be structured differently to eliminate progressive rates and encourage a smarter use of gas and power in houses and firms.
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 2016, all nuclear power plants, except for two, 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 will be 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. In principle, both the approval required for entry into the town gas industry and the price of the gas itself are strictly regulated under Japanese law. In contrast, entry into the LPG industry only requires registration with the relevant authority, and the prices for the provision of LPG may be freely set by the provider. As of March 2016, statistics show that there are similar numbers of consumers for both types of gas, with around 29.7 million consumers using town gas while the number of consumers for LPG is close to 25 million. In parallel with the Electricity System Reform, the Gas System Reform, which includes the full liberalisation of entry into the gas retail business and the legal unbundling of gas transmission from generation, is also in progress.

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.

ii 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 1 April 2016, 280 entities are registered as retail companies.

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.

**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 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 targeting general consumers*
The GBA stipulates that entities intending to operate gas businesses targeting households, corporations and other such general consumers must obtain the relevant approval to become an operator of such gas businesses (general consumer gas utility business operators, or GCGUBOs) from the METI.

Applications for the relevant approvals involve the necessary submission of application forms in which statutorily required data such as details of the service area, gas generating facility and other necessary information are described. The criteria stipulated in the GBA for the grant of approval include the existence of sufficient demand for gas in the intended service area, the adequacy of the applicant’s gas provision capability, whether the applicant’s entry into the market will result in an excess in the supply of gas in the service area, whether the applicant has sufficient financial resources and technical capabilities to properly operate such a business, and whether the proposed gas utility is based on a reliable business plan.
Although the foregoing criteria do not specifically limit town gas providers to one provider per service area, in reality, the public administrative procedures utilised by the relevant regulatory authorities requiring that the applicant’s entry into the market does not result in an excess in the supply of gas in the service area effectively limits each service area to a single town gas provider. If all necessary criteria are met, the METI must grant its approval. In principle, the entire application and approval process will require around four months to complete.

As of March 2016, 206 GCGUBOs had received the necessary approvals and were currently operating such businesses (of this number, 29 are public utilities).

Regional monopolies have been recognised in relation to these 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 four major corporations (Tokyo Gas, Osaka Gas, Tohou Gas and Saibu Gas) providing service areas in large metropolitan areas accounts for about 73 per cent (based on sales volume as of February 2016).

Other types of town gas business
In addition to the above, the GBA also imposes certain restrictions on operators providing LPG to housing estates and other such residences by entities through the use of simplified gas-generating facilities (community gas utility business operators), facilitating the large-volume supply of gas (defined as the provision of gas to consumer in excess of 100,000 cubic metres per year, discussed in greater detail below) via gas pipelines over a certain size, which are independently maintained or utilised by such operators (gas pipeline service operators) and undertaking the business of providing large-volume supply of gas to consumers (commercial-scale gas suppliers).

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 Minister for Economy, Trade and Industry 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 consumer gas utility business requires authorisation from the METI before it can be effective, as does the merger or demerger of any entity that is a GCGUBO whereby all or part of a general consumer gas utility 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.

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 the 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 2020. That means that the 10 former general electricity utilities 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 ten 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.
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.

**Transportation obligations for town gas**

As mentioned earlier, because GCGUBOs are, pursuant to public administrative procedure, restricted by the practical principle of one town gas service provider per service area, it has been acknowledged that town gas provider monopolies exist within certain regions.

In exchange for this monopoly, GCGUBOs are obligated to broaden the piping grid, in other words to provide gas transportation. As mentioned later in this article, the revitalisation of competition through the utilisation of the piping grid by GCGUBOs to liberalise rates for commercial-scale supplying of gas is highly anticipated.

Nevertheless, current transportation rates are still relatively expensive and revitalisation of competition merely through the utilisation of the piping grid by GCGUBOs is far from sufficient.

**Rate system for gas businesses**

A GCGUBO wishing to possess a regional monopoly, because its consumers lack the freedom to choose their provider, is required to base its rate upon its costs incurred while under ‘efficient management’ plus a reasonable rate of return (a rate calculated by discounted cash flow) as stipulated in the general supply provisions approved by the METI. Costs incurred while under ‘efficient management’ refers to costs assumed to be incurred by a GCGUBO in its business operations pursuant to the necessary exercise of its corporate activities, while ‘reasonable rate of return’ refers to the reasonable total amount of production costs, provision and distribution costs and general administrative costs as calculated based on actual and realistic future prospects of operations, plus the amount of any funds obtained from interest and dividends to the extent fairly raisable or attainable respectively, as necessary for the realisation of the reasonable development of the business.

Raising of rates is subject to the approval of the METI; however, the lowering of rates is not subject to such a requirement and merely requires notification of the relevant change in rate.

LPG pricing is not subject to regulation and prices may be set as negotiated between the relevant parties of each transaction. Because of the accumulation of retailer’s overheads, which accounts for over 60 per cent of the retail price of LPG, said retail price of LPG has become more expensive than that of town gas.
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 1 April 2016, 144 companies were trade affiliates of the JEPX. As of 1 April 2016, JEPX has the spot market opening 365 days and established a market in which members can trade electricity until 1 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 on certain code of conducts such as to deliver explanation and documents in terms of certain matters for their supply to customers.

Gas

Obligation to supply

In recognition of the inevitably monopolistic nature of the general consumer gas utility business and other such considerations, GCGUBOs are subject to an obligation to supply gas and accordingly are prohibited from rejecting an application for the supply of gas received from a consumer and, in principle, from cutting off gas already supplied to a consumer.

This is not the case with LPG and no such obligations are imposed on LPG business operators.

Liberalisation of the town gas business

As a result of amendments to the relevant legislation, the town gas industry is currently experiencing an overhaul of its competitive environment because of the relaxation of regulations. Specifically:

a it has become possible for a town gas supplier to supply gas to the service area of another town gas supplier or other ‘white’ areas (areas not already serviced by any specific town gas supplier);

b companies other than town gas suppliers may now enter into the commercial scale gas utility business;

c pricing for commercial scale gas supplying has been liberalised; and
to encourage new entrants to enter the market, a gas transport system has been set up whereby the utilisation of existing gas piping belonging to other business operators is allowed.

In particular, the scope of the liberalisation of commercial-scale gas supply pricing has been progressively expanding because of legislative amendments. Beginning with the first round of reforms in March 1995, which saw the liberalisation of the rates for the supply of gas to consumers whose annual usage exceeded over 2 million cubic metres, as of the fourth round of reforms, which took effect from April 2007 the rates for supply of gas to consumers whose annual usage exceeds 100,000 cubic metres have also been liberalised, accounting for the liberalisation of roughly 62 per cent of the total volume of town gas sales in Japan.

As a result of these efforts, 38 new gas companies entered into the gas industry (based on approval applications and notifications as of 31 March 2015) and as of 2014, 11.7 per cent of the total volume of commercial-scale gas supplied could be attributed to them. New entrants entering into commercial-scale gas supplier business include such entities as electric power companies, domestic natural gas utilities and commercial enterprises.

In addition, the amendment to the GBA is scheduled to come into effect in April 2017. This amendment implements full liberalisation of entry into the gas retail business, which accounts for 36 per cent of the total gas supply. 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 transmission (pipeline) business.

iii Market developments

Electricity

The Amendment to the Commodity Futures Act provides that electricity becomes subject to commodity futures trading, which enables market participants to avoid the risk of volatility.

Further, the Tokyo Stock Exchange, Inc (TSE) established an infrastructure fund market in April 2015, which enables the listing of funds that invest in certain infrastructure such as electric generation facilities. Funds investing in renewable energy generation facilities are expected to be listed on the market. The listing of the first ‘infra-fund’ that invests in solar power facilities was approved by the TSE in April 2016 and is scheduled to be listed in June 2016.

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 electric power is bought back at a fixed price). The Renewable Energy Act became effective on 1 July 2012, the major requirements of which can be summarised as follows:
a Electric power companies, including certain retail companies and general transmission companies, are expected to become providers of renewable electric energy and as such must execute all applications for contracts for sale of electric power submitted to them by renewable electric energy suppliers and facilitate the connection of the power generating facilities of these suppliers to their own electric facilities for transformation, transmission and distribution of electric power.

b Renewable electric energy is defined as electric power obtained and converted through the use of electric transduction facilities from renewable energy sources such as solar, wind, water (currently statutorily limited only to small and medium hydroelectric generators with output of less than 30,000kW), geothermal, biomass and other sources as stipulated in the relevant cabinet order. Electric power suppliers that wish to become part of the aforementioned system are required to obtain approval from the METI for power-generating facilities.

c Sales prices and contract terms shall be as set by the METI upon the input of the Committee for Calculation of Procurement Cost and Related Matters. The sales prices and contract terms will be revised every financial year and, in principle, these electric power sales and connection contracts will have to be executed in the same financial year; the METI’s approval should also be obtained for the facilities.

d All transactional costs will ultimately be borne by the end-consumers (both private and corporate).

Sales prices and contract terms
Set out below are the changes in sales prices and contract terms for 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.

<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>JPY 38</td>
<td>JPY 37</td>
</tr>
<tr>
<td>≥ 10kWh</td>
<td>JPY 36</td>
<td>JPY 32</td>
</tr>
<tr>
<td>Wind power</td>
<td></td>
<td></td>
</tr>
<tr>
<td>&lt; 20kWh</td>
<td>JPY 55</td>
<td>JPY 55</td>
</tr>
<tr>
<td>≥ 20kWh</td>
<td>JPY 22</td>
<td>JPY 22</td>
</tr>
<tr>
<td>Off-shore wind power*</td>
<td>JPY 36</td>
<td>JPY 36</td>
</tr>
<tr>
<td>Geothermal power</td>
<td></td>
<td></td>
</tr>
<tr>
<td>&lt; 15000kWh</td>
<td>JPY 40</td>
<td>JPY 40</td>
</tr>
<tr>
<td>≥ 15000kWh</td>
<td>JPY 26</td>
<td>JPY 26</td>
</tr>
</tbody>
</table>
### 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>Power Source</th>
<th>Solar Power (&lt; 10kWh)</th>
<th>Solar Power (≥ 10kWh)</th>
<th>Wind power</th>
<th>Hydroelectric power</th>
<th>Geothermal power</th>
<th>Biomass power</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>April 2013 to March 2014</td>
<td>485,686.0</td>
<td>425,466.9</td>
<td>489,638.3</td>
<td>93,552.6</td>
<td>570.9</td>
<td>316,940.0</td>
<td>1,811,854.7</td>
</tr>
<tr>
<td>April 2014 to March 2015</td>
<td>578,017.8</td>
<td>1,317,731.0</td>
<td>492,082.3</td>
<td>107,277.2</td>
<td>608.1</td>
<td>364,438.0</td>
<td>2,860,154.0</td>
</tr>
<tr>
<td>April 2015 to December 2015</td>
<td>514,854.4</td>
<td>1,860,298.5</td>
<td>349,975.4</td>
<td>112,223.6</td>
<td>3,931.7</td>
<td>383,095.3</td>
<td>3,224,378.9</td>
</tr>
</tbody>
</table>

On the other hand, problematic businesses, such as those that utilised favourable pricing to obtain facility approval but delayed commencement of work and attempted to obtain fraudulent profits, had been frequently reported. In response, the METI has moved to revoke the approval for some of these businesses since 2014. Further, the METI implemented a rule for facility approval issued in or after April 2014, under which solar power facilities with capacity of 50kW or more that have not secured a site and equipment within a certain deadline of receiving approval will have their approval lapse in principle.

Further, in 2014, five general electric utilities (i.e., those in Hokkaido, Tohoku, Shikoku, Kyusyu and Okinawa) announced that they could temporarily suspend or withhold
the execution of a contract for applications for all or part of contracts for the sale of electric power because of the possibility of excess of supply if all the approved renewable-source energy generation facilities were to start generation. To solve this problem, the METI implemented a new rule that allows electricity business entities designated by it to unlimitedly restrict output from renewable-energy facilities, and which is applied in certain situations where oversupply of electricity is expected to occur; as a result, the electric companies resumed executing contracts for new applications.

ii Gas

In terms of gas-related renewable energy, biogas has been generating a lot of attention in recent years. Biogas is a flammable gas produced by the fermentation of organic waste such as raw sewage, food waste and livestock excretions, a feature that allows it to be harvested at sewage treatment plants, food factories and other such locations. Major town gas utilities such as Tokyo Gas and Osaka Gas have in recent years established guidelines for and promoted the purchase of biogas. Additionally, several local governments began to produce biogas in a sewage facility or refuse disposal facility.

VI THE YEAR IN REVIEW

The electric power industry regulations have, following the events at Fukushima in 2011, already witnessed great reforms. First, the electric system reform started, including full liberalisation of entry into the electricity retail business, and the following phase of the reform, including legal unbundling of the electric power transmission function and sector from the existing dominant power suppliers, will be implemented in 2020. Second, the introduction of FITs has encouraged the emergence of new entrants to the renewable energy industry and the renewable energy market has been expanded, but the FIT system is being revised to address several problems.

As explained above, the gas system is scheduled to undergo reform along the same lines as the electric system reform, and it is expected that, from 2017, the full liberalisation of entry into the gas retail business will be implemented. 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 and a code of conduct for gas transportation (pipeline) businesses will be imposed; and, in another measure to ensure competitiveness in the gas market, access to pipelines will be open to all at fair prices.

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 2016, all 48 nuclear power stations in Japan except two are stopping operating. In the meantime, the Nuclear Regulation Authority issued new nuclear power station safety standards in July 2013 and currently 19 nuclear power stations are in the process of review for restart under the new safety standards (seven 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 increasingly 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.
Chapter 21

KOREA

Wonil Kim and Kwang-Wook Lee

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 Geun-Hye Park administration, which took power in 2013, has designated its basic goals for its energy policy as reasonably establishing plans for supply and demand of energy, strengthening energy safety, such as prevention of nuclear accidents, engaging in political and technical efforts to reduce greenhouse gases, promoting an energy rate policy that accurately reflects production costs, and stabilising overseas resource development. The enactment and amendment of the relevant laws reflect this policy.

1 Wonil Kim and Kwang-Wook Lee are partners at Yoon & Yang LLC.
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:

a Electricity: the Electric Utility Act (EUA) regulates matters such as the production, distribution and sale of electricity and the Electrical Construction Business Act was enacted to ensure the safety of businesses that engage in electricity-related construction.

b Petroleum and gas: the Petroleum and Petroleum Substitute Fuel Business Act (PBA), as amended in 2015, and the Urban Gas Business Act (UGBA), as amended in 2015, regulate the adequate distribution of petroleum and gas to consumers, and the High-Pressure Gas Safety Control Act was enacted to introduce safer measures to prevent the possibility of gas exploding.

c Nuclear energy: the Nuclear Energy Promotion Act regulates the research, development, production and use of nuclear energy; the Nuclear Safety Act regulates the safety of nuclear energy; and the Nuclear Damage Compensation Act regulates matters regarding damage compensation arising in relation to nuclear energy.

d New and renewable energy: the Act on the Promotion of the Development, Use and Diffusion of New and Renewable Energy (the New and Renewable Energy Act), 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.

ii Regulated activities

Electricity

Under the EUA, electric utility businesses are categorised into five types of business, the definitions of which are as follows:

a Electricity generation business: a business, the main purpose of which is to generate and supply electricity to operators of the electricity sales business via the electric utility market.\(^2\)

b Electric transmission business: a business, the main purpose of which is to set up and operate electric installations necessary to transmit electricity produced at power stations to operators of the electricity distribution business.\(^3\)

c Electric distribution business: a business, the main purpose of which is to establish and operate electricity installations necessary to distribute electricity transmitted from power stations to consumers of electricity.\(^4\)

d Electric sales business: a business, the main purpose of which is to deliver electricity to consumers.\(^5\)

e District electric business: a business, the main purpose of which is to generate electricity with electric generating units of up to 35,000kW to meet the demand of a specific supply district, and to supply the produced electricity to consumers of electricity in that specific supply district, not via any electric utility market.\(^6\)

The Korea Electric Power Corporation (KEPCO) had a monopoly on the production and supply of electricity in Korea until the late 1990s, and was entirely responsible for generation, transmission, distribution and sales. Currently, KEPCO is still responsible for transmission, distribution and sales of electricity, KEPCO’s subsidiaries and various private companies are competing in the electricity generation business.

According to Article 7 of the EUA, any person who intends to operate an electric utility business must obtain a licence, based on the business type, from the Minister of the MOTIE (the Minister); the Minister’s approval is required when the person intends to modify important matters relating to the licence, such as the business district or specific supply district, supply voltage and, in the case of electricity generation businesses and district electric businesses, the place of electric installations, equipment capacity and the type of motive power.\(^7\) To obtain a licence, the following documents must be submitted to the Minister:\(^8\)

\[
\begin{align*}
a & \quad \text{an application for a licence;} \\
b & \quad \text{a business plan;}
\end{align*}
\]

\(^2\) 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.
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).

The Minister will grant an electricity utility licence after an application has undergone deliberation by the Electricity Regulatory Commission. The criteria for issuing the licence as provided by Article 7(5) of the EUA are:
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 60 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

**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)’10 and categorises petroleum businesses into three types of business: petroleum refinery businesses,11 petroleum export and import businesses12 and petroleum sales businesses.13

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

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9 Article 9(1) of the EUA.
10 Article 2(i) and (ii) of the PBA.
11 Article 2(iv) of the PBA.
12 Article 2(v) of the PBA.
13 Article 2(vi) of the PBA.
to Article 25-2 of the PBA[^14]. 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.[^15]

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.[^16] Such a registration, however, is not required by 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.[^17] 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 30 days’ worth of planned domestic petroleum sales or 5,000kL.[^18] This provision was amended in 2012 from ‘the greater of the quantity of 45 days of the planned domestic sales of petroleum or 7,500kL’ to promote competition in the petroleum export and import business by relaxing the requirements.

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,[^19] petroleum sales businesses that fall under (6) need to be reported to the head of the local government.[^20]

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.[^21] 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.[^22] 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.[^23]

[^14]: Article 5(1) of the PBA; Article 4(1) of the Enforcement Rule of the PBA.
[^15]: Article 5(2) of the PBA; Article 8(1) of the Enforcement Decree of the PBA.
[^16]: Article 9(1) of the PBA; Article 8(1) of the Enforcement Rule of the PBA.
[^17]: Article 9(1) of the PBA; Article 10(2) of the Enforcement Decree of the PBA.
[^18]: Article 12(1) of the Enforcement Decree of the PBA.
[^19]: Article 10(1) of the PBA; Article 12(1) to (6) of the Enforcement Rule of the PBA.
[^20]: Article 10(2) of the PBA; Article 12(7) of the Enforcement Rule of the PBA.
[^21]: Article 9(1) of the PBA.
[^22]: Article 39(1)(iii) of the PBA.
[^23]: Article 41-3 of the PBA.
**Urban gas**

The UGBA defines the term ‘urban gas’ as natural gas (including liquefied gas), petroleum gas, by-products from naphtha cracking and biogas, and synthetic natural gas (SNG). Under the UGBA, 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.

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.

- **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.

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24 Article 2(i) of the UGBA; Articles 1-2 of the Enforcement Decree of the UGBA.
25 Article 2(i) of the UGBA.
26 Article 2(i-2) of the UGBA.
27 Article 2(ix-2) and (ix-3); Article 10-2(3) of the UGBA.
28 Article 10-6 of the UGBA.
29 Article 2(iii) of the UGBA.
30 Article 2(iv) of the UGBA.
31 Article 2(iv-2) of the UGBA.
32 Article 2(iv-3) and Article 8-3 of the UGBA.
33 Article 2(iv-4) of the UGBA.
34 Article 2(vii) 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 and a person who intends to operate general urban gas business must obtain a licence from the head of the local government. A licence for the gas wholesale business and general urban gas business will only be granted if applications meet the following requirements: (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. A person who intends to operate an SNG manufacturing business must obtain a licence from the Minister for each place of business.

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). 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. Anyone who intends to operate a business that carries natural gas in and out must report the business to the Minister.

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. The UGBA strengthens safety requirements by stipulating that, in cases where liquefied petroleum gas facilities are changed into urban gas facilities, urban

35 Article 2(ix-2) of the UGBA.
36 Article 3(1) of the UGBA.
37 Article 3(2) of the UGBA.
38 Article 3(7) of the UGBA.
39 Article 3(3) of the UGBA and Article 3(4) of the UGBA.
40 Article 3(5) of the UGBA.
41 Article 10-2(1) of the UGBA; Article 10-6 of the Enforcement Rule of the UGBA.
42 Article 10-5(1) of the UGBA.
43 Article 10-2(3) of the UGBA.
44 Article 10-5(2) of the UGBA.
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.\textsuperscript{45} The UGBA also requires that safety measures for gas plumbing and gas use facilities be implemented in the case of an extension or alteration to a building where urban gas pipelines are installed.\textsuperscript{46} The UGBA also newly introduces penalty provisions against those parties that cause damage, or inflict harm to the functionality of, urban gas pipelines.\textsuperscript{47}

\textbf{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.\textsuperscript{48} 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.\textsuperscript{49}

The New and Renewable Energy Act provides that tradable renewable energy certificates 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, renewable energy certificates 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.\textsuperscript{50} 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.\textsuperscript{51}

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.\textsuperscript{52} 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.\textsuperscript{53} Moreover, the New and Renewable Energy Act requires a new and renewable energy facility certification holder to take out

\begin{itemize}
\item Article 2-2 and 54(6) of the UGBA.
\item Article 28-3 of the UGBA.
\item Article 48(4) and (8) of the UGBA.
\item Article 5(1) and (2) of the New and Renewable Energy Act.
\item Article 6(1) of the New and Renewable Energy Act.
\item Article 12-7 of the New and Renewable Energy Act.
\item Article 13 of the New and Renewable Energy Act.
\item Article 12-11, 12-12 of the New and Renewable Energy Act.
\end{itemize}
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.

### 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. 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 28 February 2014, the number of private companies operating electricity generation business increased to 543 (of these, 529 were new and renewable energy development companies), and the electricity generated by private companies other

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56 Article 10(1) of the EUA.
than KEPCO’s subsidiaries accounts for about 11.8 per cent of all electricity generated. 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.

### 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\(^{57}\) and, other than a consumer who uses 30,000kVA or more, no consumer may purchase electricity directly from the electric utility market.\(^{58}\) 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\(^{59}\) and the operator of an electric utility business must maintain the quality of service that it provides.\(^{60}\) 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.\(^{61}\)

**Petroleum**
The PBA has various provisions that regulate the management of the quality of petroleum products and prevent the distribution of pseudo-petroleum products.\(^{62}\)

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.\(^{63}\) Any operator will be prohibited from

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57 Article 44 of the EUA.
58 Article 32 of the EUA; Article 20 of the Enforcement Decree of the EUA.
59 Article 14 of the EUA.
60 Article 18(1) of the EUA.
61 Article 27 of the EUA.
62 Products manufactured by a method of mixing petroleum products with other petroleum products or petrochemicals; Article 2(x) of the PBA.
63 Article 25(1) of the PBA; Article 28(1) of the Enforcement Rule of the PBA.
serving or delivering petroleum products that have failed the quality inspection. According to Article 29(1) of the PBA, no one may engage in manufacturing, importing, storing, transporting or keeping pseudo-petroleum products.

Meanwhile, to promote the expansion of the exporting of petroleum products, Article 29(2)(v-2) of the PBA stipulates that the blending of petroleum products at the general bonded area for the purpose of export only, as well as storing and transporting such mixtures, will not be viewed as the manufacturing of fake petroleum products.

**Urban gas**

No gas wholesale business operators shall refuse to supply natural gas, or have the supply thereof interrupted, to general urban gas business operators, urban gas charging business operators or bulk buyers without justifiable cause.

Each urban gas business operator must have the urban gas that it supplies inspected by an urban gas quality inspection institution to confirm that the gas fulfils the required quality standards.

### 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. 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. 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.

**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.

**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

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64 Article 27 of the PBA.
65 Article 29(2)(v-2) of the PBA.
66 Article 19 of the UGBA.
67 Article 25-2(1) of the UGBA.
68 Article 16(1) of the EUA; Article 16(1) of the Enforcement Rule the EUA.
69 Article 17 of the EUA.
70 Article 15(1) of the EUA.
71 Article 38-2(1) of the PBA.
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).

iv Security and technology restrictions

Electric power
Where an operator of an electric utility business intends to perform the works for setting up or altering electric installations for the electric utility, he or she must obtain approval for the plan for the works from the Minister, 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.

IV ENERGY MARKETS

i Development of energy markets

Electricity
As previously described, transactions regarding electricity take place at the KPX pursuant to the EUA, which was established as an independent legal entity on 2 April 2001. Specifically, transactions occur between the over 500 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

72 Article 61(1) of the EUA.
73 Article 65 of the EUA.
74 Article 12-5(1) and (2) of the New and Renewable Energy Act; Article 18-3 of the Enforcement Decree thereof.
75 Article 12-6(1) of the New and Renewable Energy Act.
and supervises each of the duties of the wholesaler operator and local governments oversee and supervise each of the duties of retail operators. In December 2015, the MOTIE released its twelfth long-term plan for natural gas procurement, with the aim of timely expansion of the natural gas supply infrastructure so as to effectively execute a new supply–demand management system, ensure the security and flexibility of natural gas supply, improve the resilience of natural gas management capabilities and increase city gas penetration.

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 to 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 Corp. Urban gas businesses purchase urban gas from the Korea Gas Corp and sell it to consumers.

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 promoting domestically 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.

*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 general output, an obligation for public institutions to use new and renewable energy and new and renewable energy equipment certification procedures, etc., which made it possible to create an early market for new and renewable energy.

The Basic Plan for Development and Use of New and Renewable Energy (2003–2012) was established and implemented for the further promotion of new and renewable energy development and dissemination, and the relevant law was again amended in 2004.

Korea applied FITs from 2002, but in 2012 they were replaced by the Renewable Portfolio Standard (RPS), which obligates certain operators of energy businesses to supply certain amount of new and renewable energy. 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 2016, the Korean government is increasing the RPS quota from the previous 3 per cent to 3.5 per cent and is integrating the solar and non-solar market by abolishing the separate RPS quota for solar energy. 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. The government also plans to support overseas expansion of Korean
renewable energy companies by improving regulations, increasing investment and enhancing
competitiveness in equipment technologies. In 2016, the government is expanding the
installable areas for solar power facilities to include riverbeds and idle power-plant land, and
it is investing 180 billion won in research and development (R&D) for clean energy-related
materials and parts. This investment is expected to promote joint overseas expansion by
state-owned energy companies and small and medium-sized solar energy companies.
Currently, small and medium-sized domestic solar energy companies and state-owned energy
companies are jointly operating a solar demonstration site (130kW) in Uzbekistan.

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.

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.

iii   Technological developments

In 2004, Korea held the Green Energy Expo in Daegu City, as a pioneer in new and renewable energy technology development. While recently the solar power industry has been facing relative difficulties, technical development in the alternative energy field – such as wind power – is very active. In particular, in the case of Korea, there is rapid development in the fuel cells field. Also, based on the joint participation of the government and private sector, a strategy for technical development for energy called the Green Energy Strategy Roadmap has been established and implemented and this road map has information on the short, medium and long-term plans for 15 technical sectors that require intensive development.

If recognised to be necessary for use and supply of new and renewable energy, the Minister can provide support such as financial support for some of the necessary costs for the speciality company.76

In the case of the smart grid, on the basis of the February 2009 Report by the Presidential Committee on Green Growth, Korea (1) selected the smart grid as the core infrastructure for green growth in Korea; (2) became the first country to establish a smart-grid country road map; (3) enacted the Act on Promotion of Deployment and Utilisation of Intelligent Electricity Networks; and (4) built the Jeju Island Smart Grid Test-Bed.

The MOTIE plans to implement smart-grid proliferation projects that will maximise energy efficiency and provide high-quality power services for the electric-vehicle and ESS-related sectors in 13 regions nationwide from 2016 to 2018. It aims to further expand the relevant market by allowing these services to be privately operated from 2019 to 2025.

VI   THE YEAR IN REVIEW

On 23 November 2015, the MOTIE released its new energy industry plan designed to address energy and environment issues in the face of climate change. The key aspects of the plan include the following:

a   deregulating energy markets and mitigating KEPCO’s monopoly over the energy market by opening an energy prosumer market, where individual consumers can sell

76 Article 27 of the New and Renewable Energy Act.
energy generated by themselves through small-scale, renewable energy technologies, and allowing electric vehicle-charging operators to resell electricity that they have purchased;

b fostering the electric vehicle industry with the goal of 1 million electric vehicles on the roads by 2030;

c securing empirical experience by creating a variety of business models – including energy self-sufficiency islands, public housing and eco-friendly towns, such as Hong Cheon Eco-Friendly Energy Town – which are expected to solve energy and environmental issues at the same time by creating biogas energy using sewage and waste;

d establishing the Climate Change Global Technology Cooperation Centre within the Ministry of Science, ICT and Future Planning for cooperation on technology in the energy industries;

e strengthening support infrastructure for small and medium-sized companies that intend to expand their business overseas; and

f easing market entry restrictions on new energy technologies and new energy companies by permitting the sale of electricity produced and stored by mass storage ESS at the KPX and allowing small electric power brokerage businesses to sell small-scale electric power at the KPX.

To facilitate its new energy industry plan, the government will invest 1.289 trillion won in total (including 440 billion won for R&D, 650 billion won for financing and 195 billion won for dissemination) based on the 2016 budget, and KEPCO and six state-owned development companies will invest 1.5 trillion won in the renewable energy sector until 2017, thus increasing the RPS quota by 4.2 per cent.

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 is expected to ratify the Paris Agreement in June 2016. One of the key goals of the Paris Agreement is to limit the increase in the global average temperature to 1.5°C. In contrast to the 1997 Kyoto Protocol, all 195 counties that adopted the Paris Agreement are bound by obligations to reduce greenhouse gas emissions. For that purpose, each country will determine its own action plan to reduce greenhouse gas emissions. The first scheduled global stocktake, whereby all reports and communications from the parties will be analysed to track collective progress towards achieving the Agreement's fundamental aims, will be in 2023, then every five years thereafter. The Korean government already submitted its Intended Nationally Determined Contribution to the UN Framework Convention on Climate Change in June 2015. Its 2030 target is reducing greenhouse gas emissions by 37 per cent from business-as-usual levels. To achieve that goal, the government has, since 1 January 2015, implemented a national greenhouse gas emissions trading system in accordance with the Act on the Allocation and Trading of Greenhouse Gas Emission Rights.

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.

Meanwhile, as of 2013, the production capacity of Korea’s petrochemical businesses is the fourth-largest in the world. While there are limitations to focusing on new and renewable energy-concentrated policies in Korea, since – compared with other countries whose focus is on service industries – its high levels of energy consumption rely heavily on imports, it does need to make continuous efforts to address climate change.

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. To address the new climate regime scheduled for 2020 under the Paris Agreement, the MOTIE launched its new energy industry policy task force in July 2015, and has been promoting eight projects relating to electric vehicles, the demand resource market, energy self-sufficiency islands, ESS, eco-friendly energy towns, zero energy buildings, power plant thermal heat utilisation and solar rentals. To successfully carry out these innovative projects, the government is promoting private investment in the new energy industries and employing export industrialisation strategies at the same time. These efforts by the government are expected to lead to a creative economy in the energy sector and create more new job opportunities.
Chapter 22

MEXICO

Juan Carlos Serra Campillo and Jorge Eduardo Escobedo Montaño

I OVERVIEW

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.

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2 www.diputados.gob.mx.
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 four calls to tender that have been issued by the National Hydrocarbons Commission (CNH).

Currently, 30 exploration and extraction agreements have been awarded to private companies for onshore and offshore oil and gas fields and although their commercial exploitation will not commence immediately, these new contracts represent important investment in Mexico for the coming years. Furthermore, Pemex will farm out some of the oilfields that it was awarded in the Round Zero allocation; 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 this year, resulted in 11 agreements to purchase electricity from private companies.

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;

\[b\] to organise bidding procedures for the award of hydrocarbon exploration and extraction contracts;

\[c\] to execute hydrocarbon contracts with awarding companies;
to manage and supervise allocations and exploration and extraction contracts; and

to provide technical advice to SENER.

CNH has issued four 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.

**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.

ASAE’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.

**National Energy Control Centre (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.
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:

a  SENER: for hydrocarbons, petrol and fuel import and export activities; treatment and refining of oil; and, process of natural gas; and

b  CRE: transportation, storage, distribution, commercialisation and public dispensing of petrol.

Permits required for electricity industry activities are issued by CRE and CENACE, as follows:

a  CRE: permits related to the generation, independent production, small-scale production, and the supply of electricity; and

b  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 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 where 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.

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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.

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 year 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 ENERGÉTICAS

i Desarrollo de mercados energéticos

Certas actividades de mercado energético, como la exploración o extracción de hidrocarburos, están sujetas a procesos de subasta y solo pueden realizarse siguiendo un proceso de subasta y la concesión de un contrato que permita a empresas privadas o de propiedad del gobierno operar en un área determinada o bloque.

Aunque CRE ya ha otorgado permisos para la venta de productos petrolíferos, el mercado actualmente está dominado por franquicias de Pemex. Este sistema de venta se ha aplicado en México durante años, con Pemex como único participante en la cadena de exploración, extracción, refinado, suministro y distribución.

Debido a que el nuevo marco legal de energía permite la participación privada a lo largo de toda la cadena productiva, CRE ya ha otorgado permisos para la comercialización y venta pública de productos petrolíferos. A partir del 1 de abril de 2016, las importaciones de productos petrolíferos y combustibles en México son permitidas, y una nueva actividad en el mercado de estos productos surgirá en los próximos años.

Aunque el mercado de gas natural es más organizado y hay una gran cantidad de empresas privadas que realizan almacenamiento, distribución y venta de gas natural, es importante tener en cuenta que las ventas directas de estos productos también se realizaban exclusivamente por Pemex.

Los mercados eléctricos organizados se están empezando a formar, con partícipantes privados comenzando a moverse en las áreas permitidas por la ley que, antes de la reforma energética, estaban completamente cerradas a las empresas privadas y inversores extranjeros. No obstante, ya se han establecido reglas por SENER y se han emitido llamados a licitación para procedimientos de subasta para comprar y vender electricidad.

ii Reglas y regulaciones de mercado energético

Diferentes reglas se aplican en los mercados eléctrico y de gas. Para mercados eléctricos, las reglas principales son (1) el Código Eléctrico y sus regulaciones; y (2) el Programa de Mercado de Energía Eléctrica (las Reglas) emitido por SENER.

El mercado eléctrico es reglamentado por CENACE. Segundo a las Reglas, individuos o empresas que concluyan contratos con este cuerpo gubernamental – como generadores o proveedores comerciales, entre otros – podrán realizar transacciones relacionadas con la compra y venta de electricidad.

En la industria del gas natural, CRE ha emitido un número de reglas administrativas con el fin de regular el mercado y la venta de productos de gas natural.

iii Contratos de venta de energía

Los participantes en el mercado están permitidos a entrar en contratos individuales para la venta de gas natural siempre que los términos y condiciones de dichos contratos cumplan con los requisitos establecidos en las leyes correspondientes (es., términos y condiciones, y tarifas relacionadas con el gas natural, que deben tener el consentimiento previo de CRE).

Se debe considerar los detalles de cada operación de energía, como la manera en que la energía será entregada al comprador, porque, como se ha mencionado, la interconexión al Sistema Eléctrico Nacional requiere un permiso de 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 preparing and carrying out all hydrocarbon bidding procedures and electric power auctions.

The main developments in Mexico’s energy markets concern oil and gas. Three tender procedures have been conducted by CNH resulting in the award of 30 exploration and extraction contracts, representing estimated investments of US$6.9 billion. In addition, a fourth tender process is under way, which proposes a contractual licence scheme. At the time of writing, there are 25 interested companies in this fourth tender process, of which nine have already registered.

Additionally, CENACE has already concluded the first electricity auction, following which 11 companies were 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.\(^4\) 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:

- \(a\) to facilitate the gradual increase of clean energies in the electricity industry;
- \(b\) 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 first auction by CENACE of long-term supply and purchase contracts, 11 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.

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4 www.diputados.gob.mx/LeyesBiblio/pdf/LTE.pdf.
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 tons 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.

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 2015 was an important one for Mexico regarding the energy industry. Three calls for tender were conducted by CNH, following which 30 exploration and extraction contracts were awarded to private companies.

Additionally, a fourth call for tender, for exploration and extraction contracts in deep waters, was issued by CNH, and is currently in process. It is expected that this procedure will be finalised in December 2016.

5 www.sener.gob.mx.
Although 2015 was a particularly difficult year for the oil industry because of the low prices of crude oil, 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 2015, the first long-term electric auction was conducted by CENACE and 11 contracts were awarded for the purchase of electric power and clean-energy certificates.

During 2015, 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 it having a considerable availability of resources.

The new Mexican energy legal framework was almost completed during 2015. The coming years will be important years for the industry in Mexico since the hydrocarbon contracts awarded to private companies will be implemented.

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 23

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

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2 Law No. 21/97 of 1 October.
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.

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 which 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:

a) promotion of compliance with legislation in the electricity sector;
b) issuance of opinions on a variety of issues, such as expropriation proposals for electric facilities’ projects, new concessions and tariffs;
c) performing studies on different aspects of the electricity sectors; and

d) 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:

a) management of National Petroleum Database;
b) research activities;
c) powers relating to petroleum development, production and transport activities;
d) powers relating to the safekeeping of operators interests; and

e) general powers of administration, monitoring and regulation.

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)

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3 In practice, CNELEC has not yet fully assumed its role as a regulatory authority, mainly exercising advisory functions in respect of the aforementioned matters.
are subject to a regulatory approval by the Ministry of Natural Resources and Energy, the Council of Ministers or local authorities, depending on what is established in the applicable law, in the form of a concession agreement. Activities in the petroleum products value chain (production, storage, transport, distribution and sale, as well as the operation of unloading terminals and oil pipelines) are subject to licensing by the Ministry of Natural Resources and Energy in accordance with the terms of the Petroleum Products Regulation.

Energy facilities across all sectors are also subject to licensing, pursuant to the terms of the relevant legislation.

Concessions in the electricity sector are subject to tender offers, in accordance with the Energy Concessions Regulation. Tenders must follow the guidelines set out in the terms of reference and are directed to the relevant competent authority (i.e., the Council of Ministers, the Ministry of Natural Resources and Energy or local authorities). Tenders must also specify the technical and financial details of the project and provide sufficient evidence of the appropriate qualifications of the applicant. Hydroelectric projects require additional information on the characteristics of the hydroelectric use of the water resources; energy generation and transport concessions are also subject to additional requirements.

After the tender has been requested, 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 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 anti-competitive effects stemming from the granting of the licence. Licences may be subject to conditions to be defined by the relevant licensing entity.

Before the start of operations of any of the aforementioned activities in the petroleum products fuel chain, licences must be registered after a mandatory site visit, to be carried out by a commission that includes representatives of various regulatory authorities, including the licensing entity.

iii Ownership and market access restrictions

In the electricity sector, there are no obvious limitations on the ownership of both new and existing assets and companies in this business sector, nor direct restrictions on asset ownership save for the general merger and takeover control provisions introduced in Law No. 10/2013, enacted on 20 March 2013 (the Competition Act), the scope of which is the protection of competition in the undertaking of economic activities. Preference, however, is given to applicants for oil or natural gas concessions that are Mozambican nationals or are associated with Mozambican nationals if two or more applicants are on equal footing.

In the petroleum products sector, however, several restrictions of this nature exist, set out in the Petroleum Products Regulation, the most relevant being:

- the prohibition of the mingling of distribution and retail activities, except when it relates to liquid petroleum gas (LPG) or compressed natural gas and for training purposes (undertaken in fuel stations);
- licensed entities may be entitled to hold more than one licence in the value chain, as long as no anti-competitive effects stem from this situation; and
- only Mozambican nationals and Mozambican companies may hold licences for petroleum products (there appears to be no restrictions for Mozambican companies held by foreign equity holders, however).

There are no restrictions on the provision of regulated services (i.e., supply of electricity and natural gas) and no restrictions on the ownership of assets or licensed activities other than those set out in the previous paragraph.

iv Transfers of control and assignments

Transfer of interests in electricity concessions, of assets encompassed by an electricity concession and of establishment licences of electricity facilities are subject to regulatory approval by the regulatory authority that granted the concession or the licence, according to the terms of
the applicable Mozambican law. Transfer of operation licences of electrical facilities is not possible under Mozambican law and, as such, should the licensee change, a new licence will have to be issued pursuant to the terms of Decree No. 48/2007 of 22 October.

The procedure for the transfer of operation licences 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 practice 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.4

### 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.

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4 Article 19(3)(b) of the Competition Act establishes that the following is considered an abuse of a dominant position: the refusal by a company to grant to any other company, for adequate compensation, access to a network or other essential infrastructure that the first company controls as long as the other company cannot, for legal or practical reasons, operate as a competitor of the company that controls the assets at issue. This provision is not applicable if the company that controls the assets at issue demonstrates that such access is impossible under reasonable conditions.
iv Rates
As a general rule, rates for transport and distribution of energy are mostly determined by bilateral contracts rather than regulated tariffs (which are only set for the sale of electricity, natural gas and fuels to the end-consumer). There are, however, standards that some concessionaires must consider when setting the fees for the rendering of their services.

Nonetheless, the Electricity Act in the electrical sector establishes a ‘transit tariff’ for third-party use of transmission and distribution facilities, which is not regulated. The National Transmission System Regulation determines that contracts entered into with transmission concessionaires must set rates that:

a assure non-discriminatory treatment of consumers;
b assure the coverage of costs consistent with ‘standard costs’;
c stimulate new investment in the expansion of electrical systems;
d induce the use of electrical systems; and
e minimise the costs for expansion or use of electrical systems.

As for distribution, rates are fixed with generation and energy supply concessionaires. For the latter, a tariff for use of the distribution system must be set.

Oil and gas pipelines are subject to tariffs set in the relevant concession agreement and are based on the following principles:

a the tariff is to contemplate total reserved capacity for the infrastructure;
b the tariff shall include the cost of capital and operational costs;
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;
the obligation to be subject to a five-year inspection obligation on petroleum product facilities; and

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
Recently, 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 2015 for Mozambique included:

a the enactment of the new Petroleum Operations Regulation and the regulation for the taxation and tax benefits regarding oil activities;
b onshore natural gas prospection by Indonesian oil company Buzi Hydrocarbons commenced;
c a natural gas-fired power plant was completed in Ressano Garcia, next to the South African border;
d the first natural gas (downstream) distribution network commenced operations;
e ENI announced it is to construct a floating LNG platform for the purposes of starting natural gas prospection in Rovuma Basin Area 4;
f the tender process in the fifth round of bids for the exploration of hydrocarbons in the Rovuma Basin was finalised, and the exploration areas (both onshore and offshore) have been assigned to several consortiums of international oil players.

VII CONCLUSIONS AND OUTLOOK

The Mozambican energy sector faces a multitude of challenges, outlined throughout this chapter:

a the country's infrastructure is not sufficient to meet demand, which is reflected in the fact that large areas of the country are without electricity or natural gas, and electrical power distribution networks are outdated;
because of the inefficient power purchase arrangement with South African utility company Eskom, Mozambique still has to ‘import’ electrical energy from its own hydroelectric power plant in Cahora Bassa; and

Mozambique’s oil and gas findings require a stable governance structure, and experienced participants in the oil and gas industry, for commercial development of the findings to begin. The enactment of the new Petroleum Act and the approval of corresponding regulations, which are to be made in the foreseeable future, 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 and off-grid projects, 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 24

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

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1 Roland de Vlam is a senior associate and Max Oosterhuis is a partner at Loyens & Loeff NV.
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 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 GDF Suez (rebranded ‘Engie’ in April 2015). Other large-scale generators are Intergen, EPZ, EDF/Delta and Eneco. 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. An overhaul of this Heat Act is expected in early 2017 because the current Act has resulted in more inefficiencies and uncertainties than were originally expected to be resolved.

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 these occur at a depth of more than 100 metres beneath the earth’s surface.
Dutch midstream and downstream energy legislation implements the EU Directives regarding the internal energy markets (the 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 last year’s chapter we 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. This STROOM bill, however, was rejected by the Senate in December 2015 by a one-vote majority because of a controversial group prohibition provision (see Section V.i, *infra*). A new legislative proposal to amend the Electricity Act 1998 and the Gas Act has been published for public consultation, which is open until 12 May 2016. The proposal copies certain elements of the STROOM bill with the objective of facilitating the national energy transition. The bill is expected to be presented to parliament in early 2017.

The Heat Act entered into force on 1 January 2014. The objective of the Heat Act is to offer protection to small-scale consumers connected to a heat distribution system. It regulates the price of heat supply, and includes a price cap equivalent to the reference price of consumers with individual central heating (gas-fired). This statutory regulation replaced the existing self-regulation methodology. The Act has been heavily criticised by end users, suppliers and even the ACM. A complete revision of the Heat Act is expected to commence in 2016. On 2 April 2015, the Minister of Economic Affairs (MEA) published his ‘Heat Vision’, announcing a total review of the current Heat Act, and which includes researching 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, including a report by Ecorys, which may in large part provide the outlines for the new policy to be laid down in a completely new Heat Act. The MEA planned to publish the draft bill for the new Heat Act for public consultation before the summer of 2016, as he is striving to submit the bill to the parliament’s Second Chamber before the end of 2016.

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.

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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.
The ACM is the designated regulator under the Electricity Act 1998, the Gas Act and the Heat Act. The ACM is assigned with supervision of compliance with the Electricity Act 1998, the Gas Act, the Heat Act and EU Regulations 714/2009, 713/2009 and 1227/2011. With respect to supervision of transmission and distribution, the ACM is assigned 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.

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 will apply 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.

The market for supply of gas and electricity has been fully liberalised since 2004. All customers are entitled to choose their supplier. No specific licensing is required for supply of gas or electricity. Only the supply to small-scale end users is subject to (non-exclusive) licence requirements regulated by the ACM. 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 balancing responsibility. Balancing responsibility of small-scale end users is attributed by law to supply companies, 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 (formerly GDF Suez) and Uniper, (formerly E.ON), 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 to be laid down in a ministerial regulation, but the regulation does not exist and has not yet been announced by the Ministry.
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.3 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.4

The Supreme Court ruled that the unbundling provisions are justified by public interest and that these measures are appropriate and proportionate, leaving Essent empty-handed. The Eneco and Delta cases have been referred back to the Amsterdam Court of Appeal to investigate one remaining issue – the appeal of Eneco and Delta with regard to their claim that two provisions in the energy acts (i.e., on the ‘group prohibition’) are in violation of Article 1 of the First Protocol of the European Convention on Human Rights, which concerns the protection of property. As such, this remaining issue may still affect the binding force of the unbundling provisions. The judgment of the Supreme Court is final and without referral for Essent, since Essent did not appeal on this particular matter.

On 3 December 2015, the ACM rendered administrative enforcement orders imposing penalty payments on Delta and Eneco on the grounds that both energy companies acted in breach of the energy acts, and ordering both companies to execute the unbundling plan. Delta has been ordered to meet the unbundling requirements by 30 June 2017 at the latest (otherwise it will have to pay €1.5 million per full week up to a maximum of €30 million). Eneco has been ordered to meet the unbundling requirements by 31 January 2017 at the latest (otherwise it will have to pay €4.5 million per full week up to a maximum of €90 million).5 At the beginning of May 2016, Delta officially announced the reorganisation and divestment of its production and supply divisions.

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

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4 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).
5 ACM Case No. 15.0880.52 and 15.0924.52 (Delta), 3 December 2015 and ACM Case No. 15.0881.52 and 15.0925.52 (Eneco), 3 December 2015.
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 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.

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 Rates
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.6 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.

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6 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. On 1 March 2013, the largest national exchange for futures and physical trading (spot) for gas and power, APX-ENDEX, separated into two companies: the power spot exchange APX and the gas spot, gas derivatives and power derivatives exchange, ENDEX. As of 27 March 2013, Intercontinental Exchange (ICE) is the majority shareholder of ENDEX. The name of the new company is ICE Endex. 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.

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 February 2013, France-based Powernext launched an exchange in the Netherlands for gas futures, TTF products and PEG Nord/TTF spreads.

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). 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.

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:

a 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;

b 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;

c 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;

d 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;

e 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 above) 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 doubled in 2014 with 100,000 new PV installations installed, resulting in a total registered capacity of 665MW. An important incentive for local production is the possibility to net electricity from the grid with the self-produced electricity up to 5,000kWh on an annual basis. Effectively, the consumption of self-produced electricity is fully exempt from taxes and levies, resulting in a net advantage for the local energy producer of approximately €0.23/kWh (including 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 roll-out of smart meters is expected to be completed then, so that real time data will be available for production and consumption. A change in law effective as of 1 January 2015 already broadened the scope of the energy tax rules, making it virtually impossible to benefit from the netting facility or exemptions in situations where the owner of the building is not the same as the owner of the PV installation. This clearly illustrates the tension in the Netherlands between the financial (tax) interests and the successful incentives for increasing renewable energy production to meet the ambitious targets for 2020.

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 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 programme to put out to tender licences and subsidies for 700MW every year from 2016 (the Borssele area) to 2019, up to a total of 3500MW of new offshore wind energy production capacity in addition to the 860MW currently in place (OWEZ, Amalia, Luchterduinen) and under construction (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 220 kilovolt 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 on 1 April 2016.

The OWEA introduces a new procedure for offshore wind licensing within the three currently designated wind areas: Borssele, Hollandse Kust Noord-Holland and Hollandse Kust Zuid-Holland. 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 new 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 tender, for 700MW in the Borssele area, opened on 10 April 2016 and closed on 12 May 2016. At the time of writing this chapter, the first tender had closed with a total of 38 bids, as announced by the MEA. The winning bid will be announced on 11 August 2016 at the latest. The second tender, again for 700MW, will open as early as September/October 2016. A third tender will open in 2017, a fourth 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 roll-out 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 yet 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.

VI  THE YEAR IN REVIEW

Earthquakes in Groningen and natural gas production

Natural gas production in Groningen continues to cause feelings to run high. A series of earthquakes in the Netherlands’ most northern province of Groningen, which have caused damage to houses and buildings, prompted a recent decision by the MEA to impose a production ceiling on gas production from Europe’s largest onshore gas field, the Groningen field (see more details on Groningen gas in Section I, supra).

NAM’s initial amended production plan took into account the results of further research that the state supervisor of mines and NAM conducted on the relationship between gas production and the recent earthquakes. The research followed the government’s earlier decision to scale down the maximum gas production levels to 42.5bcm in 2014, 42.5bcm in 2015 and 40bcm in 2016. Production near the vulnerable village of Loppersum was scaled down by 81 per cent. Since then, seismic activity around Loppersum has decreased, while an
increase was noted in regions where the production rate had been scaled up. Although it is too early to draw final conclusions, these results appear to indicate the possibility of resolving the problem.

Subsequently, new production ceilings were set at 42.5bcm in 2014, 39.4bcm in 2015 and 39.4bcm in 2016. The MEA estimated that this will lead to a further loss of €700 million in gas profits in 2015 and €130 million in 2016. The measures announced by the MEA also include plans to reinforce buildings, houses and infrastructure. Furthermore, a compensatory payments package of €1.18 billion will be made available to the region. NAM will finance €1.125 billion; the province will finance the rest. As the Dutch state participates in the exploitation of the Groningen field through a limited partnership with NAM, through a complicated profits and costs allocation system, the state will ultimately bear 64 per cent of these costs (€114 million per year), while receiving 90 per cent of the profits. The state’s reduced profits over the coming three years are estimated at €2.3 billion.

On 15 April 2015, the Administrative Court of the State Council rendered its preliminary ruling on the appeals of interested parties against the minister’s consent for NAM’s adjusted production plan, imposing a further production reduction of 3bcm (Loppersum cluster), with the exception that production from the Loppersum area shall only be permitted if other reservoirs have reached their production ceilings and are insufficient to guarantee security of supply. On 18 November 2015, the same Administrative Court of the State Council ordered the MEA to review its decision of January 2015 approving extraction and its amendment decision of June 2015. NAM is temporarily limited to extracting a maximum of 27bcm of gas from the Groningen field. NAM can only raise its extraction volume to 33bcm if 2015–2016 proves to be relatively cold.

On 1 April 2016, NAM submitted an up-to-date 2016 production plan (for the year 2016–2017) to the MEA, in which NAM upholds the current annual production level of 27bcm (if no unforeseen circumstances occur). The 2016 production plan will be 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)). After the consultation round, the government aims to publish the final consent decision on the NAM production plan before 1 October 2016.

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. These bills are currently being debated in the Second Chamber of the parliament.

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7 Administrative Court of the State Council, case 201501544/2/A4, 14 April 2015.
8 Administrative Court of the State Council, case 201501544/1/A4, 18 November 2015.
9 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).
Coal fired combustion plants and CO2 emission reduction

On 1 January 2016, the Decree amending the Activities (Environmental Management) Decree\(^{10}\) 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, which have 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.\(^{11}\)

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 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.

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’.\(^{12}\)

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.

VII CONCLUSIONS AND OUTLOOK

The past year, with the taking of preparatory legislative measures, marked the beginning of actual developments in energy transition, particularly the implementation of the offshore wind regulatory framework. The outcome of the first and second tenders for the Borssele wind area in 2016 will largely determine the level of success of the government’s energy policy of the past and future four years.

Another interesting topic could well be the outcome of the revision of the Heat Act. In his Heat Vision take on the heat market, the MEA stressed the importance of relying less on heating from natural gas and relying more on heat from other (sustainable) resources. To be able to move from a gas system-oriented heat supply to a heated water system, research

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\(^{10}\) Bulletin of Acts and Decrees 2015, 387.

\(^{11}\) Parliamentary Papers Second Chamber, 2015/16, 32 813, No. 122.

is being conducted into heat roundabouts (heat from (heavy) industry areas transported to residential areas); third-party access to the heat grid; types of business cases in the heat market; and other methods of calculating heat tariffs (instead of using the principle of the link to natural gas). An adjunct (political) argument is that a move away from gas may help to mitigate earthquake-related damage in the Groningen gas production areas, and may also help to curtail the Groningen reservoir depletion.

Finally, the question remains as to which parts of the rejected STROOM bill will be reintroduced, either as a new bill or as amendments to current energy legislation. As mentioned above, one part has already been published for consultation.
NIGERIA

Chapter 25

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

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1 Gbolahan Elias is presiding partner, and Okechukwu J Okoro and Chinedu Kema are associates at G Elias & Co.
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.

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
The NNPC is not a regulator. It is a vertically-integrated state-owned statutory corporation. The NNPC has various subsidiaries, one of which is the Nigerian Gas Company (NGC). The NGC owns and operates the main gas transmission systems in Nigeria. The Nigerian Petroleum Development Company Limited has the responsibility for petroleum exploration and production activities. The National Petroleum Investment Management Services, a division of the NNPC, oversees the NNPC’s interests in joint venture arrangements, production sharing contracts and service contracts with IOCs. The Pipelines and Products Marketing Company Limited and NNPC Retail Ltd import and market refined petroleum products respectively.

There are a number of regulations made pursuant to the PA that regulate specific aspects of the industry. The Mineral Oils (Safety) Regulations 1962 prescribe standard safety measures for lessees and licensees. The Petroleum Regulations 1967 regulate importation, shipping, unshipping and landing of petroleum; storage of petroleum; transport of petroleum; fuelling of aircraft and so forth. The Petroleum (Drilling and Production) Regulations 1969 regulate applications for leases and licences, exploration and drilling, field development, and payment of fees, rents and royalties. The Petroleum Refining Regulations 1974 regulate construction, operation and maintenance of refineries.

The construction, operation and maintenance of oil pipelines are regulated by the Oil Pipelines Act 1956 and the Oil and Gas Pipeline Regulations 1995. The transportation of crude oil in Nigerian waters and payment of terminal dues on any ship evacuating oil from terminals in Nigeria are regulated by the Oil in Navigable Waters Act 1968 and Oil Terminal Dues Act 1969 respectively. The Associated Gas Re-injection Act 1979 regulates the re-injection of associated gas into oil wells. The Petroleum Profit Tax Act 1958 taxes profits from upstream mining operations in Nigeria.

Electricity

EPSRA is the principal statute for the electricity industry in Nigeria. Under EPSRA, NERC, as the regulator of the Nigerian electricity industry, issues regulations and orders giving effect to EPSRA. NERC is also vested with the power to grant licences for the generation, transmission, system operation, distribution, and trading of electricity. NERC is also required to promote competition and private sector participation, and ensure quality standards in the electricity industry. EPSRA further established the Rural Electrification Agency to promote, support and provide access to electric power by rural and semi-urban areas of Nigeria.

The Federal Ministry of Power (FMoP), guided by EPSRA and the FGN’s National Electric Power Policy 2001, formulates electricity policy in Nigeria. The FMoP is empowered under EPSRA to issue general policy directions to NERC on the electricity industry, and NERC is bound to comply except where such policy is in conflict with EPSRA or the Constitution. The Energy Commission of Nigeria (ECN) also plays a strategic role in the electricity industry. The ECN was established by the Energy Commission of Nigeria Act 1979 (as amended) with the mandate to plan and coordinate national policies in the field of energy, and has been promoting the use of renewable energy sources in generating electricity.
The TCN has two key operating officers: the systems operator and the market operator. The market operator administers the wholesale electricity market, promotes efficiency and competition. The systems operator is responsible for planning, administration and grid discipline. In addition, the National Inland Waterways Authority established under the National Inland Waterways Authority Act 1996, regulates inland waterways navigation and issues permits for generation projects requiring water usage.

ii Regulated activities

Petroleum

The petroleum industry consists of the upstream, midstream and downstream sectors. The rights to explore, prospect, produce, process and distribute petroleum and petroleum products are granted through the issuance of leases, licences and permits by the Minister and the DPR (in some cases) to operators in these sectors.

For the upstream sector, the relevant leases and licences are the Oil Exploration Licence (OEL), Oil Prospecting Licence (OPL) and Oil Mining Lease (OML). An OEL confers a non-exclusive right to explore for petroleum for a term of one year. An OEL can be further renewed for one year.

An OPL has a duration of not more than five years including renewals, and confers a right to prospect for petroleum. However, the duration of an OPL granted in respect of the deep offshore and inland basin is a minimum of five years and an aggregate period of 10 years. An OML has a duration of 20 years and is subject to renewal. The OML confers an exclusive right to explore, carry away and dispose of petroleum. A drilling rig licence is also required to operate a drilling rig while a permit is required to conduct seismic data survey.

For the midstream and downstream sectors, a licence is required to construct or operate a refinery or processing plant, export, import, store, sell or distribute petroleum and petroleum products. The approval of the DPR is required to construct and operate a petroleum products filling station, and a blending plant, and to retail lubricants. A permit is required to survey the route for a pipeline. A licence is required to construct and operate a pipeline, any pumping station, storage tanks, loading terminals or other ancillary installations. Further, to construct pipelines, a right of way must be obtained from the state government on which the land is located. This may be conveyed through a certificate of occupancy or permit from the relevant state government or by special agreement with the owner of the land (subject to payment of compensation).

DPR permits are also required to render services in the petroleum industry. The permits are in three categories: general, major; and specialised. The general category covers minor supply, works and maintenance services. The major category covers rehabilitation, upgrade and fabrication works, onshore pipeline and storage facility maintenance, equipment supply, consultancy, survey and calibration. The specialised category covers pipeline laying, drilling, exploration, technical consultancy, dredging and environmental restoration services.

The procedures for obtaining these leases, licences and permits vary but are all overseen by the DPR. In addition, the EIA Act requires the issuance of a certificate stating that an environmental assessment of a petroleum project has been conducted before one can embark on such a project, and that the outcome has been officially approved. The environmental laws of some states make it mandatory to obtain a permit from the state environmental agency to construct or operate any project or activity that affects the environment.
Electricity
As with the petroleum industry, activities in the Nigerian electricity industry are also strictly regulated. Through EPSRA, a NERC licence is required to construct, own or operate an electricity generation, transmission, distribution, system operation or trading undertaking. Applications for licences are made in writing to the chairman of NERC, accompanied by the prescribed fees and in the manner prescribed by NERC.

Licences issued by NERC include generation licences, which authorise the licensees to construct, own, operate and maintain generation stations. A licence is not required, however, to construct or operate a generating plant not exceeding 1MW in capacity.

A transmission licence allows the licensee to carry out grid construction, operation and the maintenance of transmission system in Nigeria, or connect Nigeria with a neighbouring country. The holder of a transmission licence may also be required to carry out system operation and the procurement of ancillary services. A system operation licence authorises the licensee to carry out system operation such as generation and transmission scheduling, transmission management and coordination, procurement and scheduling of ancillary services and administration of wholesale electricity market.

A distribution licence holder has the right to construct, operate and maintain a distribution system and facilities such as supply of electricity, installation, maintenance and reading of meters, billing and collection. A licence is not required for a distribution station not exceeding 100kW in aggregate. A trading licence authorises the licensee to purchase, sell and trade in electricity. NERC may also issue a temporary bulk purchase and resale licence authorising the purchase of electrical power and ancillary services from independent power producers and Gencos for resale.

In addition to the licences required under EPSRA, the Factories Act 1987 requires factory owners (which includes electricity generating and distribution companies) to apply to the Director of Factories for registration within a month of commencement of business. A licence from the Minister of Water Resources is also required to undertake any hydroelectricity project as the Ministry of Water Resources regulates the diversion, storage, pumping or use on a commercial scale of any water.

iii Ownership and market access restrictions
Petroleum
Except for the general requirement to incorporate a Nigerian company before carrying on business in Nigeria, there are no restrictions on a foreign company acquiring an interest in the petroleum industry in Nigeria. The NCA, however, provides for certain privileges for companies in the industry with over 51 per cent Nigerian equity participation. Under the NCA, such companies will be given first consideration in the award of oil leases and licences. Also, in awarding contracts for the provision of services, Nigerian indigenous companies will be exclusively considered. The DPR also has a practice of not granting majority stakes in OPLs or OMLs to foreigners.

The Minister has the right to require refinery licence holders to deliver petroleum products to the FGN, or OPL or OML holders to deliver crude oil to a person with a refinery licence. Also, where there is a state of emergency or war, the Minister has the right of pre-emption of all petroleum obtained under a lease or licence subject to payment of an agreed price; or, if there is no such agreement, a fair price for the time being at the point of delivery as may be agreed; or in default of such an agreement, by arbitration. By the National Domestic Gas Supply and Pricing Policy (the Domestic Gas Policy) and National
Gas Supply and Pricing Regulations 2008 (the Gas Pricing Regulations), OPL and OML holders are required to supply up to a specific volume of gas for domestic consumption. An OML holder is further required to relinquish one-half of the leased area 10 years after the grant of the OML.

The Minister may revoke an OPL or OML if the holder is not conducting operations in accordance with the basic approved work programme and good oilfield practice, or fails to pay rent, royalties, furnish reports on its operations or comply with the PA, regulations and the terms of the licence or lease. The Minister may also revoke these rights if the holder becomes controlled directly or indirectly by a citizen of or a company incorporated in a country the laws of which do not permit citizens of Nigeria or companies incorporated in Nigeria or controlled by Nigerians to acquire, hold and operate petroleum concessions on conditions that, in the opinion of the Minister, are reasonably comparable with the conditions upon which such rights are granted to subjects of that country.

**Electricity**

EPSRA prohibits anyone holding a NERC licence from assigning or ceding his or her licence or transferring his or her undertaking without the prior consent of NERC. Similarly, no person holding a licence from NERC may, without NERC’s consent, acquire or affiliate with, the licence or undertaking of any other licensee or person who is in the business of generating, transmitting, distributing or trading electricity.

In addition, every licensee is required by NERC Regulations on National Content Development for the Nigerian Electricity Supply Industry 2013 to develop a framework for the development and promotion of ‘Nigerian content’ in the electricity industry. The licensees are also mandated to maintain a technology transfer plan (detailing various technologies deployed by the operator and the modalities for transfer to Nigerians where applicable).

iv Transfers of control and assignments

**Petroleum**

The prior consent of the Minister is required before any transfer of an interest, power or right in a licence or lease whether by way of acquisition, merger, takeover, exchange or transfer of shares, listing, testamentary devises, judgment or arbitral award. For the farm-out of marginal fields, the consent of the President is required. The DPR is, however, to be notified prior to the commencement of any such transaction. The responsibility for obtaining consent is that of the assignor. Also, a production sharing contract or joint venture agreement, depending on the contractual arrangement of the parties, may require that the non-assigning parties waive or assert their pre-emption rights.

Consent will only be granted where the Minister is satisfied that the proposed assignee is of good reputation, has sufficient technical knowledge, experience and financial resources to effectively carry out the operations under the licence or lease and is in all other respects acceptable to the FGN. For the farm-out of marginal fields, the President will only give his consent if he is satisfied that it is in the public interest to do so. In the case of a non-producing marginal field, the marginal field must have been left unattended for an unreasonable time, not less than 10 years, and the parties to the farm-out must be acceptable to the FGN.

**Electricity**

NERC has the statutory responsibility to consider whether or not to approve a merger, acquisition or affiliation. To do so, NERC may require information from licensees, undertake
inquiries and establish or contract with an independent entity to provide monitoring services. The prior consent of NERC is required for a licensee to assign or cede his licence or transfer his undertaking, or any part of it, by way of sale, mortgage, lease, exchange or otherwise to another. The prior written consent of NERC is required for a licensee to acquire, by purchase or otherwise, or affiliate with, the licence or undertaking of any other licensee under the EPSRA. However, a distribution licensee may also be issued with a trading licence to provide electricity to customers.

The approval of the Securities and Exchange Commission is required for mergers, acquisitions, takeovers and business combinations. Mergers and schemes of arrangement are also required to be sanctioned by the Federal High Court. In addition, mergers, acquisitions and other forms of business arrangements concluded through schemes of arrangement are to be registered with the Corporate Affairs Commission (Nigeria’s companies’ 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. However, the FGN proposes to remove completely with all deliberate speed 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. The MYTO does not apply to embedded power. Embedded power is priced on a discrete basis to cover cost of production and distribution with a margin added. Purchases of embedded power are 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 are now producing electricity.

The long-awaited transitional stage 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

Petroleum

In 2014–2015 some IOCs divested their interests in onshore and shallow-water oil acreages to indigenous operators with a view to improving local competency in the upstream petroleum sector. Given the volatility in crude oil prices, the revenues and cash flows of these acquiring indigenous operators were and still are 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, the FGN has indicated that it will remove subsidy payments on petroleum products. Subsidy payments were not included in the 2016 budget. Nonetheless, it is unclear whether, and if so, for how
long, the FGN will continue with subsidy payments. 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.

Electricity

In the past year, NERC introduced a new tariff (MYTO-2015), 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.

The Nigerian Electricity Management Services Agency (NEMSA) Act, 2015 has also been enacted. The new Act established the NEMSA, which is responsible for the enforcement of technical standards, regulations, technical inspection, testing and certification of all categories of electrical installations, electricity meters and instruments to ensure efficient production, delivery and measurement of safe, reliable and sustainable electricity power supply in Nigeria and also to guarantee safety of lives and property in the Nigerian electricity industry.

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 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 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.
Chapter 26

NORWAY

Per Conradi Andersen and Christian Poulsson

I OVERVIEW

The Norwegian onshore energy sector is almost 100 per cent based on electricity generated by hydropower. Other energy sources play a rather modest role in the onshore energy sector. Hence, the description in this chapter will focus on electricity generated by hydropower.

The Norwegian electricity sector is highly influenced by public ownership combined with hard restrictions on private ownership. This does not necessarily differ from other countries around the world, but stands in contrast to the fact that Norway has since 1990 had a well functioning market for electricity and connected commodity derivatives ahead of most other countries.

The main sources of law include the Industrial Concession Act, Watercourse Regulation Act, Energy Act, Water Resources Act and Ocean Energy Act.

II REGULATION

i The regulators

The Ministry of Petroleum and Energy (OED) holds the overall administrative responsibility for energy and water resource management in Norway.

The Ministry's responsibility is to ensure that the resource management is carried out in accordance with guidelines given by the Parliament.

The Norwegian Water Resources and Energy Directorate (NVE) is a subordinate agency of the Ministry. The NVE holds the managing responsibility according to the Energy Act and the Water Resources Act. Furthermore, the NVE is assisting the Ministry of Petroleum and Energy managing the Industrial Concession Act and the Watercourse Regulation Act. The NVE has legislative powers to issue regulations and individual decisions and perform preparatory procedures of cases to be resolved by the Ministry of Petroleum and Energy.
Statnett SF is the National Grid Company and Transmission System Operator (TSO) responsible for operation and development of the central grid for electricity transmission.

ii Regulated activities
A concession is mandatory for anyone who wants to develop hydropower plants, wind power plants, gas-fired power plants, power lines, district heating systems, domestic transmission pipelines for natural gas, etc.

The Industrial Concession Act specifies that anyone who acquires ownership or shares in companies with such rights must obtain a licence. The Act also regulates prolongation of existing long-time user rights to a waterfall, and the right to short-term (up to 15 years) user rights. Development of a waterfall and construction of a power plant usually require an additional licence pursuant to the Water Resources Act.

The Energy Act requires licensing for the construction, ownership and operation of all installations for generation, conversion, transmission and distribution of electricity, all the way from power plant to consumer, as well as district heating plants over 10MW. A licence pursuant to the Energy Act is also required for trade in electricity and for the organisation of markerplaces for such trading.

Systems for transporting natural gas intended for delivery to natural gas undertakings in another region, cannot be constructed or operated without a licence pursuant to the Natural Gas Act. Minor LNG installations and small-scale facilities for transmission or distribution of natural gas do not need to be licensed.

A developer, or licensee, must have a licence pursuant to the Watercourse Regulation Act to carry out regulatory measures or divert water in a watercourse.

The Watercourse Regulation Act gives the licensee the authority to expropriate the necessary property and rights to carry out the regulatory measures. For other energy projects, corresponding expropriation rights are laid down in the Expropriation Act of 1959. Expropriation questions are often handled as part of the licensing process for energy projects.

The Ocean Energy Act regulates renewable energy production, conversion and transmission of electricity at sea. A licence is needed in order to construct, own or operate production facilities and cabling systems located outside the baseline, but within the Norwegian continental shelf. The same applies to reconstruction or extension of any such existing facilities.

iii Ownership and market access restrictions
For more than 100 years, Norway has had huge restrictions on acquisition of waterfalls and hydropower generators. During the 20th century these restrictions were developed to include restrictions on the lease of such facilities and partial ownership in a way that established preferential treatment of public (state, county or municipal) ownership.

The main principle on acquisition of ownership to hydropower plants is found in the Industrial Concession Act (of 14 December 1917). Without a concession, only the Norwegian state may acquire ownership or the right to use waterfalls of a certain size. The threshold for application for a concession has recently been lifted from 1,000 (736kW) to 4,000 natural horsepower. Waterfalls under this limit may be acquired or rented without concession.

Norwegian state enterprises, municipalities and counties will normally be entitled to a concession for the acquisition of a waterfall. The same applies to legal entities (joint-stock
companies, enterprises and organisations) in which at least two-thirds of the capital and the votes are owned by a Norwegian state enterprise, a Norwegian municipality or county (or a combination of such owners); in other words, a publicly owned company.

Private entities (domestic and foreign) as well as publicly owned foreign companies may, on application, be granted a concession to acquire ownership up to one third of the shares in the legal entity registered as a waterfall owner. In these instances, it is, however, an additional condition that the legal entity in question be organised so that a genuine public ownership is manifest. This condition may entail limitations as to, inter alia, the influence granted to minority private or foreign owners through, for example, shareholders’ agreements. It also excludes partnerships with private or foreign minority owners as eligible owners of such waterfalls.

Before 2008–2009, concessions for the acquisition or rent of waterfalls or other acquisitions of production rights were given to private owners or foreign public owners for a maximum period of 60 years. However, Norwegian public owners and publicly owned companies may be (and have always been) given concessions in perpetuity.

When a concession was granted for a maximum period of 60 years, several conditions applied. Most important were the conditions concerning reversion of the shares or the waterfall rights (including power plants, among other things). Reversion means that the shares or waterfall rights are assigned to the Norwegian state without compensation at the end of the concession period (60 years). There are still concessions with such conditions, and so in the future several power plants will revert to the state.

To avoid reversion a private owner may transfer the ownership (through a regular sale) to publicly owned companies before the date for reversion. This will most likely lead to transactions on hydropower plants in the future.

The scheme of reversion was challenged by the EFTA Surveillance Authority under the EEA agreement in 2006. After a ruling in the EFTA Court, the Norwegian government had to change the legislation. The reversion system was abolished for new acquisitions, and the previous possibility for private entities and publicly owned foreign entities to acquire waterfalls was removed. As set out above, these entities are now left with the opportunity to acquire only one third of publicly owned companies holding such assets.

As an equivalent to transfer of ownership, it is still possible to lease waterfall rights with adjacent generators, but only for a maximum period of 15 years. The lessee has to apply for a concession when parties enter into such agreements.

According to the Energy Act a licence is necessary to own and to operate electricity grids (transmission and distribution) and certain installations such as transformers.

iv Transfers of control and assignments

Transfer of more than 20 per cent ownership to companies holding licences according to the Industrial Concession Act will need an acceptance from the government (OED). If as much as 90 per cent is acquired, this will be considered as an acquisition of the underlying assets and calls for a complete concession process. Generally, the Act is construed to catch up with agreements where a party receives a position equivalent to direct ownership through voting rights, shareholders agreements, etc.

Contrary to the Industrial Concession Act, the Energy Act has no regulations on partial transfer of ownership to companies holding such assets or licences. However, acquisition of more than 90 per cent will be considered as a change of ownership to the underlying assets, even if the business continues unchanged.
III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling
The Norwegian Energy Act is based on the principle that natural monopolies, such as operation of the grid, shall be fenced against any influence from, and cross subsidies to, the competitive market embracing generation and trade of electricity. Since the Act was implemented in the early 1990s, the authorities have given incentives to fulfil the aim of unbundling vertically integrated companies into separate entities, preferably as limited liability companies covered by the Limited Liability Company Act.

ii Transmission/transportation and distribution access
Grid companies with an area licence have a supply requirement, according to Section 3-3 of the Energy Act. The supply requirement entails a connection requirement towards non-professionals (private) customers.

For producers, the grid company’s only requirement will be to provide market access with non-discriminatory and objective tariffs and conditions.

Grid companies can require an investment contribution to cover construction costs of connecting new production or extending production capacity.

In cases where the connection causes reinforcement of installations with several network users, a pro rata share of these costs may be included in the investment contribution.

iii Rates
The Norwegian Water Resources and Energy Directorate (NVE) is responsible for monitoring grid management and operations, including determination of income caps for each grid company. The income cap reflects factors that influence area-specific costs, such as climate, topography and settlement patterns. The company’s income, which mainly derives from transmission tariffs, must not exceed the maximum permitted level determined by the directorate. This system is intended to ensure that grid companies do not make unreasonable monopoly profits and that cost reductions also benefit the grid customers.

Income caps are updated annually. To promote quality of service, a mechanism that imposes direct consumer compensation for long interruptions was introduced in addition to the already existing mechanisms that provide for a reduction in the total revenue for the grid companies when interruptions occur.

All grid companies are required to use point tariffs when charging for transmission and distribution. Point tariffs mean that grid customers pay the same transmission tariff regardless of whom they buy electricity from or sell to. An individual customer only pays a transmission tariff to its local grid company. Consumers pay one tariff to tap electricity from one point in the grid (consumption tariff), whereas generating companies pay another tariff to feed power into a connection point (input tariff).

The grid companies’ transmission tariffs are controlled by Regulation No. 302 of 11 March 1999 concerning financial and technical reporting, permitted income for network operations and transmission tariffs. The regulations require that tariffs to household customers must consist of a fixed component and an energy component.

The fixed component is an established annual amount, and at minimum shall cover customer-specific costs. These are costs related to metering, settlement, invoicing, etc.
The fixed component is independent of the current input of power and shall give grid companies sufficient income according to regulated permitted income fixed annually for each company by NVE. The central grid input tariff should be normative for the fixed component by power input into regional and distribution networks.

The energy component depends on the customer’s current input of power. When power is transmitted some of the power is lost. The energy component should reflect costs (NOK/kWh) related to power loss when one extra kWh is transmitted (marginal loss). The energy component should refer to the connection point.

In addition, the transmission tariff (i.e., fixed component plus energy component) should cover the fixed costs in the network.

### iv Security and technology restrictions

As a result of increased fear of terror around the world and climate changes the authorities have increased focus on security of supply in the energy sector.

During the winter of 2012, several parts of Norway were struck by storms, which took down the electricity grid in many places. More than 421,000 people were without electricity for some time during Christmas as a result of the ‘Dagmar’ storm. For more than 10,000 people this lasted for several days. This has led to increased focus on transmission tariffs and the grid companies’ duty to maintain the quality of the grid.

### IV ENERGY MARKETS

#### i Development of energy markets

The Nordic countries’ power systems have been interconnected for many years, and the countries’ systems are mutually dependant. The power price is determined in the market based on generation, transmission and consumption conditions in the Nordic region, and thus the price will vary both short and long term. With the price-coupling of north-western Europe and south-western Europe in 2014, the Nordic region is now part of a market coupling system that covers 17 European countries: Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden and the United Kingdom (Poland is also connected through the SwePol interconnector). An essential feature of this system is the allocation of cross-border interconnector capacity through the use of implicit auctions. Over the past years, consumption in Norway has been slightly higher than power production in years with normal precipitation and temperature conditions, which means that Norway has been dependent on imports from abroad. In years with low inflow, the need for power imports has been even higher. Temperature and weather conditions influence short-term demand in the Nordic region and Europe, which also affects the power prices. In particular, periods with cold temperatures and high demand can result in higher power prices. Currently the prices are low, based on a production above the consumption.

**Wholesale market**

The power market is often divided into wholesale and end-user markets (retail market). The wholesale market embraces generators, suppliers, big industrial enterprises, traders and other undertakings. Electricity is traded physically on a day-ahead basis in the spot market organised by the Nordic power exchange, Nord Pool Spot, which accounted for a traded volume of approximately 489TWh in 2015. In addition, wholesale participants trade
power derivatives representing multiple volumes in the financial forward and futures market organised by Nasdaq OMX Commodities. Electricity is also traded bilaterally between wholesale participants, both on a physical and financial basis.

**End-user market**
Anyone who buys electricity for his or her own consumption is an end user. Small end users normally buy power from an electricity supply company. Larger end users, such as industrial enterprises, often buy directly in the wholesale market.

All end users are free to choose electricity supplier and contract type. The most common contracts for households have prices that vary according to market conditions.

**International power trading**
Norway was traditionally a net exporter of power. However, in the late 1990s consumption of electricity rose faster than the power supply, as hydropower development has been limited in recent times. Thus, Norway is on average a net importer.

Norway has interconnectors towards Sweden, Denmark, Finland, the Netherlands and Russia. Concessions for a connection to Germany were granted by the Norwegian government in October 2014, and on 10 February 2015 Statnett SF decided to invest in the new 700km, 1,400MW cable to Germany. A similar connection is in the process of being built to England.

The transmission capacities towards Finland and Russia are low, and the connection with Russia is used only for imports to Norway. The highest transmission capacity from Norway goes towards Sweden, at about 3,600MW, while the capacity in the other direction is somewhat lower. Capacity between Norway and Denmark is about 1,000MW.

**Energy market rules and regulation**
Nord Pool Spot organises the leading power market in Europe and offers both day-ahead and intraday markets to its customers. 380 companies from 20 countries trade on the market. In 2014, the group had a total turnover of 501TWh, which includes the auction volume in the UK market N2EX. In 2015, total volumes traded over Nord Pool Spot amounted to 489TWh, including the UK auction volume on N2EX.

Nord Pool Spot AS is owned by the Nordic transmission system operators Statnett SF, Svenska Kraftnät, Fingrid Oy, Energinet.dk and the Baltic transmission system operators Elering, Litgrid and Augstsprieguma tīkls. Nord Pool Spot AS is licensed by the NVE to organise and operate a market place for trading power with physical delivery, and by the Norwegian Ministry of Petroleum and Energy to facilitate the power market with foreign countries.

Nord Pool Spot and NASDAQ OMX Commodities operate the N2EX in the UK market.

While a licence is required under the Energy Act to trade or organise marketplaces for physically deliverable electricity (see Section II.ii, supra), certain aspects of financial trading in electricity falls to be regulated under the Securities Trading Act. Regulated activities comprise, *inter alia*, receipt, mediation and execution of orders, portfolio management and investment advice in electricity derivatives, all of which require an investment services licence. The licensing regime implements Directive 2004/39/EC (MiFID). In addition, the Securities Trading Act regulates market behaviour, such as insider dealing, market manipulation, etc., by implementing the requirements of Directive 2003/6/EC (MAD).
iii Contracts for sale of energy

Physical or financial electricity trading that takes place on Nord Pool Spot, Nasdaq OMX Commodities or other regulated marketplaces follow standardised contracts and rule books applied by the relevant exchange or regulated marketplace in respect of the product in question.

Bilateral OTC contracts for sale of electricity in the wholesale market are, to a large extent, standardised as well. Different organisations have contributed with standardised contracts, including the Nordic Association of Electricity Traders, the European Federation of Energy Traders and the International Swaps and Derivatives Association. These types of trades usually take place within a master agreement framework that provides for swift exchange of documentation in respect of individual trades, as well as risk mitigating mechanisms such as early termination and netting in the event of bankruptcy. Such mechanisms are generally recognised by Norwegian law in so far as commodity derivatives are concerned. The demarcation of commodity derivatives under Norwegian law basically follows the demarcation applied under Directive 2004/39/EC (MiFID). This means that as a main rule financially settled electricity contracts may generally be netted in a bankruptcy situation, while the same only holds for certain physical contracts.

Contracts for sale of electricity to households and similar end users are generally standardised by the retail electricity suppliers, while larger contracts concerning electricity deliveries to industrial end users vary significantly depending on the commercial strength of and negotiation process between the parties.

iv Market developments

Since its deregulation, the Norwegian electricity market has, represented by the Energy Act in 1990, developed into one of the most liberal electricity markets in the world, easily accessible to producers, end users and traders alike.

On the power production side, because of the Norwegian-Swedish electricity certificate scheme introduced from 1 January 2012, there is a marked expectation for the installation of significantly more production capacity in the years to come (see Section V.i. infra). Coupled with lower expected electricity consumption in the industrial sector, as well as limited transmission capacity between the Nordic market and continental Europe, the market has experienced lower prices over the past years. An additional growing concern is that electricity prices will stay low in the long term.

On the regulatory side, through the EEA Agreement, Norwegian law is closely connected to EU law. Thus the developments in this sector are expected to follow the developments in the EU on an overall basis.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

From 1 January 2012, Norway has been part of a Norwegian-Swedish electricity certificate market, which was introduced to increase production of renewable energy. The intention was then to expand the electricity production in Norway and Sweden based on renewable energy sources by 28.4TWh. This corresponds to the power consumption of more than half of all Norwegian households. On 8 April 2015, the Treaty on the electricity certificates between Norway and Sweden was amended by expanding the Swedish ambition by 2TWh. Hence the
total target was lifted from 26.4 TWh to 28.4 TWh. The increase in ambition is supposed to be fully financed by an increased number of certificates on the Swedish side. The following plants are entitled to electricity certificates:

- **a** power plants above 10MW based on renewable energy sources (hydro or wind), with construction starting after 7 September 2009;
- **b** existing power plants expanding their production on a permanent basis, with construction starting after 7 September 2009; and
- **c** hydroelectric power stations with installed capacity of up to 10MW, where construction started after 1 January 2004.

The system may cover the entire production or parts of it.

Power plants must be built in accordance with the licensing terms or comply with conditions for exemption from licensing. Any received government investment aid had to be repaid by 30 April 2012 to receive certificates.

All actors delivering electricity to end users must buy or obtain by other means (e.g., own production) a certain yearly quota of electricity certificates. In addition, certain electricity users that have entered into bilateral agreements, for example with a producer, have to buy electricity certificates. Moreover, generators who use their own electricity are to a certain extent required to buy electricity certificates.

The end users finance the system, as the costs of purchasing certificates is added on to the electricity bill. However, the certificate cost shall be an upfront fixed part of the suppliers handling costs. In this way the suppliers must calculate the cost before delivery starts and in this respect compete with other suppliers in offering the lowest handling costs. However, the certificate costs shall be a separate item on the invoice to the customers.

The NVE manages the electricity certificates in Norway in cooperation with Statnett (register coordinator) and Energimyndigheten (the Energy Agency) in Sweden to develop a fully-functioning Norwegian-Swedish electricity certificates market.

Statnett issues electricity certificates to accredited power generators, and maintains an electronic certificate register that shows how many electricity certificates power producers and electricity certificate-liable actors hold.

Certificates are sold in the Norwegian-Swedish electricity certificate market. Power suppliers and some electricity users are required to purchase electricity certificates for a certain proportion of the electricity they deliver or use.

At the end of March each year the power suppliers have to update their balance of certificates and annul a number of certificates according to a calculation based on the amount of electricity and certificates sold to the end users.

The NVE and the Swedish Energy Agency accredit power plants, which receive one electricity certificate for each MWh of electricity generated. Thus, the support is independent of whether the power plant is located in Sweden or Norway, and which renewable energy source is used.

On the Finnish island Åland, the Finnish company Ålands Vindkraft AB applied for approval of the Oscar wind farm for allocation of electricity certificates. The application was denied by the Swedish public authorities. The power company launched a case before the Swedish court Förvaltningsrätten, which, in turn in December 2012, referred the case to the Court of Justice of the European Union for a preliminary ruling under Article 267 TFEU. The Finnish company argued that the only connection between the island Åland and the mainland is a high-tension cable to Sweden. As registered in a Member State of the European
Union the Finnish company argued that it had a right to be treated on equal terms with any Swedish company, and hence has the right to certificates. The Court of Justice EU concluded in 2014 (Case C-573/12) that Sweden was entitled to deny the application for electricity certificates based on production at Åland.

The electricity certificate liable actors, namely, the power suppliers and certain electricity users, may choose to purchase their electricity certificates in Norway or Sweden. Trading of electricity certificates across national borders means that the renewable energy resources in both countries are utilised more effectively than if national markets were established.

The price of electricity certificates is determined by supply and demand. The demand is determined by how much power is used and the set electricity certificate quota for each year. The supply is dependent of how much electricity is being produced. Large-scale investments in new energy production will result in many certificates in the market and the price of each certificate will drop. Few power plants under construction will cause rising certificate prices, until the prices reach a level where the energy market will attract new investors. The average price on certificates from 28 April 2015 to 28 April 2016 was 161.58 kroner.

II Energy efficiency and conservation
Both the NVE and ENOVA focus on Energy efficiency. While the NVE implements regulations regarding energy efficiency, ENOVA is a state-run entity supporting various activities and incentives to trigger an environmental conversion in the consumption and generation of energy in Norway.

ENOVA’s programmes and activities within industry, construction, and housing are meant to stimulate the market into introducing new energy efficient solutions and adopting them into use. In recent years, construction programmes have been revised and now have a greater focus on innovators in the market, in particular the passive house standard. In addition ENOVA focus on increased use of alternative sources, increased production from renewable energy sources and introduction and development of new technologies and solutions.

III Technological developments
Norway is at the forefront of development of offshore floating wind power generation.

Statoil’s Hywind project is the first full-scale floating wind turbine in the world. In 2009, Statoil invested about 400 million kroner in construction and completion of the pilot, including scientific research and development of the wind turbine concept. ENOVA SF has given 59 million kroner in support of the project.

The concept has been verified during the first two years of testing and the results have, throughout that time, been above expectations. With few operational challenges, great production results and well-functioning technical systems, it is expected that the Hywind concept will have great influence on offshore wind production in the future. Statoil is currently looking for possible future locations within the United States and the United Kingdom for pilot wind farm projects with three to five floating wind turbines.
VI THE YEAR IN REVIEW AND OUTLOOK

In May 2014, an expert group delivered a report on the Norwegian electricity distribution sector. The group concluded that the sector as a whole would benefit by merging some of the smaller entities into larger ones. This has sparked debate on how many grid companies there should be in Norway.

The report was followed up by a consultation paper from the Ministry of Petroleum and Energy dated 15 April 2015, which proposed to expand the current unbundling requirement in the Energy Act (Section 4-6) concerning corporate and functional division for grid companies with more than 100,000 grid customers. It was proposed to apply this requirement to all entities with a concession to operate a grid, regardless of the number of grid customers, within a transition period of three years.

On 4 December 2015, the Ministry of Petroleum and Energy sent a proposal to the parliament to amend the Energy Act (Prop. 35 L (2015–2016)) according to the consultation paper. The Ministry proposes that grid companies, regardless of the number of grid customers, have to split (functionally and as a company) the business covering the regulated grid monopoly from other business, such as power trade, generation etc. The proposal will most likely be adopted by the parliament and then lead to an avalanche of restructuring in the grid sector.

On 15 April 2016, the Ministry of Petroleum and Energy sent a proposal to the parliament to amend the Industrial Concessions Act. The aim of the amendment is to make private owners able to acquire one-third ownership in power-generating companies owned by partnerships consisting of counties or municipalities.

On the same day, the Ministry of Petroleum and Energy sent a proposal to the parliament (Prop. 98 L (2015–2016)) to amend the Energy Act Article 4-2, 1 to allow the granting of concessions to operators other than the system operator to own and operate interconnectors.

The market price of electricity is still at a low level. The market forecast promises no significant changes. Nonetheless, in February 2016, Statkraft announced the decision to join forces with TrønderEnergi and the European investor consortium Nordic Wind Power DA to realise Europe's largest onshore wind power project at Fosen in Central Norway, comprising six onshore wind farms, with a combined capacity of 1000MW. The total investment in the wind farms amounts to approximately €1.1 billion. Construction will commence in summer 2016 and commissioning will be completed in 2020.
Chapter 27

POLAND

Krzysztof Cichocki and Tomasz Młodawski

I OVERVIEW

Demand for primary energy sources in Poland is currently estimated at 100.2 million tonnes of oil equivalent (Mtoe) per annum. It is satisfied primarily by coal (36.9 per cent), oil (25.4 per cent), natural gas (14.1 per cent), lignite (14.3 per cent) and renewable energy sources (9.2 per cent). According to the information published by the Polish Main Statistical Office with respect to 2014, the renewable energy sources (RES) included in the Polish primary energy mix comprised solid biomass (76.62 per cent); biofuels (9.23 per cent); water (2.33 per cent); wind (8.18 per cent); biogas (2.57 per cent); photovoltaic (0.21 per cent); and smaller shares of other sources (municipal waste, geothermal and solar heat), with an increasing installed capacity of wind farms.

Local production satisfies the entire hard coal demand and approximately 28 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 it is based on energy demand of: industry (27.4 per cent); transport (28.1 per cent); residential (31.8 per cent); 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.

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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 boost natural gas consumption by liberalising natural gas market, currently monopolised by only one single player – the Polish Oil and Gas Company (PGNiG) controlled by the State Treasury; (2) to intensify RES consumption, with special emphasis on stable electricity generation units based on biogas; and (3) 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.

II REGULATION

i The regulators

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 2011 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; and

m the 2010 Act on special powers of the minister competent to the State Treasury affairs and their enforcement with respect to certain companies and capital groups conducting their businesses within the electricity, crude oil and natural gas sectors.
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) organise tenders for 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;
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 or combined heat and power (CHP) installation 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 of liquid fuels, except for local storage of liquid gas in installations with capacity below 1MJ/s or storage of liquid fuels in retail trading;

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;

h 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 gaseous fuels provided that the annual turnover does not exceed €100,000, (4) trading in liquid gas provided that the annual turnover does not exceed €10,000, (5) trading in heat provided that the total ordered capacity does not exceed 5MW, (6) 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 (7) 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

i 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:

a the experience of the bidder in the prospecting or exploration and production of hydrocarbons;

b the technical and financial capacity of the bidder;

c the proposed technology to be utilised in the licensed operations;

d the scope and time frame of the proposed geological works and sampling; and

e 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. In addition, the licence for 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, supra, 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 (1) used for generation and transmission of electricity, and for production, refinement, processing, storage, transmission or transhipment of natural
gas, LNG, crude oil or petroleum products; and (2) 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 and the 2010 Act on Special Powers of the Minister Competent to the State Treasury affairs and their enforcement with respect to certain companies and capital groups conducting their businesses within the electricity, crude oil and natural gas sectors. 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 and to provide the Minister of the State Treasury with all the legal acts performed and resolutions adopted in the course of exercising their powers as owners or operators of critical infrastructure, including: disposal, alienation, decommissioning, lease or establishment of encumbrances over critical infrastructure, and adoption of investment, financial or strategic plans, or dissolution of the company. The Minister of the State Treasury has power to raise objections to, and hence invalidate, any legal acts or resolutions if performance or enforcement of the act or resolution would pose an actual threat to the functioning, continuity of operation or integrity of critical infrastructure.

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 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. 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

i 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 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 returns. 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 Towarowa 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 Towarowych 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) 
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 should significantly change the RES support system as of 1 July 2016. The 2015 RES Act should introduce 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 Renewable Energy 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 will 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:

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<td>a</td>
<td>limit the total period of support to 15 years from commissioning of given installation; and</td>
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<td>b</td>
<td>limit the amount of support addressed to multi-fuel power plants using biomass and hydro-power installations.</td>
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According to the press releases, the 2015 RES Act is envisaged to be further amended in mid-2016 to increase the support addressed to stable RES power generation units, including biomass and biogas-fired power plants.

At the same time, a draft bill on investments in wind power plants has been submitted to the Sejm, which – once adopted – is likely to introduce regulations negatively affecting onshore wind-farm businesses in Poland, including:

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<td>a</td>
<td>setting of a minimum distance between wind turbines and buildings, which may negatively affect viability of projects including wind farms under construction and modernisation of existing wind farms;</td>
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<td>b</td>
<td>changes to the rating of wind turbines for the purposes of property tax, which – if adopted – may result in a significant increase in property tax paid on wind turbines;</td>
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<td>c</td>
<td>a requirement for an additional approval to be obtained every two years for the operation of wind turbines, and upon each repair of wind turbines, with the approvals subject to the positive completion of compulsory technical inspections of the wind turbines; each such inspection would be subject to a fee not exceeding 1 per cent of the value of the wind turbine.</td>
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**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; these investments are selected within tenders organised by the President of the Energy Regulatory Office. According to the 2011 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 electricity sold to end-users or pay a substituting fee (the fee working in practice as the maximum level of support available to beneficiaries). The foregoing scheme is effectively designed for the period 2012–2016 (while some of obligations should be performed by 31 March 2017). 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 operator will be able to benefit from the new auction system from 1 July 2016 (see Section V.i, *supra*), while RES prosumers will be 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 a need to adopt regulations that would, in particular, strengthen the coal-mining sector, support stable (including coal, lignite, gas and biogas-fired) power generation units, impose increased administrative and tax burdens on onshore wind-farm developers and operators, develop application of smart-grid technology 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 of 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 (see Section V.i, *supra*);

b legislative work on amendments to the 2015 RES Act and on a draft bill on investments in wind power plants, which is likely to affect negatively wind-farm businesses in Poland (see Section V.i, *supra*);

c 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

d the entry into force 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 2016 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.
Chapter 28

PORTUGAL

Nuno Galvão Teles and Ricardo Andrade Amaro

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 2017, all consumers will shift to the liberalised markets.

Generation and supply of electricity and natural gas are free and 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

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1 Nuno Galvão Teles and Ricardo Andrade Amaro are partners at Morais Leitão, Galvão Teles, Soares da Silva & Associados, Sociedade de Advogados RL.
4 Taking into account their geographical limitations, electricity and natural gas activities on the archipelagoes of Azores and Madeira continue to be developed by vertically integrated companies, and therefore the considerations that follow refer mainly to mainland Portugal.
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.

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, revaluing 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.

\(^5\) 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.
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 power-generating or exploration licences.

In summary, while ERSE is the independent national regulatory authority for electricity and natural gas, the DGEG is the body that represents the state on energy matters, also being competent to grant licences and receive the corresponding applications or requests.

Regarding the upstream oil sector, the DGEG, via its oil exploration and production division is the competent authority to, among other things:

a. manage, organise and integrate all data and technical information resulting from oil exploration and production activities and other relevant data;
b. promote and carry out specialised studies aimed at establishing the value of oil resources;
c. promote the oil potential of Portuguese basins throughout the industry;
d. negotiate and ensure the proper procedures to grant (by direct negotiation or public bidding), transfer and annul exploration and production rights;
e. prepare and supervise licences for preliminary evaluation and concession contracts;
f. evaluate work programmes and specific technical projects during the execution of the contracts; and

g. regulate and supervise the activities during the execution of contracts, ensuring that legal provisions and regulations are followed, including those related to health, safety and environmental protection.

In relation to the downstream oil sector, following a recent legislative change a state company, Entidade Nacional para o Mercado de Combustíveis, EPE (ENMC), acting through the members of government responsible for finance and energy matters, is the competent authority to, among other things:

a. monitor, jointly with DGEG, security of supply of the national petroleum system and follow up on the supply conditions concerning raw petroleum and petroleum products, as a function of future consumption necessities;
b. monitor the functioning of the raw petroleum and petroleum products market;
c. give opinions on licensing procedures of large petroleum facilities, notably refining, transportation and storage;
d. approve registration of suppliers of petroleum products; and

e. receive complaints concerning activities in the liquefied petroleum gas value chain.

ENMC also has powers concerning the regulation of biofuels and the constitution and maintenance of oil reserves.

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

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6 Decree-Law No. 244/2015, of October 19.
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,7 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.

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,8 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. Although over the years, Portugal has been targeted with exploration and prospection studies, no actual discovery of any commercial interest has been made to date.

Bearing this in mind, the law established a more attractive and simple legal framework for the development of upstream activities. Apart 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.

8 Which, in general terms, refers to high and medium-voltage grids.
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.

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.

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9 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).
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.¹⁰

In 2012, in line with the latest European directives, the Portuguese legal framework for the electricity and natural gas sectors allows transmission activity to be developed by a vertically integrated company. In this case, however, the transmission system operator must be a legal entity separate from the rest of the companies, forming an independent transmission operator (ITO). The ITO must observe strict independence obligations and comply with several independence criteria to avoid falling foul of discriminatory behaviours, namely those set out in Article 9 of Directives 2009/72/EC and 2009/73/EC. Compliance with such obligations and independence criteria is assured by means of a certification process, monitored by ERSE and the European Commission, and that the ITO must fulfil to develop transmission activity.

The distribution of electricity and natural gas is subject to a legal unbundling regime. This means that operators of distribution networks must be independent from a legal, organisational and decision-making process standpoint from other activities unrelated to distribution. Distribution companies that serve fewer than 100,000 clients are not subject to the legal unbundling regime, but they must still implement accounting and functioning unbundling measures.

Supply activities are also subject to the unbundling regime, implying that they must be legally separate from other activities. The last-resort supplier is also bound by this unbundling regime, even in relation to common suppliers.

The operation of LNG terminals and storage facilities is also subject to the legal unbundling regime. To a lesser extent unbundling requirements also exist in the downstream oil sector (see Section II.iii, 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 markets participants and to abstain from adopting any discriminatory behaviour or practices.

¹⁰ Both companies are wholly-owned by REN Redes Energéticas Nacionais SGPS, SA, a listed company.
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 TNOs 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 DGEG, the concessionaire of electricity transmission activity published a Report for Monitoring the Safety of Supply of the NES for 2013–2020. This report describes, *inter alia*, the NES, provides future grid scenarios, planned and installed capacity, and levels of power generation by source.\(^\text{11}\)

### 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.

\(^\text{11}\) Available at www.dgeg.pt.
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, signed on 1 October 2004. It establishes the general principles for the organisation and management of MIBEL and, in particular, the framework for the organisation of the spot market and the derivatives market.

The MIBEL derivatives market, because of its financial nature, is directly subject to Portuguese law and jurisdiction and, therefore, to the legislation applicable to this type of market, which is primarily:

- the Securities Code;
- the Securities Market Commission (CMVM) Regulations; and
- the CMVM Instructions.

The derivatives market is under the direct supervision and regulation of the CMVM, in coordination with ERSE.

Notwithstanding the powers granted to the Portuguese authorities, the regulation and supervision of the derivatives market is carried out in conjunction with the equivalent Spanish authorities, the National Energy Commission and the National Securities Market Commission.

In addition, regulation of MIBEL takes place through market rules developed by the market operators, OMIE and OMIP, which have the duty of developing and jointly applying all the market rules.

MIBGAS and trading conducting therein, on the other hand, are governed solely by Spanish law.

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12 The Agreement between the Portuguese Republic and the Kingdom of Spain relative to the constitution of an Iberian Electrical Energy Market.
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.

During this period, transitory tariffs with a gradually increasing premium component will apply and also be updated quarterly by ERSE.

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.

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.\textsuperscript{13}

After the establishment of the PNAEE, the Energy Efficiency Fund was created,\textsuperscript{14} which finances the programmes and measures provided for in the plan.

In 2011, the government, by Decree-Law No. 29/2011 of 28 February, created a specific public tender procedure to expedite and facilitate the formation and execution of energy efficiency contracts, to be entered into by the public administration and private companies to implement measures improving energy efficiency in public buildings.

ERSE has tried to ensure that regulation of the sector galvanises actions that contribute to the promotion of energy efficiency. In the Tariffs Regulation for the electricity sector, a competitive mechanism called the Consumption Efficiency Promotion Plan (PPEC) has been established to promote measures for managing demand. In the electricity PPEC, incentives are awarded for the promotion of measures aimed at improving efficiency in electricity consumption through measures taken by suppliers, network operators and organisations that promote and protect the interests of electricity consumers in mainland Portugal and in the autonomous regions, and that are aimed at consumers in different market segments. The actions result from specific measures proposed, subject to a selection process, whose criteria are defined in the Rules for the Consumption Efficiency Promotion Plan. This process allows the selection of the most promising measures for energy efficiency to be 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.

\textsuperscript{13} Council of Ministers Resolution No. 20/2013 of 10 April.

\textsuperscript{14} More information about energy efficiency in Portugal can be found at:
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 over costs incurred with respect to the purchase of electricity from special regime generators.

iii Technological developments
Driven by the growing dependence on oil for energy and by the environmental impact of the use of fossil fuels, Portugal is investing in new energy models for mobility that aim to improve quality of life and reduce pollution.

This has led to the creation of the Electric Mobility Network, an integrated network linking 1,300 charging stations in Portugal, managed by MOBI.E, which will enable electric vehicles to recharge, using a charge card.

Its main goal is to contribute to a more sustainable mobility model, promoting the integration of electric power coming from renewable sources into the functioning and development of cities, and maximising its advantages.\textsuperscript{15}

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.\textsuperscript{16} 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

2015 marked the year in which the Portuguese economy started, albeit slowly, to come out of the recession sparked by the eurozone crisis.

Perhaps because of the improved economic outlook, the year also saw increased mergers and acquisitions activity in the sector (especially in the field of renewable energy), with several investors taking advantage of a combination of stable, guaranteed-remuneration regimes, low interest rates and mature projects from an operational perspective; the sales of landmark participants in the wind market Iberwind and Finerge to foreign investors are key transactions in the energy sector in 2015 and reflect this trend.


\textsuperscript{16} More information on this project can be found at www.inovgrid.pt/en.
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 has also been scheduled to apply in 2016, the government set up the Fund for the Systemic Sustainability of the Energy Sector, with the goal of creating 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.

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.

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.
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 2012, the GoS adopted a Letter of Development Policy for the Energy Sector. The main axes of the Letter of Development Policy for the Energy Sector are:

a ensuring energy security and increasing energy access for all;
b developing a policy mix combining thermal generation, bio-energy, coal, gas and renewables, and seizing opportunities offered by regional interconnections;
c continuing and accelerating the liberalisation of the energy sector by encouraging independent production and institutional reform of the sector;
d improving the competitiveness of the sector to lower the cost of energy and reduce sector subsidies; and
e strengthening regulation of the sector.

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1 Mouhamed Kebe is a partner and Codou Sow-Seck is a senior associate at Geni & Kebe Law Firm. The information in this chapter was correct as of June 2015.
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:

a the Minister of Energy;
b the Electricity Sector Regulatory Commission (CRSE), which is an independent authority responsible for regulating the production, transmission, distribution and sale of electricity; and
c the National Committee for Hydrocarbons, created by Act No. 98-31 of 14 April 1998 on import, refine, storage, transport and distribution of hydrocarbon, is a consultative organ.

The regulators are different for each segment of the energy sector:

a the CRSE deals with the electricity segment; and
b 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.

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:

a advising the Minister of Energy on all legislative and regulatory plans for the electricity sector; and
b 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:

a examine applications for a licence or concession;
b 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.
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 prospecting;

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.

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 time 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 segment, 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.

iii 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.

Moreover, Senegal is a country with a strong favourable natural potential for development of renewable energy such as solar, wind, hydropower and biomass.

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.

Purchases of materials and equipment for research and development in the field of renewable energy also benefit from tax incentives.

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.
I OVERVIEW

The extensive transformation that the South African energy sector has experienced in recent years continued in 2015, and all indications are that the transformation will stay on course in 2016.

The South African government launched Rounds 4 and 4.5 of its Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) calling for an additional 6,300MW of independently produced renewable energy. The REIPPPP is an unprecedented, world-class procurement programme launched by the government’s Department of Energy in August 2011 with the audacious goal of the country producing 17,800MW of renewable energy by 2030. To date, the REIPPPP has facilitated the introduction of 92 independent power producers (IPP) to the South African energy sector, with generation capacity in excess of 6,327MW. Investments in renewable energy under the REIPPPP programme have been approximately 53.4 billion rand. While the REIPPPP has served as an important pillar for the transformation of the South African energy sector – through the introduction of large-scale renewable energy to the sector – it is only but one pillar of the South African government’s energy transformation strategy, which was born in the 1998 White Paper on Energy Policy and given legs in the government’s Integrated Resource Plan 2010 (the Integrated Resource Plan).³

In 2015, the South African government has further launched, and received bids, for its 2,500MW Coal Baseload IPP Procurement Programme; called for expressions of interest

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1 Lido Fontana and Deon Govender are international partners and Sharon Wing is an associate at Chadbourne & Parke (South Africa) LLC.


for proposed gas-to-power projects, and advanced discussions around the development of the country’s shale gas capacity, additional nuclear energy generation capacity and further procurement of electricity from cross-border generators.

This chapter primarily considers developments in the electricity sector together with the regulatory framework underpinning that sector. The article touches on the regulatory framework supporting other energy subsectors, albeit on a cursory basis.

II REGULATION

i The regulators

In South Africa, energy regulation is split among three regulators, being:

- the National Energy Regulator (NERSA), established under the National Energy Regulator Act, 2004, which regulates electricity, piped gas and petroleum pipelines industries;
- the National Nuclear Regulator (NNR), established under the National Nuclear Regulator Act, 1999, which regulates nuclear energy; and
- 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 licenses for the storage, transportation and reticulation of petroleum through pipelines are issued by NERSA. Although the procedure for applying for the licences is similar to that of Licensed Activities, only owners of storage, transportation and reticulation facilities respectively, may apply for licenses for the storage, transportation and reticulation of petroleum.

Licenses 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 Holdings SOC Limited (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.

4 Section 10(2)(a)–(h) of the Electricity Regulation Act, 2006.
5 Section 73(1) of the MPRDA.
6 Section 5(1) of the MPRDA.
The REIPPPP has served as the primary vehicle through which the South African government has procured renewable energy from private sector power producers. That programme provides that projects developed thereunder must be 40 per cent owned by South Africans with people of colour holding a minimum of 12 per cent (with a target of 20 per cent), and a minimum of 2.5 per cent ownership by local communities (those communities within a 50km radius of the project). In addition to the ownership requirements, REIPPPP bidders are also required to bid on other non-price factors known as ‘economic development requirements’, which are designed to achieve the government’s Integrated Resource Plan objectives of promoting job growth, domestic industrialisation, community development and black economic empowerment (a programme designed to counter the adverse economic impacts of apartheid by initiating, among other things, ownership and control of capital by South Africans of colour, women and disabled persons (Historically Disadvantaged Persons or HDSA), as well as skills transfer and enterprise development of legal entities owned by HDAs).

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 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 HDAs in their respective companies. Companies active in the upstream sector are obliged to reserve participation interest of not less than 9 per cent for HDAs, while companies in the midstream and downstream sectors must reserve a 25 per cent participating interest for HDAs. These companies must further make contributions towards the funding of skills development initiatives.

iv Transfers of control and assignments

Transfer of control and the assignment of a licence issued in respect of Licenced Activities, including generation licences issued to IPPs, are restricted by conditions imposed on the licensee by NERSA. Accordingly, each licence must be reviewed on a case-by-case basis to determine what specific approvals are required for its transfer. However, the Electricity Regulation Act generally provides that a licensee may not cede or transfer its powers or duties under a licence to any other person without the prior consent of NERSA. The transfer of control and the assignment of licences issued to IPPs are further regulated by the Implementation Agreement between the South African 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 license 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

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7 Section 15(1)(k) of the Electricity Regulation Act, 2006.
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 license 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.

The government has apprised the market that a new ISMO Bill is currently being drafted.

Gas
The gas pipeline network comprises the Rompco Pipeline (used to transport gas from Mozambique into South Africa), which is the main pipeline network in South Africa, and several 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.

8 This is a joint venture between South African Gas Development Company Limited (iGas), Companhia Limitada de Gasoduto (CMG) and Sasol Gas Holding Proprietary Limited.
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.

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, which is based on several international conventions to which South Africa is a party, provides for the establishment of internationally endorsed

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9 www.eskom.co.za/Whatweredoing/Pages/Wheeling_Of_Energy.aspx.
10 Nuclear Energy Act 46 of 1999.
11 For example, the Convention on Nuclear Safety, 1994; the Convention on Early Notification of a Nuclear Accident, 1986; the Convention on Assistance in the Case of Nuclear Accident
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 (MISS) 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.12

Several of Eskom’s power stations and other facilities, as well as municipality distribution installations, have been designated national key points. National key points are strategic installations, which require heightened state security.

IV   ENERGY MARKETS

i   Electricity

NERSA is mandated to, inter alia, regulate trading activities such as electricity resale (buying and selling). Eskom purchases electricity that is supplied by IPPs to the national grid and in turn sells the electricity to industrial, mining, commercial, agriculture and residential customers in South Africa, some members of the Southern African Development Community and redistributors (municipalities), who in turn redistribute electricity to businesses and households within their areas.

Section 155(6)(a) and (7) Schedule 4B of the Constitution13 lists electricity reticulation as a competence of municipalities in South Africa. Each municipality is a service authority for the electricity reticulation function for the whole of its jurisdictional area and has the right to set tariffs in respect of its sale of electricity in its areas of jurisdiction. On 30 October 2014, the South African Local Government Association entered into a memorandum of understanding and active partnering agreement with all distributors, including Eskom, to ensure cooperative and collaborative working relationships.

Electricity can also be onsold to multiple customers by persons with bulk supply points, such as bodies corporate and office parks (known as Resellers). These Resellers are ‘non-licensed traders’ of electricity in terms of the Electricity Pricing Policy.14 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.

12 www.nnr.co.za/nuclear-security/.
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 2003.15

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. The focus on gas has manifested in, among other things, the Mozambique Gas Pipeline Agreement and the multiple exploration right applications submitted to the Department of Mineral Resources by Shell International, Falcon Oil and Gas in partnership with Chevron, and Bundu Gas to explore the possibility of a shale gas resource of 485 trillion cubic feet in the Karoo Basin. The applications for rights to explore for shale gas in the Karoo Basin in terms of the MPRDA are still, after five years, in process, as these have been met with a number of environmental and health-impact challenges, primarily relating to the hydraulic fracturing techniques used to recover shale gas.

In May 2015, the Strategic Environmental Assessment (SEA) on shale gas was announced and is expected to be finalised in 2017. The SEA is a science-based assessment to improve government understanding of the risks and opportunities of shale gas development and to inform shale gas regulations.

On 3 June 2015, shale gas regulations were promulgated well ahead of the results from the SEA. This was met with a High Court application brought by AfriForum and Treasure Karoo Action Group against the Department of Mineral Resources. The application challenges the validity of the regulations as the applicants believe that the regulations are patently flawed (the application is still ongoing).

The Minister of Energy also opened the way forward for the exploration of shale gas with the publication of a Determination (i.e., regulations providing for state procurement of additional energy capacity) on 18 August 2015, providing for new generation capacity of 3,126MW from gas to be generated from any gas type or source, shale gas included.

In the South African government’s Economic Sectors, Employment and Infrastructure Development Cluster media briefing on 8 March 2016, Minister Gugile Nkwinti reported that the exploration activities in respect of shale gas are scheduled to commence in the next financial year. Anti-fracking campaigners were quick to respond with threats of filing urgent applications to interdict fracking in the Karoo region.

No applications for the exploration of shale gas have been granted and it would seem that until the SEA has finalised its investigation regarding the environmental impact of fracking the licence applications will be continuously met by opposition.

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 is less frequent presently, 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, it is understood that this document has not been finalised.

The IRP is subordinate legislation to the Department of Energy’s Integrated Energy Plan (IEP), which 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.
What is the IPPPPP?
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. To date, bids totalling 17.5GW, from 305 bid submissions, have been received in the REIPPPP bidding process across all five procurement bid windows. Of the renewable energy capacity procured, 3,922MW (from bid windows one, two and three) are at various stages of construction or have commenced commercial operation. As of June 2015, 37 IPPs had already started commercial operation and had added 1,860MW capacity to the power system.

Bid window four brought the total number of participating IPPs to 92, with the combined generation capacity that has been procured since the announcement of the first preferred bidders in late 2011 reaching 6,327MW, to be generated from a range of renewable sources including photovoltaics, wind, concentrated solar power, small hydro, landfill gas, biomass and biogas. Preferred bidders for bid window 4.5 have not yet been announced.

VI THE YEAR IN REVIEW

i 2015 Determinations

Section 34 of the Electricity Regulations Act empowers the Minister of Energy to:

a 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;
b ‘determine the new generation capacity needed to ensure uninterrupted supply of energy’; and
c determine the energy sources, and the buyers and sellers of electricity generation.

On 18 August 2015, the Minister of Energy, in consultation with NERSA, published three Determinations in a Government Gazette. These Determinations were in addition to, or amendments to, the Determinations previously published in Government Gazettes of 12 December 2012. The Ministerial Determinations of 2015 can be summarised as follows:

16 Act 4 of 2006.
Cogeneration IPP Procurement Programme 2015 and Amendment to the Medium Term Risk Mitigation Project IPP Procurement Programme 2012:
- the Medium Term Risk Mitigation Project Procurement Programme 2012 to be amended to increase the capacity to be procured from industrial cogeneration energy sources from 800MW to 1,800MW; and
- the types of generation sources to be amended to include: (1) waste heat or furnace off gas; (2) cogeneration; and (3) an energy source that is a co-product, by-product, waste product or residual product of an industrial process or sustainable agricultural forestry activity.

Renewable Energy IPP Procurement Programme 2015: added 6,300MW to further bid windows where the renewable energy would be procured from the following renewable energy sources: concentrated solar power, wind, solar photovoltaics, biogas, biomass, landfill gas, small (≤40MW) hydro and small projects (≤5MW based on any of the sources aforementioned).

Gas Independent Power Producers Procurement Programme 2015 and Amendment to the Baseload IPP Procurement Programme 2012 and Medium Term Risk Mitigation Project IPP Procurement Programme 2012:
- the deletion of the provision relating to new generation capacity generated from gas from the Baseload IPP Procurement Programme 2012 and Medium Term Risk Mitigation Project IPP Procurement Programme 2012; and
- allocation of 3,126MW to be generated from any gas type, which includes: (1) natural gas delivered to the power generation facility by any method, including by pipeline from a natural gas field or elsewhere or a liquefied natural gas (LNG) base method; (2) coal bed methane; (3) synthesis gas or syngas; (4) above or underground coal gasification; (5) shale gas; and (6) any other gas type or source as may be considered appropriate by the procurer.

The Determinations reflected at (b) and (c) above both determined that the procurer would be the Department of Energy; the buyer will be Eskom; and the capacity shall be procured through one or more IPP procurement programmes as contemplated in the New Gen Regulations,19 which may include cross-border projects.

On 21 December 2015 a further Determination was published in a Government Gazette20 in respect of nuclear energy. The 2015 Determinations 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.

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The Determinations provide for a 20-year projection of electricity supply in South Africa and stipulate that 40 per cent of South Africa’s electricity must be generated from renewable sources.

**ii Amendments to the MPRDA and the Gas Act**

The controversial Mineral and Petroleum Bill B15 of 2012 (the Bill) provides for state participation in any successful minerals and gas or oil development exercises carried out by the private sector that would result in the state receiving a right to free carried interest in all such exploration and production rights. The ‘free carry’ was published in the Government Gazette at 20 per cent. This Bill was referred to the President for his assent during March 2014. It has, however, been referred back to Parliament and is currently being reviewed on the grounds of its being unconstitutional.

The Gas Bill was published for comment on 2 May 2013 and aims at amending the Gas Act by taking into account new technological advancements and transportation technologies such as LNG and compressed natural gas, and other unconventional gases not currently included in the Gas Act. Moreover, the amendments are set to improve the regulatory framework in the gas industry and facilitate gas infrastructure developments.

**VII CONCLUSIONS AND OUTLOOK**

All in all, 2015 was a great year for the electricity sector. Great strides were made in realising some of the South African government’s key objectives for the transformation of that sector, which will ultimately result in greater liberalisation of the electricity sector. Developments in the gas and LNG sectors have been relatively muted. All of this has resulted in South Africa being ranked among the top 10 renewable energy-investing countries in 2016 by the United Nations Environment Programme.21

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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 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
Spain

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).

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.

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.
Spain

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.

g. 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 per cent tax on energy production.

Lastly, the Royal Decree gives consumers, installers and other agents a period of six months to adapt to its provisions.

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:

a rearrangement of the powers of the different regulatory authorities;
b development of the rules governing access to networks;
c the functional separation of regulated activities;
d regulating the activity supply of last resort;
e creation of the Supplier Switching Office; and
f 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:

a effective separation of network activities from supply and production activities;
b 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:

- the accrual and collection of the remuneration generated by transmission and distribution facilities placed into service in year ‘n’ will start from 1 January of year ‘n+2’;
the remuneration will consist of assets in operation that have not been
deprecated. The basis for their financial return will be the net value of the assets;
the financial rate of return on the assets eligible for remuneration out of the electricity
system for transportation and distribution companies will be linked to the yield on
10-year government debt securities on the secondary market plus a suitable spread; and
the remuneration is determined for each regulatory period, which will last for six
years, but the remuneration parameters can be reviewed before the start of each
regulatory period.

The remuneration methodology of transportation activity should comprise economic
incentives for the improvement of the availability of the facilities and any other goal. In
the case of distribution, the remuneration methodology must include the formula for
remunerating other regulated functions performed by distribution companies, as well as any
incentives that may be appropriate for the improvement of the supply’s quality, reduction of
losses, combating fraud, innovating technology and any other goals.

v Security and technology restrictions

Security in relation to transportation facilities of electrical energy is relevant from the
perspectives of both industrial safety and security of supply.

Industrial safety is dealt with by Law 21/1992 of 16 July and the Electricity
Act 24/2013, and is understood as safety aimed at risk prevention and control, as well as
protection against accidents and disasters capable of causing harm to the population or
damage to flora, fauna, property or the environment. Security of supply is dealt with under
the sector-specific regulations. The Electricity Act 24/2013 states in this regard that the ‘few
basic technical rules needed will be established to ensure the reliability of electricity supply
and installations of transport network’.

IV ENERGY MARKETS

i Development of energy markets

According to the Electricity Act 24/2013, electricity production takes place in the electrical
power production market in a free-competition regime. The electricity production market
is composed of all energy purchase and sale business transactions and other services related
to the supply of electricity. It includes forward markets, a daily market, an intraday market,
the resolution of system technical constraints, ancillary services and the management
of deviations.

The Spanish electricity market has historically offered competitive prices for end users
compared with other European markets. The Iberian Electricity Market was started in 2007,
and the results of integration in the market have been obvious: while in the second half of
2007 the average price differential between the Portuguese and Spanish electricity systems
was €10 per MWh, this fell to €0.3 per MWh by 2010, with identical rates on both sides of
the border for the majority of the time.

The operation of the wholesale market at any given time is determined by the mix of
generation structure, import capacity, the imperfect meshing of the network, the inelasticity
of demand and the system reserve margin. The market-design rules can make this operation
more or less efficient, but cannot make up for significant deviations in these factors.
From the opening to competition of the generation market in January 1998 to 2005, almost all of the transactions in wholesale energy were carried out in the pool. Forward markets and bilateral contracts have been developed gradually with the evolution of the regulations. Thus, in recent years, the energy involved in the daily market run by OMIE has ranged between 45 and 55 per cent of demand, with the remainder opting for bilateral transactions.

Despite the reduction in the quantities traded in the daily market, its price still represents the main visible energy price reference and the underlying settlement of bilateral contracts, the over-the-counter (OTC) market and forward markets organised by OMIP.

In this context the significant increase in OTC negotiations on the financial market should also be noted. The volume of energy traded in this market went from 6 per cent of domestic demand in 2007 to 10 per cent in 2010.

The low prices in the Spanish wholesale market compared with their European counterparts have reflected the influence of generation technology’s price takers. As an illustrative example, in the period from December 2009 to March 2010 the market price showed a very substantial fall even below fuel price, reaching an average of €19.6 per MWh in March 2010, reflecting, inter alia, prices of zero euros per MWh for almost 300 hours. One of the main causes of this was a 1.91 per cent reduction in demand, along with growth in wind production coinciding with intense rainfall.

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, 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.
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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.

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. There were several reforms during 2015, in particular the new regulation on self-consumption and non-mainland territories, and the reform of the gas market initiated by the Spanish government:

a Self-consumption is regulated through the enactment of Royal Decree 900/2015, which regulates the administrative, technical and economic requirements for the methods of supplying and generating electricity for self-consumption. 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 (criticised as the ‘tax on the sun’).

b Royal Decree 738/2015 was passed, which regulates the production of electricity and the procedure for dispatching power in non-mainland territories’ 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.

c Like the electricity sector, the gas sector has undergone several reforms accomplished by the Spanish government in its desire to ensure the principle of financial and economic sustainability. 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.
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

TURKEY

Okan Demirkan, Melis Öget Koc and Zeynep Buharalı

I OVERVIEW

Following the elections held in Turkey in November 2015, Mr Berat Albayrak was appointed as the new Energy and Natural Resources Minister. The new minister recently declared that in the long term Turkey aims to (1) increase its general energy storage capacity; (2) increase storage obligation rates for imports from 10 per cent to 20 per cent; (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 264 billion kWh. Furthermore, as announced by the minister, Turkey is planning to make an investment of 15 quadrillion Turkish liras to strengthen the infrastructure of its electricity supply system network in the coming five years. As it did in 2015, so Turkey continues to take concrete steps to meet energy demands and to keep doubling 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:

1. increasing total installed power to 120,000MW;
2. increasing the share of renewable energy sources from 25 to 30 per cent;
3. maximising the use of hydropower;
4. increasing wind-power installed capacity to 20,000MW;
5. installing power plants with 600MW of geothermal and 3,000MW of solar energy;

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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 exchange;
commissioning at least two nuclear power plants;
building a coal-fired power plant with a capacity of 18,500MW; and
eliminating its petroleum and gas import costs, currently as high as US$56 billion.

Among these targets, establishment of an energy exchange will not only support market liberalisation but also ensure transparency and help maintain a healthy balance between supply and demand. Turkey enacted a new Electricity Market Law\(^3\) (EML) in 2013.\(^4\) The EML stipulates the creation of an electricity exchange market, which will be administered through a newly incorporated company, EPİAŞ.\(^5\) As detailed in Section VI, infra, EPİAŞ was established on 18 March 2015.

The Turkish electricity market is one of the fastest growing electricity markets in the world, with an approximately 9 per cent annual increase on average. Natural gas consumption in Turkey is increasing as well. According to the MENR,\(^6\) 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 dependent on imports. Turkey imports petroleum mainly from Iran, Russia, Iraq, Saudi Arabia and Kazakhstan, and natural gas from Russia, Turkmenistan, Azerbaijan and Iran, in addition to its long-term liquefied natural gas (LNG) imports from Nigeria and Algeria.\(^7\)

With the enactment of the Natural Gas Market Law\(^8\) (NGML) in 2001, BOTAŞ\(^9\) 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 80 per cent of the natural gas consumed in Turkey. 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.

Turkey enacted a new Turkish Petroleum Law\(^10\) (TPL) in 2013, abolishing the former Petroleum Law. Then, the Turkish Petroleum Law Implementation Regulation\(^11\) entered into force in early 2014. An amendment law proposing substantive changes to the Natural

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4. In addition to the EML, many long-awaited regulations entered into force in the last quarter of 2013 and in early 2014, such as the Electricity Market Licence Regulation, the Electricity Market Distribution Regulation and the Electricity Market Connection and Use of the System Regulation.
5. Enerji Piyasaları İşletme Anonim Şirketi.
6. The Ministry of Energy and Natural Resources.
7. Turkey also imports spot LNG.
9. The Petroleum Pipeline Corporation, BOTAŞ is a state-owned company.
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. However, at the time of writing, these amendments still have not been enacted.

In line with Turkey's substantial demand potential and its renewable energy targets, Turkey has also introduced the Regulation on Generating Electricity without a Licence; the Regulation on Documentation and Support of Renewable Energy; the Regulation on Technical Evaluation of Solar Energy Based Licence Applications; the Communiqué on Wind and Solar Measurements for Preliminary Licence Applications; the Contest Regulation on Pre-Licence Applications Regarding Generation Facility Based on Solar and Wind Energy; and the Regulation on Renewable Energy Resources for Electricity Generation.

II REGULATION

i The regulators

The MENR is responsible for preparing and implementing energy policies, plans and programmes in coordination with its affiliated institutions. The Energy Market Regulatory Authority (EMRA), is responsible for regulating and supervising the operation of the electricity, downstream petroleum and downstream natural gas markets. It exercises its powers through EMRA’s board. With its competence to regulate and supervise the energy markets, EMRA has the following duties:

- issuing licences;
- drafting, amending, enforcing and auditing performance standards, as well as distribution and customer services;
- setting out the pricing principles indicated in the law; and
- ensuring the development and implementation of an infrastructure.

The primary legislation for the electricity market is the EML and the Electricity Market Licence Regulation. While the Petroleum Market Law, the Liquefied Petroleum Gas Market Law and the Petroleum Market Licence Regulation govern downstream petroleum

12 Entered into force on 2 October 2013.
13 Entered into force on 1 October 2013.
14 Entered into force on 1 June 2013.
15 Entered into force on 17 June 2013.
16 Entered into force on 6 December 2013.
17 Entered into force on 27 November 2013.
18 The General Directorate of Petroleum Affairs is the regulatory authority responsible for upstream market.
19 The Energy Market Regulatory Board.
21 Entered into force on 2 November 2013.
22 Entered into force on 20 December 2003.
23 Entered into force on 13 March 2005.
activities, the NGML and the Natural Gas Market Licence Regulation\textsuperscript{25} govern downstream natural gas activities. As for the upstream market, the TPL governs upstream oil and gas activities,\textsuperscript{26} and the Law on Transit Passage through Petroleum Pipelines\textsuperscript{27} (the Transit Law) governs the transit passage of oil and gas.

\begin{enumerate}[ii]
\item \textbf{Regulated activities}

\textbf{Electricity}

To conduct any one of the following market activities, companies must obtain a licence from EMRA:

\begin{itemize}
\item[a] generation;
\item[b] transmission;
\item[c] distribution;
\item[d] wholesale;
\item[e] retail;
\item[f] market operation;
\item[g] import; and
\item[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 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.

Under 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. An amendment to the Regulation on Generating Electricity without a Licence came into force on 23 March 2016. Pursuant to this amendment, 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.

Among other significant changes, the new amendments introduced share transfer restrictions. Accordingly, shareholders of companies that applied for grid connection for

\begin{footnotesize}
\begin{enumerate}
\item\textsuperscript{25} Entered into force on 7 September 2002.
\item\textsuperscript{26} Under the TPL, the definition of ‘petroleum’ includes both crude oil and natural gas.
\item\textsuperscript{27} Entered into force on 29 June 2000.
\end{enumerate}
\end{footnotesize}
unlicensed electricity generation projects 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.

Downstream petroleum and natural gas

The following downstream petroleum market activities require a licence:

- a) refining;
- b) processing;
- c) lubricant oil production;
- d) storage;
- e) transmission;
- f) eligible consumer;
- g) bunker delivery;
- h) distribution;
- i) transportation; and
- j) dealership.

Under the NGML, the following activities require a licence:

- a) import;
- b) export;
- c) transmission;
- d) storage;
- e) wholesale;
- f) distribution; and
- g) 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. Non-compete undertakings for indefinite terms or those exceeding five years can no longer be granted a block exemption from the prohibition of agreements, concerted practices or decisions that restrict competition in a specific market. According to the Competition Board’s latest decisions, all personal or real rights related to dealership agreements (such as loan contracts, equipment contracts and long-term lease contracts and long-term usufructs) must be limited to five years.

Natural gas

Under the NGML, import companies cannot conclude new natural gas purchase agreements (except for LNG) with countries that currently have existing natural gas sale and purchase agreements with BOTAŞ. The barrier to market entry is actually even higher, because under EMRA’s Board Decree No. 725 (Decree No. 725), EMRA must obtain BOTAŞ’s opinion 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).
Decree No. 725 requires consultation with BOTAŞ (in its capacity as a transmission system operator (TSO)) on the technical suitability of the proposed importation through BOTAŞ’s transmission network.

The Draft Amendment Law abolishes the prohibition on import companies for concluding new natural gas purchase agreements with countries that currently have existing natural gas purchase agreements with BOTAŞ. This is a clear sign of the government’s intention to further liberalise the Turkish natural gas market.

The NGML imposes storage-related obligations on applicants for import and wholesale licences. Import licence applicants must obtain commitments and guarantees from storage licence holders, regarding their capacity to store 10 per cent of annual gas imports in Turkey within five years. 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. The Draft Amendment Law will not change these market share restrictions.

iv Transfers of control and assignments

In the electricity market, licence holders must obtain EMRA’s approval for any of the following transactions:

\[ a \] transferring of 10 per cent or more shares (5 per cent or more in publicly held companies) in licence holding companies;
\[ b \] any transaction resulting in the change of control of a licence holding company;
\[ c \] any transaction resulting in the change of ownership or usage right on licensed facilities;
\[ d \] share pledges; and
\[ e \] merger, in accordance with Article 59 of the Electricity Market Licence Regulation.

In the natural gas market, licence holders must obtain EMRA’s approval for any of the following transactions:

\[ a \] transferring of 10 per cent or more shares (5 per cent or more in publicly held companies);
\[ b \] transferring of shares, resulting in any shareholder’s shares exceeding 10 per cent or decreasing below 10 per cent;
\[ c \] any transaction resulting in acquisition of the right to vote in the licence holder company;
\[ d \] share pledges;
\[ e \] creating or lifting privilege over shares or issuing a dividend right certificate; and
\[ f \] 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\textsuperscript{28} 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\textsuperscript{29} 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.

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 Draft Amendment Law also includes provisions concerning BOTAŞ’s restructuring. 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.\textsuperscript{30}

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, provided that these demands meet certain conditions.

\textsuperscript{28} The state transmission entity.
\textsuperscript{29} The state distribution entity.
\textsuperscript{30} (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.
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 based on certain specific grounds. 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
Turkey currently has 535 million m³ of LNG and 4.11 bcm of natural gas storage capacity, and aims to increase its total storage capacity. There are only four storage facilities in Turkey. The number of storage facilities explains the insufficiency of storage capacity.

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 six storage licences in force.\(^{31}\) As the current storage capacity is insufficient, third-party access is practically impossible.\(^{32}\)

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 31 December of the relevant year. The tariffs will be effective for the tariff period between 1 January and 31 December of the following year.

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.

\(^{31}\) Two new storage licences were issued in February 2014.

\(^{32}\) 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.
iv Security and technology restrictions

There are various pieces of legislation in Turkey dealing with the security of energy infrastructure facilities.\(^{33}\) Turkey is also a party to international agreements and forums regarding the security of critical infrastructure facilities.\(^{34}\)

IV ENERGY MARKETS

i Development of energy markets

In Turkey, supply licence holders can conduct electricity trading activities.\(^{35}\) 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. The MFRC\(^{36}\) operates the day-ahead market, as well as the balancing market.

As for natural gas, since there is no energy exchange in Turkey yet, gas trading is physical. In Turkey, gas trading is conducted by four types of licence holders:

- production lease;\(^{37}\)
- import licence;
- export licence; and
- wholesale licence.

ii Energy market rules and regulation

In addition to the EML and the Electricity Market Licence Regulation, electricity trading is regulated by the Regulation on Electricity Market Balancing and Settlement.\(^{38}\) 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.

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\(^{33}\) 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.

\(^{34}\) 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.

\(^{35}\) i.e., wholesale, export, import and retail sales.

\(^{36}\) The Market Financial Reconciliation Center.

\(^{37}\) The licence holder can conduct petroleum trade. However, it cannot conduct natural gas trade without a wholesale licence.

\(^{38}\) Entered into force on 15 April 2009.
iii Contracts for sale of energy

Electricity is traded mostly through bilateral agreements on an over-the-counter basis. Agreements are not subject to EMRA's approval and, thus, all commercial terms and conditions are freely negotiable. Electricity can also be traded on a day-ahead and real-time basis.

As for natural gas, suppliers and consumers must conclude private law contracts to participate in natural gas trading. A natural gas sale agreement is the primary agreement executed within the framework of natural gas sale and purchase activities.

In addition to a natural gas sale agreement, the following agreements must be concluded by the parties:

- operation agreements;
- system connection agreements; and
- lease agreements.

iv Market developments

Turkey aims to create a liberal and competitive energy market and increase investment opportunities by establishing an energy exchange market. Aside from this, Turkey's involvement in international oil and gas pipelines significantly supports its aim to become, in the short term, a regional energy hub.

International oil and gas pipelines

The transit passage of oil and gas through Turkey is governed by the Transit Law. However, for the Transit Law to apply as the legal regime of a transit pipeline, there must be an international agreement regarding that pipeline. The Transit Law, the international agreement (generally an intergovernmental agreement (IGA)) and the project agreements apply as the legal regime to the transit pipeline.

In addition to 'transit' pipelines through Turkey (e.g., the BTC Pipeline and the contemplated TANAP), there are pipelines that transport oil or gas to or from Turkey. These are non-transit pipelines, such as the Kirkuk–Yumurtalık Crude Oil Pipeline. The legal regime applicable to these pipelines is either in the form of a Council of Ministers' Decree (pursuant to the former Petroleum Law (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 the Caspian Sea 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);

39 The Trans-Anatolian Natural Gas Pipeline.
40 Entered into force on 16 March 1954.
The following contemplated projects will make Turkey a true oil and gas transport hub:

- **a** TANAP, to transport natural gas from Azerbaijan’s Shah Deniz gas field (Stage II) to Europe, through Turkey;
- **b** the Trans Adriatic Natural Gas Pipeline Project, to transport natural gas from Turkey to Southern Italy and further to Europe through Greece and Albania;
- **c** the Trans Caspian Natural Gas Pipeline Project, to transport natural gas from Turkmenistan to Erzurum, Turkey and possibly to Europe;
- **d** the Mashreq–EU Natural Gas Pipeline Project, to transport natural gas from the Mashreq countries to Turkey, Iraq and the EU;
- **e** Turkey–Bulgaria Natural Gas Pipeline Project, to transport natural gas from Turkey to Bulgaria;
- **f** the Northern Region of Iraq–Turkey Crude Oil Pipeline Project, to transport crude oil from the Northern Region of Iraq to Turkey; and
- **g** the Iran–Germany Natural Gas Pipeline Project, to transport natural gas from Iran to Germany through Turkey.

Although in late 2014 and in the first half of 2015 there was considerable progress in the negotiations for the ‘Turkish Stream’ pipeline project, following the recent tension between Turkey and Russia, this project has been virtually put on hold.

### 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 600MW of geothermal and 3,000MW of solar energy.

#### Incentive regime

The Law on the Utilisation of Renewable Energy Resources for the Purpose of Generating Electrical Energy (the RER Law) established a renewable energy support mechanism. 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

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41 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.

42 Entered into force on 18 May 2005.
of the RER Law. The RER Law provides that the prices in Schedule I (see below) will apply for 10 years for those generation facilities subject to the RER Support Mechanism and commissioned until 31 December 2020.43

<table>
<thead>
<tr>
<th>Type of facility</th>
<th>Prices applicable (US$ cent/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydroelectric</td>
<td>7.3</td>
</tr>
<tr>
<td>Wind</td>
<td>7.3</td>
</tr>
<tr>
<td>Geothermal</td>
<td>10.5</td>
</tr>
<tr>
<td>Biomass (including landfill gas)</td>
<td>13.3</td>
</tr>
<tr>
<td>Solar power</td>
<td>13.3</td>
</tr>
</tbody>
</table>

The RER Law further provides that renewable energy facilities can, subject to a Council of Ministers’ Decree, benefit from certain tax incentives, such as customs duty and VAT. Additional incentives are provided if domestic equipment is used in facilities commissioned before 31 December 2020.

ii Energy efficiency and conservation
Under the Energy Efficiency Law,44 the EECC45 regulates energy efficiency activities. This law sets forth several mandatory obligations.46 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 GDRE47 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.

43 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.
45 The Energy Efficiency Coordination Committee.
46 e.g., the use of labelled equipment in industrial companies and buildings.
47 The General Directorate of Renewable Energy.
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, Turkey privatised several electricity generation assets owned by EÜAŞ.\(^{49}\) Below is a summary of privatisations that have been completed as of 1 May 2016:

<table>
<thead>
<tr>
<th>Power plant</th>
<th>Approximate bid value (millions of Turkish liras)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Orhaneli and Tünçbilek TPP</td>
<td>1,360</td>
</tr>
<tr>
<td>Soma B TPP</td>
<td>1,789</td>
</tr>
</tbody>
</table>

Below is a summary of privatisations that were approved but are still waiting for parties’ signatures as of 1 May 2016:

<table>
<thead>
<tr>
<th>Power plant</th>
</tr>
</thead>
<tbody>
<tr>
<td>Manavgat HPP</td>
</tr>
<tr>
<td>Fethiye HPP</td>
</tr>
<tr>
<td>Karacaören 1 and Karacaören 2 HPP</td>
</tr>
<tr>
<td>Kadıncık 1 and Kadıncık 2 HPP</td>
</tr>
</tbody>
</table>

In addition to the privatisation of electricity generation assets, the tender for privatisation of İGDAŞ\(^{50}\) is expected to be announced after the enactment of the Draft Amendment Law.

ii EPİAŞ
The EML introduced the ‘market operation activity’, to be conducted by a newly incorporated company, namely EPİAŞ. EPİAŞ was finally incorporated in March 2015. 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 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. This plant is expected to generate approximately 35GW per year. The EIAR\(^{51}\) was approved

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48 This article only includes certain significant developments until 11 April 2016.
49 The state generation entity.
50 Istanbul’s natural gas distribution company.
51 Environmental impact assessment report.
by the MEU\textsuperscript{52} on 1 December 2014. The next phase is obtaining a construction licence from
the TAEA\textsuperscript{53} and concluding an electricity sale agreement with TETAŞ.\textsuperscript{54} It is expected that its
first unit will be operational in 2020.

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:
\begin{itemize}
  \item[a] the memorandum of understanding between the Republic of Turkey and the Republic
       of Azerbaijan regarding the TANAP system; and
  \item[b] the text of amendment to the HGA between the Republic of Turkey and the TANAP
       project company.
\end{itemize}

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.\textsuperscript{55}

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,\textsuperscript{56} 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.

\begin{itemize}
  \item[52] The Ministry of Environment and Urbanisation.
  \item[53] Turkish Atomic Energy Agency.
  \item[54] The state trading entity.
  \item[55] 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.
  \item[56] With a capacity of up to 8,000MW.
\end{itemize}
iv Shale gas
In September 2014, TPAO57 officials stated that negotiations between TPAO and ExxonMobil for projects related to shale gas reserves in the Thrace region of Turkey are continuing. TPAO also plans to sign an agreement with Halliburton, for exploration and production of shale gas in the Thrace region. In addition, TPAO has been collaborating with Shell for exploring shale gas reserves in Diyarbakır. However, according to TPAO officers, the first results of studies conducted for shale gas in Turkey will be available in 2016. According to experts, Turkey has 1.8 trillion m3 of shale gas reserves and these reserves could meet Turkey’s 40-year gas demand.

v Solar-based energy generation licence applications
Significant developments were also witnessed in renewable energy investment in 2015. EMRA received applications for solar-based energy generation licences between 1 and 7 April 2015. Although the designated total capacity for solar-based generation licences is 600MW, applications were submitted for nearly 8,900MW. Thus, several contests will be organised in different regions to decide who will obtain the generation licence in the relevant region. Below is a summary of the contests 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–Neşehir–Aksaray</td>
</tr>
<tr>
<td>Fifth package</td>
<td>29 April 2015</td>
<td>Kahramanmaraş–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>

57 The Turkish Petroleum Corporation.
Turkish Petroleum Law

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.

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.

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

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58 Although these enactments took place in 2013, we will provide brief information on them in this chapter because of their importance.

59 The long-awaited TPL was enacted in 2013, replacing the PL after nearly 60 years.

60 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.

61 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.

62 Although these enactments took place in 2013, we will provide brief information on them in this chapter because of their importance.

63 The EML entered into force in March 2013.
country’s foreign trade deficit. Because of insufficient domestic energy generation, Turkey’s primary goal is to strengthen its security of supply. Turkey aims to diversify its energy supply routes and sources, such as nuclear energy, and to increase the share of renewable energy.

Turkey’s importance in the energy markets is not just increasing as a growing consumer with a huge domestic market, but also as an energy transit hub. Although Turkey has limited energy resources, its position is critical for petroleum and natural gas trade between the East and the West, as it lies between energy-demanding European countries and energy-rich eastern countries. Turkey is a natural transit country for the maritime and pipeline transportation of gas and oil. Accordingly, international crude oil and natural gas pipelines and pipeline projects hold great importance and improve Turkey’s role as a reliable transit country.
I OVERVIEW

Because of its unique geographical location and its gas storage capacity, Ukraine plays a key role both in the European and global fuel and energy markets. On one hand, Ukraine is an energy-dependent country with insufficient volume of its own conventional energy sources (oil and gas). On the other hand, Ukraine is important for the global energy markets, being a major transit centre for exports of Russian oil and natural gas to both eastern and western Europe.

The key Ukrainian programme document dealing with energy is the Energy Strategy for the period up to 2030 (the Energy Strategy), which sets out the basis for the state's energy security and determines the main energy policy objectives and tasks, as well as outlining the major directions, priorities and future development of the energy sector. The Energy Strategy was approved by Resolution of the Cabinet of Ministers No. 1071 dated 24 July 2013, which simultaneously repealed the older version of the Energy Strategy adopted on 15 March 2006. According to the Energy Strategy, the main objectives of the document are to create conditions for reliability and quality in meeting the demand for energy products; improving energy security of the state; improving the efficiency of energy use and consumption; reducing the anthropogenic impact on the environment; and support of civil protection in the field of technological security of the Fuel and Energy Complex.

On 9 June 2015, the Ministry of Energy and Coal Industry of Ukraine published the draft of the Energy Strategy of Ukraine until 2035. The project aims to actualise the provisions of the Energy Strategy of Ukraine until 2030, taking into account existing threats.

1 Maryna Ilchuk is an associate at Arzinger.
The Strategy envisages achieving key tasks in the Ukrainian energy sector in certain stages. According to the document, Ukraine needs to ensure:

**a** until 2020:
- Ukraine’s energy sector transition to market principles of operation and competition;
- elimination of Ukraine’s dependence on the monopoly of energy supply; and
- diversification of routes and sources of energy supply; and

**b** until 2025:
- the integration of Ukraine’s energy sector into the EU energy markets and the European energy security system; and
- competitiveness of the national energy sector on the European energy market; and

**c** until 2035:
- full participation of Ukraine’s energy sector in the functioning of the European energy market with free movement of energy, investment and technology; and
- completion of technological modernisation of the energy sector.

On 7 August 2015 another programme document – the New Energy Strategy of Ukraine: Safety, Efficiency, Competition – was published on the Ministry’s website. The latter is a complex system document containing a deep analysis of the current situation in Ukraine’s energy sector and defining particular steps to be taken by Ukraine to complete the necessary reforms.

### II REGULATION

**i** The regulators

According to the Law of Ukraine on the Electric Power Industry (the Electric Power Industry Law), the state regulator for activities in the electricity industry is the National Commission (NCSREU), which performs state regulation in the energy sector.

On 10 September 2014, the Order of the President of Ukraine No. 715/2014 on approving the Regulations on the National Commission for State Regulation of Energy and Utilities was issued to establish the National Commission for State Regulation of Energy and Utilities (NCSREU). Thus, the NCSREU is a state collegial body subordinated to the President of Ukraine and accountable to the Parliament of Ukraine. The NCSREU is a state authority regulating activities in the field of energy and utilities. It has become the legal successor to the National Commission for State Regulation in the Field of Energy and of the National Commission Regulating Utilities. The authority that implements state policy in the sphere of efficient usage of energy resources, energy efficiency, renewable energy and alternative fuels is the State Agency of Ukraine on Energy Efficiency and Energy Saving (the Energy Efficiency Agency).

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4 Order of the President of Ukraine No. 715/2014 dated 10 September 2014 on approving the Regulations on the National Commission for State Regulation of Energy and Utilities.
5 Decree of the President of Ukraine No. 462/2011 on Approval of the Regulation on the State Agency of Ukraine on Energy Efficiency and Energy Saving, dated 13 April 2011.
The issue of determining the legal status of the Ukrainian regulator still remains open. The independent regulator plays the key role on the energy market, exercising overall control over the market, promoting competition and protecting the consumers’ interests.

To perform its obligations as a party of the Energy Community Treaty, Ukraine needs to adopt the specific law regarding the regulator. On 12 April 2016, a draft Law on National Commission Exercising State Regulation in the Field of Energy and Utilities was passed at first reading.

The Draft envisages such important amendments as:

a. a more transparent procedure for the appointment of the chairman of the NCSREU on the basis of open competitive selection for this post. The competitive selection is performed by the competition committee, which functions under the supervision of the President of Ukraine. The members of the commission are appointed by the Verkhovna Rada of Ukraine from the list of candidatures proposed by the Parliamentary Committee on Housing (two persons) and the Parliamentary Committee on the Fuel and Energy Sector (three persons);

b. the chairman of the NCSREU is re-elected every two years after the date of the first appointment by the competition committee;

c. ensuring the rotation of NCSREU board members. For this purpose, the rotation scheme is set to provide for the assignment of two new members of the NCSREU board each calendar year; and

d. clarification of the NCSREU’s power regarding the regulation of natural monopolies. In particular, the NCSREU is provided with the power to impose penalties on the subjects of natural monopolies and entities in adjacent markets.

Currently, the draft has been prepared for its final reading by the Verkhovna Rada of Ukraine and if adopted, will become effective as of the date of publishing (except for several provisions specified therein).

ii Regulated activities

Licensing of activities in the electric power industry is regulated by Article 13 of the Electric Power Industry Law.

Production, transmission and supply of electric power in Ukraine are subject to obtaining an appropriate licence from the NCSREU. The scope of the licensed activities in the energy sector is set by several laws: the Law of Ukraine on Licensing of Types of Economic Activities, the Law of Ukraine on Electric Power Industry and Waste Energy Potential, the Law of Ukraine on Natural Monopolies, and the Law of Ukraine on Licensing Activities in the Field of Nuclear Energy.

Energy suppliers obtain licences for types of activity in the electric power sector with regard to the needs of consumers in the territory in which the licensed activity takes place.

Licences are issued by the NCSREU for each single type of activity:

a. electricity production (amounts not exceeding the level requiring licensing);

b. electricity supply;

c. performance of the functions of the guaranteed buyer;

d. performance of the functions of the system operator.6

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transportation of oil and oil products, natural and petroleum gas and other substances through pipelines;

distribution of oil and natural gas through pipelines;

storage of natural gas in amounts exceeding the level set by the terms and rules of entrepreneurial activity of natural gas storage (licensing conditions);

transmission of electricity through main and interstate power grids;

distribution of electric power (electric power transmission via local electric systems);

transportation of heat;\(^7\)

transportation and distribution of natural gas, natural gas (methane) of coal deposits, its storage in amounts exceeding the level set by the licensing conditions, and their supply (except for the supply of natural gas, natural gas (methane) of coal deposits at non-regulated tariffs);

centralised water supply and disposal, in addition to water supply and disposal at non-regulated tariffs; and

heat production, heat transportation through main and local (distribution) heat networks and heat supply, except for production, transportation and supply of heat at non-regulated tariffs.\(^8\)

On 16 June 2000,\(^9\) Energorynok SE was licensed to carry out business activities in the wholesale supply of electricity, effective from 1 July 2000.

The NCSREU is also empowered to license economic activities in the natural gas market, and approve licensing terms for implementation of certain types of economic activities within the natural gas market.\(^10\) Each activity is licensed separately in the order established by the NCSREU.

iii Ownership and market access restrictions

Article 6 of the Electric Power Industry Law regulates property rights in the electric power industry. Power generation facilities may fall under different forms of ownership. The list of power generation facilities that are not subject to privatisation will be approved by the Supreme Council of Ukraine upon provision of the Cabinet of Ministers of Ukraine (CMU). Privatisation of facilities in the electric power industry is performed in accordance with the laws of Ukraine on privatisation.\(^11\)

Any property that ensures the integrity of the Unified Energy System of Ukraine and centralised operational process management, the main and interstate power grids, and property of research institutions of national importance will not be subject to privatisation.\(^12\)

\(^7\) Law of Ukraine on Natural Monopolies, No. 1682-III, dated 20 April 2000.

\(^8\) Law of Ukraine on Licensing of Types of Economic Activities, No. 222-VIII, dated 2 March 2015.

\(^9\) NCSREU Order No. 684.


\(^12\) Law of Ukraine on the List of Objects of State Property That Cannot Be Privatised, No. 847-XIV, dated 7 July 1999; such objects include Ukrenergo, Ukrintenergo, and public research institutes of thermal power.
Further, the gas pipeline system itself is not subject to privatisation. There are 42 gas supply companies (Oblgas) providing supply and transportation of natural gas to end consumers, and these exist in the form of public joint-stock companies (PJSCs). Some Oblgas were privatised in the mid-1990s. Private Oblgas operate gas-distributing pipelines on lease terms. To comply with the requirements set by the Law of Ukraine on the Natural Gas Market and detailed in NCSREU Decree No. 9 on Approval of Licensing Terms for Exercising Economic Activities on the Natural Gas Supply, Supply of Gas (Methane) of Coal Deposits at Regulated Tariffs, the Oblgas can no longer perform supply and distribution of gas simultaneously and are obliged to split into two separate entities, each of which shall perform gas supply or distribution respectively (combining both functions is prohibited). Accordingly, in 2015, Oblgas split into gas supply entities and entities performing gas distribution, which is one of the first steps towards the reform of the gas market.

In terms of coal, according to Article 24 of the Code on the Subsoil of Ukraine, legal entities that have the right to use the subsoil are entitled to ownership of useful extracted mineral resources unless otherwise provided by the law or their licence. As all mineral resources are initially owned by the state, the owner of a mine has the ownership both of the mine and its coal resources, but has to pay a rent fee each calendar quarter (three months) stipulated by the production-sharing agreement. Coal mines are not included on the list of state property that cannot be privatised.

In early June 2010, the President of Ukraine announced a programme of economic reforms for the 2010–2014 period, which envisaged the privatisation of regional electricity distribution companies (Oblenergos) and of energy generation companies. As a result, on 12 April 2015 the Cabinet of Ministers of Ukraine passed Resolution No. 271 on Approval of The List of State Property Objects To Be Privatised in 2015. They include a number of iconic energy enterprises, such as Centrenergo, (78.29 per cent of the shares) Dniproenergo, (25 per cent) Kyivenergo, (25 per cent) Zakhidenergo, (25 per cent) Donbasenergo, (25 per cent) and distribution companies Dniprooblenergo, (25 per cent) Donetskoblenergo, (25 per cent) Sumyoblenergo, (25 per cent) Zaporizhiaoblenergo,(60.24 per cent) Mykolaivoblenergo, (70 per cent) Ternopiloblenergo, (50.99 per cent) Kharkivoblenergo, (65.001 per cent) Khmelnytskoblenergo,(70 per cent) Odesaoblenergo,(25 per cent) and Cherkassyoblenergo (46 per cent). Also, the privatisation list included about 40 packages of regional and city (Oblgas and Gorgas) gas enterprises. The Resolution also included the following combined heat and power generation companies: PJSC Khersonska CHP (99.83 per cent of the shares); PJSC Odesska CHP (99.99 per cent of the shares); PJSC Nikolaivska CHP (100 per cent of the shares); and Dniprodzerzhynska CHP (99.92 per cent of the shares). Because of economic and political factors, the privatisation of the above objects has been delayed. The listed objects are to be sold in 2016 according to the Decree of the State Property Fund of Ukraine No. 2064 dated 30 December 2015 on

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14 NCSREU Decree No. 9, on Approval of Licensing Terms for Exercising Economic Activities on the Natural Gas Supply, Supply of Gas (Methane) of Coal Deposits at Regulated Tariffs, dated 12 January 2015.
15 Article 388.1 of the Tax Code of Ukraine.
16 The electricity generation companies currently operating in Ukraine are PJSC Dniproenergo, PJSC Centrenergo, PJSC Zapadenergo and PJSC Donbassenergo.
Approval of the List of Objects of B, Г, Categories for Sale in 2016. The final complete list of objects for privatisation in 2016 has not yet been approved by the Cabinet of Ministers of Ukraine.

Thus, in recent years, Ukraine has taken steps to privatise the energy sector. This is normal practice in countries with transitional economies that are not able to ensure the development of industry and to invest in the infrastructure by themselves. Taking into account, however, that the current state of the infrastructure is quite poor, the effectiveness of such actions depends on whether private investors invest seriously in the development of the privatised objects. Another issue is the readiness of the Ukrainian government to properly organise the privatisation procedure and meet the set privatisation schedules.

iv Transfers of control and assignments
The NCSREU determines compliance of liquidation, reorganisation in the form of a merger, consolidation, participation in unions as well as acquisition or alienation of more than 25 per cent of shares (stock) in assets of economic entities on the electricity market with the rules and conditions of exercise of the licensing activity.

The NCSREU also determines compliance with the licensing conditions of liquidation, reorganisation in form of consolidation, merger, participation in unions as well as acquisition or alienation of more than 10 per cent of shares (stocks, equities) of assets of economic entities on the natural gas market.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES
i Vertical integration and unbundling
On 9 April 2015, the Parliament of Ukraine adopted the Law of Ukraine on the Natural Gas Market. It is substantially different from the previous law regulating the Ukrainian gas market – the Law of Ukraine on Principles of the Functioning of the Natural Gas Market. The Law of Ukraine on the Natural Gas Market was enacted on 1 October 2015.

The Law provides for the following:

a a legal, economic and organisational basis for the functioning of the natural gas market;
b creating a legal framework for activities in the natural gas market;
c providing a non-discriminatory access to the natural gas market to its subjects and consumers; and
d creating a fully-fledged natural gas market in Ukraine based on the principles of free competition with an appropriate level of consumer protection (in particular, consumer categories in need of special protection), energy supply security, and the ability to integrate with gas markets of parties to the energy community, including through the establishment of regional natural gas markets.

A significant change in the legal framework is its full linkage to ‘the human rights practices of the energy community, and in particular to the decisions of the Court of Justice, the practice of the EU Court of Justice, the practice of the European Commission and the Energy Community Secretariat’, as well as the emphasis on non-discriminatory treatment of market participants.
Apart from that, the law separates gas transmission activities from other types of activities and contains requirements for certification and approval of transmission system operators (independent transmission operators and independent system operators), as well as safety and transparency requirements for the gas market.

The general purpose of the law is to bring Ukrainian legislation into line with the Third Energy Package.

Also, the draft Law on the Electricity Market No. 4493 is expected to be adopted by the Verkhovna Rada of Ukraine in the very near future. The draft Law is aimed at meeting the requirements of the EU Third Energy Package, in particular the requirements regarding the legal and organisational separation of the distribution and transmission of electricity from other activities. In particular, the draft envisages:

a. separation of transmission system operator (TSO) functions of the distribution of electricity through (local) electric networks and energy suppliers in terms of electricity supply from existing entities (Oblenergos);

b. full separation of the TSO, which has to become a separate independent entity and not a part of a vertically integrated undertaking (VIU) performing the production, distribution or supply of electricity;

c. introduction of the day-ahead energy market;

d. introduction of the intraday energy market; and

e. addition of traders to the list of market participants. According to the draft, a trader is defined as any entity that purchases electricity solely for the purpose of resale, except for sales to consumers. Traders will carry out the sale of electricity under bilateral (direct) contracts, on intraday or day-ahead market.

Naftogaz is a leader in the Fuel and Energy Complex and is one of the largest Ukrainian companies. It combines the largest gas and oil-producing enterprises, and holds a monopoly on natural gas transit and its underground storage, as well as on oil piping within the country’s territory. Naftogaz carries out the full operation cycle for gas exploration and development, operational and test well-drilling, gas and oil transportation and storage, and consumer supply of natural and liquefied gas. Currently, the state is the only stockholder of Naftogaz, which has a number of subsidiaries carrying out operations in the gas industry, including production, transmission, distribution and technical support.

Independent activities of such operators should be achieved via a prohibition on holding more than one office in the structure of a vertically integrated company and by independent decisions regarding current financial and other business operations. On 14 August 2014, the parliament of Ukraine passed a Bill on Amendments to Ukrainian Laws on Reforming the Management System of the Unified Gas Transportation System of Ukraine into law. This Law was adopted to reform the national joint-stock company Naftogaz of Ukraine to meet Ukrainian commitments under the Protocol concerning the Accession of Ukraine to the Treaty Establishing the Energy Community. According to the document, dispatcher control (of operations and technology) functions are performed by the operator of the Unified Gas Transportation System of Ukraine. Functions of the operator

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17 Bill on Amendments to Ukrainian Laws on Reforming the Management System of the Unified Gas Transportation System of Ukraine No. 4116a, dated 18 June 2014.
of the Unified Gas Transportation System of Ukraine are assigned to an enterprise that may be founded or owned exclusively by the state, or (in the case of a joint venture) the state (owning at least 51 per cent of participation rights) and a legal entity owned and controlled by residents of Member States of the EU, the United States or the Energy Community. The above amendments are reflected in the Law of Ukraine on the Natural Gas Market. The aforementioned law envisages two models for the separation of natural gas transmission operations: Article 23 stipulates the ownership unbundling (OU) model (separation via unbundling of ownership), and Article 27 mentions the independent system operator (ISO) model (separation by engaging an independent system operator to oversee gas transmission operations). Ukraine inclines towards the OU model. Thus, at the beginning of may, the energy community provided its conditional approval of the OU for the natural gas TSO in Ukraine, with the requirement that a firm road map for the unbundling process comes into effect not later than 1 June 2016.

Under the terms of its obligations towards the Energy Community, Ukraine must reform its electricity market in line with Directive 2003/54/EC. Therefore, on 24 October 2013 the Law of Ukraine on Operating Principles of the Electricity Market No. 663-VII (the Electricity Market Law) was adopted. One of the issues, regulated by the document is the unbundling of Oblenergos. In accordance with Article 15 Part 5 of the Electricity Market Law, electricity distribution companies are not allowed to carry out activities for the production, transmission and supply of electricity. Such activities shall be legally and organisationally separated from other activities of the vertically integrated business organisation, which are not related to the distribution of electricity.

ii Transmission/transportation and distribution access

The Law on the Natural Gas Market implements another significant principle: the opening up of the gas market – the main condition for establishing real competition. Opening the market means the guarantee of the right of consumers to freely select gas suppliers, which requires equal access to the market both for companies already existing in the market and for those recently appearing therein. Thus, the only ‘restriction’ on access to the market would appear to be the licensing system, which admits such activities as transportation, distribution, supply, storage or production based on objective, transparent and non-discriminatory criteria determined by the regulator. The rules for conducting activities on the gas market are detailed in the Code on the Gas Transportation System, the Code on Gas Distribution Systems, the Code on Gas Storage Facilities and the Code on LNG Installation. The above codes are approved by the regulator (NCSREU).

The Electricity Market Law also provides for non-discriminatory and transparent access to the main, interstate or local power networks, as well as non-discriminatory access

19 Splitting vertically integrated energy companies to separate energy transmission operations from energy production and supply lies at the core of the Third Energy Package, in particular, the Directive 2009/72/EC (for electricity) and Directive 2009/73/EC (for gas).
to the electricity market. Access to the network capacity of interstate power networks is provided to all energy suppliers and producers of electricity. Energy distribution companies must provide non-discriminatory access to local power networks on the electricity market.

According to NCSREU Regulation No. 3158 on Establishing the Tariffs for PJSC Ukrtransgaz for Services of Natural Gas Transportation through Cross-Border Pipelines for Entry and Exit Points, the tariffs for gas transportation as of 1 January 2016 are set for entry and exit points as detailed in the Regulation and include norms of production, technological and regulatory expenses for exit points set in percentages. The corresponding calculation system is aimed at setting a fair market price for gas transportation, in particular for Russian monopolist PJSC Gazprom.

iii Storage, processing and treatment
According to the Law on the Natural Gas Market, storage (injection, extraction) of natural gas is carried out based on an agreement, under which the operator provides the client with the services of natural gas storage (pumping, extraction) by providing access to the gas storage facilities on the terms stipulated in the agreement, and the client pays the operator the cost for such services set in the agreement. Obligatory conditions for gas storage operators and consumers of gas storage services are determined in a standard agreement on natural gas storage. The standard agreement on natural gas storage is approved by the regulator. The new standard form of the natural gas storage agreement was approved on 30 September 2015 by NCSREU Regulation No. 2499 dated 30 September 2015.

The operator is obliged to provide the information on current tariffs on its official website. The operator is also obliged to publish on its website the form of the standard contract of natural gas storage, the current edition of the Code on Gas Storage Facilities, applications on capacity distribution, nomination or renomination and other documents and forms stipulated by the agreement and the Code.

Among other important obligations of the operator are:

a ensuring the availability of the required capacities at the entry and exit points of the gas transportation system to gas storages or entry points to the gas transportation system from gas storage facilities in accordance with the capacity allocation;
b ensuring proper functioning of its dispatching service;
c ensuring the proper quality of gas of the client at the gas transportation system entrance points from its storage facilities; and
d to recalculate the cost of the services provided under the agreement in the event of non-compliance of the quality or the volume of the pressure or extraction of the natural gas by the client.

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22 NCSREU Regulation No. 3158 on Establishing the Tariffs for PJSC Ukrtransgaz for Services of Natural Gas Transportation through Cross-Border Pipelines for Entry and Exit Points dated 29 December 2015.
23 NCSREU Regulation on Approval of the Contract of Natural Gas Storage (Pumping, Extraction) No. 2499 dated 30 September 2015.
The OU model set by the Law on the Natural Gas Market applies to the operator, which according to Article 23 of the Law cannot be a part of VIU and has to perform its activities independently from natural gas extraction, division and supply as well as from the activities of the wholesalers.

**Rates**

To resume lending to Ukraine under the Stand-by programme, the Ukrainian government and the International Monetary Fund have agreed upon an increase of tariffs for housing and communal services for the population to economic levels. According to the arrangement, the gas price in 2015 has risen by 280 per cent and heat supply by 66 per cent. In addition, on 1 June 2015 the National Commission responsible for regulation in the energy sector, raised electricity tariffs for the population by 10–40 per cent, depending on the volume of consumption. Furthermore, on 27 April 2016 the Cabinet of Ministers of Ukraine decided to establish a uniform gas price for the population: 6,879 hryvnias per thousand cubic meters. The new gas price became effective as of 1 May 2016. The price now corresponds with the market conditions, as its structure includes the cost of gas transportation and related taxes.

**Electricity**

The NCSREU regulates the prices (tariffs) for goods (services) of natural monopolies in the Fuel and Energy Complex of Ukraine, based on the regulatory principles as defined by the applicable law, mainly addressing the balance between the economic interests of producers and consumers of their goods and services, as well as the principle of full compensation by the consumer of reasonable expenses for production, transmission and supply of electricity. The market order of price formulation is not differentiated for consumers within different economic sectors.

The NCSREU established a system of price regulation that includes a number of controls over pricing at each stage of the process (production, transmission and supply of electric energy). The concept adopted in Ukraine, and set out in the Law on the Electric Power Industry, as well as in many acts of the CMU, provides for market-led pricing of electricity.

**Gas market**

The limiting (upper) levels of natural gas prices for all consumer categories are approved by the NCSREU in accordance with regulatory documents. These methods provide for the addition of prospecting, transmission and gas supply costs to overall production costs. Naftogaz sends the prices to the NCSREU and the reasoning thereof, which are required for further revision of tariffs, as well as for revision of tariffs for gas transmission via main pipelines and for natural gas supply.

At present, there are both regulated and non-regulated natural gas prices for Ukrainian consumers. The main function of state regulation is the establishment of state-regulated prices and tariffs for services provided by monopolists. Regulated tariffs apply to the immediate gas supply to consumers by licensees pursuant to licensing terms under established price formulation rules. Non-regulated tariffs apply to the immediate gas

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24 A gas consumer is a legal entity or an individual entrepreneur obtaining gas under a gas supply agreement and using it as fuel or raw stock, or a natural person obtaining gas under a gas supply agreement to use for its individual household needs, including cooking food,
Supply to consumers made by licensees under licensing terms under contract principles at free prices and under competitive conditions. Therefore, the licensee sets the price for natural gas at its own discretion, which may not exceed the upper price level for natural gas established by the NCSREU. A non-regulated tariff will be introduced to create a certain competitive environment.

According to draft Law No. 2250 on the Natural Gas Market, NCSREU, as the national regulator in the field of energy, is vested with a broad scope of powers in accordance with the draft. Thus, the National Commission will not only set prices and tariffs for gas, transmission and storage services, and delivery to consumers, but will also be given extensive rights to control the observance of transparency and free competition rules for all participants in the country’s gas market.

v Security and technology restrictions

The main document providing for security in the energy sector is the National Security Strategy of Ukraine, approved by Decree of the President of Ukraine No. 287/2015 dated 26 May 2015. The document includes separate articles covering threats to energy security and strengthening of energy security.

The priorities of Ukrainian energy security are set as follows:

a reform of the energy markets, ensuring transparency of business activities, competition in these markets and their demonopolisation; and integration of Ukraine’s energy sector into the EU energy markets and the system of European energy security;

b promotion of energy efficiency and energy saving;

c diversification of sources and routes of energy supply, overcoming dependence on Russia in supply of energy and technology, and development of renewable and nuclear energy on the basis of environmental and nuclear safety priorities;

d creation of conditions for a reliable energy supply and energy transit through Ukraine, and protection of energy infrastructure from terrorist threats; and

e formation of the power supply system of the national economy and society within a specific period.

In addition, in 2006, Law No. 307-V on the Functioning of the Fuel and Energy Complex during a Specific Period was adopted. This Law regulates relations regarding the generation, transmission, delivery and use of energy resources over a specific period by companies, entities and organisations in the fuel and energy complex, without regard to the form of ownership or

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25 Heating water and heating premises (Item 1.3 of NCSREU Decree No. 9 on Approval of Licensing Terms for Exercising Economic Activities on the Natural Gas Supply, Supply of Gas (Methane) of Coal Deposits at Regulated Tariffs, dated 12 January 2015).

26 Ibid.
their interactions with, among others, government bodies. In addition, work has intensified in the environmental safety sector as part of the National Security Strategy, in particular to increase the level of safety at the Chernobyl nuclear power plant.

On 9 February 2015 the Cabinet of Ministers of Ukraine adopted Instruction No. 1296 on Taking Temporary Emergency Measures in Electricity Market. This Instruction was adopted on the initiative of the Ministry of Energy and Coal Industry of Ukraine and remained in force for a month as a temporary document aimed at ensuring the reliable and stable functioning of the Ukrainian energy system. The Instruction envisaged ‘manual’ control of the Ukrainian energy market by the state, which included adjustment of tariffs for electric power and of the ‘green tariff’, adjustment of tariffs for electricity transmission, adjustment of licensee investment programmes, etc. The Instruction entered force on 19 February 2015 and remained in force until 19 January 2016.

IV ENERGY MARKETS

i Development of energy markets

In Ukraine the electricity market functions separately from the gas market. The CMU adopted a decree in February 1996, according to which the energy market began operations on 16 July 2015.

The wholesale electricity market (WEM) is a market established by business entities for the purchase and sale of electric energy under contract.

Today, the WEM operates based on the Electric Power Industry Law, as amended on 22 June 2000. In accordance with this Law, activities on the energy market are regulated by wholesale market rules, by agreement between parties (or members) of the WEM, by bilateral contracts on the sale of electricity or by the NCSREU licence on production, transmission and supply of electric energy. Regulation of the energy market is provided by the NCSREU, including the establishment of fixed rates for electricity producers, fixed tariffs on transmission and supply for electricity providers, and the rate for households. Control over the energy market is also exercised by the Ministry of Fuel and Energy of Ukraine.

Given that a considerable number of the WEM participants are natural monopolies, its operation is also based on the Laws of Ukraine on Natural Monopolies, on the Protection of Economic Competition, and on Protection against Unfair Competition.

The WEM operates according to the single-buyer model. All entities forming the WEM are licensees (producing companies, distribution companies and electricity suppliers),

28 Resolution of the Cabinet of Ministers of Ukraine No. 3 on Approval of Rules and Regulations of Entrepreneurial Activity on Production of Electricity, dated 8 February 1996.
29 Article 1 of the Electric Power Industry Law.
30 Agreement on the WEM, dated 15 November 1996.
31 Transmission of energy is transportation of energy through networks based on agreement (Article 1 of the Electric Power Industry Law).
32 Supply of electricity is provision of electricity to consumer through technical transmission and distribution means based on agreement (Article 1 of the Electric Power Industry Law).
and the executive body of the WEM administration is the Market Council. Energorynok SE (State Enterprise) is a commercial WEM operator, and thus a ‘single buyer’ therein (it exclusively buys electricity from generating companies and sells it to distribution companies). National Energy Company (NEC) Ukrenergo, owner and operator of the main network of 220kV to 750kV voltage class, carries out management tasks as the WEM technical operator.

Energy distribution companies are represented in the WEM according to the number of regions: 25 regional (Oblenergos) and two municipal energy companies (Kiev, Sevastopol). WEM energy suppliers are divided by licensing rules into two major groups: suppliers at regulated (fixed) tariffs and suppliers at non-regulated (free) tariffs. Tariffs for electricity suppliers at regulated tariffs are set by the NCSREU, whereas tariffs for supply of electricity at unregulated tariffs are determined by agreements between electricity suppliers and consumers. Consumers buy electricity from Energorynok SE through electricity suppliers, and Energorynok SE, in its turn, orders and buys the necessary volume of electricity from generating companies. Physically, the electricity produced by generating companies reaches consumers via the main and distribution electric networks based on agreements on the transfer of electricity between the relevant WEM entities.33

ii Energy market rules and regulation
As mentioned above, on 24 October 2013 the Law of Ukraine on Operating Principles of the Electricity Market No. 663-VII (the Electricity Market Law) was adopted by the parliament.34 The main purpose of the Law is to liberalise the WEM and create effective competition within the energy market. The Electricity Market Law also provides for non-discriminatory and transparent access to the main, interstate or local power networks, as well as non-discriminatory access to the electricity market. Access to the network capacity of interstate power networks is provided to all energy suppliers and producers of electricity. Energy distribution companies must provide non-discriminatory access to local power networks on the electricity market.

The Law foresees the implementation of a model of operation under direct agreements on Ukraine’s electricity market, the market of ‘day-ahead’ contracts and a balancing market, which will provide an opportunity to regulate the imbalance that appears during electricity generation. The document also suggests the creation of a market of additional services for purchases from peaking power plants.

On the bilateral conditions market, producers sell their generated electricity and energy suppliers buy it under the agreement of the parties regarding the price, volume and term of the electricity supply based on the concluded bilateral conditions.

In the ‘day-ahead’ market the generators and energy suppliers buy and sell electricity during the organised trading in electric energy for the following day by the conclusion of relevant agreements with the operator of the market based on the results of trading.

Prices and volumes of selling and buying of electricity on the following day are determined in accordance with the rules of the ‘day-ahead’ market.

33 Ukrenergo owns the main networks with the right of economic management (may not sell them), whereas Oblenergos are owners of native (local) distribution networks.
Prices for electricity generated based on results of trading in electric energy for the following day can be used as an indicator in determining the price of purchase and sale of electricity in the bilateral conditions market and balancing market.

In the electric energy retail market consumers buy electricity from the energy suppliers (independent or guaranteed).

The Law foresees the creation of a Cost Imbalance Allocation Fund, which is to be formed using funds to be paid by nuclear and hydropower plants.

The fund will also handle settlements for electricity sold at feed-in tariffs, and compensate guaranteed suppliers' losses from the sale of electricity to consumers at regulated prices.

The Electricity Market Law provides for the development of a number of regulations for its implementation, including the Electricity Networks Code and the Commercial Accounting Code.

According to the Law, the new market will be introduced by 1 July 2017. As mentioned above, the Electricity Market Law will be accordingly updated in compliance with the requirements of the Third Energy Package with the adoption of the draft Law on the Electricity Market. The draft will replace the current Electricity Market Law, the aim of which was to implement the requirements of the Second Energy Package.

The draft Law on the Electricity Market takes into account the norms of the current Electricity Market Law and at the same time envisages significant changes in the legislation regulating the functioning of the electricity market.

The draft provides that the energy market of Ukraine shall consist of the following parts:

a bilateral agreements;
b day-ahead market;
c intraday energy market;
d a balancing market;
e a market of supporting services; and
f a retail market.

According to the recommendations of the Energy Community Secretariat, the draft provides for the replacement of the Cost Imbalance Allocation Fund by set by the current Electricity Market Law with a new mechanism to support ‘green tariff’ electricity producers. The draft provides that the entire amount of electricity produced from renewable energy sources is bought by a guaranteed buyer. The expenses of the guaranteed buyer are reimbursed by the TSO. The guaranteed buyer’s obligations can be set by the Cabinet of Ministers of Ukraine for any market participant.

Moreover, traders are added to the list of market participants. According to the draft, a trader is defined as any entity that purchases electricity solely for the purpose of resale, except for sales to consumers. Traders will carry out the sale of electricity under bilateral (direct) contracts, on the intraday or day-ahead market. The draft Law is expected to be adopted in the very near future.

### Contracts for sale of energy

As previously mentioned, both energy and gas markets are currently undergoing a period of reform, the main purpose of which is market liberalisation. As a result, ‘qualified’ consumers will be free to choose their gas suppliers. The qualification criteria have been established by the NCSREU for each specific class of consumer, with effect from 1 January 2015.
Reformation of the Ukrainian electricity market envisages a gradual transition from the current system to a bilateral contract model with a balancing market.

iv Market developments
The main market developments have been described in previous sections and are aimed at liberalisation of energy and gas markets in accordance with Ukraine’s obligations as a member of the Energy Community.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy
In 2012, significant amendments were introduced to the renewable energy legislation. On 20 November 2012, the Law on Amendments to the Law of Ukraine on the Electric Power Industry (on promoting electricity generation from biogas) was adopted.\textsuperscript{35}

The Law extended the scope of the Law on the Electric Power Industry. It introduced a coefficient of 2.3 for the electricity produced from biogas.

The green tariff coefficient rate schedule under the Renewables Law is provided below. It also includes a 10, 20 and 30 per cent reduction in tariffs for power plants commissioned after 2014, 2019 and 2024 respectively, stipulated by the current legislation.

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</thead>
<tbody>
<tr>
<td>Wind energy, rated capacity &lt;600kW</td>
<td>1.20</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Wind energy, rated capacity 600kW–2,000 kW</td>
<td>1.40</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
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<tr>
<td>Wind energy, rated capacity &gt;2,000kW</td>
<td>2.10</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Wind energy, installed capacity of the unit &lt;600kW</td>
<td>–</td>
<td>1.20</td>
<td>1.08</td>
<td>1.08</td>
<td>1.08</td>
<td>0.96</td>
<td>0.84</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Wind energy, installed capacity of the unit 600kW–2,000kW</td>
<td>–</td>
<td>1.40</td>
<td>1.26</td>
<td>1.26</td>
<td>1.26</td>
<td>1.12</td>
<td>0.98</td>
<td>–</td>
<td>–</td>
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<tr>
<td>Wind energy, installed capacity of the unit &gt;2,000kW</td>
<td>–</td>
<td>2.10</td>
<td>1.89</td>
<td>1.89</td>
<td>1.89</td>
<td>1.68</td>
<td>1.47</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Biomass energy</td>
<td>2.30</td>
<td>2.30</td>
<td>2.07</td>
<td>2.30</td>
<td>2.30</td>
<td>2.30</td>
<td>2.07</td>
<td>1.84</td>
<td>–</td>
</tr>
<tr>
<td>Biogas energy</td>
<td>–</td>
<td>2.30</td>
<td>2.07</td>
<td>2.30</td>
<td>2.30</td>
<td>2.30</td>
<td>2.07</td>
<td>1.84</td>
<td>–</td>
</tr>
<tr>
<td>Solar energy, surface power facilities</td>
<td>8.64</td>
<td>6.30</td>
<td>5.67</td>
<td>3.15</td>
<td>2.97</td>
<td>2.79</td>
<td>2.51</td>
<td>2.23</td>
<td>–</td>
</tr>
<tr>
<td>Solar energy, power facilities fixed on roofs, rated capacity &lt;100kW</td>
<td>7.92</td>
<td>6.66</td>
<td>5.99</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
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\textsuperscript{35} Law No. 5485-VI, the Renewables Law.
The table below provides the tariff coefficients for objects commissioned:

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</thead>
<tbody>
<tr>
<td>Solar energy, power facilities fixed on roofs, rated capacity &gt;100kW, objects fixed on facades</td>
<td>8.28</td>
<td>6.48</td>
<td>5.84</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Solar energy, power facilities fixed on roofs of the private houses, rated capacity &lt;30kW</td>
<td>–</td>
<td>6.66</td>
<td>5.99</td>
<td>3.72</td>
<td>3.53</td>
<td>3.36</td>
<td>3.02</td>
<td>2.69</td>
</tr>
<tr>
<td>Wind energy, power facilities fixed on roofs of the private houses, rated capacity &lt;30kW</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>2.16</td>
<td>2.16</td>
<td>2.16</td>
<td>1.94</td>
<td>1.73</td>
</tr>
<tr>
<td>Micro-hydropower station, installed capacity &lt;200kW</td>
<td>2.16</td>
<td>3.60</td>
<td>3.24</td>
<td>3.24</td>
<td>3.24</td>
<td>3.24</td>
<td>2.92</td>
<td>2.59</td>
</tr>
<tr>
<td>Mini-hydropower station, installed capacity 200kW–1MW</td>
<td>2.16</td>
<td>2.88</td>
<td>2.59</td>
<td>2.59</td>
<td>2.59</td>
<td>2.59</td>
<td>2.33</td>
<td>2.07</td>
</tr>
<tr>
<td>Small hydropower station, installed capacity &gt;1MW</td>
<td>2.16</td>
<td>2.16</td>
<td>1.94</td>
<td>1.94</td>
<td>1.94</td>
<td>1.94</td>
<td>1.75</td>
<td>1.55</td>
</tr>
<tr>
<td>Geothermal energy</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>2.79</td>
<td>2.79</td>
<td>2.79</td>
<td>2.51</td>
<td>2.23</td>
</tr>
</tbody>
</table>

Amendments also concerned coefficients for electricity produced by solar objects. Accordingly, the Law provided for a decrease in the coefficients for solar energy (the coefficients were increased again in 2015).

Also, the document introduced differentiation between small hydropower stations in accordance with their installed capacity and increased coefficients for the electricity produced by small hydropower plants.

An important innovation stipulated by the document is the green tariff for individuals. The document states the following:

> For electricity produced from solar energy by power facilities fixed on roofs of private houses, rated capacity <10kW, in volumes exceeding consumption by such households, the green tariff shall be awarded. Such electricity is produced without any licence. The NCSREU shall define the procedure for purchase of and payment for such electricity (which shall be done by energy supply companies).

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36 Consequently, such a company may not be a member of the WEM either.
On 3 February 2015, the Parliament of Ukraine adopted Law No. 514-VIII on Amendments to Certain Laws of Ukraine Regarding the Competition Environment in Production of Electricity from Alternative Energy Sources amending the following: the Law of Ukraine on Electricity, the Law of Ukraine on Alternative Energy Sources, the Law of Ukraine on Alternative Fuels, and the Law of Ukraine on the Electricity Market Platform in Ukraine. The Law envisages a whole set of qualitative changes to the incentive mechanism for the production of electricity from renewable energy sources.

The most significant amendments introduced by the Law are the following:

a. extension of the definition of biomass, stipulating that products will be also considered as biomass. Thereby, wood chips, pellets and energy crops will be included into the concept of biomass, which complies with the Directive 2009/28/EC of the European Parliament and of the Council;

b. increase of the green tariff for the producers of electricity from biomass and biogas;

c. the green tariff rate is brought into line with the current cost of renewable energy electricity production technologies, in particular, to handle an excessive stimulation of electricity generation from solar energy – in particular, the green tariff rate for solar energy, which was decreased by Law No. 5485-VI, has been almost doubled by Law No. 514-VIII;

d. introduction of the green tariff for household wind power plants;

e. increase of the capacity limit from 10 to 30kW for private households producing solar or wind energy entitled to receive the green tariff for energy produced in volumes exceeding the household’s consumption;

f. introduction of the green tariff for geothermal energy;

g. the WEM will buy out the electricity produced by power plants minus the electricity consumed by the power plants for their own operation;

h. the local content requirement is cancelled, at the same time, a markup to the green tariff for usage of Ukrainian equipment is introduced (the markup constitutes 5 per cent if 30 per cent of Ukrainian equipment is used and 10 per cent if 50 per cent of Ukrainian equipment is used);

i. the elements to be considered as local equipment are specified in a list.

In general, the Law has been considered quite positively by market experts. The aforementioned amendments have allowed for a reduction of the price burden on Ukrainian electricity consumers, have improved the state’s investment appeal and are expected to contribute to diminishing Ukraine’s energy dependence.

ii Energy efficiency and conservation

Energy conservation in Ukraine is governed by the Law of Ukraine on Energy Conservation. This Law stipulates a number of principles in the energy conservation sphere including:

a. a combination of methods of economic stimulation and financial responsibility for the purpose of rational and efficient use of fuel and energy resources;

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popularisation of the economic, ecological and social advantages of energy conservation; and

an increase in public awareness of the subject.

By raising its energy-efficiency level, Ukraine could significantly reduce its dependence on Russian gas; therefore steps are currently being made towards this goal. Currently, the Ukrainian government is taking a number of measures to encourage energy efficiency in the residential and budget sector, including providing for incentive credits for taking thermomodernisation measures, stimulating gas substitution technologies and others. In addition, on 9 April 2015, the Law on Introducing New Investment Opportunities, Guaranteeing Rights and Legal Interests of Business Entities for Conducting Large-Scale Energy Modernisation No. 327-VIII and the Law on Amendments to the Budget Code of Ukraine (Reintroducing New Investment Opportunities, Guaranteeing Rights and Legal Interests of Businesses Entities for Conducting Large-scale Energy Modernisation) No. 328-VIII were adopted. The aforementioned laws provide the legal basis in the budgetary sphere for the activities of energy service companies, the concept of which is actively supported by the European Bank for Reconstruction and Development (EBRD) in Ukraine.

iii Technological developments

Loss of electricity in Ukraine equates to approximately 15 per cent of output. Therefore, the issue of implementing smart grids in Ukraine is much discussed. This implementation measure is being discussed, but currently there are no incentives from the government for this technology.

VI THE YEAR IN REVIEW

The year 2015 was characterised by Ukraine’s gradual transition towards the European energy market model. However, the positive steps taken in the legislative field are still awaiting full implementation.

The factors that continue to negatively influence the Ukrainian energy sector are annexation of Crimea by Russia and the military action in eastern Ukraine. The zone in eastern Ukraine where military action is taking place (named under Ukrainian legislation as the Zone of Anti-Terrorist Operations) is rich in coal, and the military action has resulted in Ukraine suffering a coal deficit estimated at 1.5 million tons by the end of the year. This in turn produced the need to import coal from South Africa and Russia. Among other negative consequences, the annexation of Crimea resulted in Ukraine losing approximately US$800 million worth of Black Sea oil and gas drilling rigs, which were shipped to Russia in 2015, as well as losing approximately 494,87MW of renewable energy capacity (mostly solar).

Taking into the account the Crimean situation and the military action in eastern Ukraine, on 13 August 2014 the Cabinet of Ministers of Ukraine passed Resolution No. 372 of 13 August 2014 on Approval of Procedure for Taking Temporary Emergency Measures to Overcome the Effects of Prolonged Disruption of the Normal Operation of the Electricity Market, which determines the grounds and procedure for decision-making on temporary emergency measures to overcome the effects of prolonged disruption of the normal operation of the electricity market due to emergency situations in the unified energy system of Ukraine.
Currently, gas prices, dependence on Russia and the possible sale of the Ukrainian gas transportation system are the hottest topics in Ukraine. It is obvious that the price of gas influences almost all areas of the economy, including tariffs for housing and communal services. Ukraine is looking for different ways to reduce its gas dependence. Since 2012, the government has taken serious steps to develop shale gas extraction in Ukraine.

For a while now, Ukraine has been negotiating with a number of international oil extractors such as Shell, Chevron and ExxonMobil. Shell won a tender to sign a production-sharing agreement (PSA) for the Yuzivska field (Kharkiv and Donetsk regions) and Chevron won a tender to sign a PSA for the Oleske field (Lviv and Ivano-Frankivsk regions). In August 2012, ExxonMobil, Royal Dutch Shell, Petrom and National Joint-Stock Company (NJSC) Nadra Ukraine, bidding jointly, won a PSA for the Skifske oil and gas field on the Black Sea shelf.

In addition, on 24 January 2013, at the World Economic Forum in Davos, Shell, Nadra Yuzivska LLC and the government of Ukraine signed a PSA concerning unconventional gas extraction in the Yuzivska field. On 12 September 2013, Minister of Energy and Coal Industry Eduard Stavytsky announced the signing of an operating agreement with Nadra Yuzivska and Royal Dutch Shell. The operating agreement actually permits commencement of work in the Yuzivska area.

Moreover, On 30 October 2013, the government approved the draft product distribution agreement between Chevron Ukraine and Nadra Oleske, which was signed within the framework of the investment forum on 5 November in Kiev. The PSA foresees an initial investment of US$350 million by Chevron in exploratory work aimed at establishing how commercially viable shale reserves are at Oleske field, which covers 5,260 square kilometres. Total investments, including extraction after exploratory drilling, total around US$10 billion, thus deputies in western Ukraine cleared the way for the deal when a majority voted in favour of the government's plans for exploration at Oleske field, overcoming opposition from local lobby groups concerned about possible ecological damage from the project. In addition, the force majeure events that took place in Ukraine at the beginning of 2014 had a significant influence on Ukraine's energy market, and resulted in tremendous changes with regard to the energy market in the Autonomous Republic of Crimea. In February 2014 pro-Russian forces gradually took control of the Crimean peninsula. On 17 March, the Crimean parliament officially declared its independence from Ukraine and requested to join the Russian Federation. As a result, on 18 March, the President of Russia declared Crimea to be a part of Russia. This annexation of Crimea caused an unprecedented event in the history of modern Ukraine: Russia extended its jurisdiction to the territory of Ukraine. Recognition of that fact by the existing political forces in Crimea, and their acquisition of control of certain infrastructure facilities, have substantially affected the rights and obligations of business entities whose activities are linked to the peninsula.

Currently, the issues of power supply to Crimea, regulation of energy prices and operation of energy companies – which Crimea is attempting to nationalise, and subsequently, privatise – are being actively discussed.

On 11 March 2015 the Board of Directors of the International Monetary Fund (IMF) approved the new four-year credit programme Extended Fund Facility (EFF) in the amount of US$17.5 billion for Ukraine. The Memorandum of Economic and Financial Policies is the main document, providing for the reform programme implementation, with financial support from the IMF and other donors.
In particular, the Memorandum stipulates Ukraine’s policy in the energy sector. The ongoing reform programme was launched in 2014. Thus, the following steps are contemplated: 

\( a \) ‘financial recovery’ of the NJSC Naftogaz of Ukraine by means of:
- increasing the prices for gas and heat energy up to the pay-off level under international standards;
- improved corporate governance and restructuring;

\( b \) further increase in consumer tariffs. The prices should be brought to a reasonable level by 2017:
- retail prices for gas – the average increase will be 285 per cent for households;
- retail prices for heat – the average increase will be 67 per cent for households;

\( c \) gas sector reform:
- delineation of the main activities of Naftogaz (transmission, storage and sale of gas);
- improved transparency in the field of gas distribution by conducting audits in distribution companies and installing gas meters along the whole gas chain;

\( d \) reforming the state energy companies. With the help of the EBRD, improvement is planned for the corporatisation of key state-owned companies, such as NEC Ukrenergo, SE NNEGC Energoatom, and NJSC Naftogaz; and

\( e \) implementing various energy efficiency programmes, in particular ensuring the total deployment of gas and heat meters by the end of 2016, and some other measures.

As mentioned above, in 2015 Ukraine took steps to implement these measures. Gas prices have risen from 1 May 2016 and are set at the level that corresponds to market conditions. The prices for electricity are gradually rising in accordance with the five-stage plan set by NCSREU Regulation No. 220 on Setting Tariffs for Electricity Sold to the Population. The Law on the Natural Gas Market has been adopted, the Law on the Electricity Market is expected to be considered in the very near future and the Law on the National Commission Exercising State Regulation in the Field of Energy and Utilities has passed its first reading.

VII CONCLUSIONS AND OUTLOOK

The Ukrainian energy sector is undergoing a complex transformation. As a member of the European Energy Community, it must implement the energy chapter of the EU aquis communautaire in full, including the Third Energy Package.

Ukraine has huge biomass potential and the largest agricultural market in Europe, and it also has access to the Black Sea. Its biomass potential could be used for biofuel production and, further, Ukraine has good conditions for producing wind and solar energy, especially in southern Ukraine and Crimea. The Ukrainian government is encouraging investment into the establishment of bioenergy facilities by offering benefits to producers, one being the green tariff.

Ukraine also operates one of the world’s largest natural gas transportation systems, but because of its reputation as an unreliable transit country, its transit business is in decline. To make matters worse, on 8 November 2011 the first line of the North Stream pipeline was inaugurated, and the construction of South Stream pipeline was supposed to be completed by 2015. Both pipelines are diversifying Russian gas routes away from Ukraine, directly connecting Russia with Germany and western Europe. On 4 September 2015, Gazprom, BASF, ENGIE, E.On, Shell and OMV have signed an agreement to expand the capacity of...
A pending issue is the unbundling of Naftogaz. The company will be divided into several separate companies, with production separated from transportation. On 1 April 2016, Naftogaz published the proposed plan for the complete separation of the gas TSO in accordance with the Third Energy Package.

As part of its obligations under its membership of the Energy Community, Ukraine will have to implement other elements of EU energy policy that regulate energy and environment-related issues, introducing transparency and competitiveness in the energy sector.

Following the results of the hearing on 15 October 2013 on the status of Ukraine’s fulfilment of international commitments under the Energy Community Treaty, the Energy Community declared itself satisfied with Ukrainian policy on renewables while stressing the need for Ukraine to define socially vulnerable customers and put in place adequate measures for their protection, and to liberalise urgently its electricity and gas prices. The liberalisation of prices was considered a key precondition for much needed investment in energy infrastructure, along with the removal of unsustainable energy company losses, which threaten the state’s stability. Reform of the gas market is also to be accelerated.

The new Law on the Electricity Market will lead to reform in the electricity market. The Law shall solve the problem of cross-subsidisation, and the retail electricity market will be liberalised. Oblenergos will no longer be a monopoly producer as there will be unbundling of the transportation and supply functions of the companies.

A transparent and competitive market system with a predictable pricing mechanism will attract investment in the energy sector, which it desperately needs. In general, some improvements in the energy market are expected in relation to fulfilment of Ukraine’s obligations towards the Energy Community and signing of the EU–Ukraine Association Agreement. Thus, on 16 March 2015 the Association Council between Ukraine and the EU approved an updated Association Agenda, which will contribute to the process of expanding the reform and modernising the economy of Ukraine.

In terms of diversification of the gas supply, taking into account its huge estimated resources of shale gas, Ukraine has an opportunity to overcome its dependence on natural gas and develop these industries as the United States did. Thus, imports of gas from Russia in 2015 decreased by a factor 2.4 times compared with 2014 (from 14.5 to 6.1 billion cubic metres). Of total gas consumption, the percentage imported from Europe constituted 63 per cent, while the rest was imported from Russia.

Obviously, further development of the renewable energy sector will depend on the investment climate in Ukraine, and on prospective amendments to the green tariff in pending draft legislation. However, investors still show great interest in the Ukrainian market, as effective legislation provides them with sufficient incentives and competitive green tariffs, and prospective energy service market also has great potential.
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

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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.

The generation, transmission and distribution of electricity in the UAE is dominated by five water and power authorities. Four of these authorities are owned by the governments of the emirates of Dubai, Abu Dhabi, Sharjah and more recently Ras Al Khaymah, whereas the federal 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. Whereas 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 is the only emirate so far that has private sector participants owning up to a 40 per cent economic interest in a number of electricity generation plants in the emirate. In 2011, Dubai enacted legislation to enable private sector participation in the power generation sector. A privatisation policy has also been announced by the federal government for the northern emirates.

So far, only Dubai and Abu Dhabi have enacted laws creating specialised regulatory bodies for the electricity sector. These consist of the relatively recently constituted Supreme Energy Council (SEC) and the Regulatory and Supervisory Office for Electricity and Water Sectors in Dubai (the Office), and the much older Electricity Regulation and Supervision Bureau of Abu Dhabi (the Bureau). The Federal 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 UAE’s Federal Ministry of Energy, the primary regulator at the federal level, was formed pursuant to Federal Decree No. 3 of 2004 (the Ministry of Energy Decree) 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, 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;
b. the Rationalisation and Energy Usage Efficiency Department; and
c. the Regulation and Control Department.

The restructuring was intended to create a more specialised and robust central regulatory authority at the federal level. However, the Ministry 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 Bureau is the regulatory body responsible for implementing the legal framework and its authority includes the power to:

a. issue licences to conduct regulated activities;
b. monitor licensees and ensure compliance with terms of licences issued; and
c. 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 Bureau 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). Presently, Dubai has enacted a number of laws to modernise and open the sector to private investment. Two new
regulatory bodies have been created: the SEC,\textsuperscript{2} established under Dubai Law No. 19 of 2009, as the apex regulator for the energy sector, and the Office, established pursuant to Dubai Executive Council’s Resolution No. 2 of 2010 (Dubai Office Resolution), as the specialist regulatory authority for the electricity sector.

As the primary regulator of the energy sector, the SEC regulates the exploration, production, storage, transmission and distribution of petroleum products (natural gas, liquid petroleum, petroleum gases, crude oil) and electricity. It ensures that the energy and electricity sources satisfy the current and future demands of the emirate of Dubai at affordable prices. The SEC 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).

The Office is authorised to regulate the electricity sector subject to the supervision of the SEC. The Office 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.

\textbf{ii} \textit{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 Bureau.

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 the Office.

\textbf{iii} \textit{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 1200MW clean coal power plant, to a consortium led by Harbin Electric International and ACWA Power.

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).

\textsuperscript{2} Member organisations of the SEC are DEWA, Dubai Aluminium Company Ltd (DUBAL), Emirates National Oil Company, Dubai Supply Authority, Dubai Petroleum Establishment, Dubai Nuclear Energy Committee, Dubai Municipality, Dubai Petroleum Affairs and Road and Transport Authority.
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 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 Bureau 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 ADEWA, being the largest two, account for about 87 per cent of the UAE's entire installed capacity. As of the figures available for 2012, ADWEA accounts for approximately 52 per cent of the UAE's entire power generation capacity (at 13,849MW), DEWA for 35 per cent (at 9,646MW), SEWA for 9 per cent (at 2,400MW) and FEWA for about 4 per cent (at 1,150MW).

3 Federal Law No. 2 of 2015 on Commercial Companies abrogated Federal Law No. 8 of 1984 (as amended).
**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 is the owner of the Abu Dhabi Power Corporation (ADPC), a holding company established to own shares in operating-level companies that generate, transmit and distribute water and electricity in the emirate. ADPC in turn owns ADWEC, the single buyer of water and electricity in Abu Dhabi, and TRANSCO, the main transmission company in the emirate.

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:

- a. Al Mirfa Power Company;
- b. Arabian Power Company;
- c. Emirates CMS Power Company;
- d. Emirates SembCorp Water and Power Company;
- e. Fujairah Asia Power Company;
- f. Gulf Total Tractebel Power Company;
- g. Ruwais Power Company;
- h. Shuweihat Asia Power Company PJSC;
- i. Shuweihat CMS International Power Company;
- j. Shams Power Company PJSC; and
- k. Taweelah Asia Power Company.

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4 Under the Abu Dhabi Electricity Law, ADPC was established with the following subsidiaries: (1) Abu Dhabi Water and Electricity Company (ADWEC); (2) Abu Dhabi Transmission and Dispatch Company (TRANSCO); (3) Al Taweelah Power Company; (4) Al Mirfa Power Company; (5) Umm Al Nar Power Company; (6) Bainounah Power Company; (7) Abu Dhabi Distribution Company (ADDC); (8) Al Ain Distribution Company (AADC); (9) Abu Dhabi Company for Servicing Remote Areas; (10) Al Wathba Company for Central Services; (11) Industrial Security Company; and (12) Central Workshop Company.

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 ADEWA 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.
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 11 plants in the emirate whose individual capacities vary between 400MW to 1400MW, with a total installed capacity of over 9,600MW. Although the Dubai government wants to promote private investment in its electricity generation sector, to date, all of the power generation capacity of Dubai, except for captive power produced by certain entities (e.g., DUBAL), is owned by DEWA.

In 2011, Dubai passed legislation allowing the private sector to participate in electricity generation. The Dubai Electricity Privatisation Law 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, Dubai has launched two independent power projects (IPPs). The first IPP is Al Hassyan 1 IPP, a 1,600MW gas-fired power plant, for which bids were solicited in December 2011. The project has, however, been deferred indefinitely. Another Al Hassyan 1 IPP, a 1,200MW clean-coal power plant, was launched in 2014. In 2015, Dubai awarded the development, construction ownership and ownership of phase one of the plant to a consortium led by Harbin Electric International and ACWA Power. DEWA will own 51 per cent of the equity in Hassyan while ACWA Power and Harbin Electric International will own the remaining 49 per cent.

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. A further expansion of the M-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

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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.
April 2018. All existing electricity plants in Dubai are currently gas fired, but by 2030 Dubai plans to generate 5 per cent of its energy requirements from solar power, 12 per cent from coal, 12 per cent from nuclear power and the remainder from gas.

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 the Sharjah Electricity and Water Authority (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, practically 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.
iv Transfers of control and assignments
Any transfer of control or assignment of an interest in an IWPP requires the consent of the relevant regulator.

Under the Abu Dhabi Electricity Law, a licence may not be transferred unless it specifically permits its transfer. Prior consent of the Bureau is required for any transfer (including the creation of security over assets of the licence holder), which consent may be subject to such conditions as the Bureau 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 the Office. 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 the Office. 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:

a ADDC, which operates in the city of Abu Dhabi and the western region of the emirate; and

b AADC, which operates in Al Ain city and the surrounding areas.

In response to the power shortages faced in the northern emirates, TRANSCO has become involved in the planning, development and operation of electricity transmission networks in the northern region. TRANSCO’s involvement, given its resources and experience, coupled with ADEWA’s supply of its excess power, has largely alleviated the power problems faced by these emirates in the past.
Dubai
DEWA is the sole purchaser of electricity in Dubai and presently owns all the generation, transmission and distribution capacity of the emirate. 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). In 2016, DEWA announced its plans to build another nine substations and a total of 64 substations in the next three years. In October 2014, DEWA completed a new 132kV underground transmission cable network to redistribute the electricity load.

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 28.5 million dirhams) to ensure the reliability of power supply throughout Sharjah. Other projects include replacing all old electric cables and meters with new improved infrastructure, establishing four fuel tanks in the Hamriyah plant and completing the construction of a natural gas pipe network in new residential districts.

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 are as follows:

1. 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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8 DEWA operates a network of overhead lines (876 kilometres of 400kV, 437 kilometres of 132kV and 113 kilometres of 33kV lines) and underground cables (1,486 kilometres of 400kV, 1,992 kilometres of 33kV and 24,942 kilometres of 6.6 and 11kV lines) that are, in turn, connected to a distribution system of lower voltage substations and distribution lines.

9 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 2015, FEWA inaugurated Al Hamra substation in Umm al-Quwain and plans future expansion of the same. In the same year, FEWA also 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.

**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:

1. ADWEA: 40 per cent;
2. DEWA: 30 per cent;
3. FEWA: 20 per cent; and
4. 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 Barakah power plant and photovoltaic panels respectively.

**The 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 the Arab and European networks (through Turkey) and trade energy beyond the GCC region.

**Transmission/transportation and distribution access**

**Abu Dhabi**

The Abu Dhabi Electricity Law requires ADWEC to purchase all power produced within the emirate. Although the Abu Dhabi Electricity Law contemplates private ownership in all segments of the electricity supply chain, so far private ownership has been limited to generation only.

**Dubai**

The Dubai Electricity Privatisation Law prohibits a licensed entity from selling electricity to any entity other than DEWA.
iii Rates

Abu Dhabi

ADWEC, being the single buyer of electricity in the emirate of Abu Dhabi, purchases electricity from the power producers under long-term power and water purchase agreements (PWPAs) and sells it to the distribution companies via annual bulk supply tariff (BST) agreements. The distribution companies pay ADWEC the BST for the electricity purchased and receive revenue from their customers and a subsidy from the government. TRANSCO is paid a transmission use of system (TUoS) charge by the distribution companies.

The components making up the electricity tariff in Abu Dhabi are the following:

a) BST, which is the charge paid by the distribution companies to ADWEC for its generation costs (in turn paid by ADWEC to power producers).

b) TUoS, which is the charge paid by the distribution companies to TRANSCO for use of its transmission network.

c) Distribution use of system, which is the fee that the distribution companies charge for use of their distribution network.

d) Sales cost, or the cost incurred by the distribution companies for serving customers for meter reading and billing.

e) Government subsidy, consisting of direct payments from the government to the distribution companies. The quantum of the subsidy allows the government to determine the electricity tariffs for different classes of consumers. The higher the subsidy, the lower the tariff charged.

The electricity tariff is determined by adding components (a) to (d) and subtracting (e).

The rates charged by the state-owned power companies (ADWEC, TRANSCO, ADDC and AADC) are subject to government control, exercised via the Bureau. The Bureau 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 Bureau. 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 last year 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 Bureau on its website are divided according to consumer categories as follows:

- **UAE nationals (flats):** 5 fils per kWh until 30kWh/day, 5.5 fils post 30kWh/day;
- **UAE nationals (villas):** 5 fils per kWh until 400kWh/day, 5.5 fils post 400kWh/day;
- **non-UAE nationals (flats):** 21 fils per kWh until 20kWh/day, 31.8 fils post 20kWh/day;
- **non-UAE nationals (villas):** 21 fils per kWh until 200kWh/day, 31.8 fils post 200kWh/day;
- **industrial establishments (below 1MW):** 16 fils per kWh;
- **industrial establishments (above 1MW):** 16 fils per kWh at off peak hours, 30 fils per kWh at peak hours;
- **commercial establishments:** 16 fils per kWh;
- **governmental offices:** 29.7 fils per kWh; and
- **farms and ranches:** 3 fils per kWh.

Prior to the revision to the electricity rates, the government subsidy for water and electricity in Abu Dhabi accounted for nearly 86 per cent of the cost of a unit of electricity for nationals and 50 per cent for expatriates.

**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 SEC Law, the electricity prices have been determined by the SEC and DEWA now sets its prices in accordance with the SEC’s directives. The SEC Law empowers the SEC to impose a ‘definite tariff based on cost when necessary’. The SEC 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 (3) commercial, (4) governmental, charitable, public utility, etc. and (5) houses and farms of nationals. 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 Al Hassyan 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 act 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, only Abu Dhabi has permitted up to 40 per cent private ownership in the generation of electricity. Although Dubai has enacted new legislation permitting private sector participation in the electricity sector, as at the date of writing no private sector company has yet established a power generation plant in Dubai.

ii **Energy market rules and regulation**

Under the Abu Dhabi Electricity Law, ADWEC is required to contract with power producers for the purchase of all production capacity from licensed operators in the emirate. ADWEA is authorised to allow ‘by-pass sales’ from power producers directly to eligible consumers provided that:

a the first independent commercial power generation project in the emirates shall have commenced commercial operations;

b the majority of the shares in the company are privately owned; and

c the Bureau issues a report stating that the energy market in the country is stable enough for it to be in the public interest that the sale of electricity by producers to eligible consumers be permitted.

To date, no ‘by-pass sales’ of electricity have been allowed by ADWEA in Abu Dhabi and all existing producers in the emirate are required to sell their production exclusively to ADWEC.

Similarly, power producers in Dubai are obligated by law to sell their entire production capacity to DEWA.

All power generation companies in the northern emirates and Sharjah are required to sell their power production to FEWA or SEWA respectively. 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.\textsuperscript{10}

The PWPA usually have a term of about 20 to 25 years from the commencement of commercial operations. Payments to IWPPs by ADWEC under PWPA comprise three main components:

\begin{itemize}
  \item[a] capacity (or availability) payments covering the fixed costs of the plant (return on capital, depreciation and fixed operating and maintenance costs);
  \item[b] operation and maintenance costs, paid when plant is available for production irrespective of whether and how much the plant produces; and
  \item[c] output (or energy) payments for variable operation and maintenance costs, payable only for the electricity actually produced by the plant and dispatched.
\end{itemize}

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 two power purchase agreements:

\begin{itemize}
  \item[a] the first with a consortium led by ACWA Power and TSK and shareholder agreement for the second phase of Mohammed Bin Rashid Al Maktoum Solar Park to produce a 200MW expansion of the photovoltaic solar panels; and
  \item[b] the second with a consortium led by Harbin Electric International and ACWA Power for the construction of phase 1 of Hassyan clean-coal power plant.
\end{itemize}

V RENEWABLE ENERGY AND CONSERVATION

Development of renewable energy

High energy use, encouraged by subsidised energy prices and the construction of energy intensive industries such as aluminium smelting has resulted in the UAE having one of the highest per capita carbon footprints in the world. The development of renewable energy is therefore crucial in reducing the country’s carbon footprint and diversification of its economy away from fossil fuels. The UAE has announced that it aims to produce 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 has established the Abu Dhabi Future Energy Company (Masdar) 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 10MW of electricity 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 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, Um Al Zomul solar photovoltaic plant, and a 543 kWp photovoltaic plant that delivers energy to Rashid Abdulla Omran Hospital. Two new solar photovoltaic plants called Noor 1 and Noor 2 are proposed to be constructed by 2020, which will have a combined generating capacity of 250MW. 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), and 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) and Egypt’s Siwa solar photovoltaic plant (10MW). 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

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11 Masdar is a wholly owned subsidiary of Mubadala Development Company, one of the Abu Dhabi government’s main investment arms.

12 The project company, Shams Power Company, is 60 per cent owned by Masdar, 20 per cent by Total SA and 20 per cent by Abengoa Solar.
Agency, the Abu Dhabi government, also granted US$57 million in loans to Argentina, Cuba, Iran, St Vincent and the Grenadines and Mauritania to finance renewable energy projects. Masdar is also involved with the UAE-Pacific Partnership Fund in developing renewable energy projects in the Pacific Islands. Currently, four new solar projects are under way in the countries of Kiribati, Fiji, Tuvalu and Vanuatu. An agreement was signed between Masdar and New Zealand to develop a solar photovoltaic power plant (1MW) in the Solomon Islands.

E.ON Masdar Integrated Carbon, a joint venture between E.ON and Masdar, develops and invests in carbon abatement projects in industry, power and oil and gas across Africa, Asia and the Middle East under the UN’s clean development programme.

**Dubai**

The SEC 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 5 per cent of its energy demand from solar energy, 12 per cent from nuclear energy, 12 per cent from clean coal and 71 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, Shaikh Mohammad Bin Rashid Al Maktoum, the Ruler of Dubai, launched a 12 billion-dirham solar power project, known as the Mohammad Bin Rashid Al Maktoum Solar Park. This solar park is expected to have a total installed capacity of 5000MW by 2030. The project is being implemented by the SEC 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, a 200MW photovoltaic plant, is under way based on the independent power producer model, and is expected to be operational by April 2017. DEWA has recently organised a conference for qualifying international developers to send proposals for the third phase of the solar park by the end of 2015 to increase its output by a further 800MW. To date, DEWA has received five bids.

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 SEC established Etihad Energy Service Company (EtihadESCO), which will serve, notably, to retrofit existing buildings and lower the water and energy consumption of such buildings.

DEWA has launched the Shams Dubai Initiative, which aims to encourage energy efficiency by equipping residential and commercial buildings with solar panels and connecting the panels to DEWA’s electricity grid. In 2014, in line with this initiative, the emirate of Dubai issued Executive Council Resolution No. 46 of 2014 Concerning the Connection of Generators of Electricity from Solar Energy to the Power Distribution System in the emirate of Dubai (Resolution 46) to encourage the generation of electricity using solar panels. Resolution 46 enables DEWA consumers to supply power to DEWA’s grid by connecting their solar panels and the power supplied to DEWA can then be adjusted against the consumer’s electricity bill.
In 2015, Dubai established the Dubai Green Fund, worth US$27 billion, which provides easy loans to investors in the clean energy sector. In 2016, DEWA issued a request for proposals for consultants to develop the structure, execution and governance of the Dubai Green Fund.

In 2016, Dubai launched one of the largest photovoltaic projects on a single rooftop of the M-station in Jebel Ali (1.5MW) and installed electric-vehicle green charging stations to encourage the use of electric vehicles.

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 has recently launched SEWA 2020 Vision 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. 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 30 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 Korea (2009), the United States (2009), France (2008), the United Kingdom (2008), Canada (2012), Russia (2012), Argentina (2013), Japan (2013) and Australia (2015) 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, Barakah 1, 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 1, which will have a total capacity of 5,600MW. The project consists of the construction and installation of four 1,400MW reactors with the first reactor scheduled to be completed in May 2017 and the fourth by 2020.

In 2016, ENEC signed a deal with TRANSCO to transmit nuclear power generated from Barakah through TRANSCO’s power lines to the ENG.

**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, the Office 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 Sheikh Mohammed bin Rashid Al Maktoum 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 has allowed private power companies to participate in its energy sector for a number of years. More recently, because of the rapid growth in demand for power in the country, Dubai and the federal government have both launched initiatives to permit private sector participation in the generation of electricity. Following the enactment of the Dubai Electricity Privatisation Law in 2011, Dubai has recently awarded the construction and partial ownership of a Hassyan clean-coal power plant to a consortium led by private power companies. FEWA has yet to follow Abu Dhabi and Dubai’s example and permit private sector participation in its electricity network (with the exception of UTICO’s participation in the electricity network of Ras Al Khaymah). It seems that 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 30 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 2017. An agreement was also signed this year 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 has 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. The completion of the GCC Grid and its proposed expansion to Arab 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, UAE is expected to continue its projects such as retrofitting buildings, establishing solar parks and energy efficient communities, which will require the investment and research capabilities of the private sector. Despite the encouragement for private investment in alternative energy sources and energy efficiency measures, investment in the sector looks likely to continue to be led by the state-owned water and power authorities.
Chapter 35

UNITED KINGDOM

Munir Hassan and Dalia Majumder-Russell

I OVERVIEW

The United Kingdom has one of the most mature electricity and gas markets. Starting from the mid-1980s, when the Energy Act 1983 opened up the supply markets, through to the privatisation programmes that followed in the 1980s and 1990s, the United Kingdom has been at the forefront of liberalising its electricity sector and creating wholesale markets where electricity generators could sell their electricity in real time. At present, the market is fully liberalised and privatised.

Over the past decade, spurred on by the United Kingdom’s 2020 renewable energy targets agreed as part of the European Renewable Energy Directive, concerns about the need for decarbonisation have incentivised growth in renewable generation (especially onshore wind and solar technologies). Recently government policy has shifted to focus on security of supply and lowering the costs to consumers. This has led to a number of shifts in renewable support policies (as discussed below).

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).² The Utility Regulator for Northern Ireland, an independent non-ministerial government department, regulates the electricity and gas markets in Northern Ireland. Its duties are to protect the short and long-term interests of electricity, gas, water and sewerage consumers

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1 Munir Hassan is a partner and Dalia Majumder-Russell is a senior associate at CMS Cameron McKenna LLP.

2 This chapter focuses on Great Britain and only gives a brief overview of electricity and gas regulation in Northern Ireland.
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 sectoral 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 (further discussed in Section VI, infra).³

**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 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 of Energy and Climate Change (DECC) and the Department for the Economy (DFE)**
While not regulators, DECC and DFE are government departments responsible for setting the policies affecting the UK electricity and gas markets. The Secretary of State for Energy and Climate Change 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. DECC is responsible for formulating UK energy policy, which is implemented through legislation. In addition, there are some regulatory

³ [https://www.gov.uk/cma-cases/energy-market-investigation](https://www.gov.uk/cma-cases/energy-market-investigation)
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 hold 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 coming into force over 2017–2018.

Electricity
Unless an exemption applies, a licence is required for the following specified activities under the Electricity Act:

a generation;
b participation in transmission (defined to cover both the operation and ownership activities);
c distribution;
e supply; and
f participation in the operation of an electricity interconnector.

From September 2012, providing smart metering services also requires a licence. The position regarding electricity storage is currently unclear.

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

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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)).
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).

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 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, production 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 (SHETL) and Scottish Power Transmission Limited (SPTL), the Scottish owners, were granted certification on grounds of Article 9(9) subject to certain conditions and information-sharing restrictions.
United Kingdom

**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 transmission system operator (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.

Transmission and distribution is largely regulated through a series of industry codes. NGET has the licence obligation to maintain and administer various industry codes dealing with the operation and use of the transmission system, including the Connection and Use of System Code (CUSC), the Grid Code and, in conjunction with ELEXON, the Balancing and Settlement Code (BSC).

The CUSC sets out the main rights and obligations in relation to the connection to, and use of, the NETS, along with additional provisions on some ancillary and balancing services. The Grid Code deals in detail with matters such as connection conditions, operational liaison and safety coordination, and all material technical aspects relating to connections to, and the operation and use of, the transmission system. The governance of balancing and settlement arrangements is set out in the BSC, to which all generation or supply licensees must be party.

**Access**

Pursuant to its licence, NGET must not discriminate between any persons or class or classes of 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, ScottishPower Energy Networks, UK Power Networks, and Western Power Distribution. The DNO in Northern Ireland is Northern Ireland Electricity. Each DNO holds an electricity distribution licence and owns and operates the local electricity distribution system.

Pursuant to the Electricity Act, DNOs must develop and maintain an efficient, coordinated and economical system of electricity distribution and facilitate competition in the supply and generation of electricity. As with transmission, the electricity distribution licence conditions subject the DNOs to obligations such as non-discrimination in the provision of use of system and connection to system; safety and security; and use of system and connection to system charges.

Similar to the obligations of NGET under its transmission licence, under the terms of their distribution licence conditions, DNOs are each required to maintain and comply with the Distribution Code dealing with technical aspects relating to connections to and the operation and use of the licensee’s distribution system, and one of the objectives of the licences and the codes is to facilitate competition in the generation and supply of electricity.

**Access**

Under the Electricity Act, DNOs have an obligation to make a connection between their distribution system and any premises when requested to do so by the owner of the premises or an authorised electricity supplier. Pursuant to the licences, DNOs must not discriminate between any persons or class or classes of persons in the carrying out of works for the purpose of connection to the licensee’s distribution system, or in the provision of use of the system, and must on application made by any person offer to enter into an agreement for use of the distribution system.

**Gas Transportation**

The GB gas transmission network, the National Transmission System (NTS) – a high-pressure pipeline system which 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 SGN (Scotland and Southern England (including South London)). As at June 2016, NGG is pursuing the sale of some of its GDNs.

There are also a number of smaller gas transportation networks connected to the GDNs and owned and operated by six independent gas transporters (IGTs). The IGTs compete with each other and the GDN owners to provide gas transportation services. Unless an exemption applies, each IGT and GDN owner is required to hold a gas transporter licence.

Access
Under the Gas Act, gas transporters must, following any reasonable requests for connection, grant access to their pipeline system, in so far as it is economical to do so, convey gas by means of that system to any premises and comply with any reasonable request to connect to a pipeline system operated by another authorised transporter.

Access to the gas network is provided on an entry-exit basis instead of on a point-to-point basis. As access rights comprise entry and exit capacity at entry and exit points, shippers are required to book entry capacity and exit capacity to flow and take gas (there are relatively few entry points – principally gas terminals at which gas is landed from offshore fields).

iii Rates
For electricity, the rates payable for connection to and use of the transmission system are set out in NGET’s charging statements. The charges are broadly made up of the following:

a transmission network use of system charges: to recover the revenue for the transmission system owners, that is NGET, the Scottish transmission owners and OFTOs;
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
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).

**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 (further discussed in Section VI, infra) 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’.

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.

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.

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 (EMR) programme. Prior to its introduction, the main support measures available for low-carbon generation were in the form of the Renewables Obligation (RO) for large-scale, and Feed-in Tariffs (FiTs) for small-scale projects.

CfDs are 15-year contracts entered between a government-owned company, the Low Carbon Contracts Company, and the eligible low-carbon generators. The CfD mechanism works by setting a fixed price (strike price) thus reducing the generator’s exposure to electricity prices volatility and consequently the cost of capital of the investment. The first allocation round for CfDs took place in October 2014 and contracts were awarded to 27 projects in February 2015.

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 proportion of their electricity from RE generation.

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6 For more information on the EU 2030 Energy Strategy see https://ec.europa.eu/energy/node/163.

suppliers to source a fraction of their electricity from renewable generation, and compliance with this obligation is shown by obtaining RO certificates issued to generators accredited on the scheme (with the number of certificates issued varying depending on the technology and the value of each certificate being broadly maintained through terms, such as a buyout price, set from time to time by the electricity regulator).

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 March 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.

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.

VI THE YEAR IN REVIEW
The majority of changes in the UK energy policy continue to be in the electricity sector.

The government ‘energy reset’ in November 2015 signalled a shift of focus from low-carbon generation to greater emphasis on budgetary control. At the same time, the government cancelled its flagship £1 billion funding through the CCS competition and reiterated its support for nuclear. The new nuclear-build plant at Hinkley C remains a cornerstone of the government’s security-of-supply programme.

There have been a number of changes to the renewables support schemes through the revisions of the FiT and RHI schemes, as well as early closure of the RO scheme. In addition, for renewable generation the removal of the CCL exemption has been another unexpected change in policy. The CCL is a tax levied on the supply of electricity, gas and certain other fuel commodities to non-domestic customers. Electricity generated from renewables was exempt from the CCL and therefore Levy Exemption Certificates (LECs) were issued to eligible renewable generators for each MWh of electricity generated. Renewables generators could sell their LECs to suppliers, as those suppliers can make a profit on exempt electricity by charging a price that includes additional profit in lieu of the CCL or by lowering the price of electricity and hence being more competitive. Further changes are also mooted to the ‘embedded benefits’ regime, which is a benefit to renewable generators connected to the distribution network, and which are, in simple terms, savings arising from avoiding the need to use the high-voltage transmission system.

On a positive note, the decreases in the cost of lithium-ion batteries and their uptake in other markets have also seen an increase in interest in energy storage for the electricity sector. Further developments in the legislative framework are expected later in 2016.

Finally, in June 2016, the CMA published its final report on the energy market investigation, setting out a number of measures aiming to reform the market. The proposed measures include:

\( a \) ensuring that the CfD process, by which the government supports investment in low-carbon generation, is carried out transparently so that the impact on customer bills is assessed beforehand. There should be a clear rationale for the allocation of funding to different technologies and for the exceptional circumstances in which competitive auctions are not used. The report includes one case study where a more competitive process for offshore wind could have saved consumers £250 million to £310 million per year, but it has not assessed other projects;

\( b \) ensuring that both electricity and gas settlement processes are reformed to deliver lower costs to consumers by enabling more accurate measurement of consumption and more efficient supply – and to enable the full benefit of smart meters to be realised;
c requiring micro-business suppliers to disclose their prices and prohibiting them from locking their customers into rollover contracts;
d introducing a transitional price cap for customers on prepayment meters from 2017–2020;
e introducing a locational pricing system to take account of transmission losses incurred when transporting electricity, to reduce the overall cost to customers; and
f improving the policy and regulatory framework to provide a clear division of responsibilities between Ofgem and DECC, and transparency in relation to policy creation and implementation and changes to industry codes. This includes strengthening Ofgem’s independence, reporting powers and ability to drive changes forward.

VII CONCLUSIONS AND OUTLOOK

The UK energy market remains a mature and attractive market for domestic and foreign investors. The gas market has been largely stable with the recent changes to the regulatory regime coming from the European Union-wide Network Codes being implemented. On the electricity side, the CfD regime has largely been positively received and the capacity market while not perfect has run three successful auctions so far. The key tests here will be on delivery against the aims of the EMR programme in two to three years’ time, when the contracted capacity is due to come online. While it may no longer be as attractive for encouraging large uptake in new greenfield renewable generation, government signals about the need for new gas-fired electricity generation, developments in energy storage and the proposed sale of gas distribution networks by National Grid continue to make this a thriving market for investors.

Finally, in June 2016, the United Kingdom narrowly voted to exit the European Union. While much of EU-led legislation has been transposed into national law, it remains to be seen whether there is likely to be an eventual divergence in policy goals and regulatory architecture (including competition and state-aid law enforcement), as well as what the impact will be on the regulation of interconnected energy markets of the United Kingdom and other EU Member States.
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, 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, 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 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,

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.

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 responsible for issuing authorisations to import and export natural gas to and from the United States, including liquefied natural gas (LNG). The DOE is led by the Secretary of Energy, a member of the President’s cabinet.

Numerous other federal agencies and departments regulate certain aspects of the US energy industry, including the 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, 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 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 regulated assets.

Under the Natural Gas Act, FERC is authorised to approve the construction and operation of new interstate natural gas pipeline and storage facilities and LNG import and
export terminals. Owners of natural gas facilities authorised by FERC 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 or 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 capacity on certain new electric transmission and oil pipeline facilities.

The Natural Gas Act 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. 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 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 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, the Department of Interior’s offshore pipeline responsibilities were carried out by the Mineral 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 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’, which in both cases is 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 ownership interests or 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.

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;

b 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

c 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 legislation 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 generating 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, 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 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.

Interstate natural gas pipelines and storage companies are permitted to offer rate discounts and negotiate rates. 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.

The safety and security of natural gas and liquids pipelines is regulated by the US Department of Transportation (DOT) through its Pipeline and Hazardous Materials Safety Administration (PHMSA), and, for interstate pipelines, if certified by PHMSA, state PUCs. 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, 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.

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 in any hour 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 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, although generally 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 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. 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 2016, 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 (1) guarantee customer cost savings in comparison to utility rates or (2) guarantee that the energy delivered consists of at least 30 per cent renewable energy. These requirements, which have been stayed pending judicial review, would apply both to new customers and to contract renewals by existing 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 has also proposed but not yet finalised 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 federal government provides or has provided various tax incentives for renewable energy, including:

- 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;
- 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
- 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 US President’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 greenhouse gases (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. In 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. During 2015, a number of states took steps to revisit or revise their net metering policies in response to concerns by retail electricity suppliers 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 retail transmission and distribution systems. Notably, while regulators in California, the state in the United States with the largest market for distributed solar electric systems, recently 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 Nevada approved a new net metering tariff that lowered the existing retail credit and imposed higher fixed charges, including for existing customers, while regulators in Hawaii closed the state’s largest utility’s net metering programme to new participants.
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 in less than five years, 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 are actively considering establishing, and since 2011 three states, most notably 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 been limited to commercial properties because of federal home mortgage insurance policies.
VI THE YEAR IN REVIEW

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. Environmental regulation of fossil fuel-fired generation, especially coal-fired generation, is expected to increase significantly by 2016. Of particular significance, the Environmental Protection Agency’s proposed Clean Power Plan (currently subject to a stay of implementation pending judicial proceedings) would begin to limit CO2 emissions from existing electric generating facilities in 2020 and seeks to reduce these emissions by approximately 32 per cent from 2005 levels by 2030. In addition, the increasing rate of penetration of intermittent renewable generation resources often requires natural gas fuelled generation as a reliability backstop. The increasing reliance on natural gas for electricity generation, together with severe weather experiences across the United States in recent years, have continued to put pressure on the existing natural gas transportation infrastructure and highlighted several issues with respect to how the natural gas and electric industries interact. After several years of technical conferences and public comments on these issues, in April 2015, FERC issued Order No. 809, entitled ‘Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities’, adopting proposals submitted by an industry forum to modify the scheduling practices used by interstate natural gas pipelines to schedule natural gas transportation service and provide additional contracting flexibility to firm natural gas transportation customers through the use of multiparty transportation contracts and revised nomination timelines. FERC also directed each FERC-jurisdictional RTO and ISO to propose tariff revisions to coordinate its day-ahead energy market with the scheduling practices adopted in Order No. 809 or to show cause why its existing scheduling practices need not be changed.

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.

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’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., ‘negawatts’) 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 energy markets sought to improve generator reliability during these periods by significantly revising their 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. 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 2015 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 initiated a proceeding ‘Reforming the Energy Vision’ (REV), that resulted in a ‘Track One’ order issued in early 2015 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 order 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. 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 by July 2015, and to propose a ‘Distributed System Implementation Plan’ in early 2016. In a series of proceedings, regulators in New York are expected to consider a wide range of issues relating to the REV, 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 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 US$5 billion ‘Clean Energy Fund’ that will in part support the New York Green Bank and a solar electric incentive programme, and the development of a ‘Clean Energy Standard’ to succeed New York’s RPS (which expired at the end of 2015) that would require 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.

ii  Natural gas and fossil fuel liquids pipelines, LNG terminals and rail transportation of crude oil

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. 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 2014 and 2015, 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.

Since 2013, FERC approved the construction and operation of seven large-scale LNG terminals for the export of LNG produced from natural gas originating in the continental United States. One of these projects completed construction and commenced commercial operation in early 2016, and four other projects are under construction, although several of the FERC orders approving several of these projects are subject to appeals in the DC Circuit. These appeals concern project-specific issues but also common issues regarding FERC’s NEPA review as related to more general and ‘indirect’ and ‘cumulative’ environmental impacts asserted by some environmental non-governmental organisations as resulting from increased export capacity for natural gas. The relief sought in each case is for FERC to report on and evaluate additional environmental effects, including whether the terminals will
induce increased natural gas production for export and result in the increased use of coal rather than natural gas to generate electricity, and thus contribute to GHG emissions, among other matters. The issues to be decided by the DC Circuit include whether the appellants are proper parties to appeal (i.e., have standing), whether the issues raised are more properly addressed in appeals of DOE orders authorising LNG exports, and whether FERC reasonably determined that an analysis of the alleged impacts would be too speculative to assist FERC in its decision-making process. Several of these appeals have been fully briefed and argued and are ripe for decision (although the DC Circuit may decide to address all of the appeals at the same time).

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 have sought rehearing (essentially reconsideration) of FERC’s order.

The DOE has authorised six 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). 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, but none are so far advanced as the appeals of FERC orders approving the construction and operation of LNG export terminals.

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 more closely track the issuance 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 are 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 tar 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 has been strongly opposed by environmental groups and the Secretary of State has not issued a decision on the 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, the President vetoed the bill, and a vote to override the veto in the US Senate failed in March 2015. In November 2015, the Secretary of State 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 continuing leading the world in combating climate change’.

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 willful violations of the Pipeline Safety Act (PSA). The PG&E case is currently scheduled for trial in federal district court in June 2016. Criminal charges have been brought by the federal government under the PSA only four times since 1996, including the charges against PG&E. Such prosecutions under the PSA require a violation to be committed ‘knowingly and willfully’, which is the highest, most stringent standard among criminal statutes. Congress is currently considering legislation to reauthorise the PSA, and a final bill is expected later this year. Some senior officials in the DOT are advocating that the PSA be changed to lower the liability standard from knowingly and willfully to ‘recklessly’ and provide for greater whistle-blower incentives.

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 extend existing integrity management requirements to previously exempt pipelines and would impose additional obligations on hazardous liquid pipeline operators that are already subject to existing integrity management requirements. Specifically, the proposed rule would require that all covered hazardous liquid pipelines have a system for detecting leaks, and establish a timeline for inspections of affected pipelines following an extreme weather event or natural disaster. The proposed rule would also require 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, and to implement additional measures as necessary. It would also establish shorter repair timelines for critical pipeline repairs, and tighten the standards for pressure tests. The proposal would require annual reporting of safety-related conditions and incident reports for all liquid gravity lines and liquid gathering lines. PHMSA is expected to finalise the rule in 2016.

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 both by adding new assessment and repair criteria for natural gas transmission pipelines and by extending such protocols to pipelines located in ‘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.

Responding to the recent high-profile leak of methane gas from the Southern California Natural Gas Company’s Aliso Canyon/Porter Ranch underground storage field 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. PHMSA is also reportedly working on new proposed regulations to address the safety of underground storage facilities, and several states have also begun their own legislative efforts to address the safety of underground natural gas storage facilities.

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) 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 national energy policy.
Appendix 1

ABOUT THE AUTHORS

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Masood Afridi is a partner at Afridi & Angell specialising in the areas of infrastructure and project finance, corporate and commercial, and energy law.

After working as an associate at the New York offices of the law firm of Sidley & Austin, he joined the Dubai office of Afridi & Angell in 1993. For several years, he has been a frontrunner in Pakistan's energy sector, and has participated in the development of numerous thermal and hydroelectric power projects in the country. He has also been nominated from time to time to resolve other global issues with the power purchaser on behalf of the industry.

Acting in the capacity of project developer's lead counsel, Mr Afridi has concluded transactions with a cumulative value of over US$4 billion, spread over several project finance transactions.

Mr Afridi has an LLM in international business and trade law from Fordham University (1990) and an LLB from the University of Bristol. At Fordham University, Mr Afridi received the Edward J Hawke Prize for graduating with the highest grade point average in his class.

PASCAL AGBOYIBOR
Orrick, Herrington & Sutcliffe (Europe) LLP
Pascal Agboyibor is a partner and a member of the Orrick, Herrington & Sutcliffe energy and infrastructure group. He currently advises lenders, governments and investors on major energy, mining and infrastructure projects in Africa.

RICARDO ANDRADE AMARO
Morais Leitão, Galvão Teles, Soares da Silva & Associados, Sociedade de Advogados RL
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.

**PER CONRA DI ANDERSEN**  
_**Kvale Advokatfirma DA**_

Per Conradi Andersen is a partner at Kvale in Oslo. He holds an LLM in European legal studies and is admitted as an attorney to the Supreme Court. He has been involved in the electricity sector from 1990, first as a senior executive officer at the Royal Ministry of Petroleum and Energy, then, after two years as a judge, for the past 19 years as a lawyer in Oslo-based law firms. He has written a book about the Norwegian Energy Act and several articles in various publications.

**LUCIANA BELLIA**  
_**Cleary Gottlieb Steen & Hamilton LLP**_

Luciana Bellia is a senior attorney based in the Rome office. Her practice focuses on European and Italian competition law, in particular merger notifications, antitrust law, including vertical and horizontal agreements, cartels, abuse of dominance, and state aid. She has experience in a number of industries, particularly energy and chemicals. Ms Bellia has been involved in a broad range of merger control and abuse of dominance proceedings with the European Commission and the Italian Antitrust Authority. She joined Cleary Gottlieb Steen & Hamilton LLP in 2006 and until June 2008 was based in the Brussels office. She graduated with honours from LUISS Guido Carli University Law School in 2001. While at law school she was a visiting student at the Georgetown University Law Center for a semester on a scholarship granted by the University of Rome. She obtained an LLM in advanced European legal studies from the College of Europe (Bruges) in 2006. Prior to joining Cleary Gottlieb, Ms Bellia was an associate at a major international competition law firm in Rome. Ms Bellia has been a member of the Palermo Bar since 2004. She is a native Italian speaker and is fluent in English and French.

**RIYAZ BHAGAT**  
_**Trilegal**_

Riyaz Bhagat is an associate in the Trilegal energy, resources and infrastructure team. His principal area of practice is renewable energy projects. 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. He is particularly experienced in advising clients on statutory compliance, EPC and O&M contracts and regulatory issues, especially in the context of various state solar and wind power policies.
DOUX DIDIER BOUA
Orrick, Herrington & Sutcliffe (Europe) LLP
Doux Didier Boua is a managing 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.

ZEYNEP BUHARALI
Kolcuoğlu Demirkan Koçaklı Attorneys at Law
Ms Buharalı joined Kolcuoğlu Demirkan Koçaklı in 2012. She has experience in mergers and acquisitions, energy law and competition law. Her cross-border energy transaction experience includes a variety of deal types, ranging from joint ventures to M&A transactions in the energy sector.

DANIELA BURAYE
López & Associates Law Firm
Daniela Buraye is an attorney of the Republic of Ecuador and a graduate of UEES (Espíritu Santo University) majoring in corporate law. Her languages are Spanish and English. She has taken franchise and intellectual-property practice workshops, and has attended entrepreneurship and critical-thinking workshops. She has also assisted in seminars on jurisdictional warranties and constitutional courts.

SALEM CHALABI
Stephenson Harwood Middle East LLP
Salem Chalabi, an Iraqi national and a lawyer, has been a corporate and projects partner at Stephenson Harwood LLP since June 2014.

Mr Chalabi is a graduate of Yale University (BA), Columbia University (MA) and the Northwestern University Pritzker School of Law (JD). He has practised law with international law firms Morgan Lewis (in New York), Clifford Chance (in London) and DLA Piper (in Dubai). He is also a member of the New York Bar.

In 2003, Mr Chalabi was a deputy member of the Interim Governing Council of Iraq, and a member of the finance and legal committees. In these roles, he was responsible for drafting a large number of orders and laws, in conjunction with the Coalition Provisional Authority. In addition, in 2004, he was one of two Iraqis who drafted the Transitional Administrative Law (the Interim Constitution) that 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
Sołtysiński Kawecki & Szlezak
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. Recently he has been advising clients on regulatory and contract matters in respect of licensed hydrocarbon activities in Poland (shale gas). 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
About the Authors

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 practises as a legal counsel. He is fluent in English.

MICHAEL DAMIANOS
Michael Damianos & Co LLC
Michael Damianos is the founder and managing partner of Michael Damianos & Co LLC. He is a law graduate of the University of Southampton (with first-class honours) and has an LLM from Fitzwilliam College, University of Cambridge. He is dually qualified, in Cyprus and in England and Wales (as a solicitor). Before practising in Cyprus he qualified as a solicitor at the London office of Simmons & Simmons and then moved on to the London office of Lovells LLP (now Hogan Lovells), working for the then energy, power, utilities and infrastructure department.

GIULIANA D’ANDREA
Cleary Gottlieb Steen & Hamilton LLP
Giuliana D’Andrea is a trainee based in the Rome office. Her practice focuses on European and Italian competition law, advising on restrictive practices, abuse of dominance investigations, state aid and merger control procedures. She has experience in the energy, telecommunications, banking and chemicals industries. She graduated with honours from LUISS Guido Carli University Law School in 2015 and joined Cleary Gottlieb Steen & Hamilton LLP in the same year. Her native language is Italian, she is fluent in English and has a basic knowledge of French.

OKAN DEMIRKAN
Kolcuoğlu Demirkan Koçaklı Attorneys at Law
Mr 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, 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 also includes advice to an American energy company in its proposed bid in the privatisation of Turkey’s electricity distribution entities. He is also a board member of INLA’s (International Nuclear Law Association) Turkey chapter.

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 and 2014, Mr Demirkan received the Client Choice Award for his work in energy and natural resources projects. More importantly, KDK won Law Firm of the Year: Turkey for 2015, awarded by globally published magazine The Lawyer.
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.

MARCO D’OSTUNI

_Cleary Gottlieb Steen & Hamilton LLP_

Marco D’Ostuni is a partner based in the Rome office. Mr D’Ostuni is distinguished as a leading lawyer in competition/antitrust practice (Italy) and in ‘TMT: Telecommunications’ by _Chambers Europe_. His practice focuses on antitrust, telecommunications, media and energy law. He has represented clients before the EU Commission and the Italian Antitrust Authority (IAA) in antitrust investigations and merger filings; in proceedings before the Italian Communication Authority (AgCom) and the Italian Energy Authority; and in arbitration and litigation before civil and administrative courts involving complex antitrust or sector regulation issues. Mr D’Ostuni is the co-author of many publications on antitrust matters. He joined _Cleary Gottlieb Steen & Hamilton LLP_ in 2000 and until June 2001 was based in the New York office. He became a partner in 2009. He graduated with honours from the University of Naples Law School in 1996. He obtained an LLM in advanced European legal studies from the College of Europe of Bruges in 1998. In the same year, he won the Best Advocate General prize in the EU Competition Law Moot Court Competition, awarded by the European Court of Justice (where he later briefly interned). He obtained an LLM from Columbia Law School, where he was a Harlan Fiske Stone Scholar, in 2000, after receiving a Fulbright Scholarship. In 2008, he obtained a PhD in competition law from the University of Perugia, Italy. Prior to joining _Cleary Gottlieb_, Mr D’Ostuni was a trainee at an administrative law firm in Naples, from 1996 to 1997. From 1998 to 2000, he was an associate at a major international competition law firm in Brussels. Mr D’Ostuni has been a member of the Naples Bar since 2001, and of the New York Bar since December 2003. He is a native Italian speaker, is fluent in English, French and Spanish, and has a basic knowledge of Portuguese.

NIGEL DREW

_DL Piper International_

Nigel Drew is a solicitor qualified in England and Wales and heads the firm’s successful energy and infrastructure finance team in London. He has led on some of the largest energy and infrastructure projects in Europe and Africa, and has acted for arrangers (bank and bond), sponsors, contractors and the public sector on international projects across a wide range of sectors. In his extensive experience in the energy sector, he has advised on renewable power projects throughout Europe and Africa, including the largest project financing in Poland.

Nigel has been listed in _Expert 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

_G Elias & Co_

Professor Gbolahan Elias is the presiding partner of _G Elias & Co_, one of Nigeria’s leading business law firms. He is also a visiting professor of law at Babcock University, Ilishan where
he teaches shipping, petroleum and arbitration law. He has published widely on a range of both historical and topical legal matters and served on numerous law reform committees, university administration boards and law journal editorial boards.

He read law at Magdalen and Merton Colleges, Oxford. He has DPhil, BCL (first-class honours), MA and BA (first-class honours) degrees from the University of Oxford. He was called to the New York Bar in 1990. Professor Elias was an associate at the Cravath firm in New York and has been a senior advocate of Nigeria since 2005. He is a member of the Chartered Institute of Arbitrators.

He has advised on numerous transactions in the Nigerian energy sector, including the largest acquisitions to date of electricity generation and distribution companies. He also advised on the development and negotiation of the precedent-setting power-purchase contracts and vesting contracts for the federal government-backed single buyer of grid electric power. He recently advised on a US$1.2 billion ‘gas-to-power’ project financing and a US$1.5 billion refinancing of NNPC petroleum product import receivables.

**MOSTAFA EL ZEKY**

*Shalakany Law Office*

Mostafa El Zeky obtained an LLB from Cairo University in 2011. Mostafa interned with Shalakany Law Office in 2009 and 2010, and joined the firm’s corporate department in 2011. He was on secondment to GTH (a leading international telecommunications holding company) in April/May 2013 and at Linklaters LLP (Dubai office) in January/February 2016.

Mostafa has been involved in the full process of incorporation and restructuring of companies, including drafting and reviewing of constitutional and establishment documents. He has worked on numerous M&A transactions requiring extensive due diligence, drafting of transaction documents and supervising the signing and closing process. Key M&A projects include Pamplona Capital Management LLP’s acquisition of RWE Dea Nile GmbH (a major global player in upstream oil and gas), Chevron’s sale of its Egyptian downstream assets and JTI’s acquisition of the Nakhla Tobacco group of companies. Mostafa has acted for real estate clients, including Emaar Misr, in matters including drafting due diligence reports on major real estate projects and contracts for the sale of residential, commercial and administrative units. Mostafa is a member of the firm’s projects group and has worked extensively on project-related documents. He has recently advised Emaar Misr in its recent IPO on the Egyptian stock exchange, the largest IPO on the exchange in the past decade. He is currently representing several consortia in major renewable energy feed-in tariff and BOO projects.

Mostafa advised IFC on the structuring of sovereign guarantees for the project financing of future power-producing IPP projects. Mostafa is a member of the Egyptian Bar Association.

**JORGE EDUARDO ESCOBEDO MONTAÑO**

*Basham, Ringe y Correa, SC*

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 co-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 Central School of Paris and Cairo University, Egypt.

MARIAM FAHMY
*Shalakany Law Office*

Mariam Fahmy obtained an LLB from Cairo University in 2007 and an LLM from Indiana University in August 2010. Mariam joined the firm’s corporate department in 2007 and interned with the office during 2005 and 2006. Mariam is a member of the firm’s project finance, banking and capital markets department. She is involved in providing advice on equity, debt and derivative instruments and drafting and reviewing syndicated loan documentation. Mariam recently acted for the EBRD on the financing of two separate Egyptian manufacturing projects each with a value of US$25 million, in addition to the financing for a major cement producing company to the value of US$50 million. She acted on behalf of the Egyptian Bahraini Gas Derivatives Company, the borrowers, in a US$66.5 million loan transaction, where she reviewed the whole set of documentation, including all documents related to the conditions precedent section. She also acted for the lenders in relation to a US$390 million term loan facility to the National Bank of Egypt. She is also involved in providing advice on securitisation, convertible bonds, derivatives and structured products.

Mariam is also a member of the firm’s projects group, handling several PPP projects and acting for both the procuring entity and the bidders. She was involved in Rod El Farag PPP as part of the legal advice group on behalf of the Ministry of Finance Central PPP Unit. Furthermore, she is currently acting for Rusatom as the EPC contractor for Egypt’s first nuclear power plant; acting for a number of developers on wind and solar projects under Egypt’s feed-in tariff regime; and acting for JBIC, NEXI and other commercial banks on the financing of the 250MW BOO wind farm project in the Gulf of Suez.

Mariam is involved in drafting and reviewing the full suite of documents related to company incorporation, corporate agreements, property sales, lease agreements and due diligence reports, and she provides legal advice on employee issues, including hiring, firing, discipline, leave and attendance, employment agreements, severance agreements, misconduct, internal investigations and reductions in force. Mariam is a member of the Egyptian Bar Association.
LIDO FONTANA  
_Chadbourne & Parke (South Africa) LLC_  
Lido Fontana is the managing partner of Chadbourne & Parke'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.

DEON GOVENDER  
_Chadbourne & Parke (South Africa) LLC_  
Deon Govender is an international partner at Chadbourne & Parke who focuses his practice on project development and corporate and project finance transactions across Africa, with particular emphasis on southern Africa.

ANDREAS GUNST  
_DL 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 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
 Mozambique Legal Circle Advogados
Fabrícia de Almeida Henriques is a partner at MLC Advogados. 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 consultant for Morais Leitão, Galvão Teles, Soares da Silva in 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 an associate at Linklaters LLP and a corporate and energy lawyer in Berlin. He studied in Berlin, Paris (licence en droit, Panthéon-Assas University (Paris II)) and London (LLM in competition law, King’s College) and has trained as a lawyer in Berlin and Shanghai.

Henry Hoda specialises in corporate law, M&A transactions and regulation in the energy sector. He advised EEX on its acquisition of a majority participation in the French energy exchange Powernext, and EEX, Powernext, Tennet and Elia on the integration of the electricity spot exchange businesses of EPEX SPOT and the APX group. He also advised E.ON on the spin-off of its conventional generation, trading and E&P business. He has represented gas storage and power plant operators in proceedings for adjustment of storage and supply agreements; advised Tennet and TransnetBW on their cooperation with respect to the largest German HVDC transmission line, SuedLink; and BP and Dow Chemical on questions of renewable energies regulation.

ANNA S HOLLOWAY  
Wilmer Cutler Pickering Hale and Dorr LLP

Anna Holloway is a counsel in the litigation/controversy department at Wilmer Cutler Pickering Hale and Dorr LLP in Washington, DC and a member of the firm’s international arbitration practice group.

Ms Holloway’s practice focuses on international commercial arbitration, and covers a wide range of industries, including in particular the energy, oil and gas, banking and finance, and telecommunications sectors. Her practice also includes representing clients in public international law arbitrations. Ms Holloway has represented companies, states and state-owned entities before a variety of international arbitration tribunals constituted under the auspices of various leading arbitral institutions, including ICC, LCIA, PCA, VIAC, SCC and others, sited in both common and civil law jurisdictions, and has also represented clients before the English High Court.

MARYNA ILCHUK  
Arzinger

Maryna Ilchuk specialises in advising on different issues of energy law (particularly renewable energy) and public–private partnership issues. Maryna heads the energy practice at Arzinger.

She advises foreign and Ukrainian clients on the implementation of Ukrainian legislation when entering local energy markets, on the award of green tariffs for electricity produced from renewable energy sources, licensing, access to grids, and interconnection of the Ukrainian and foreign grids. Ms Ilchuk consults clients on structuring and implementing PPP-type transactions. She has also taken part in a number of large-scale projects in the area of alternative energy and cooperation of foreign investors with state enterprises and legal authorities.

Ms Ilchuk actively takes part in preparing publications at Arzinger (Energy Law Guide (second edition), Biogaserzeugung und -nutzung in der Ukraine), and she is also author of a number of articles on energy and PPP law.

She graduated from the National University of Kyiv-Mohyla Academy in Ukraine, and has a specialist degree and a master’s degree in law.
RYUTARO KANNO
*Anderson Mōri & Tomotsune*

Ryutaro Kanno is an associate at Anderson Mōri & Tomotsune. He studied at Keio University (LLB) and Keio University Law School (JD) and is admitted to the Bar in Japan (Dai-ichi Tokyo Bar Association).

MOCHAMAD KASMALI
*Soemadipradja & Taher*

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).

KANAN KASUYA
*Afridi & Angell*

Ms Kasuya is an associate at Afridi & Angell. Her practice focuses on corporate and commercial matters, including: advising clients on the establishment, structuring and winding down of business in the UAE; and advising clients on the general corporate, commercial and other matters related to the conduct of business, financing, employment matters, real estate and regulatory compliance.

Ms Kasuya interned at Afridi & Angell prior to joining the firm in 2014. Prior to that, she interned at legal clinics at the University of Montreal and McGill University in Montreal, Canada, and at a reputable law firm in Cairo, Egypt. Ms Kasuya has an LLB from the University of Montreal (2012) and a BA (with distinction) from McGill University (2009). Ms Kasuya is fluent in English, Arabic, French and Japanese.

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:

1. 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;
2. advised the Abhijeet Group on an electricity equity investment in Senegal;
3. 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.

CHINEDU KEMA

G Elias & Co

Chinedu Kema is an associate in the law firm of G Elias & Co. He holds a degree in law from Imo State University, Owerri, and a first-class honours from the Nigerian Law School.

He has been involved in several of the firm’s oil and gas deals, including advising a consortium on its proposed acquisition of 45 per cent participating interest in an OML and Africa Finance Corporation on its investment in and divestment from the acquirer of a 45 per cent participating interest in an OML. He is also a member of a team advising an upstream company on a US$640 million working capital facility from a syndicate of international and local lenders.

WONIL KIM

Yoon & Yang LLC

Wonil Kim is a partner at Yoon & Yang LLC, with over 15 years’ experience in all areas of intellectual property, including patents, trademarks, designs, copyright, unfair competition, trade secrets and telecommunications and broadcasting. Prior to joining Yoon & Yang LLC, Mr Kim served as a judge at the Inchon District Court. As chair of the firm’s ‘cleantech’ and intellectual property group, Mr Kim has extensive experience in the areas of energy, copyright, trademarks, energy, telecommunications and broadcasting, and regulatory matters in Korea.

NICOLAJ KLEIST

Bruun & Hjejle

Nicolaj Kleist has extensive experience in advising on regulatory matters and public law issues, especially within the energy sectors, where he advises energy and supply utilities in the areas of oil, gas, electricity, heating and renewables. He regularly assists in disputes before public authorities, complaints boards and the courts, and has assisted in a number of landmark cases regarding price issues.

MELIS ÖGET KOC

Kolcuoğlu Demirkan Koçaklı Attorneys at Law

Ms Melis Öget Koç is a senior associate at Kolcuoğlu Demirkan Koçaklı. Before joining the firm in 2015, she was a senior associate at another major Istanbul-based law firm for seven years.
Ms Koç has significant experience in M&A transactions and has participated in a wide range of M&A deals. She has led several acquisition transactions in a variety of regulated sectors, including the energy sector.

**MARCOS CHAVES LADEIRA**

*Pinheiro Neto Advogados*

Marcos has been a partner at Pinheiro Neto Advogados since 1998, and is active in corporate law, M&A, private equity and regulatory law (energy). He is a founding member of the Brazilian Institute of Energy Law (IBDE), and a member of the Brazil–Germany Chamber of Commerce and Industry. He holds an LLB from the University of São Paulo School of Law and a specialisation degree from the Getúlio Vargas Foundation Brazilian School of Public and Business Administration. He was a foreign associate at Cleary, Gottlieb, Steen & Hamilton, New York (1994–1995), and is fluent in Portuguese, English and German. He advised BTG Pactual in the acquisition of Globenet for 1.75 billion reais (2013), which was recognised by *LatinFinance* magazine as Private Equity Deal of the Year; as well as AEI in the US$2.4 billion sale of equity participation in Elektro Eletricidade e Serviços SA (2011), which was recognised by *LatinFinance* magazine as Cross-Border M&A Deal of the Year. He is consistently ranked among the nation’s top corporate and energy lawyers by a number of publications, such as *Análise Advocacia*, *The Legal 500* and *IFLR1000*.

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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 from environment and ‘cleantech’ business.

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Additionally, he has contributed to international publications, including *Getting the Deal Through: Dispute Resolution*, Ecuador chapter 2014; *Getting the Deal Through: Oil Regulation*, Ecuador chapter 2014; and *The Oil and Gas Law Review*, Ecuador chapter 2014.

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Roger Martella is an international environmental attorney with Sidley Austin LLP in Washington, DC, focusing on assisting multinational corporations with environmental compliance, sustainable development and litigation across the globe. Prior to joining Sidley Austin, Mr Martella was the general counsel of the US Environmental Protection Agency and the principal counsel for complex litigation for the Justice Department’s Natural Resources Section. Mr Martella is the co-editor of the ABA’s book *International Environmental Law: The Practitioner’s Guide to the Laws of the Planet*, co-chair of the International Bar Association’s Presidential Task Force on Climate Change Justice and Human Rights, vice chair of the American Bar Association’s Sustainable Development Task Force, vice chair of the ABA’s World Justice Forum committee, the author of *International Environmental Law: A Guide for Judges*, and the author of the chapter on international environmental ethics in the ABA’s upcoming environmental ethics book. Mr Martella is also the founder of the US EPA–China Environmental Law Initiative. In 2015, *Who’s Who Legal* listed Mr Martella as the top environmental lawyer globally. Mr Martella graduated from Vanderbilt Law School, where he was editor in chief of the *Vanderbilt Law Review*, and from Cornell University.

FIONA MEATON  
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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  
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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 Getulio Vargas
Foundation (FGV), Brazil. She was recognised in the 2014, 2015 and 2016 editions of *IFLR1000* as a Leading Lawyer in Latin America for project development (power sector) within energy and infrastructure.

**NEERAJ MENON**

*Trilegal*

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 advises industry associations on policy and regulatory issues in the energy and infrastructure sectors.


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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.

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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’.

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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.

**OKECHUKWU J OKORO**

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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 is a senior associate 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 Federal 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/SP) and a member of the Brazilian Institute of Energy Law (IBDE).

Max Oosterhuis, attorney at law, heads the Loyens & Loeff energy team. Max specialises in EU and national energy law, and is an expert on 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.

Tim is a law graduate at Squire Patton Boggs (AU) having graduated from the University of Western Australia in 2015. Tim’s area of practice is corporate energy and resources law and he has assisted with due diligence, drafting and researching issues particularly as they relate to Corporations Act compliance and the ASX Listing Rules.

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.

Sebastian Pooschke is a managing associate at Linklaters LLP and a corporate and energy lawyer in Berlin. He studied law in Berlin, Glasgow and Amsterdam and practised in Brussels, London and Berlin.
Sebastian Pooschke has specialised experience in corporate and contract law, M&A and regulation in the energy sector. He has represented GdF Suez on the swap of a power plant portfolio with E.ON and on joint ventures for generation and supply of electricity, gas and district heating. He has also advised GdF Suez in farm-in transactions in Germany and in the sale of shares in its E&P business to China Investment Corp. He has advised on access to oil, gas and electricity networks under regulation and competition law and acted for gas storage and power plant operators in proceedings for adjustment of long-term storage and supply agreements. He has also advised TenneT and TransnetBW on their cooperation with respect to the largest German HVDC transmission line, SuedLink; financial institutions on gas trading and storage in Germany; and on the acquisition of electricity and gas networks; for example, with respect to the former E.ON and RWE gas transmission networks. Sebastian Pooschke regularly publishes and lectures on energy law.

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 *Doyles, The Legal 500 – Asia-Pacific* for corporate and M&A, and the *IFLR1000 Energy and Infrastructure guide.*

CHRISTIAN POULSSON

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Christian Poulsson is a partner at Kvale in Oslo. He has been involved in the electricity sector since 1996, first as in-house counsel at Norsk Hydro ASA, then, after 15 months as a judge, for the past 14 years as an attorney in Oslo-based law firms. He has written several articles in various publications.

HELENA PRATA

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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.
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Kai Pritzsche is a partner at Linklaters LLP and a corporate and energy lawyer in Berlin. He studied law and political sciences in Freiburg, Geneva, Bonn, Berkeley (LLM) and Cologne (Juris Doctor) 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; a group of exchanges and transmission system operators on the integration of the Dutch APX with the French EPEX; RWE and E.ON on the introduction of incentive regulation and unbundling in Germany; seven European transmission system operators and four energy exchanges on the introduction of the Central Western European market coupling regime; 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 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; and BP on refinery and pipeline projects. Kai Pritzsche regularly publishes and lectures on questions of corporate law and energy law.

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Paula Duarte Rocha is a partner at MLC Advogados. Engaged as a legal assistant, she had started her career even before completing her law degree. She then became a legal assistant to a partner at Pimenta, Dionísio & Associados. From 2000 to 2002 she provided multidisciplinary legal consultancy at the tax and legal services department of PricewaterhouseCoopers, cooperating with national and foreign investors. She was also an associate lawyer and senior legal adviser at MGA Advogados & Consultores.

More recently, Ms Rocha was a lawyer and managing partner at Ferreira Rocha & Associados, Sociedade de Advogados, involved in all areas of practice, advising national and foreign private companies with respect to public sector laws, public tenders and contracts, as well as advising foreign entities on compliance with all Mozambican tax, labour and commercial obligations.

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Myria Saarinen is a partner in the litigation department of the Paris office of Latham & Watkins.

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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 (FERC), various state public utility commissions, the US Department of Justice (DoJ), the Federal Trade Commission (FTC), the Securities and Exchange Commission (SEC), the Commodity Futures Trading Commission (CFTC) and the Department of Energy (DoE).

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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Juan Carlos Serra Campillo graduated from the National Autonomous University of Mexico and has a master’s degree from Georgetown University (Fulbright Scholarship). He also holds a postgraduate degree in corporate and economic law from the Panamerican University and a diploma degree in energy law from the Ibero-American University.

He is recognised as a ‘Leading Lawyer’ for Latin America by IFLR1000’s Energy and Infrastructure Guide, and he 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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Kenneth Simon is a partner in the finance department and energy regulatory and markets group of Latham & Watkins’ Washington, DC office. He represents companies, lenders and investors engaged in the ownership, operation and financing of electric, natural gas, and oil pipeline companies and facilities.

Mr Simon led the effort to develop the first new-build independent power producer in the United States among other electric generating and pipeline projects, the first case in which FERC approved charging market rates to an affiliate; the formulation of transmission pricing policies and regional transmission organisations; litigation regarding the royalty payments due to the US Office of Natural Resource Revenue and the reliability of service provided by a major public utility; and the acquisition or sale of public utilities, electric generating assets, pipelines, and LNG facilities. He has also assisted lenders and investors with regulatory matters relating to several new LNG export facilities and sponsors of new interstate and cross-border oil and gas pipelines. Mr Simon has been recognised as an outstanding energy and project finance lawyer by numerous publications for more than 20 years, and in a 2005 poll conducted by *Legal Times* he was voted by his peers as the leading lawyer in energy in Washington, DC.

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Samantha is an experienced corporate and commercial lawyer with a strong background in supporting companies across all industries in commercial transactions and corporate governance, particularly across the resources sector.

Samantha specialises in advising in relation to public and private mergers and acquisitions, the development of independent power projects, joint venture and farm-in arrangement structuring and secondary capital raisings. Samantha also regularly provides advice to clients on a broad variety of corporate law issues and corporate governance risk mitigation, including directors’ duties, continuous disclosure requirements, company secretarial matters and general regulatory compliance issues involving the Corporations Act and the ASX Listing Rules.

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Since February 2016, Shaghayegh Smousavi has been head of the CMS operations in Tehran together with Jürgen Frodermann, and she is managing director of the new CMS Pars office. 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. She also regularly represents her clients in arbitration proceedings and before authorities such as the German Federal Court of Justice or higher regional courts.

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 a big Anglo-Saxon firm, 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 senior associate at Geni & Kebe Law Firm.

Her practice areas are transport, corporate and private-public agreements.

Recent work on energy sector:

a. advised Jindal Steel & Power (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; and

b. advised the Abhijeet Group on an electricity equity investment in Senegal.

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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Hao Su, part of Herbert Smith Freehills' global energy practice in Beijing, is admitted as a solicitor in Hong Kong. He is also admitted as a solicitor in England and Wales. He has worked in Hong Kong, Beijing and London. Hao has experience in a wide range of commercial and corporate transactions including mergers and acquisitions in the oil and gas sector, foreign direct investment into China, natural resources projects, IPOs and acquisition finance.

Hao is a native speaker of Mandarin Chinese and is fluent in English.

MONICA SUN

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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.

REIJI TAKAHASHI

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Reiji Takahashi is a partner at Anderson Mōri & Tomotsune. He studied at the University of Tokyo (LLB) and the University of Virginia (LLM). He is a lecturer of the University of Tokyo School of Law and is admitted to the Bar in Japan (Dai-ni Tokyo Bar Association) and New York.
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NUNO GALVÃO TELES
Morais Leitão, Galvão Teles, Soares da Silva & Associados, Sociedade de Advogados RL
Nuno Galvão Teles joined the firm in 1987 and became a partner in 1995. He is the managing partner of the firm. He coordinates one of the corporate and commercial and capital markets teams. He also leads the firm’s energy team, an area in which he has extensive experience.

His relationship with the Portuguese energy sector dates back to the early 1990s. During the past 15 years, he has been involved with enterprises in the energy sector and given support to the Portuguese government on some of the most important transactions to have occurred in the country’s energy sector.

He has advised and assisted several companies and banks with a focus on M&A and capital markets operations. During recent years he has played an active role in key M&A transactions in Portugal or carried out overseas by Portuguese companies.

Mr Teles has led the team of lawyers responsible for some of the major privatisation transactions in Portugal, in the energy, pulp, motorway and cement industries.

ELECTRA THEODOROU
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Electra Theodorou is an associate at Michael Damianos & Co LLC. She is a law graduate of the University of Leeds, has obtained an LLM in international commercial law from the University of Nottingham and graduated from the Legal Practice Course (LPC) at BPP Law School. She is a qualified Cypriot lawyer and a member of the Cyprus Bar Association. She has lectured at an international conference on cybersecurity in the oil and gas industry, held under the auspices of the Ministry of Communication and Works of the Republic of Cyprus.

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Paulette Toro is an attorney of the Republic of Ecuador and a graduate of UEES (Espíritu Santo University). Her languages are Spanish and English. She is a specialist in corporate, civil, procedural, banking and financial, and trust law. She has also attended intellectual-property and corporate-governance workshops.

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John Trenor is a partner in the litigation/controversy department at Wilmer Cutler Pickering Hale and Dorr LLP in Washington, DC and a member of the firm’s international arbitration practice group.

Mr Trenor has represented companies, states, state-owned entities, international organisations, and individuals in a wide variety of disputes in the aviation, defence, financial services, manufacturing, oil and gas, pharmaceutical, technology, telecommunications and other industries. He has advised clients regarding commercial, investor-state and state-to-state arbitrations under virtually all of the major institutional as well as ad hoc rules, including ICC, LCIA, AAA, SCC, VIAC, ICSID, UNCITRAL and others, and regarding international
About the Authors

ROLAND DE VLAM
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Roland de Vlam, attorney at law and member of the Loyens & Loeff energy team, specialises in energy law. He advises energy companies and other market parties on regulatory aspects of transactions and represents his clients in court proceedings as well as in litigation before the Energy Department of the Netherlands Authority for Consumers and Markets (ACM). The scope of his work extends across the entire energy chain: from natural gas (E&P, storage, LNG, transport and supply), power (generation, transport and supply) and renewables, to heat and CO2. He is also involved in other regulated markets and EU law.

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Sharon Wing is a corporate and project finance lawyer at Chadbourne & Parke with experience working on traditional and renewable energy projects and corporate transactions across Africa. She has experience with hydropower and mining projects throughout Africa.

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Part of the global energy practice in Beijing, James has advised clients on upstream oil and gas (including LNG) projects in Africa, the United Kingdom, North and South America, Southeast Asia, the Middle East, Australia and Greater China, in respect of equity M&A, project development, project operation, facility tie-in and joint venture arrangements. James also has experience in electricity, nuclear power and construction.
Appendix 2

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