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GLOBAL LEGAL INSIGHTS – ENERGY

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CONTENTS

PREFACE

We are pleased to present the 7th edition of *Global Legal Insights – Energy*. The book contains 31 country chapters, spanning the six major continents of the world and providing a truly international and far-reaching snapshot of energy policy, industry and regulation across the globe.

The book is designed to provide general counsel, financial institutions, government agencies and private practice lawyers with a comprehensive insight into the most important trends and developments in the energy market across a range of key jurisdictions.

The energy industry is never static, with both the industry and policy and law-makers constantly responding to new challenges and opportunities. Some of these developments have had an impact across the globe – such as the rise of unconventional oil and gas resources, and technological advances in battery storage – while others have been more localised – such as Brexit in the UK. Nonetheless, there are always common themes in the way in which governments across the globe seek to balance issues such as energy security, energy affordability, economic development and sustainability issues, including climate change.

In producing *Global Legal Insights*, we have gathered together the views and opinions of a group of leading energy practitioners from around the world in a unique volume. The authors were asked to provide personal views on practical issues, policy issues, strategic issues, and legal and regulatory issues in their own jurisdiction, with a free rein to decide the focus of their own chapter.

One of the attractions of comparative analysis is that developments in one jurisdiction can inform understanding and practice in another.

Our thanks to all the authors for their contributions, and particular thanks to our colleague Justyna Bremen for her invaluable help. We hope that this book will prove interesting and stimulating reading for you.

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Albania

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Overview of the current energy mix, and the place in the market of different energy sources

Power

The generation of power in Albania is performed by entities (either private or public) that have been licensed by the Energy Regulatory Authority (ERE). KESH Sh.a. (state-owned) is the main producing entity, with an installed capacity of 1,448 MW. Currently, KESH Sh.a. operates three hydro power plants (HPPs), Fierza HPP, Komani HPP and Vau i Dejës HPP, together with the Vlora thermal power plant (the latter has an installed power capacity of 98 MW but has never been put into operation).

A considerable number of private entities have been licensed by ERE upon stipulation of concession agreements for the construction and operation of HPPs with the Albanian government. According to the Albanian government, currently there are 540 HPPs under concession agreements, out of which 147 (with installed capacity of 833 MW) have started their production, whereas 109 HPPs (with an installed capacity of 557 MW) are in the construction phase, and 284 have not yet commenced construction.

According to ERE, for the year 2017, the power production for public consumption was fully generated by HPPs, in a net production which reached the amount of 4,525,173 MWh, despite one of the main objectives of the National Action Plan for Renewable Energy Sources 2015–2020 being diversification into renewables, to ensure security of production (and supply).

Oil and gas

Similar to the power sector, operations in the oil and gas sector are subject to government agreements, by means of which the contractor is entitled to prospect and produce petroleum in the relevant contract area.

According to the National Agency of Natural Resources (AKBN), oil production in 2016 was 1,055,725.5 tons, a slight decrease on the year 2015, mainly due to the reduction in oil prices. Albpetrol Sh.a. is the state-owned company which is entitled to produce and trade oil and/or gas. Private companies also operate in the sector, with Bankers Petroleum Albania being the largest (having approx. 87.38% of the total annual production of crude oil for the year 2016).

Gas production, on the other hand, is entirely produced as associated gas and used for technological processes in the oil industry. Albania does not possess any natural gas production capacity yet. However, it is part of the corridor involved in the Trans-Adriatic-Pipeline TAP project and will benefit from the TAP project.

To this end, the Albanian parliament ratified the host government agreement entered into with the project investor for the development of the TAP project in 2013. TAP is a large-scale project in the sector, which is expected to contribute to the establishment of the required gas infrastructure.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

As noted above, Albania secures its power exclusively from HPPs (in addition to the net imported power, which varies between 30% to 60% of the total consumption needs). Thus, the country is exposed to a considerable degree to the risk of supply insecurity, due to changes of the hydrological conditions. The Albanian government has acknowledged that regardless of the record year of 2016 (in which Albania was a net exporter of energy), the need for diversification of energy sources is urgent. By way of example, in the year 2017 the production of energy was lower than the multi-annual average amount (4,682 GWh).

Therefore, as also outlined in the National Action Plan on Renewable Energy 2018–2020, Albania will continue to support the development of renewable energy sources, including diversification, with a particular focus on solar and wind capacities.

In this context and with the aim of securing the production of power from renewable energy (38% by 2020), for the period 2018–2020, there are three main pillars upon which the governmental policy will be based: (i) effective measures for the adoption of sub-legal acts foreseen by Law no. 7/2017 "On Promotion of Renewable Energy Sources"; (ii) wider technical and economic analysis in consideration of the interests of operators of the renewables market, in the application of 'supporting measures'; and (iii) improvement of the legislation governing biofuels in the transport sector, in consideration of the sustainability and transparency criteria, and applying measures for their trading/usage by end consumers.

As for the gas sector, natural gas is seen as an important source for the diversification of energy sources, but its usage has not seen any significant growth, mainly due to the minimal production level as well as the lack of investment in research and development of new fields. According to ERE, Albania does have considerable gas reserves both on land and sea, which have generated investors' interest to commence research for new gas areas. However, as noted above, no significant developments have been achieved.

Nonetheless, in relation to relevant infrastructure, from the development of the TAP Project, Albania is working on certain new projects, among which we could mention the ALKOGAP project, which consists of a gas pipeline linking Albania and Kosovo. Also, in cooperation with Montenegro, the pre-design phase for an International Advisory Panel (IAP) on Energy project is foreseen.

Developments in government policy/strategy/approach

On 09.05.2018, the Council of Ministers adopted the National European Integration Plan 2018–2020, which provides certain main pillars which the Albanian government will be working on for the energy field:

(i) supply security – the adoption of a new Law, "On the Establishment, Maintenance and Management of Minimal Security Reserves of Crude oil and/or its By-products" is foreseen, which aims to be partially approximated with Directive 2009/119/EC;

(ii) strengthening of the energy market in pursuance with the newly adopted National Energy Strategy 2018–2030;

(iii) energy efficiency and renewable energy; and

(iv) nuclear safety and radiation protection.

In brief, there are three main challenges regarding the energy sector, which Albania is currently facing:

(i) meeting the energy demand/need according to the economic development in different sectors and the citizens' energy consumption;

(ii) improvement of the energy intensity indicator; and

(iii) strengthening of supply security, by improving energy efficiency, usage of renewable sources together with conventional production means, as well as regional cooperation and integration.

The above served as the cornerstone for the design of the new Energy Strategy 2018–2030, which was approved on 31.07.2018 by the Albanian government.

Developments in legislation or regulation

On 02.02.2017, the new Law no. 7/2017 "On Promotion of Renewable Energy Sources" was adopted as a result of the undertakings of the Albanian government to comply with the Energy Community Treaty and the Directive no. 2009/28/EC "On Renewable Energy Sources" (although not fully harmonised), which directive sets compulsory national objectives for the utilisation of renewable sources in order to promote especially the production of electricity, heating and cooling, as well as biofuel for the transport sector. The new law repealed Law no. 138/2013 "On Renewable Energy Sources" which, according to the authorities, failed to be completely implemented due to the lack of sublegal acts and non-compliance with the new Law no. 43/2015 "On Power Sector".

Law no. 7/2017 provides for "incentive schemes" as a direct engagement of the government in order to reach the target on the use of power produced from renewable sources. These schemes, similar to countries in the region, are those instruments, schemes or mechanisms encouraging the utilisation of energy from renewable sources by reducing the costs of such power, raising the price at which it may be sold, or by increasing the volume of purchased power through obligations for the use of renewable energy or other means. This includes, but is not limited to, support for investment, operation, tax exemptions or lower taxes, tax reimbursement, etc.

Moreover, Law 7/2017 also reiterates the principles set out in the new Power Sector Law regarding access to the electricity network. The transmission and distribution of electrical energy on a transparent, non-discriminatory basis and based on tariffs approved by ERE, is guaranteed. Producers of power from renewable sources have a priority on access to the electricity networks. Any new producer of power from renewable sources, which requests to be connected to the network, must be provided with the necessary and comprehensive required information on such connection by the transmission and distribution system operators. Upon request of the producer, they propose a connection point that best suits the interest of the producer from renewable sources in respect to costs and distance aspects. The expenses necessary for the connection of the plants at the connection point, and the measurement devices, are borne by the power producers. The costs for the optimisation, strengthening and expansion of the system network are borne by the system operator.

A vast range of sublegal acts were enacted in compliance with Law no. 7/2017 but many others are foreseen to be enacted, such as those that will regulate the auctions for the granting of supporting measures (i.e. Contracts for Difference). A Memorandum of Understanding was also signed between the Ministry of Infrastructure and Energy (MIE) and European Bank for Reconstruction and Development (EBRD), regarding technical assistance for the organisation of the said auctions.

In February 2018, the Parliament adopted a set of amendments to Law no. 43/2015 "On Power Sector". Such amendments were necessary for the establishment and operation of an organised day-ahead electricity market, and removing the remaining obstacles to the establishment of the Albanian power exchange (APEx) in line with the market model, which was approved by the Council of Ministers in 2016. Under the 2018 amendments, it was defined that the market operator shall be the responsible structure for the administration of the day-ahead (and same day) market as well as all other associated activities, including the financial clearing among the market operators, in pursuance with market rules. APEx shall be the market operator and shall be established by OST (in cooperation with other entities).

In the gas sector, on 23.09.2015 the Albanian Parliament adopted the new Law no. 102/2015 "On Natural Gas Sector", transposing the main provisions of the Third Package on gas. Many sublegal acts have been enacted, and also the adoption of the Gas Master Plan is foreseen.

In 2017, Albgaz Sha. was established in pursuance of Law no. 102/2015 "On Natural Gas Sector". Albgaz Sha. functions as combined gas operator by undertaking transmission and distribution activities. Following the establishment of Albgaz Sha., ERE proceeded with the adoption of sublegal acts pertaining to licensing, certification and price methodology.

Judicial decisions, court judgments, results of public enquiries

On 26.12.2014, ERE adopted decision no. 143 "On the revision of the purchase price of electricity for the producers of electricity from existing HPPs, with installed capacity up to 15 MW for years 2013 and 2014", and decision no. 144 "On the revision of the purchase price of electricity for the producers of electricity from new HPPs, with installed capacity up to 15 MW for years 2013 and 2014". The effect of these decisions was to reduce the sale price of energy that KESH Sha. has paid to the said operators, by obliging them to pay back a part of the price to KESH Sha. These decisions put the operators in difficult financial conditions.

Licensed operators (i.e. small producers) brought a claim with the court against the above-indicated decisions of ERE. Following the decision of the Administrative Court of Appeal, which dismissed the claim of the operators and upheld the decisions of ERE, the case was brought to the Supreme Court. On 13.06.2017, the Supreme Court ruled in favour of the operators and thus revoked Decisions no. 143 and 144 adopted by ERE, based on the fact that the unilateral changes with retroactive effect had materially affected the position of the power producers, and such acts of the regulator were in breach of the legal certainty principle. Apart from the immediate financial benefits to the operators, who will get back the amount from KESH ShA., the court decision is important for the development of the market and setting up a precedent in the application of regulated tariffs.

Major events or developments

With the aim of achieving a complete energy market opening, there have been certain steps undertaken.

The Power Sector Law provides for the deregulation of prices of production and supply for customers which are connected to the high voltage grid (+110 kV) and others with annual consumption which exceeds 50 million kWh. According to the law, such customers have entered the deregulated market, upon the entry into force of the Power Sector Law. Customers connected in the 35 kV grid should have entered the deregulated market not later than 30.06.2016; those connected in 20 kV no later than 31.12.2016, and customers connected in 10 kV and 0.6 kV, no later than 31.12.2016. On the other hand, customers connected in 0.4 kV voltage, have the right to freely choose their supplier.

Nonetheless, the majority of 35 kV customers have not switched supplier since the amendments adopted in February 2018, granted the possibility to continue the supply by a last-resort supplier for two years, following the date on which the said customers were informed by the distribution system operator that a change of supplier could be effected from a technical perspective. As a result, the market-opening process did experience a drawback.

Furthermore, under the unbundling obligation, within the meaning of European energy law and the Albanian Power Sector Law, Albanian transmission system operator OST Sha. was unbundled and certified by ERE, and also became a member of ENTSO-E in April 2017.

On the other hand, in March 2018, OSHEE established three new companies: the Universal Service Supplier; the Free Market Supplier; and the Distribution System Operator. However, to date, none of such newly established companies has undertaken any activity, thus the results of the unbundling initiative, and compliance with the law, are yet to be seen. Unbundling provisions under European energy law were designed to secure the separation, in vertically integrated undertakings, of control over transmission, distribution or supply on the one hand, and other activities (i.e. production) on the other, with the final aim to eliminate potential conflicts of interest.

The Council of Ministers adopted Decision no. 519, dated 13.07.2016, On the approval of the electricity market model ("Decision no. 519"), drafted in accordance with the requirements of the Energy Community Treaty which was ratified by the Albanian Parliament in 2006. The power market model (Albanian Market Model) aims at ensuring a sustainable structure and creating the necessary conditions for further regional integration. The Albanian Market Model is designed as a wholesale market, based on bilateral transactions and contracts entered into by two market participants Over the Counter (OTC), or as a regulated pre-day or intra-day market, organised through the Albanian Power Exchange ("APEx"). APEx is not yet functional, notwithstanding the changes in the Power Sector Law which removed the obstacles to the establishment of the APEx.

Also, in March 2018, the transmission system operator OST invited the transmission system operators of Kosovo, former Yugoslav Republic of Macedonia and Montenegro to join APEx as shareholders. The Kosovo transmission system operator has confirmed its interest and APEx is expected to be launched in 2019.

In the renewables field, until 31.12.2017 the Ministry of Infrastructure and Energy has obtained approximately 30 applications for the construction of PV plants with a capacity up to 2 MW, out of which six also obtained final authorisation, and three signed contracts with the Ministry of Infrastructure and Energy.

Recently, the Ministry of Infrastructure and Energy invited interested investors to submit their bids for a new PV project with a capacity of 50 MW (the largest so far), located in Vlora.

Proposals for changes in laws or regulations

Apart from the enactment of certain sublegal acts that we have already referred to above, the following laws and decisions are expected to be adopted during year 2018:

- Law "On Production, Transportation and Trade of Biofuels and Other Renewable Fuels, for Transport".
- Law "On the Establishment, Maintenance and Management of Minimal Security Reserves of Crude Oil and/or By-products".
- Decision of the Council of Ministers "On the adoption of the instruction for the energy infrastructure in the hydrocarbons sector, which will be part of the Trans-European energy infrastructure".

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Bangladesh

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Overview of the current energy mix, and the place in the market of different energy sources

With a population of more than 160 million, Bangladesh is one of the most densely populated countries in the world. Despite this, Bangladesh has observed enormous economic growth at the rate of more than seven per cent (7%) in the last few years. In its report entitled, "The long view: how will the global economic order change by 2050?", PricewaterhouseCoopers (PwC) has predicted that Bangladesh will be the 28th largest economy by 2030, up from 31st in 2016, and has the potential to become the world's 23rd largest economy by 2050. Meanwhile, gross domestic product (GDP) at purchasing power parity (PPP) terms is expected to grow from US$ 628 billion in 2016 to US$ 1,324 billion in 2030, and US$ 3,064 billion by 2050.

Overview of the power sector			
	2009	**2017**	**Increase/Decrease (-)**
Power Plants (No)	27	111	84
Expired Plants (No)	0	3	3
Grid Capacity (MW)	4,942	15,821 (with Captives)	10,879
Highest Production (MW)	3,268 (6 Jan 2009)	9,507 (18 Oct 2017)	6,239
Import (MW)	0	660	660
Total Consumers (Million)	10.8	26.7	15.9
Transmission Line (Ckt km)	8,000	10,436	2,436
Distribution Line (km)	260,000	412,000	152,000
Access to Electricity (%)	47	80	33
Per Capita Generation (kWh)	220	433 (with Captives)	213
ADP Allocation (BDT in Billion)	26.8	225.8	199
System Loss (%)	16.9	12.2	-4.7

The fairy-tale economic growth of Bangladesh, as projected by PwC, substantially depends on the availability of electricity. However, since its independence from Pakistan in 1971, Bangladesh has struggled to generate adequate electricity to meet demand. Despite the enormous historic gap between supply of power and demand for it, the current government, during its two-term tenure, has remarkably managed to increase production capacity from around 5,000 MW to almost 19,000 MW (with captive).

The power sector has indeed charted a long journey by moving beyond the highest recorded production of 3,268 MW in 2009, to its highest production recorded ever, of 11,387 MW, on

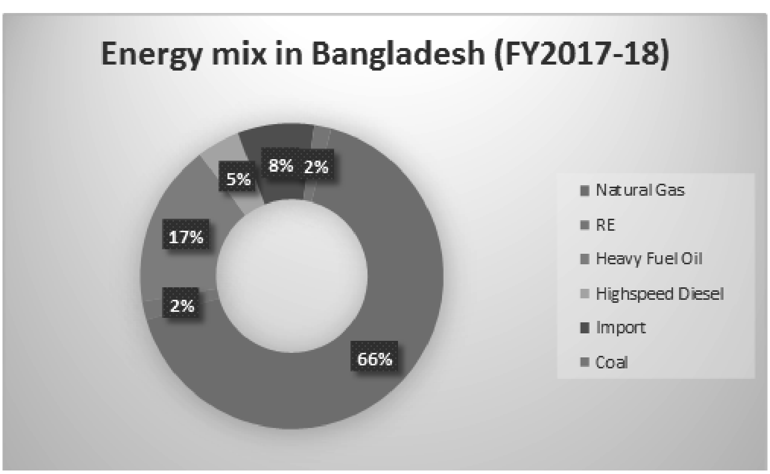
18th July 2018. The Power System Master Plan (PSMP) 2016 targets to increase the current power generation cap to 24,000 MW, 40,000 MW and 60,000 MW respectively within 2021, 2030 and 2041. At present, 54% of generated power comes from the public sector, while the rest comes from privately owned enterprises, with about 5% being imported from India.

In addition to potentially vast gas deposits which it lacks the technology and political will to exploit, Bangladesh has small reserves of natural coal and oil. FY2016–17 has seen total production of 57,276 kWh of net energy, of which 66.15%, 21.96%, 8.13%, 1.76% and 2% were contributed respectively by gas, oil, import, coal and hydro/solar based plants. By 2041, the PSMP 2016 aims to achieve an energy mix of 35% coal, 35% gas and LNG and 30% nuclear and renewables.

Fossil fuel

Dependency on natural gas, the primary native source of energy, and on imported LNG, is targeted by the PSMP 2016 to be slashed, from the current 65% down to 35% by 2041. The country is already struggling with a decline in the supply of local gas, in response to which the PSMP originally set a goal to import 500 mmcfd during 2018, which was supposed to eventually be increased to 1,200 mmcfd by 2020, and to 2,200 mmcfd by 2040. However, in the face of LNG being available at a relatively cheap price in the global market, the government has suddenly decided to increase LNG importation to 4,000 mmcfd just by 2018. However, the downward price movement in the international market of LNG is not going to be long-lived and already, the World Bank has intimated a sharp increase in the prices of natural gas, oil and coal. If that turns out to be true, the government may be forced to revisit its plans regarding LNG imports. Therefore, local gas will keep on losing share in the overall energy mix due to the ongoing gas crisis, while LNG's future contribution in the energy mix is likely to be determined by the price movement in the international market.

To meet the ever-increasing electricity demand, the government is betting mainly on coal. The price of coal in the global market is relatively cheap and subject to less volatility, making imported coal an attractive substitute for local gas which is declining at an alarming rate. With 23,000 MW of new coal-powered plants in the pipeline, the PSMP envisages raising the generation of coal-based electricity from 2% to over 50% by 2030, which would eventually settle down to 35% by 2041. A large number of coal-fired power plants, including those in Payra Port, Rampal, Matarbari and Maheshkhali (each with about 1,300 MW capacity), are currently being constructed. *As per* the government's current plan, clearly coal is going to rule the energy landscape for power generation in Bangladesh.



Nuclear and renewables

PSMO 2016 has set a goal of achieving 10% nuclear-based power generation by 2041, which will require the construction of nuclear power plants with generation capacity of at least 7,200 MW. The Ruppur nuclear plant, which will be the country's first footstep towards harnessing nuclear energy, will have a 2,400 MW atomic reactor. Further, an area of about 8 sq km in Barishal has been selected by the Bangladesh Atomic Energy Commission to set up a second nuclear power plant.

The PSMP obligates the share of renewables in power generation to be 10% by 2020. Across the spectrum of renewables, only solar energy seems to have a bright prospect due to the tropical climate of Bangladesh, making it an ideal breeding ground for solar projects. At present, only 217 MW of power is generated from solar installations, which is still less than current hydro-based power with a generation capacity of 230 MW.

Renewable Energy Status in Bangladesh

Year	Solar		Wind		Hydro		Bio-Gas		Bio-Mass		Total
	Off Grid	On Grid	Off Grid	On Grid	Off Grid	On Grid	Off Grid	On Grid	Off Grid	On Grid	
2018	0.55	1.27	-	-	-	-	-	-	-	-	1.82
2017	13.97	6.98	-	-	-	-	0.05	-	-	-	20.80
2016	5.16	4.57	-	-	-	-	0.40	-	-	-	10.13
2015	10.37	4.08	1.00	-	-	-	0.13	-	0.40	-	15.98
2014	0.14	0.45	-	-	-	-	0.03	-	-	-	0.62
2012	-	-	-	-	-	-	0.02	-	-	-	0.02
2010	0.10	-	-	-	-	-	0.05	-	-	-	0.15
2008	-	-	1.00	-	-	-	-	-	-	-	1.00
2006	-	-	-	0.90	-	-	-	-	-	-	0.90
1988	-	-	-	-	-	230.00	-	-	-	-	230.0
Total	30.09	17.35	2.00	0.90	0.00	230.00	0.68	0.00	0.40	0.00	281.42

Source: Sustainable and Renewable Energy Development Authority

Overall renewable energy generation capacity is set to be increased to 2,900 MW by 2021, of which 1,470 MW is expected to be solar-generated, warranting a sevenfold hike in solar power capacity. Meanwhile, although the contribution of locally generated hydro power would remain static at 230 MW, Bangladesh intends to import 9,000 MW electricity including hydro power from India, Nepal and Bhutan by 2041 to mitigate the increasing demand of electricity.

Wind power is expected to contribute 1,150 MW. But this appears to be somewhat ambitious considering that wind power is still at an experimental stage, although strong wind is a frequent phenomenon in the coastal and some border areas. The Sustainable and Renewable Energy Development Authority (SREDA) has carried out wind resource mapping in various parts of the country and is supposed to publish the results soon.

There are also significant restrictions on the growth of on-grid solar power. First, in a densely populated but small country like Bangladesh, land is a scarce commodity and government rules keep agricultural land beyond the purview of solar installations. '100 MW solar power from 300 acres of land' is still too much for this country. Another restriction is lack of incentive from the government. For instance, China gives a 17% incentive to local solar panel and photovoltaic cells. On top of this, a huge tax duty has been imposed in the budget for this fiscal year on imported solar panels, which will obviously thwart the intended solar movement.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Most of the recent changes in the energy situation are discussed either directly or indirectly under the headings below. Major among the remaining ones are as follows:

New gas field discovered

Following a recent 3D seismic survey, a gas field with an overall estimated reserve of 600 billion cubic feet (cf) has been discovered recently in Bhola district. The discovery of Bangladesh's 27th gas field came at a time when the government is stressing the importation of LNG. Initial tests suggest that the gas field looked to be the most promising in Bangladesh. The well was planned under the Rupkalpa 4 Drilling Project, to meet increasing demand for natural gas as part of the government's Vision 2021 initiative.

In December last year, Russia's oil & gas exploration and supply company Gazprom started drilling the Bhola North 1 onshore gas exploratory well as a contractor on behalf of Bangladesh Petroleum Exploration and Production Company Limited (Bapex). Gazprom claimed that the gas reserves in Bhola might be the largest gas field in Bangladesh. The gas pressure was found to be 5,600 PSI (pounds per square inch) which is the highest among all gas fields in the country, as reported by Bapex. According to Bapex, the country has about 11–12 trillion cubic feet of gas reserves with an annual consumption of about one trillion cf.

Power fair

The Cabinet Committee on Public Purchase has greenlighted a proposal to initiate 10 new power plant projects. All of these projects, ranging from 100–200 MW in capacity, will be exclusively petroleum fuelled. Meanwhile, the Cabinet has also approved draft joint venture agreements with various China-based companies for the setting-up of three 1,320 MW thermal plants, one in Patuakhali and the other two in Maheshkhali and Mirsarai.

Further, various independent electricity producers are currently in negotiation with the government to set up LNG-run power plants – ranging from 450 MW to 4,500 MW – in different parts of the country.

Importation of electricity from neighbouring countries

As part of the cross-border power trade among the SAARC countries, Bangladesh is planning to import 9,000 MW of electricity from India, Myanmar, Nepal and Bhutan by 2041. The Government of Bangladesh is also interested in joint investment in hydroelectricity projects in these countries. US$1 billion of investment in hydroelectricity in the neighbouring countries has already been approved by the Government of Bangladesh, and it has already engaged in discussions with India, Nepal and Bhutan.

Bangladesh is currently importing 660 MW electricity from India. Additionally, on 10th August 2018, the Government of Bangladesh executed a memorandum of understanding with the government of Nepal for the importation of 500 MW of hydro power electricity.

Developments in government policy/strategy/approach

Energy imports get boosted

The most notable change in the government's approach may be opting for a radical increase in the volume of LNG from 500 mmcfd to 4,000 mmcfd in 2018, though how this would affect the previous target set for future importation is still unclear. This radical hike in the volume of imported LNG is quite inconsistent with the government's policy expressed in the PSMP to achieve a gradual gas-to-coal dependency transition, particularly when eight new coal-fired power plants are already being set up.

In spite of the vision to cut down dependency on oil for power generation to zero by 2040, the government is considering setting up 10 new quick-rental oil-fired power plants, even though already 35 oil-fired plants (15 quick-rental, 5 rental and 15 independent supplier) are currently operational. Accordingly, a sharp rise is expected in the volume of imported petroleum fuels. For the period of July–December alone, 1.8 million tonnes of various petroleum fuels, worth about US$ 1.2 billion, will be bought, as decided by the relevant cabinet committee. It is reported that some 1.5 million tonnes of diesel valued at $1 billion; 45,000 mt of octane at US$ 35 million; 170,000 mt of Jet A-1 fuel at US$ 125 million; and 100,000 mt of furnace oil at US$ 45 million, will be imported.

New PSC awaits approval

The Government of Bangladesh has long been negligent in taking proper steps to realise the true potential of its mineral deposits. Even when the successful outcome of the maritime dispute with neighbouring countries, namely India and Myanmar, opened up vast possibilities for the energy sector, and especially when these neighbouring countries have already displayed some success in mineral exploration, the government has still been hesitant to take timely decisions. But the relevant government agencies have stressed that changes are to come into this stepmotherly attitude towards its own minerals. Even a new Production Sharing Contract (PSC), drafted by Petrobangla, is likely to come into play this year, with alluring offers for international explorers of oil and gas which would include, but not be limited to, the entitlement to sell more than half of the produce at Petrobangla at a significantly increased rate, and exemption from various tax duties.

Developments in legislation or regulation

QEES(SP)A 2010 to be extended

The *Power and Energy (Special Provision) (Amendment) Act 2018* has recently been passed, extending the tenure of the infamous *QEESA 2010* for the third time, this time by three years. In the shadow of a nagging electricity crisis impeding the country's prospective development, the 2010 Act was passed to create a short-term mechanism to facilitate the Quick Rental Power Policy. The law indemnifies relevant agencies against prosecution for awarding contracts without following the provisions of the *Public Procurement Act 2006* and *Public Procurement Rules 2008*.

Electricity Act 2018

The *Electricity Act 2018,* repealing the provisions of its British-era precursor (*EA 1910*), has recently been passed by the Parliament. A chain of penal measures, intended to serve temporary demands, have been taken. Anyone involved with electricity misappropriation, pilferage or wastage, or with interference or destruction of supply lines, be they civilians or government officials or corporations, may now be subject to both fines and imprisonment. Further, the officials of PDB, DESCO and DESA are barred from conducting official activities without permission from the higher authority. In contrast, unlike the 1910 Act, the current Act does not require officials to obtain a magisterial order before entering the premises of consumers to test or terminate supply. Likewise, the requirement for the service of a 10-day notice before discontinuation of supply to a consumer who neglects payment is removed by the under the new Act. However, the new Act stands out most from its predecessor through its adoption of a unitary operating system, as opposed to the manifold structure under the old law.

Inconsistent directions for solar

In an attempt to promote local produce disregarding its relatively low quality, a range of customs and tax duties, translating into a maximum 37.5% additional duty, have been imposed on imported photovoltaic cells and solar panels. This will undoubtedly severely impede the intended solar power march to 2,000 MW by 2020. Thanks to the zero-levy benefit hitherto enjoyed by importers of solar modules and photovoltaic cells, Bangladesh is already the largest operator of home solar systems. Experts worry that the newly imposed levy will increase the cost of nine ongoing and 25 planned mini-grids and megawatts capacity solar projects by 50%.

Major events or developments

One of the notable recent developments is the remarkable reduction of transmission and distribution (T&D) loss, from about 17% to a mere 12% during the tenure of the current government. In contrast to 55% electricity coverage in 2010, more than 80 out of every 100 Bangladeshis now have access to electricity. The government has plans to ensure universal coverage within 2021. Additionally, the increase in *per capita* consumption, from 240 kWh in 2010 to 433 kWh at present, is noteworthy.

It has recently been confirmed that the import of LNG will be completely tax-free, which is going to put a heavy load on the government exchequer, considering the drastic increase in the volume of LNG to be imported this year. Experts contend that the government has failed to pay sufficient consideration to the long-term economic consequences of LNG importation. In comparison to the average cost of locally produced gas of BDT 5.32 cbm, the average cost of LNG procured from the global market is estimated by Petrobangla to be BDT 33.44 cbm.

This means that even if LNG is mixed with local gas and then distributed, the gas price would likely be doubled or tripled in the near future. In fact, Petrobangla hinted back in March 2018 that the current gas price would be immediately doubled once the importation of LNG started. Another danger looming is that the price of oil on the international market is not going to be long-lived, and increases by the Bangladesh Petroleum Corporation (BPC) will automatically amplify LNG import costs. BPC is already seeking a price hike or, alternatively, subsidies worth Taka 80 billion for FY 2018–19 in response to the loss of approximately BDT 220 million a day it has incurred because of the jump in the oil price from US$47 in June 2017 to US$79 per barrel in July 2018. The government is also responding in its turn by planning to raise its subsidy outlay by 232% to Taka 196 billion for non-financial institutions, including Petrobangla and BPC, the two state-run entities responsible for LNG imports. The subsidy allocated to Petrobangla was about BDT 25 billion in the just-concluded fiscal year, which is likely to go up to BDT 50 billion this year.

A floating storage and re-gasification unit (FSRU) is being built close to Chittagong, where LNG will be converted and distributed at a projected rate of 4,000 million cft per day during this year. Additionally, the government is currently negotiating with various international power producers for the setting-up of some additional FSRUs, which points to a long-term dependency on LNG. However, considering that public dissatisfaction about the never-ending gas and electricity price hikes is about to explode, this could be fatal for the country's economy.

Proposals for changes in law or regulation

In light of the halted prospecting for new gas fields, the thin size of the current reserve as against the 5% annual increase in demand, the possibility of gas reaching a state of entropy has become an ominous concern in the public domain. But this must be balanced against the history of growth in the reserve. In 1993, the remaining reserve was estimated to be 10 Tcf, which was predicted to be depleted by 2003. However, the remaining reserve in 2001 was recorded at 15 Tcf which, again, was expected to run out within the next 10/12 years. Yet the size of the estimated current reserve is 13 Tcf, thereby indicating that instead of depleting, the reserve is actually flourishing.

The history of growth in the gas reserve is undoubtedly in line with geologists' belief that a large delta area like Bangladesh should be a gas-rich province, but this has not been realised due to lack of exploration. The onshore explorations carried out so far have been restricted to easily identifiable upper strata, with only six exploratory wells drilled in the last 10 years. While significant gas has been found in such strata in the eastern parts of the country, the relatively complicated and latent prospects haven't been explored yet. Less conventional or unconventional prospects, such as stratigraphic, synclinal or tight gas prospects, which have proven gas-bearing in Assam and Tripura, are yet to be utilised.

The offshore exploration in Bangladesh likewise could be called anything but serious, despite the vast potential. Only four of the 26 offshore blocks have been explored, and that too in a very limited manner. Myanmar, lying just on the other side of maritime edge, has recently run some successful gas explorations, particularly in the offshore Arakan basis. Two gas columns have been discovered just in the last two years, respectively within Blocks A-6 and AD-7, with the help of Australian oil and gas tycoon Woodside. Considering the fact that the Arakan basin is a natural continuation of Cox's Bazar-Teknaf coastal basin, there is no reason why this success could not be reproduced on our side of the Bay of Bengal.

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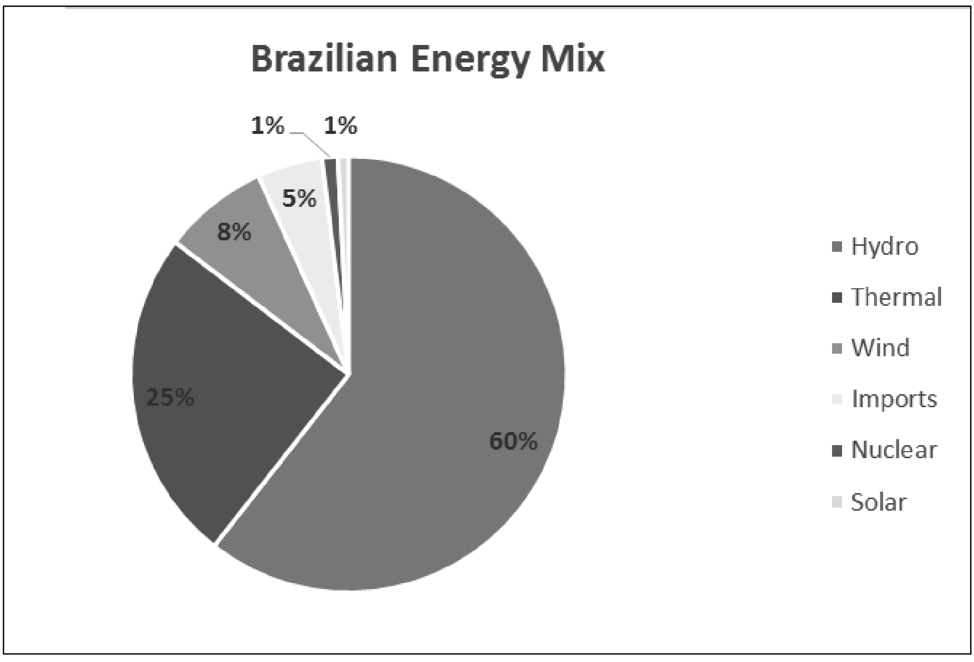
Overview of the current energy mix, and the place in the market of different energy sources

Considering that Brazil is a country with large territorial extension, the national energy matrix comprises a wide range of energy sources. According to the National Electric Energy Agency ("ANEEL"), Brazil has an installed capacity of 160,066,672kW, divided into the following energy sources: (i) 60.75% corresponds to hydro power plants; (ii) 24.86% corresponds to thermal power plants; (iii) 7.86% corresponds to wind power plants; (iv) 4.85% corresponds to energy imports; (v) 1.18% corresponds to nuclear power plants; and (vi) 0.78% corresponds to solar power plants:



Nonetheless, it is important to highlight that the Energy Research Company ("EPE") provides in its 10-year plan *(Plano Decenal 2026)* that a substantial increase of renewable energies shall take place in the Brazilian energy matrix within the next ten years. Upon the expected investment of BRL 1.4 trillion on renewable energies, an increase of 11.8GW of wind power plants and 7GW of photovoltaic power plants is expected to occur by 2026.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

In 2017 and the beginning of 2018, the Federal Government undertook the organisation of public auctions for the construction of new power plants and supply of their energy to distribution companies.

In addition, governmental authorities initiated a debate concerning the review of the legal and regulatory framework applicable to the energy sector. Together with the recovery of the national economy and stabilisation of the political crisis, such initiative was important to draw the attention of national and foreign investors to the country´s electric energy market once again.

Stabilisation of the economic crisis and restart of public auctions

In August 2016, the National Congress approved former president Dilma Roussef's impeachment which, besides the appointment of Michel Temer as the country's president, resulted in several changes associated with the structure and personnel of the Federal Government.

In this scenario, in order to meet market demand for new energy auctions (scarce since 2014), at the end of 2017, the Ministry of Mines and Energy ("MME") and ANEEL carried out two different auctions for the sale of energy produced by thermal, hydro, photovoltaic and wind power plants within four and six years as of the occurrence of the auction. These bids represented the restoration of the auctions system in the Brazilian energy market.

In the A-4/2017 Auction, 25 projects sold energy in the bid, representing 891.1 MW for the grid. The chart below summarises the number of projects that won the relevant auction per energy source and the respective average price charged by the power producers (average goodwill of 54.65% in comparison with the ceiling-prices defined under the auction rules):

Energy Source	Number of Projects declared Winners in the A-4/2017 Auction	Average Price (R$/MWh)
Wind	2	108.00
Hydro	2	181.63
Biomass	1	234.92
Photovoltaic	20	145.68

As to the A-6/2017 Auction, 63 undertakings were declared winners in the auction, representing 3,842 MW for the basic grid, as detailed below:

Energy Source	Number of Projects declared Winners in the A-6/2017 Auction	Average Price (R$/MWh)	Goodwill
Wind	49	98.58	64.3%
Hydro	6	218.91	22.1%
Biomass	6	216.04	34.3%
Natural Gas	2	212.91	33.3%

In this A-6 Auction, it was also possible to observe the increase associated with the participation of gas-fuelled power plants (especially Liquefied Natural Gas – LNG power plants), which are called to produce energy in periods of variation regarding hydro, wind and photovoltaic energy production.

In view of the successful auctions held at the end of 2017, MME and ANEEL carried out A-4 and A-6 Auctions on April 4, 2018 and August 31, 2018, respectively, which resumés are presented below:

A-4 Auction			
Energy Source	**Number of Projects declared Winners**	**Average Price (R$/MWh)**	**Goodwill**
Wind	4	67.60	73.50%
Hydro	4	198.12	31.90%
Biomass	2	198.94	39.5%
Photovoltaic	29	118.07	62.2%
Total	39		

A-6 Auction		
Energy Source	**Number of Projects declared Winners**	**Average Price (R$/MWh)**
Wind	48	90.45
Small Hydro Power Plants	6	193.99
CGH	4	195.00
Hydro	1	151.68
Biomass	2	175.59
Gas-Fuelled	1	179.98
Total	62	

Developments in government policy/strategy/approach

Reformulation of the legal and regulatory framework applicable to the energy sector

In July 2017, MME opened two public hearings aimed at receiving contributions from market players in order to reformulate and improve the Brazilian power sector's legal framework. The first public hearing discussed general principles and guidelines applicable to the sector and the other discussed specific measures that could positively affect the market. These public hearings resulted in a draft of Bill of Law, which is now under discussion in the Congress.

The hearings recommended the end of discounts applicable to TUST and TUSD fees (fees regarding connection to transmission and distribution systems) for new renewable energy projects, as well as discussing the impossibility of their replacement by brownfield power plants after the relevant licence term. Such recommendation was justified by the fact that Brazil already has a sustainable, developed and strong renewable energy market and, therefore, these incentives would no longer be required.

In this regard, it should be noted that Law No. 9,427/1996 authorised ANEEL to grant a discount on the TUST and TUSD fees for wind, solar, biomass and small hydro power plants, which were able to reduce costs of production and, consequently, the price of the generated energy.

Also, the hearings suggested gradual opening of the free market to new players until 2028, by means of the decrease of the access requirements from 200kW to 75kW of power consumption. The Bill of Law under discussion retains the idea of a gradual opening, but the end of this process would be 2026 (and not 2028).

Lastly, the hearings also recommended the possibility of the establishment of public auctions specifically for capacity sale (instead of the currently existing auctions, which purpose is to sell energy produced by power plants).

In addition to the reformulation of the regulatory framework applicable to the energy sector, Federal and State Governments have been discussing the sale of their participation in state-owned companies with activities in the energy sector, as detailed below.

Eletrobras: privatisation of its distribution companies

Centrais Elétricas Brasileiras S.A. ("Eletrobras")' process of privatisation dates back to 2015, when the company refused to renew the concession agreements executed by its distribution companies of the States of Alagoas, Piauí, Roraima, Rondônia, Amazonas and Acre through the terms and conditions provided by Law No. 12,783/2013.

In this scenario, the Federal Government resumed the process of privatisation of Eletrobras' distribution companies upon the enactment of Law No. 13,334/2016, on September 13, 2016, which inserted such enterprises within the Investment Partnership Program (*Programa de Parcerias de Investimentos* – "PPI"). The PPI was established in order to enable the definition of policies for investment in the infrastructure sector by means of the implementation of partnerships with the private sector.

The privatisation process consisted in the concession of the public distribution services of six Brazilian states, along with the transfer of corporate control of the distribution companies, upon the payment of a symbolic value of BRL 50.000 per concession. In addition, Eletrobras' successors would have to invest substantial amounts of resources in order to assure gains related to the distribution companies' efficiency, management and an improvement in the quality of services provided to local consumers.

Despite the judicial lawsuits filed in order to avoid the privatisation process, corporate control of the following distribution companies has already been sold within public auctions:

Distribution Company	Concession Successor
Eletrobras Distribuição Piauí (CEPISA)	Equatorial Energia
Eletrobras Distribuição Roraima (Boa Vista Energia)	Consortium Oliveira Energia
Eletrobras Distribuição Acre (Eletroacre)	Energisa S.A.
Eletrobras Rondônia (CERON)	Energisa S.A.

Please note that the public auction for the selling of Eletrobras Amazonas Energia is expected to take place on October 25, 2018, while sale of the corporate control of Companhia Energética Alagoas ("CEAL") through a public auction has been suspended by a preliminary injunction granted under a judicial lawsuit.

Eletrobras: Privatisation of equity interest in power production and transmission SPVs

Along with the privatisation of its six distribution companies, Eletrobras intends to sell its equity interest in 71 special purpose vehicles ("SPV") that are holders of power production and transmission facilities.

Eighteen batches *(lotes)* shall be offered by means of public bidding, among which: (i) eight batches will comprise 59 SPVs for wind power generation, with an installed capacity of approximately 1,605 MW; and (ii) 10 batches will comprise 12 SPVs which operate transmission lines of approximately 2,912km of extension and 5,530 MWA of transformer capacity.

Sale of CESP's corporate control

Companhia Energética de São Paulo ("CESP") is a state-owned company created by the Government of the State of São Paulo in 1996, which today operates three distinct hydro power plants, namely UHE Porto Primavera, Paraibuna and Jaguari.

On July 7, 2018, the Government of São Paulo enacted the auction rules associated with the sale of its majority equity interest in CESP, which shall take place on October 2, 2018.

Roraima's energy auction for energy supply and storage

In addition to initiatives associated with changes to the energy sector's regulatory framework and with the role of the Government in such a market, other governmental measures regarding the development of the sector in the past months should be highlighted, such as energy storage and efficiency auctions as detailed further below.

Energy storage technologies have received little investment in Brazil so far and there is still a lack of regulation regarding such matter. Nonetheless, the MME has already confirmed the execution of an energy auction for contracting energy supply and storage to the State of Roraima, considering the state may face energy supply difficulties as a consequence of Venezuela's political crisis.

In this way, in order to avoid further impacts to Roraima's energy supply provided by Venezuela, the MME has confirmed that it will publish the guidelines for the execution of a public auction aimed at contracting energy supply and storage to such state. In addition, the MME has advised that the guidelines will not be published until the end of 2018, while the public auction is expected to occur by 2019.

As it is the first public auction whose purpose is providing energy storage in Brazil, and considering the importance of providing a legal framework for the matter, the establishment of a regulatory framework for energy storage has been included in ANEEL's Regulatory Agenda for the biennium of 2018/2019.

Creation of a power efficiency auction

ANEEL has initiated Public Hearing No. 07/2018 with the purpose of obtaining contributions related to: (i) the definition of a concept for power efficiency auctions; along with (ii) the methodology and the assumptions to be considered in the analysis of the regulatory impacts related to a pilot project to be implemented in the State of Roraima (for further information regarding this energy auction, please refer to item, "Roraima's energy auction for energy supply and storage").

Initially, the proposal consisted in holding a reverse power auction, in which ANEEL would set the annual amounts of energy consumption, to be reduced throughout the efficiency program duration. In this way, bidders would compete for the lowest price of energy by implementing a number of projects for reducing the amounts of energy consumption, such as the changing of light bulbs, refrigerators or air conditioners, implementation of distributed generation, modernisation of public lighting, among others.

In this regard, it should be noted that the State of Roraima has its energy supply provided by energy imports and from diesel-fuelled local generation, which is an expensive and highly polluting source of energy. For this reason, the studies within Public Hearing No. 07/2018 aimed at implementing a pilot project in Roraima, a state whose economy consumes 4MW average per year.

The contributions have already been submitted to Public Hearing No. 07/2018; however, no decisions were provided regarding the execution of a power efficiency auction in the State of Roraima up to this moment.

Developments in legislation or regulation

As mentioned previously, the National Congress is currently evaluating a Bill of Law proposal that has the purpose of reformulating the regulatory framework applicable to the energy sector. Nevertheless, other legal and regulatory changes were implemented recently in order to foster the development of the national energy market, such as discussions associated with the update of the regulation regarding distributed energy and LNG projects, as detailed below.

<u>Distributed Generation and Future Changes in the Regulation</u>

ANEEL has regulated, through Normative Resolution No. 482/2012 (REN No. 482/2012), micro and mini on-site generation. Such measure allows final consumers to install power generation projects (wind, solar, etc.) in their residences or on other commercial or industrial facilities, in order to offset energy with the local distributor (energy generated is injected into the grid and is used to reduce the consumption of electricity from the consumer unit). The rule is valid only for consumer units that use renewable energy sources (such as hydro, solar, biomass, wind and qualified cogeneration).

Consumers that install on-site generation systems are not allowed to commercialise the excess energy produced by the power plant, and may only offset such excess energy with credits from the distribution company.

The on-site generation system may be: (i) micro systems that comprise power plants with installed capacity lower than or equal to 75kW; or (ii) mini systems that comprise power plants with installed capacity superior to 75kW, and inferior to or equal to 5MW.

Despite the increase by 167% of the Brazilian distributed generation market, the improvement of REN No. 482/2012 was included in ANEEL's Regulatory Agenda for the biennium of 2018/2019. Considering the necessity of constantly improving the regulation, the matter is being discussed within Public Hearing No. 10/2018; however, no decisions have been provided in such Public Hearing up to this moment. Among other matters, Public Hearing No. 10/2018 discusses increases in the distributed generation´s limits, funding for distributed generation projects, and the impacts of such undertakings on the distribution grid.

<u>Penalty applicable in case of lack of fuel to thermal power plants</u>

ANEEL enacted on August 23, 2018, Normative Resolution No. 827/2018 (REN No. 827/2018), which updates the guidelines that must be observed regarding the application of penalties to thermal power plants due to lack of fuel.

Among other provisions, Resolution No. 827/2018 untied the penalty value applicable to thermal power plants from the Differences Settlement Price (*Preço de Liquidação de Diferenças* – "<u>PLD</u>"), thus basing the calculation of fines on the Unitary Variable Cost ("<u>CVU</u>") of the respective plant.

In addition, Resolution No. 827/2018 allowed free negotiation between power producer and fuel supplier concerning the penalty to be applied in case of lack of fuel.

The alterations provided by REN No. 827/2018 follow the evolution of discussions held in ANEEL and at the National Oil & Gas Agency ("<u>ANP</u>"), and take into account the relevance of the development of thermoelectricity integrated with fossil fuel markets, as well as the specific supply and logistics conditions for the supply of liquid fuels.

Judicial decisions, court judgments, results of public enquiries

Through the Energy Reallocation Mechanism ("MRE"), each hydro power plant receives its level of generation output and shares the hydrological risks with other participants of such a mechanism.

The result of MRE depends on a monthly comparison between the energy produced by the hydroelectric generators that participate in the mechanism and the sum of their generation outputs (*garantia física* – "GF"). If the energy produced exceeds the total generation output, the outstanding energy amount is shared between the hydroelectric generators that produced energy below their generation output, and those participants that exceeded their level of production are financially compensated by the mechanism. If the energy produced under MRE is below the sum of all GF of the participants, the generation output of each participant is reduced in that month by the Generation Scaling Factor ("GSF"), which could obligate the generator to acquire energy on the spot market. The GSF is the ratio between the energy produced by the generators participating in MRE and the sum of their generation output:

GSF = total power production in MRE/sum of MRE's generators GF

In 2012, the level of the reservoirs considerably decreased, affecting the power generation by hydro power plants. In January of 2013, the GSF reached its lower level, meaning that hydroelectric generation was below the combined generation output of MRE's participants. The adverse scenario continued through 2014 and 2015, when many agents of the power sector filed lawsuits, with preliminary injunction requests, aiming at the limited application of GSF to hydroelectric generators participating in MRE.

Many of the plaintiffs in these lawsuits argued that they were bearing costs, within MRE, that had no relation to hydrologic risks, such as: (i) delays regarding the start of commercial operation of new hydro power plants; and (ii) unlimited dispatch of expensive thermal power plants. In addition, it was argued that the GSF mechanism was decreasing hydro power plants' generation outputs above the legal limit (5%), given the extraordinary context.

In this scenario, the Federal Government introduced through Federal Law No. 13,203, dated December 8, 2015 ("Federal Law No. 13,203/2015"), the mechanism called "Renegotiation of the Hydrological Risk". This mechanism seeks to mitigate the financial losses experienced by MRE's hydroelectric generators due to non-manageable exposure to hydrological risks. The Renegotiation of the Hydrological Risk works as a non-compulsory insurance for MRE's participants, and in order to enter into such mechanism, the interested agent waives its intention to discuss hydrological risk and its impacts judicially.

Nevertheless, GSF-related discussions still present difficulties today. Firstly, the renegotiation mechanism was not sufficient to mitigate the problems hereby presented. Secondly, the Brazilian courts have conceded many of the preliminary injunctions related to the GSF conflict, impairing financial settlement of the spot market. Today, the preliminary injunctions have generated a debt of about R$ 7 billion in the spot market, yet to be paid.

Major events or developments

Restart of public auctions

As previously mentioned, at the end of 2017 and in 2018, MME and ANEEL carried out four different auctions for the delivery of energy produced by thermal, hydro, photovoltaic and wind power plants within six and four years as of the occurrence of the auction.

For further information regarding the restart of public auctions in 2017, please refer to the section, "Changes in the energy situation in the last 12 months which are likely to have an impact on future direction of policy".

Relevant Role of MCSD during the years 2016 to 2018

Due to the excess energy in the market and a number of projects facing delays associated with the start of commercial operation, the Mechanism for Compensation of Surpluses and Deficits ("MCSD") played a relevant role during the years of 2016 to 2018 in order to balance the demands of the national energy market. MCSD is a mechanism similar to an auction provided by ANEEL's regulation which allows the partial, total, temporary or definitive reduction of the amount of energy contracted under the Regulated Power Purchase Agreements (so-called CCEARs).

MCSD was considered extremely relevant for the years between 2016 and 2018, because it allowed: (i) distribution companies with excess energy to balance their CCEARs currently in force; and (ii) projects facing commercial operation delays to keep their CCEARs.

In addition to MCSD, ANEEL has also organised an auction specifically to cancel CCEARs currently in force and has enacted a specific regulation (ANEEL Resolution No. 711, of April 19, 2016), allowing distribution companies and power producers to renegotiate the terms and conditions of their CCEARs.

Transmission companies' exemption: truck drivers' strike

On May 21, 2018, Brazilian independent truck drivers started a national strike, which would latter affect the country's entire supply chain and leave most cities without full access to basic inputs. By blocking the main highways – which are responsible for most of the input flow throughout the country – fuel distribution was severely impaired and very few companies were able to carry on with their normal activities, leaving the Brazilian economy with major financial losses. Such situation, as expected, also affected energy sector companies.

A month later, the Energy System National Operator (*Operador Nacional do Sistema Elétrico – ONS*) contacted ANEEL regarding the occurrence, during the strike period, of several concessionaires cancelling scheduled interventions on transmission systems (such as programmed corrective and preventive maintenances). A significant number of power transmission companies had not been able to perform their programmed interventions due to the lack of inputs and fuel, and such unwarned cancellations would trigger penalties pursuant to Normative Resolution No. 729/2018 (REN No. 729/2018). However, ONS argued that, considering the extraordinary circumstances, those penalties should not be applied, even though the penalty exemption hypothesis provided in REN No. 729/2018 would not embrace the situation at hand.

In this scenario, in August, ANEEL decided, in contrast to the applicable regulation, that the penalty would not be applied to cancellations that took place during the 10-day strike. The agency acknowledged that the events caused serious logistic problems that would prevent transmission companies performing their programmed interventions. In addition, ANEEL stated that energy shutdowns, which were to be held during those maintenances, were not welcome at all during that period, especially when taking into account the lack of fuel and other basic products (which had already harshly affected the national economy).

Proposals for changes in laws or regulations

Reformulation of the legal and regulatory framework applicable to the energy sector

As mentioned previously, MME opened two public hearings aimed at receiving contributions from market players to reformulate and improve the Brazilian power sector's legal framework. The first public hearing discussed general principles and guidelines applicable to the sector, while the other discussed specific measures that could positively affect the market. These public hearings resulted in a draft of Bill of Law, which is now under discussion in the Congress.

For further information regarding such Bill of Law, please refer to the section, "Developments in government policy/strategy/approach".

In addition, ANEEL is currently reviewing the regulation applicable to distributed generation in order to improve the rules associated with the implementation of this kind of project in Brazil.

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Overview of the current energy mix, and the place in the market of different energy sources

The Bulgarian energy market is dominated by electricity. Bulgaria has a diverse electricity mix, including nuclear, thermal and renewable power plants (water, wind, solar and biomass power plants). The total installed capacity of all types of electricity generation in the electricity system for 2017 was estimated at 12,070 MW. The annual gross production in 2017 amounted to 42,578,650 MWh. Gross domestic electricity consumption in 2017 was 37.7 TWh, with no significant difference compared to 2016. In 2017, the largest share in electricity generation was provided by the coal power plants – 43%; the next share, of 36%, came from nuclear power; energy from water-renewable sources represented 8%; while 8% came from wind, solar and biomass. In 2017, the largest volumes of electricity exchanged on schedules by commercial operators from Bulgaria were in the direction of Romania, with a growth of 296% compared to 2016; to Serbia, with a growth of 149%; and to Macedonia, with a growth of 112%. A drastic reduction in trade with Turkey was reported. The export to Turkey decreased five-fold, representing 21% of that in 2016, while the reverse exchange towards Bulgaria increased by 1,015%.

In the first six months of 2018, annual gross production reached 22,177,696 MWh, which is a decrease of 2.62% on an annual basis, whereas in 2017 the volume was 22,773,016 MWh. At the same time, electricity consumption dropped by 5.57%, from 20,577,364 MWh to 19,431,755 MWh. The electricity production would have been even less if the electricity export had not increased. For the first half of 2018 it reached 2,743,941 MWh, which represents a growth of almost 25%. Interestingly, the share of nuclear power plants (NPPs) and thermal (TPPs) in the energy system decreased from 84.7% in the first six months of 2017 to 80.4% in the first six months of 2018, as they generated 17,841,148 MWh.

Compensation came from hydroelectric power plants, whose production increased by more than 50% to 2,857,484 MWh. The reason for this significant increase was the high water flow of the rivers in the winter and spring. The share of HPP in the energy mix increased from 8.3% to 12.7%. After the enactment of the major legislative amendments for the liberalisation of the electricity market, the Bulgarian Independent Energy Exchange registered a record in the traded quantities of electricity on the intraday market, with a traded volume of 3,794.40 MWh with a delivery day of 01.08.2018, and on the day-ahead market for the delivery day of 19.07.2018, reaching 20,671.1 MWh, with an average hourly power of 861 MW.

In 2017, the quantity of natural gas realised by the public provider Bulgargaz EAD on the domestic market was 3,157 million m^3. The public provider sells natural gas at regulated prices and its share of sales for the year 2017 was 99.47%. The remaining 0.53% share of sales was to gas traders. The structure of consumption by individual branches was as follows: the energy industry with 946 million m^3 or 30%; the chemical industry with 1,142 million m^3 or 36%; other industries with 568 million m^3 or 18%; and gas distribution companies with 501 million m^3 or 16%. Bulgaria's energy dependence in 2017 on natural gas was very high – 98.3%. Local production is decreasing and on 01.11.2017 the local production company "Petrokertik Bulgaria" stopped production from the Galata gas field.

In 2017, the quantities of natural gas transported through the Bulgarian gas transmission network for transit traffic were 16.4 billion m^3, or 12.8% more than in 2016 (14.7 billion m^3) with an increase in the quantities of natural gas transited in all three directions. In 2017, the quantities of natural gas transported to Turkey were 13.2 billion m^3, or 12.41% more than in 2016; for Greece, they were 2.9 billion m^3, or 9.22% more than in 2016; for Macedonia they were 275 million m^3, or an increase of 30.89% compared to 2016.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Pursuant to analysis and forecast for electricity consumption made by state-owned certified independent Electricity System Operator (ESO), the country's production capacity will be sufficient by the year 2027. There is no expectation of any difficulties in the country's electricity supply under normal weather conditions and normal emergency conditions. The analysis is presented as part of the plan for the development of the transmission electricity network of Bulgaria for the period 2018–2027.

ESO prepared two main scenarios for the development of electricity consumption: maximum and minimum. The maximum scenario for gross electricity coincides with the trend of the European Union's final electricity consumption reference for the period 2015–2025. A delay in the implementation of energy efficiency measures has been set. By 2027, gross consumption is expected to reach 40,510,000 MWh. The minimum scenario provides for the maintenance of the level of electricity consumption over the entire period compared to 2018, due to more intensive implementation of energy efficiency measures. By 2027, gross consumption is expected to reach 37,960,000 MWh.

The forecast made by ESO for the development of Bulgaria's production capacities by 2027 is conservative and only based upon approved investment intentions. The forecast envisages the extension of the operation of the units of NPP Kozloduy with a gradual increase in their capacity and the renewable and cogeneration producers with contracted grid connections. The restarted NPP Belene project is not included in the forecast due to lack of certainty of its realisation.

The Bulgarian electricity grid is part of the integrated transmission network of the countries of Europe and its development is closely related to the development of the neighbouring countries' networks. All planned-for construction or rehabilitation of 400kV power lines are recognised by the European Commission as projects of common interest. For them, a thorough cost-benefit analysis has been carried out, according to the ENTSO-e methodology. By the end of 2018 the trilateral Bulgaria-Greece-Turkey project will be completed, allowing assessment of the possibilities for building a third interconnection between Bulgaria and Turkey. The construction of a second interconnector with Serbia, and a third with Turkey, are planned to take place after 2027. ESO has also taken into account the influence of Turkey on the electricity distribution network in the region. The Turkish operator's forecasts are for a large growth of new generating sources (over 140 gigawatts by 2040) and year-round export opportunities. This could lead to increased transit through the Bulgarian electricity transmission network.

Developments in government policy/strategy/approach

The year 2018 was marked by the Bulgarian Presidency of the Council of the European Union. Significant resolutions in the energy sector were reached by the Presidency, which emphasised the solidarity of the Bulgarian government with the two main European strategies – to endorse renewable energy, and to enhance cross-border integration of the energy infrastructure and market.

Negotiators of the Bulgarian Presidency reached a deal with the European Parliament at a trilogue meeting for revision of the Renewable Energy Directive. The agreement sets a headline target of 32% energy from renewable sources at EU level for 2030. The revision of the directive is one of the eight legislative proposals of the Clean Energy Package which the Commission presented in November 2016. However, the promotion of renewables has struggled in Bulgaria, whereas the country's 2020 renewable energy goal was met prematurely. The subsidy model by feed-in-tariffs encouraged investments in the sector, but also led to a steep increase of energy prices in the regulated segment of the market. This triggered legislative measures in order to balance the interests of investors and consumers. The ensuing legislation aggravated the business climate, but at least it did not provoke investment disputes against the Bulgarian state such as happened in the Spanish and Czech arbitration cases. In light of the above, it is to be expected that the Bulgarian government will follow an appropriate and consistent policy and framework for the promotion of renewable energy for its next binding 2030 target.

During the Bulgarian Presidency, the Council of EU agreed its position on the need to amend the regulation on the functions, role and remit of ACER, the EU Agency for the Cooperation of Energy Regulators. Market integration and cross-border energy infrastructure call for further coordination of national energy policies. The aim is to strengthen the tasks and competences of ACER in order to improve coordination on cross-border matters, to pave the way for increased market integration and to prevent market abuse.

To integrate the Bulgarian energy market with neighbouring European markets has also been the objective of the Bulgarian government and the steps towards this are being firmly followed. First, the proposed measures by the World Bank for further liberalisation of the Bulgarian electricity market have been implemented in the Bulgarian legislation. The day-ahead and intraday energy markets were implemented by the independent energy exchange which, pursuant to the European Commission recommendation, was transferred from the state-owned Bulgarian Energy Holding to the Bulgarian Stock Exchange in 2017.

On the way to market-coupling, the Bulgarian Independent Energy Exchange signed bilateral memorandums with neighbouring system operators in order to introduce separate export zones as an interim stage to full market integration. Second, the interconnection projects in the gas market with neighbouring countries have been promoted by the government. Bilateral agreements and projects have been reached and developed at a different pace at the borders of Bulgaria–Greece (ICGB), Bulgaria–Serbia (IBS), and Bulgaria–Macedonia. The Bulgaria–Greece (ICGB) interconnector is in the lead with a construction permit issued on Bulgarian territory and the public procurement procedure opened for design and construction. The project company has filed an application for the interconnector to be exempted from obligations under Article 36 of Directive 2009/73/EC as major new gas infrastructure which enhances competition in gas supply and security of supply.

In June 2018, the Bulgarian government presented to the European Commission the preliminary results of the feasibility study of the Balkan hub project (gas trading platform). According to Klaus-Dieter Borchardt, Director of the Internal Energy Market at the European Commission Directorate General for Energy, the project is commercially feasible and qualifies as a project of common interest for the EU. Therefore, opportunities to attract private investors, as well as international financial institutions such as the European Investment Bank, the Juncker Plan, and pension funds are deemed to be available. The concept of the gas hub has reached a review of possible entry points (13) and exit points (11) on which to move flows in the Bulgarian gas transmission network, and a business model.

The survey also assessed the potential for increasing gas demand in the European Union. Russia's natural gas, local extraction from Bulgaria and Romania, and natural gas from the Southern Gas Corridor (TAP and TANAP) are considered as the main sources for the Balkan hub. Existing and emerging liquefied natural gas terminals in Greece and Turkey could provide natural gas to be traded within the hub. The final study results conducted by Bulgarian-Swiss Consortium "AF-EMG Consult" are expected in September.

Developments in legislation or regulation

Major legislative amendments were adopted and in force as of 1 July, 2018 in order to further liberalise the Bulgarian energy market. The implemented amendments follow the transitional mechanism with contracts for differences (CfD) recommended by the report of the World Bank on financial recovery and market liberalisation. The model is deemed sustainable and was successfully introduced with the reform of the electricity market reform in the United Kingdom from 2014.

Pursuant to the new provisions of the Bulgarian Energy Act, the electricity produced by power plants with a capacity of 4 MW or over have to be traded on the independent energy exchange. The electricity necessary for technical grid losses must also be traded on the non-regulated segment of the market by the operators of transmission networks. It is envisaged that the producers of renewable and co-generation energy will be compensated through CfD. The compensation is paid by the "Security of Electrical Power System" fund, which receives on a monthly basis contributions amounting to 5% of the income by electricity producers, electricity traders, the operators of electric transmission networks and the operators of gas transmission networks. Thus, the new legislation provides for a new support scheme for renewables and cogeneration energy producers which have to be notified to the European Commission. Further amendments have provided for new competences of the energy regulator in order to investigate, detect and prevent market abuse and manipulations, and to strictly monitor the liberalised market for REMIT and transparency compliance.

Several events in the energy sector triggered legislative initiatives. The first and more debated one, was in regard to the newly introduced power of the Bulgarian energy regulator to permit share transfers of more than 20% of the capital of commercial companies performing licensing activities in the transmission, supply and distribution of electricity, heat or gas in order to ensure security of supply, the protection of national security and the public order. The considerations for the legislative initiative were connected to the sale of the Bulgarian subsidiaries of the Czech utility CEZ, including the largest electricity supply and distribution company in North-western Bulgaria. The supporters of the new competence of the Bulgarian energy watchdog argue that the regulatory framework must support strategic investors in order to guarantee security of supply and distribution; moreover, having in mind the natural monopoly of the distribution network operators. The amendments are deemed to ensure transparency of the transactions with the assets of energy companies. The opponents argue that powers to monitor compliance with the issued licences are available to the energy regulator, including for the required technical and financial capacity, human and organisational powers for carrying out the activity under the licence. Since the activity of the licensed company is regulated, the regulatory powers should be limited in respect to the licensed company, but not to its shareholders.

Another significant amendment of the Energy Act was introduced shortly before the start of the new annual regulatory period when the Bulgarian energy regulator determines the quantities and prices on the regulated segment of the electricity market. The amendment provides for the discretion of the energy regulator to exclude from the regulated electricity market, producers whose energy has a value exceeding 10% of the estimated market price for the regulatory period, with the exception of renewable and cogeneration producers and producers with long-term power purchase agreements. This has enabled the regulator to reject applications from major electricity producers to operate on the regulated segment with non-market prices for public supply.

The Bulgarian energy regulator approved a new pricing structure for access and transmission through the gas transmission network owned by the state-owned Bulgartransgaz EAD on all entry points/zones and exit/zones, based on the necessary annual revenues of the company. The new pricing model was adopted in compliance with the Commission Regulation (EU) 2017/460 of 16 March 2017 for establishing a network code on harmonised transmission tariff structures for gas. The first gas year during which the new tariff model applied was 01.10.2017 – 30.09.2018.

Judicial decisions, court judgments, results of public enquiries

Unquestionably the largest deal in the Bulgarian energy sector for the sale of CEZ assets resulted in legislative amendments and a debatable decision by the Bulgarian Commission for the Protection of Competition. In June 2018, the Commission refused to approve the acquisition of CEZ subsidiary companies by the Bulgarian company, Inercom Bulgaria EAD. Thus, it was not the energy regulator with its newly introduced powers, but the competition regulator that froze the most-debated deal on the Bulgarian energy market.

The withdrawal of Czech utility CEZ from its Bulgarian investments was announced in 2017; back then, the rumoured shortlisted bidders were said to be from Central and Eastern Europe, amongst them a Sofia-based energy consortium, Czech energy company Energo-Pro, Romanian company Electrica, and a consortium of Turkish engineering holding STFA Yatirim and a Bulgarian-based motor oils producer. Therefore, the small player Inercom caught everyone by surprise, including the Bulgarian government, which openly proclaimed it would intervene in the deal in order to protect the strategic energy infrastructure and ensure security of supply. Before public attention became focused on this particular part of the deal, CEZ managed to sell the defunct Varna thermal power station separately to a Bulgarian investor, and the deal was approved by the Competition Commission. The thermal plant is the second-largest in Bulgaria, but was stopped from working as of January, 2015, due to environmental restrictions.

The decision of the Bulgarian Commission for the Protection of Competition for rejection of approval of the CEZ deal is highly debatable, as it does not provide convincing economic arguments. Under competition law, the Commission has the power to prohibit an intended concentration when it leads to the establishment or strengthening of a dominant position, which may significantly prevent effective competition on the relevant product and geographic market. The considerations of the Bulgarian competition regulator relate to the market position of Inercom as a renewable energy producer, whereas the regulator elaborates that the concentration would lead to an increase of the market power of Inercom. The decision has been appealed before the Supreme Administrative Court and the court case is pending.

Another significant proceeding for the Bulgarian energy sector is the one against the state-owned Bulgartransgaz, initiated by a complaint of the Bulgarian company Overgas before the European Commission. The proceeding, which threatens to conclude with a fine for the Bulgarian state of up to €330m, has been comfortably delayed by the Bulgarian Presidency, but is on the forthcoming agenda of the European Commission. The Bulgarian Parliament assigned and instructed the Minister of Energy to negotiate and reach an agreement on Case COMP / B1 / AT.39849 – BEH Gas. The Bulgarian government should agree to complete the proceeding by undertaking specific commitments for organisational and restructuring measures of the state-owned companies and taking corrective actions.

The core of the complaint is in regard to denied access to the gas transmission network due to reserved capacity under an agreement between Bulgartransgaz and Gazprom. Therefore, it will be a pretty peculiar development if Bulgaria is fined because of the conditions of the commercial contracts of Bulgartransgaz while the Gazprom investigation ends without a fine for the Russian company, by assuming obligations towards the affected parties. Moreover, it is to be suspected that the proceeding will be used by the European Commission to force the Bulgarian state to privatise the lucrative Bulgartransgaz, owner of the national gas transmission network. In light of the above, the task of the Bulgarian government in the forthcoming negotiations will not be an easy one.

Major events or developments

One of the significant events of the last year is the announced 2018 restart of the Belene project, due to supposed investment interest. The Bulgarian Parliament adopted a decision to support the project on market principle and instructed the Minister of Energy to resume efforts to build Nuclear Power Plant Belene together with a strategic investor. The Parliament restricted the Ministry of Energy and gave very clear instructions on its understanding of the requirements for the development of the project – without mandatory energy purchase contracts, without preferential prices, without CfD, without state or corporate guarantees and/or other non-market mechanisms to guarantee the investment, and separating the assets and liabilities of the NPP Belene into a separate project company. It has been rumoured that there is investment interest by the China National Nuclear Corporation and Russia's Rosatom, but it is not to be reasonably expected that either of these companies will be ready to invest without any guarantees.

The Belene project continues to have a controversial status which cannot be easily overcome. Only two years ago, in 2016, the Bulgarian state provided state aid to the Bulgarian National Electricity Company in order to pay its debt to Atomstroyexport JSC in the amount of €601m under an arbitration award. The Bulgarian National Electricity Company was sued before the International Court of Arbitration at the International Chamber of Commerce in Geneva in order to fulfil its payment obligations under the contract for equipment delivery for the NPP Belene.

Since their signing, the long-term PPCs between the Bulgarian National Electricity Company and the coal power plants AES Maritsa East 1 and Contour Global Maritsa East 3 have been ongoing subjects of public and political debate. There is no formal infringement procedure, but at the end of last year the European Commission recommended to the Bulgarian government to re-negotiate relations with investors so that they comply with Community rules. The Minister of Energy announced that the preferred starting point of the negotiations by the Bulgarian government will be a proposal for a one-time compensation mechanism for return on investment. The aim is for the electrical energy produced by the power plants (which are owned by the USA corporations Contour Global and AES) to be traded on the independent energy exchange at market prices. The government has already presented its methodology for compensation and the reply of investors is to be expected. The agreement between the Bulgarian state and the investors has to be carefully settled so that the Bulgarian state will be not threatened by investment arbitration disputes.

Proposals for changes in laws or regulations

After the enactment of major legislative amendments in force as of 1 July, 2018, the legislator promptly prepared new provisions in order to fine-tune the newly introduced model. The proposed amendments are in response to the criticism by the electricity trading companies, upon which have been imposed heavy new obligations – higher bank guarantees, energy efficiency investments and pre-payment of VAT. In order to enable access to the liberalised electricity market, the legislator reduced the required amount of the bank guarantee, and introduced incentives for the market participants with no due debts. The amendments were supposed to be adopted urgently and therefore were presented within the legislative procedure of another existing bill. However, the manoeuvre to expedite the enactment failed, as the president vetoed the bill for reasons outside of the proposed amendments of the Energy Act. The amendments are expected to be enacted as soon as possible in order not to burden or prevent electricity traders from participation in the free market segment.

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Canada

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Overview of the current energy mix, and the place in the market of different energy sources

Canada is fortunate to have an abundant supply of energy from a wide range of renewable and non-renewable sources. Canada is the second-largest country in the world after Russia; it contains 10 provinces and three territories that use six time zones covering four-and-a-half hours, stretching from the Atlantic Ocean, to the Pacific Ocean, to the Arctic Ocean. Because of its large size, the energy mix varies across the country, depending on the natural resources and infrastructure in the particular province or territory, and the availability of imported sources.

Canada is the fourth-largest producer and fourth-largest exporter of oil in the world, with 10% of the world's proved oil reserves (est. 171 billion barrels); Canada can also sustain current production levels of natural gas for up to 300 years, with proved reserves of 73 trillion cubic feet. 98% of Canada's proven oil reserves are located in the oil sands in the province of Alberta. Most crude oil production occurs in Alberta, but crude oil is also produced in the western provinces of British Columbia, Saskatchewan and Manitoba, and to a lesser extent in the province of Ontario. There are also several producing offshore oil fields located in the northern Atlantic Ocean, off the coast of the province of Newfoundland. Canada's oil requirements are primarily met through domestic oil production.

In 2016, Canada produced approximately 3.6 million barrels of oil per day, while it consumed 1.8 million barrels of oil per day. Despite Canada's capability to meet its oil requirements through domestic crude oil production, in 2017, total crude oil imports averaged approximately 759,000 barrels per day.

It is estimated that Canada is the sixth-largest producer of electricity in the world, generating over 25,000 terawatt hours (TWh) in 2016, representing 3% of the world's total production. Canada is the world's second-largest producer of hydroelectricity, with 66% of Canada's electricity coming from renewable sources and 81% from non-greenhouse gases. Several provinces, including British Columbia and Quebec, rely primarily on hydroelectricity, while Ontario obtains about 60% of its electricity from nuclear power. In recent years, Ontario has engaged in several procurement programs, including a feed-in tariff program, to acquire electricity from wind, solar and biofuel, with the result that Ontario now obtains about 7% of its yearly electricity needs from wind, solar and biofuel, and 26% from hydro power, and only 4% of Ontario's power is generated using petroleum products (gas and oil). Ontario has eliminated all coal-fired electricity generation.

Alberta has set a target of 30% renewable electricity by 2030 which, pursuant to Alberta's Renewable Electricity Program, will support the development of 5,000 MW of renewable electricity. The first round of Requests for Proposals ("**RFP**") resulted in four projects being selected that will deliver almost 600 MW of wind capacity to Alberta's electricity market. The second and third RFP is currently under way and 31 companies submitted requests for qualifications to bid for up to 700 MW of renewable electricity.

In Saskatchewan, SaskPower's competitive RFP process for 200 MW of wind capacity has now closed. Eight of the 23 independent power producers who entered the Request for Qualification ("**RFQ**") phase qualified to move on to the RFP phase and were invited to submit proposals for the competition, and 15 applications qualified for the RFP. A decision on a successful candidate is expected to be announced in the fall of 2018. Currently, just under 25% of Saskatchewan's electric power comes from renewables. Saskatchewan's goal is to have 50% of its electricity capacity come from renewables by 2030, with a significant increase in wind generation. Saskatchewan is also looking at adding solar generation and a potential geothermal project.

Developments in government policy/strategy/approach

One of the major obstacles faced by Alberta's oil industry is the lack of pipeline capacity to transport Alberta's oil to tidewater for shipment to overseas markets. Approximately 99% of Canada's oil exports go to the United States. Canada has an extensive network of pipelines carrying crude oil to domestic and U.S. refineries, but there is very limited pipeline capacity to transport Alberta's oil to an ocean port. The lack of ability to reach global markets has resulted in Canadian oil selling at discounted prices.

In recent years, Kinder Morgan Canada Inc. proposed expanding its existing Trans Mountain Pipeline by twinning the existing pipeline system with approximately 987 kilometres of new pipeline segments for the purpose of transporting diluted bitumen from Edmonton, Alberta to Burnaby, British Columbia. The Trans Mountain Expansion Project also proposed a new and expanded dock facility at a marine terminal in Burnaby. The proposed project would increase the number of tankers loaded at the marine terminal from approximately five Panamax and Aframax class tankers per month to approximately 34 Aframax class tankers per month. Aframax tankers are larger and carry more product than Panamax tankers. The stated primary purpose of the proposed project is to provide additional capacity to transport crude oil from Alberta to markets in the Pacific Rim, including Asia.

In May 2016 the federal regulator, the National Energy Board of Canada ("the **NEB**") issued a report recommending that the Canadian federal government approve the Trans Mountain Expansion Project, and the federal government accepted that recommendation and approved the project in late 2016 on the basis that the expansion of the pipeline would be in Canada's public interest. Several indigenous groups (sometimes referred to in Canada as First Nations) and environmental groups filed applications with the Federal Court of Canada seeking judicial review of the NEB's report and the federal government's approval of the expansion project in an attempt to block construction of the project. In addition, the government of British Columbia, where the expanded dock facility is to be located, expressed strong opposition to the Trans Mountain Expansion Project because of concerns over increased tanker traffic off B.C.'s Pacific coast, and the British Columbia government said it would use every tool it could to stop the expansion project.

As a result of the protests and opposition, Kinder Morgan announced in April 2018 that it would be halting work on the Trans Mountain Expansion Project and that it would likely not proceed with the project unless it could reach agreement with the various stakeholders.

In late May 2018, the Canadian federal government announced that it had reached an agreement to buy the existing Trans Mountain pipeline and related infrastructure for CAD $4.5 billion. The government announced that the agreement was necessary to ensure a vital piece of energy infrastructure is built. The Canadian Finance Minister stated that the expansion project is in the national interest, and proceeding with it will preserve jobs, reassure investors and get resources to world markets. He said the government does not intend to be a long-term owner, and at the appropriate time, the government will work with investors to transfer the project and related assets to a new owner or owners.

Kinder Morgan's shareholders approved the sale of the Trans Mountain Pipeline to Canada on August 30, 2018. However, on the very same day, the Federal Court of Canada issued a decision quashing the federal government's 2016 approval of the Expansion Project. The Court stated that the approval of the project was invalid and could not stand for two main reasons:

(i) The Court found that the NEB had unjustifiably defined the scope of the project under review not to include project-related tanker traffic. The unjustified exclusion of marine shipping from the scope of the project led to successive, unacceptable deficiencies in the NEB's report and recommendations. As a result, the federal government could not rely on the NEB's report and recommendations when assessing the project's environmental effects and the overall public interest.

(ii) The Court also found that the government of Canada had not adequately consulted with indigenous First Nations groups as required by various decisions of the Supreme Court of Canada before it approved the project.

As a result, Canada is currently the owner of the existing Trans Mountain Pipeline, but Canada will have to overcome significant hurdles before it can complete the construction of the expansion project and increase the country's ability to transport oil to tidewater for shipment to overseas markets. Canada's Prime Minister Trudeau has stated that his government is committed to seeing the expansion completed, but the government accepts the Federal Court's findings that more needs to be done to consult with indigenous people and to ensure the environment is protected before the project can proceed.

Developments in legislation or regulation

<u>Federal developments</u>

In November 2016, the federal government announced a $1.5 billion Ocean Protection Plan ("**OPP**") to improve marine life health and safety in response to tanker and fuel spills that have occurred in Canadian coastal waters, which included a five-year spending commitment commencing in 2017. The purpose of the OPP is to create a marine safety system, restore ocean ecosystems, develop new methods to clean up spills and establish new legislation to hold owners responsible for the operation of their vessels. To date, over $450 million has been invested as a part of the OPP.

In furtherance of the OPP, on May 12, 2017, the Federal government introduced legislation to implement the *Oil Tanker Moratorium Act* on British Columbia's north coast. This act has not yet been proclaimed in force, but it has been passed by the Canadian House of Common, and is now being reviewed by the Canadian Senate.

After it comes into force, the new legislation will prohibit tankers from carrying more than 12,500 metric tonnes of crude oil or persistent oil products as cargo, from stopping, loading or unloading at ports and marine installations from the northern tip of Vancouver Island to the Alaska border. The Act prohibits loading if it would result in the oil tanker carrying more than 12,500 metric tons of those oils as cargo. The Act also prohibits vessels and persons from transporting crude oil or persistent oil between oil tankers and those ports or marine installations for the purpose of aiding the oil tanker to circumvent the prohibitions on oil tankers. The legislation contains penalty provisions for contravention that could reach up to CAD$5 million.

Ontario developments

The province of Ontario elected a new Conservative government in June 2018, replacing a Liberal government that had governed the province for 15 years. During the election campaign the Conservative party heavily criticised the previous Liberal government for its decision to partially privatise the province's electricity distribution company known as Hydro One, and also for high electricity prices. By some measures, Ontario's electricity prices had risen by 71% from 2008 to 2016, while during this period, the average growth in electricity prices across Canada was only 34%.

In 2017, the then Liberal government of Ontario passed legislation known as the Fair Hydro Plan which lowered electricity bills by 25% on average for all residential consumers in the province. In the months leading up to the election, the then opposition Conservative party criticised the Fair Hydro Plan on the basis that it did nothing to reduce the actual cost of generating electricity, but the Conservatives said they would keep the Fair Hydro Plan if elected.

Within a few weeks of being elected, the new Conservative government of Ontario passed several pieces of legislation or put in place new government policies for the stated purpose of implementing various campaign promises related to electricity issues. The new legislation and policies included:

The *Hydro One Accountability Act, 2018* which placed constraints on compensation for the directors, Chief Executive Officer and executives of Hydro One (the operator of most of the provincial distribution grid), and provided that the distribution rates charged by Hydro One shall not reflect amounts paid for executive compensation.

The *White Pines Wind Project Termination Act, 2018*, which provides for the retroactive termination of the White Pines Wind Project and the decommissioning of the project. This was a wind generation project that had received final approval from the previous government during the election campaign. Under the legislation, the Project is to receive compensation for its reasonably incurred expenses in relation to the development, acquisition, leasing and construction costs, and decommissioning costs, but the Project is precluded from receiving payment of any additional damages beyond what is allowed in the legislation.

Ontario's Ministry of Energy directed Ontario's Independent Electricity System Operator ("**IESO**") to immediately wind down various electricity procurement contracts that the IESO had in place under a Feed-in Tariff ("**FIT**") program and a Large Renewable Procurement ("**LFP**") program if the contracts had not yet received Notice to Proceed from the IESO or if the contracts had not yet achieved certain key development milestones. The Minister of Energy stated that the FIT and LRP projects contributed to cost increases for electricity ratepayers and the projects were no longer needed to maintain the adequacy and reliability of Ontario's electricity supply.

The new government also announced that it would be cancelling Ontario's cap-and-trade program which the previous government had introduced to control carbon emissions. The legislation, known as the *Cap and Trade Cancellation Act, 2018*, has been introduced in the Ontario legislature, but not yet enacted as of September 7, 2018. The new government has stated that it is developing a new plan to address climate change, but it has not yet released any details regarding the new plan.

Proposals for changes in laws or regulations

The Canadian "Greenhouse Gas Pollution Pricing Act"

At the end of 2017, the federal government adopted the *Pan-Canadian Framework on Clean Growth and Climate Change* (the "**PCF**") in order to meet its commitment under the 2015 Paris Agreement to cut greenhouse gas emissions by approximately 30% below 2005 levels by 2025. In conjunction with the PCF, the federal government released the draft *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**") in January 2018 for public comment, which legislation sets out the framework for a federal carbon pricing system.

The GGPPA was enacted by the federal parliament in June 2018. The federal carbon pricing system will apply on January 1, 2019 in each province or territory that requests it, and in any jurisdiction that does not have a carbon pricing system that meets the federal benchmark. All provinces and territories remain free to develop and implement their own carbon pricing systems, but if they do not have a system that meets the federal government's standards, the federal government will impose a mandatory pricing system on such provinces and territories.

The federal government requested that all provinces and territories notify it by the end of March 2018 whether they intended to follow the federal carbon pricing system. If a province intended to establish or maintain its own carbon-pricing plan, it would have to submit its own carbon-pricing plan by September 1, 2018 so that the federal government could confirm that it met federal standards. Presently, Ontario, Quebec, Alberta and British Columbia have or are implementing their own carbon pricing systems that may meet the federal standard. However, as indicated above, Ontario intends to cancel its cap-and-trade program, and therefore the federal carbon pricing system will likely apply in Ontario.

The Province of Saskatchewan recently launched a court challenge against the federal government and has asked its court of appeal to rule on whether the GGPPA is constitutional. The Province of Alberta has indicated that while it intends to continue to implement its own provincial carbon pricing system, it would no longer support the federal plan (the federal system mandates that each province's carbon pricing system must increase to $50 per tonne by 2022, and the Province of Alberta has indicated that it has no intention of raising its current tax of $30 per tonne to the federally mandated $50 per tonne). As the provinces and the federal government share jurisdiction over environmental matters, both provinces are arguing that the federal government does not have the right to decide whether each province's plan to reduce greenhouse-gas emissions is good enough and meets federal standards. Furthermore, the Province of Saskatchewan argues that the federal government cannot pursue its own policy objective with respect to matters falling within provincial jurisdiction without willing and voluntary participation of the provinces. Contemporaneously with its announcement that it would be cancelling Ontario's cap-and-trade program, the Province of Ontario also announced that it too would be launching a constitutional challenge to the GGPPA.

Despite the threatened constitutional challenges by some of the provinces, the federal government has reiterated its commitment to implementing the GGPPA.

The proposed GGPPA system has two components: a charge on fossil fuels that will generally be paid by fuel producers or distributors, and a separate pricing system for industrial facilities that are emissions-intensive, known as the output-based pricing system (the "**OBPS**").

The legislation imposes a carbon tax rate for fossil fuels that will be paid by fuel producers, distributors and importers (starting at a minimum of $10 per tonne in 2018 and rising $10 per year to $50 per tonne in 2022).

The output-based pricing system is intended to provide a price incentive for companies to reduce their greenhouse gas emissions and to spur innovation while maintaining competitiveness and reducing the risk that economic activity, and associated carbon pollution, is displaced to another jurisdiction with less stringent greenhouse gas regulations. Instead of paying the charge on fuels that they purchase, industrial facilities in the system will face a carbon price on the portion of their emissions that are above a limit, which will be determined based on output-based standards (emissions per unit of output).

The current proposal is for the OBPS to apply to industrial facilities located in jurisdictions where the federal carbon pricing system applies and that emit 50 kilotonnes of carbon dioxide equivalent or more per year, with the possibility for smaller facilities (of 10 kilotonnes and above) to opt in voluntarily. Facilities that emit less than their annual limit will receive surplus credits from the Government for the portion of their emissions that are below their limit. A facility can trade surplus credits it earns, creating an incentive for facilities to reduce emissions below the limit.

In August 2018, the federal government announced that it was updating its proposed approach to setting the output-based standard after consultations with industry, and that it would continue to refine the standards based on additional feedback from stakeholders. The updates announced in August 2018 were intended to ease the impact on heavy industrial emitters, and the government announced that an additional amendment could be made to address competitiveness fears in the Canadian business community fuelled by U.S. tax cuts, tariffs and environmental policy roll-backs.

<u>Proposed "Canadian Energy Regulator Act" and "Impact Assessment Agency of Canada</u>"

Canada's federal and provincial governments share jurisdiction over Canadian energy policy, as well as the legal and regulatory framework for the exploration of Canadian oil and natural gas reserves. Accordingly, there is no single energy policy or regulatory body governing the electricity industry or the development of oil and natural gas reserves in Canada.

Currently, the National Energy Board is the federal agency that handles the majority of the responsibilities regarding the regulation of interprovincial pipelines and energy development and trade, while each province has its own regulatory body with responsibility over intraprovincial projects.

In February 2018, the federal government introduced an omnibus bill, known as Bill C-69. Bill C-69 has not yet been proclaimed in force, but it has been passed by the Canadian House of Commons, and is now being reviewed by the Canadian Senate.

Bill C-69 provides for enactment of two new statutes which provide for the establishment of two new regulatory agencies:

1. the *Canadian Energy Regulator Act* provides for the establishment of the Canadian Energy Regulator (the "**Regulator**") which will replace the NEB; and
2. the *Impact Assessment Act* provides for the establishment of the Impact Assessment Agency of Canada.

Bill C-69 also provides for changes to the Canadian *Navigable Waters Act* and to the *Fisheries Act*, to implement additional protection for waterways, fish, and fish habitat.

The federal government has stated that the overall intention of Bill C-69 is to implement better rules to implement "a modern environmental and regulatory system that protects the environment, supports reconciliation with indigenous peoples, attracts investment, and ensures that good projects go ahead in a timely way to create new jobs and economic opportunities for the middle class".

The Canadian Energy Regulator Act

The Regulator is to have a Commission that consists of up to seven full-time commissioners, and it may also have part-time commissioners. At least one full-time commissioner must be an Indigenous person. The Commission will be responsible for the adjudicative functions of the Regulator, and it will have exclusive jurisdiction to inquire into, hold hearings, and determine any matter within the jurisdiction of the Regulator.

The *Canadian Energy Regulator Act*, among other things, provides for the regulation of:

(a) pipelines, abandoned pipelines, and traffic, tolls and tariffs relating to the transmission of oil or gas through pipelines;
(b) international power lines and certain interprovincial power lines;
(c) renewable energy projects and power lines in Canada's offshore;
(d) access to lands; and
(e) the exportation of oil, gas and electricity and the interprovincial oil and gas trade.

The Impact Assessment Act

The *Impact Assessment Act* names the Impact Assessment Agency of Canada as the authority responsible for "impact assessments", which are defined as assessments of the effects of a designated project that is conducted in accordance with the act. "Effects" is defined broadly to mean, unless the context requires otherwise, changes to the environment or to health, social or economic conditions, and the positive and negative consequences of these changes.

Among other things, the *Impact Assessment Act:*

(a) provides for a process for assessing the environmental, health, social and economic effects of designated projects with a view to preventing certain adverse effects and fostering sustainability;
(b) prohibits proponents, subject to certain conditions, from carrying out a designated project if the designated project is likely to cause certain environmental, health, social or economic effects, unless the Minister of the Environment or the federal cabinet determines that those effects are in the public interest, taking into account the impacts on the rights of the Indigenous peoples of Canada, all effects that may be caused by the carrying out of the project, the extent to which the project contributes to sustainability, and other factors;
(c) establishes a planning phase for a possible impact assessment of a designated project, which includes requirements to cooperate with and consult certain persons and entities and requirements with respect to public participation;
(d) authorises the Minister of the Environment to refer an impact assessment of a designated project to a review panel if he or she considers it in the public interest to do so, and requires that an impact assessment be referred to a review panel if the designated project includes physical activities that are regulated under the Nuclear Safety and Control Act, the Canadian Energy Regulator Act, the Canada–Nova Scotia Offshore Petroleum Resources Accord Implementation Act and the Canada–Newfoundland and Labrador Atlantic Accord Implementation Act;

(e) establishes time limits with respect to the planning phase, to impact assessments and to certain decisions, in order to ensure that impact assessments are conducted in a timely manner;
(f) provides for public participation and for funding to allow the public to participate in a meaningful manner;
(g) sets out the factors to be taken into account in conducting an impact assessment, including the impacts on the rights of the Indigenous peoples of Canada;
(h) provides for cooperation with certain jurisdictions, including Indigenous governing bodies, through the delegation of any part of an impact assessment, the joint establishment of a review panel, or the substitution of another process for the impact assessment;
(i) provides for transparency in decision-making by requiring that the scientific and other information taken into account in an impact assessment, as well as the reasons for decisions, be made available to the public through a registry that is accessible via the Internet;
(j) provides that the Minister may set conditions, including with respect to mitigation measures, that must be implemented by the proponent of a designated project;
(k) provides for the assessment of cumulative effects of existing or future activities in a specific region through regional assessments and of federal policies, plans and programs, and of issues that are relevant to the impact assessment of designated projects through strategic assessments; and
(l) sets out requirements for an assessment of environmental effects of non-designated projects that are on federal lands or that are to be carried out outside Canada.

Other judicial decisions and court judgments

In May 2016, the Federal Court of Appeal released a decision upholding the validity of certain federal regulations that require all diesel fuel produced, imported or sold in Canada to contain at least 2% renewable fuel. In *Syncrude Canada v. Canada (Attorney General)*, 2016 FCA 160, Syncrude challenged the constitutional validity of the regulations, but the court found the regulations to be a valid exercise of the federal government's jurisdiction over criminal law.

Syncrude produces diesel fuel at its oil sands operations in Alberta which is used in its vehicles and equipment. The *Canadian Environmental Protection Act, 1999* provides that it is an offence, punishable by a $500,000 to $6,000,000 fine, to fail to adhere to fuel requirements promulgated under the *Renewable Fuels Regulations.*

The unanimous Federal Court of Appeal determined that the 2% renewable fuel requirement is aimed at the reduction of toxic substances in the atmosphere, so as to maintain the health of Canadians and protect the environment. It found that the Supreme Court of Canada has consistently held that protection of the environment is a legitimate use of the federal government's criminal law power.

This decision is significant because it enables the federal government to enact legislation aimed at reducing greenhouse gases and supports the federal government's jurisdiction to further its climate change initiatives, such as the Ocean Protection Plan, through legislation that may impact the oil and natural gas sector.

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Sharon practises energy law, with a focus on regulatory matters and complex commercial arrangements. She has acted for sophisticated electricity industry clients on a wide range of regulatory and commercial issues, including compliance with the requirements of the *Ontario Energy Board Act, 1998* and the *Electricity Act*, and advising with respect to power supply agreements (including Large Renewable Procurement (LRP) and Feed-in Tariff (FIT) contracts) with the Independent Electricity System Operator (IESO) and disputes with respect to the IESO Market Rules. She represents clients at Ontario Energy Board (OEB) hearings, relating to both electricity transmission and natural gas matters. She also has extensive experience drafting complex agreements in the energy area.

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Chile

Rodrigo Ochagavia, Ariel Mihovilovic & Vicente Allende
Claro y Cía.

Overview of the current energy mix, and the place in the market of different energy sources

The most important sources of primary energy consumed in Chile are oil (27%), coal (26%), firewood and biomass (23%). The most important sources of electricity generation are hydroelectricity (27%), coal (21%) and natural gas (20%). As of December 2017, renewable sources other than hydroelectricity accounted for 18% of the electricity produced in Chile, but with a high growth rate (in 2007, electricity coming from such sources represented only 1% of the installed capacity).

Most of the fossil fuel sources are imported (approximately 90%), while biomass is the main locally produced source of energy. Lithium and hydrocarbons found in liquid or gas state are not recognised as concessible under Chilean law and thus can only be domestically exploited either directly by the Chilean State or its companies, or by third parties who have been awarded administrative concessions or entered into contracts of special operations with the State (also known as *contratos especiales de operación* – "**CEOPs**"), subject to terms and conditions approved by the President of Chile by means of a supreme decree.

The main consumers of energy in Chile are the industrial and the mining sectors (40% jointly, 23% and 17% respectively), which are supplied with electricity (33%), diesel (26%) and biomass (29%). These sectors are followed by the transport sector (35% of final consumption) which is satisfied almost in its entirety with crude oil derivatives, and the commercial, public and residential sectors which, combined, account for 21% of the aggregate final consumption. Electricity supplies 22% of the aggregate final energy consumption in Chile.

<u>Oil</u>

As noted above, oil can only be exploited in Chile either by the State or a State-owned company, or by a third party that has either been awarded an administrative concession or has entered into a CEOP with the State. As of this date, Empresa Nacional del Petróleo ("**ENAP**"), a state-owned company, and GeoPark, a private company, are the main domestic producers of crude oil in Chile, and virtually all their oil extraction operations are conducted in the Magellanean Basin (both onshore and offshore). Domestic oil production, however, represents a very small fraction of the total amount of oil consumed in Chile; most of it is imported (97%).

Import, export, storage, refinement, transport, distribution, supply and commercialisation of oil or oil derivatives in Chile can be conducted by non-State parties. However, as per Decree with Force of Law No. 1 of 1978, any person conducting such activities has to be registered with and become subject to the overview of the Superintendence of Electricity and Fuel (the "**SEC**"), who monitors and oversees compliance with the laws, regulations and technical standards governing the generation, production, storage, transportation and distribution of liquid fuels, gas and electricity generally. Other than such registration, no concession or special authorisation is required to conduct any such activity.

As of today, ENAP is virtually the sole refiner of crude oil in Chile through its three refinery plants: the Biobío Refinery Plant (located near the city of Concepción in Region VIII); the Concón Refinery Plant (located near the city of Valparaíso in Region V); and the Gregorio Topping Refinery Plant (located in Region XII, near the domestic crude oil exploitation and extraction facilities).

As to storage, while ENAP has a significant market share, certain distribution companies of oil-related products such as Copec, Shell and Petrobras have their own storage facilities as well.

<u>Gas</u>

The gas market comprises: (i) pipelines that come from, and now go to, Argentina; (ii) domestic pipelines; and (iii) regasification terminals.

There are six natural gas pipelines that connect the local market with Argentina, with two located in the extreme south of Chile (Gasoducto Posesión and Gasoducto Bandurria), two located in central Chile (GasAndes and Gas Pacifico), and two located in Northern Chile (GasAtacama and Norandino).

There are three domestic pipelines, each built to reach specific markets: Electrogas (downstream of GasAndres and GNL Quintero); Tal-Tal (downstream of GasAtacama); and Innergy (downstream of Gas Pacifico). The major consumption centres also have local distribution networks. These include the networks of Metrogas (Santiago Metropolitan Region and Region VI), GasValpo (Region V), GasSur (Region VIII), Intergas (Region IX), Gasco Magallanes (Region XII) and Lipigas (Region II).

There are two liquefied natural gas ("**LNG**") regasification terminals in Chile: one located in Region V in the Quintero Bay (GNL Quintero); and the other located in Region II in the Mejillones Bay (GNL Mejillones).

The gas industry in Chile also includes "satellite regasification plants" which are local regasification plants that supply gas in areas which are not connected to pipelines. These plants are supplied by tanker trucks. Customers of these regasification plants include agriculture-related industries.

Most of Chile's gas distribution infrastructure was constructed during the 1990s, when Chile and Argentina executed bilateral agreements to regulate and promote the export of natural gas from Argentina to Chile. More than US$ 4.6 billion was invested in natural gas-related infrastructure. Significant investments were also made in natural gas distribution networks and in the conversion of domestic, commercial and industrial customers from other sources to natural gas.

In 2004, Argentinean natural gas curtailments began and became increasingly severe over the next years until natural gas exports to Chile were halted in 2007, with the exception of residential consumption – which continued, but at significantly higher prices due to the application of new Argentine export taxes.

When the first natural gas supply restrictions from Argentina took effect, the Chilean government reacted by promoting the development of LNG terminals in order to restore gas supplies and enhance diversification and security of the country's energy matrix. This resulted in the construction of: (i) GNL Quintero, which started supplying gas in 2009, which was developed by ENAP, together with British Gas, Endesa Chile and Metrogas; and (ii) GNL Mejillones, which initiated operations in 2010, which was developed by GDF Suez S.A. (currently known as Engie Energía Chile S.A.) and Corporación Nacional del Cobre de Chile (commonly known as Codelco, which is a State-owned mining company and the largest copper producer in the world).

As noted above, gas can only be exploited and extracted in Chile either by the State or a State-owned company, or by a third party that has either been awarded an administrative concession or has entered into a CEOP with the State. Distribution and transport of gas through pipelines, on the other hand, can be conducted directly by private entities, provided that they have obtained a permanent concession that allows its holder to: (i) build, maintain, and conduct distribution activities within a given geographical region; or (ii) provide gas transport services through a pipeline or integrated network, as applicable.

Chilean law allows the existence of overlapping distribution concessions within a given geographic region and for multiple transport concessions between the same start- and end- nodes. Thus, the relevant authority cannot reject a concession request that complies with the relevant legal, technical and economic requirements.

A transport concessionaire must operate under an open access policy, which is understood as the obligation of each transport company to offer its available capacity under the same economic, commercial, technical and informational conditions to any individual demanding transport services.

Gas transport and distribution prices are freely set through bilateral negotiations between the parties involved, subject to a general maximum profitability limit up to 6% (Annual Cost of Capital) plus a 3% spread. Compliance with this limit is monitored annually by the National Commission of Energy (*Comisión Nacional de Energía* – "**CNE**"). The Annual Cost of Capital is calculated by the CNE every four years, considering the systemic risk of the activities of public gas distribution concessionaires in relation to the market, the risk-free rate of return, the market risk premium, and an individual risk factor per zone of concession.

The gas distribution industry market in Chile is also regulated and monitored by the SEC.

<u>Electricity</u>

In Chile, there are three electricity systems: the system of Aysén; the system of Magallanes; and the National Electric System (which was created through the interconnection late in 2017 of what was then known as the Central Interconnected System or SIC and the Northern Interconnected System or SING), which supplies electricity to over 97% of the national population.

In the National Electric System (hereinafter, the "**SEN**"), electricity generation is coordinated by a system operator, the National Electricity Coordinator (the "**Coordinator**"), whose purpose is to minimise operational costs and ensure the highest economic efficiency of the system, while meeting all service quality and reliability requirements established by law.

The electricity sector in Chile is divided into three segments: generation, transmission and distribution. In general terms, generation is subject to market competition, while transmission and distribution, given their natural monopoly character, are subject to price regulation. The goal of the Chilean electricity legal and regulatory framework is to provide incentives to maximise efficiency and to provide a simplified regulatory scheme and tariff-setting process that limits the discretionary role of the government by establishing objective criteria for setting prices. The expected result is an economically efficient allocation of resources. The regulatory system is designed to provide a competitive rate of return on investment to stimulate private investment, while ensuring the availability of electricity service to all who request it.

The generation segment consists of companies that produce electricity and sell their production to distribution companies, unregulated customers and other generation companies. The transmission segment consists of companies that transmit the electricity produced by generation companies at high voltage. The distribution segment includes electricity supply to final customers at a voltage no greater than 23kV. In Chile, only generation and distribution companies may commercialise electricity.

Power generation companies satisfy their contractual sales requirements with dispatched electricity, whether produced by them or purchased from other generation companies in the spot market. The principal purpose of the Coordinator in operating the dispatch system is to ensure that only the most cost-efficient electricity is dispatched to customers. The Coordinator dispatches plants in the order of their respective variable cost of production, starting with the lowest-cost plants, such that electricity is supplied at the lowest available cost. Generators balance their contractual obligations with their dispatches by buying or selling electricity at the spot market price, which is calculated on an hourly basis by the Coordinator, based on the marginal cost of production of the most expensive kWh dispatched.

No concession or particular approval is required to engage in electricity generation (except for the development and operation of geothermal generation facilities, which do require a concession). All generators can commercialise energy through contracts with distribution companies for their regulated customers and unregulated customers, or directly with unregulated customers. All contracts executed between generation and distribution companies for the supply of regulated customers after 2005 must be the result of open, competitive and transparent auction processes. Generators may sell energy to other power generation companies on a spot price basis. Power generation companies may also engage in contracted sales among themselves at negotiated prices, outwith the spot market. Contract terms are freely determined (except in the case of supply to regulated customers).

The Chilean electricity legal and regulatory framework does not require an electric concession to build and operate transmission facilities. However, in case it is difficult to process and obtain rights to use or occupy third-party land affected by the transmission facility's layout, transmission companies may request and obtain electric concession that grant the possibility of enforcing those easements in exchange for proper compensation to the owners of the affected land.

The transmission system is divided into the following segments: (i) the National Transmission System (formerly known as the trunk transmission system); (ii) the Zonal Systems (formerly known as sub-transmission systems); (iii) the Dedicated Systems (formerly known as additional systems); (iv) the new Development Zones Systems; and (v) the new International Systems. Each of these segments is subject to a different remuneration mechanism, which is subject to detailed regulation for each case, except for Dedicated Systems. In this regard, regulated revenues for transmission facilities are based on the amounts invested by the owner in building them and the costs incurred in their management.

Concessions are required to engage in electricity distribution.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

During the last few years, Chilean authorities have favoured the development of non-conventional renewable energies ("**NCRE**"), which has resulted in an explosive growth thereof. Such a growth, which in the past took place mostly in the north area of the country (nowadays there are also several projects in the central area), made the transmission facilities comprehended in the Northern Interconnected System insufficient to transport all the energy produced thereby, thus curtailments were necessary in order to avoid collapsing the system. This was addressed by amending the regulation applicable to the transmission segment, providing the interconnection of the two main electrical systems existing at such moment, SIC and SING, and the creation of SEN as virtually the only electric system in Chile. As mentioned above, the interconnection took place in late 2017, triggering new challenges for the electricity market, such as the disappearance of former operators in each interconnected system and the assumption of their duties by the Coordinator, and the future interconnection of international electricity systems – which is at a very early stage, with some power exchanges executed with Argentina.

Another consequence of the great development of NCRE in Chile was the decrease in the price at which energy is sold to distribution companies, who in turn supply such energy to regulated consumers. As described above, since 2005 all supply contracts to sell energy to distribution companies have been the result of a public tender process, and have been awarded based on the lower-cost bid. This decrease in the price at which the energy is finally supplied to regulated consumers has had two main consequences: (i) unregulated consumers are renegotiating their energy supply agreements in order to reduce the price (or assessing the convenience of terminating them and becoming regulated customers); and (ii) small power plants connected to the grid through distribution facilities ("**PMGD**") are flourishing, as the law recognises the possibility of their becoming subject to a stabilised price regime of remuneration.

Additionally, as a consequence of Law No. 20,805, enacted in 2015, which established that entities whose connected power is higher than 500 kV, but less than 5,000 kW, have the option to be supplied under the regulated regime (i.e. through distribution companies) or as unregulated clients (through direct power purchase agreements with the generators), companies of every kind moved themselves from the regulated to the unregulated price regime; for example, shopping centres, or even office buildings that met the requirements entered into power purchase agreements, expanding the market for energy sales.

Finally, during the last few years, the LNG market has also experienced significant growth, which has allowed Chile to export LNG to Argentina, in the framework of a recently subscribed agreement between ENAP and IEASA (the Argentinean equivalent of ENAP) for the exchange of LNG between both countries. Differently from what was done in the past, where the agreements included an obligation for the exporting party to import the same amount of energy as the one sold abroad, in this new agreement such restriction has been removed and no new restrictions have been imposed.

Developments in government policy/strategy/approach

In September 2015, with the participation of the government, several stakeholders, key participants of the energy sector, universities and the public at large, the Ministry of Energy produced and issued a document titled "Energy 2050", which contains Chile's long-term energy policy defining what should be the Chilean energy matrix for the years 2035 and

2050 (the "**Energy Policy 2050**", which is available at http://www.energia2050.cl/en/energy-2050/energy-2050-chiles-energy-policy/).

The Energy Policy 2050 is based on four principles identified as: (i) quality and security of supply (i.e. reliability); (ii) energy as a driving force for development (i.e. inclusiveness and social sustainability); (iii) environmentally friendly energy (i.e. environmental protection and sustainability); and (iv) energy efficiency and energy education (i.e. competitiveness, efficiency and public awareness).

Within the framework of the Energy Policy 2050, the Ministry of Energy has developed a short-term energy policy known as "Energy Route 2018-2022: Leading the modernization with a citizen seal" ("**Energy Route 2018-2022**", available at http://www.energia.gob.cl/rutaenergetica2018-2022.pdf), which contains the main ideas and projects to be conducted by the government that took office in March 2018, and includes two principal goals: (i) universal access to the electricity services; and (ii) the 'decarbonisation' of the Chilean energy matrix (that is, the reduction of coal dependence in the generation of electricity). In order to reach such goals, the following aspects were identified as the principal courses of action:

1. Modernisation of energy institutions in order to make implementation of the desired energy development easier.
2. Information-collecting on energy access, in order to make an accurate diagnosis of the current situation in such matters and be able to focus resources where they are most needed ("map of vulnerability").
3. Reduce processing time before the environmental authorities by 25%.
4. Increase the distributed generation capacity to four times the current capacity.
5. Increase by 10 times the number of electric vehicles in the country.
6. Modernisation of electricity regulations, principally in relation to the distribution segment.
7. Regulation of physical biofuels (as firewood and derivatives).
8. Create incentives for the efficient use of energy and other resources in high-demand industries (mining, manufacturing, transportation).
9. Create a program for the 'reconversion' of power plants that use coal as a source.
10. Train 6,000 people as operators, technicians and professionals in energy-related areas.

Developments in legislation or regulation

Even though no new laws have been enacted during the past 12 months targeting the energy sector specifically, there have been several developments in regulations implementing major changes recently made to said laws (especially in relation to Law No. 20,936, which introduced significant changes to the General Electricity Act in relation to electricity transmission). Such regulations include the following:

1. Technical Standards Regulation (*Reglamento de Normas Técnicas*), which was published in the Official Gazette on September 28, 2017. This regulation sets forth the procedures to regulate technical aspects in relation to the security, coordination, quality, information and economics of the electricity market. It also creates a Regulatory Annual Plan, which shall include all the regulations, procedures, standards and similar rules that should be approved during each year, creating the possibility for the industry players to participate in such plan.

2. <u>Experts Panel Regulation (*Reglamento del Panel de Expertos*)</u>, which was published in the Official Gazette on January 5, 2018. The Experts Panel is the entity that resolves certain disputes that may arise within the electricity market. A noteworthy change made by this regulation is related to the financing of Experts Panel, which is no longer part of the national annual budget (*Ley de Prespuesto*) and instead is financed through the creation of a new charge that is collected from the electricity bills paid by final customers.
3. <u>Independent Coordinator of the National Electricity System Regulation (*Reglamento del Coordinador Eléctrico Independiente del Sistema Eléctrico Nacional*)</u>, which was published in the Official Gazette on April 3, 2018. This regulation sets forth the detailed provisions to which the Coordinator is subject, establishing the internal structure thereof, the way in which each member is appointed and removed, its financing (through a public service charge), etc. According to the regulation, the Coordinator plays a broader role in the electricity market than the one played by the former CDECs (i.e. the Coordinator's predecessors), being not just in charge of coordinating an efficient operation of the electrical system, but also a secure and reliable operation with an open-access regime.
4. <u>Security Regulation for electrical facilities for the generation, transportation, supplementary services, storage and distribution of electric energy (*Reglamento de Seguridad de las Instalaciones Eléctricas Destinadas a la Producción, Transporte, Prestación de Servicios Complementarios, Sistemas de Almacenamiento y Distribución de Energía Eléctrica*)</u>, which was published in the Official Gazette on June 12, 2018. The purpose of this regulation is to provide with minimum safety and security requirements and procedures (including by referring to technical standards) for different types of electrical facilities.

Judicial decisions, court judgments, results of public enquiries

- *"Pardo v. Empresa Eléctrica Carén S.A."* (Supreme Court of Chile, Index No. 39,985-2017): On February 22, 2018 the Supreme Court of Chile suspended the operation of the run-of-the-river hydroelectric power plant "Carilafquen-Malacahuello" because the project did not have final consent for its hydraulic works from the Chilean Water Authority ("**DGA**"). This decision is relevant because the estimate is that approximately 97% of the reservoirs destined for the generation of electricity do not have such consent, which takes several months to obtain (6 to 18 months). It should be noted that such process before DGA can only be done once the relevant facilities are finished, which means that hydroelectric generators should consider this in the financial planning and modelling of their projects.
- "*Asociación Indígena Koñintu Lafken-Mapu Penco v. Serv. de Evaluación Ambiental Reg. Bio Bio y Comisión de Evaluación Ambiental Reg. Bio Bio*" (Supreme Court of Chile, Index No. 35,649-2016): On January 30, 2017 the Supreme Court of Chile revoked the environmental approval (RCA) of the Penco-Lirquén offshore LNG regasification terminal (including a FSRU terminal) planned to be located in the central-southern part of Chile (Region VIII) and expected to be operational by 2019. The decision provided relief to a complaint filed by an indigenous association based on alleged procedural violations incurred by the environmental assessment authorities during the indigenous consultation phase of the environmental assessment proceeding.

Major events or developments

- In November 2017, through a 600-kilometre transmission line owned by Transmisora Eléctrica del Norte S.A., the Mejillones substation (located in the former Northern Power Grid known as the SING) and the Cardones substation (located in the former Central Power Grid known as the SIC) were interconnected, thereby creating the National Electric System, which provides energy to 97% (approximately) of the national population. This is the most important milestone in the interconnection plan of the former two interconnected systems, which still anticipates that the construction and/or reinforcement of additional transmission facilities will be operational by 2019.
- In June 2018, Chile and Argentina, through ENAP and IEASA, entered into a framework agreement for the exchange of energy, which will allow Chile to export, during the next three years, up to three million cubic meters of LNG to Argentina.

Proposals for changes in laws or regulations

Even though the Chilean government has not sent any bills to Congress yet, the Energy Route 2018-2022 considers many amendments to Chilean electricity laws and regulations, including:

1. Modernisation of the distribution segment. The main changes that are being discussed in this regard are: (i) the change from a 'radial grid' (that is, energy flowing from generators to consumers) to a 'meshed grid' (that is, with bi-directional flows), in response to the growth experienced by distributed generation (including PMGDs); (ii) changes to the tariff mechanisms in order to create incentives for distribution companies to focus on the quality of the service; (iii) reinforcement of the role that the Expert Panel plays in the distribution segment; (iv) creation of a new segment in the electricity market: the commercialisation segment; and (v) more stringent requirements for PMGDs to be able to operate under the stabilised price regime.
2. Amendments to the Law No. 20,571 regarding residential generation, aiming to create incentives for people to inject the surplus from their residential generation to the grid and to enlarge the universe of generators that may be entitled to reduce their electricity bills, by increasing the cap of capacity thereto from 100 kW to 300 kW.
3. Reinforcement and modernisation of the SEC. No hints on the scope of the amendments have been anticipated. According to the announcement, the idea is to reinforce the control and sanctions that the SEC may impose, and the modernisation of the procedures carried out before the SEC (e.g. electrical concessions).
4. Law regarding climate change. Even though this project is at a very early stage, the government has declared that the main goals proposed in relation to this matter are: (i) a reduction in the emission of greenhouse gases, which includes amendments in the energy mix aligned to the decarbonisation of the energy matrix; and (ii) the establishment of climate institutions which are intended to be subject to the control and dependence of the Ministry of Environment together with the Ministry of Energy.
5. Hydrocarbons Law. At this time there are several laws and regulations referring to hydrocarbons, but there is no systematic regulatory body that addresses these matters in a consistent and cohesive way as there is in the electricity market. The proposal is to create such a regulatory body, including centralised entities to monitor and rule the hydrocarbons market, in order to avoid the exhaustive (and in some cases, contradictory) regulations in this regard. However, as of this date only the announcement has been made, but there are no hints on the contents of such a law.

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China

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Overview of the current energy mix, and the place in the market of different energy sources

There have been significant changes in the Chinese energy and resources market in recent years. The supply and consumption of different energy sources have undergone different development.

Energy production

In the Chinese market, the system of energy supply is now relatively well balanced, covering coal, electricity, oil, natural gas, new energy, renewable energy and other mature energy products.

Over the past few decades, the total amount of energy production has presented a continuous growth trend. Among the energy resources, fossil fuels dominate China's energy supply.

Initially, according to data on energy production published by the National Energy Administration (NEA), there was an upward trend in the production of coal during the past ten years. According to the *China Energy Big Data Report* (2018), the production of standard coal in 2017 was 3.59 billion tons, and it is reported by the National Bureau of Statistics (NBS) that there was a steady increase in the first quarter of 2018. As for natural gas, though its production accounts for a relatively small proportion, it shows a steady upward trend. By contrast, as the second-largest source of traditional energy supply in China, oil production experienced a gradual decrease in the same period.

As for non-fossil energy sources, the shares of hydropower, nuclear power, wind power and other renewables continues to grow. Generally speaking, there is a developing trend of the proportion of clean energy supply, and the production of natural gas, hydropower, nuclear power and wind power accounts for nearly one fifth of the whole market supply.

Energy consumption

Since China is a developing country, the growth of national economics still relies greatly on energy, and *vice versa*. Influenced by the persistent improvement of the macro-economy, weather and government policies, energy consumption has been growing rapidly in the past two years in China.

China's total energy consumption takes the lead in the world. According to the *BP World Energy Statistics Yearbook* (2017), China became the world's largest energy consumer in 2016, accounting for nearly a quarter of global energy consumption. In the past 12 months, the increasing trend continues.

Similar to the supply of energy, coal consumption ranks first but shows a downward trend. Natural gas, water, nuclear, wind, solar and other clean energy consumption accounted for more than 20% of the total amount, and showed an upward trend.

In terms of international energy trade, as a major energy consumer, China is usually the buyer. From the statistics by NBS, the imports of coal, oil and natural gas have been growing steadily, and are far greater than exports. Only in the first quarter of 2018, the imports of coal reached 75.41 million tons, oil 110 million tons, and natural gas 20.62 million tons. Both the growth amount and growth speed are over the same period in the previous year.

Overall, traditional energy sources still occupy the lion's share of the market, but show a gentle downward trend. The Chinese government had hoped to narrow the gap with international standards by adjusting the energy mix and developing clean and low-carbon energies. Consequently, the government published and implemented a series of energy policies such as the *13th Five-Year Plan of Energy Technology Innovation,* which obviously will promote the development of clean energies and reduce the proportion of traditional energy gradually. In this regard, it is convinced that China will pay more attention to increasing the proportion of renewable energy in the future, and a great shift of the energy mix may take place in China in the next decade.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

<u>Overproduction of coal-based electricity</u>

In its *Research Report on the Overcapacity of Coal-based Power and the Shortage of Water Resources in China,* Greenpeace in Beijing has stated that the growth rate of electricity consumption in China remained slow in the past few years, and average utilisation hours of power equipment have been decreasing year by year. Traditional industries are still the main contributor to electricity consumption as well as its increment. However, with the decline of the proportion of old kinetic energy, electricity production is gradually becoming less dependent on coal power. The rapid development of renewable energy and ultra-high voltage power grids has brought about multiple choices of power. As a consequence, building coal-fired power stations is no longer the only way to satisfy the growing demand for electricity. In addition, the State government keeps upgrading and adjusting the industrial structure, which has also caused coal-based electricity to become redundant.

In 2016, along with the rebalancing of supply and demand in the national coal market, coal prices rose, which stimulated plenty of sealed coal mines back to work, and the risk of coal mine accidents has therefore increased. To stop this trend, the government has issued a series of policies since mid-2016 aimed at resolving the overcapacity of coal-based electricity as well as promoting the development of efficient and clean coal power. It is anticipated that controlling the scale of coal-fired power station construction will remain one of the focuses of the government's energy policy. However, we do believe that if the external cost of coal fails to transfer into internal cost of the coal enterprises, it will be rather difficult for the government to control the production and consumption of coal by administrative methods alone.

Developments in government policy/strategy/approach

<u>Enhancing international cooperation in the Belt and Road Initiative</u>

Since 2015, China has been making a big push on its 'Belt and Road' Initiative, a development strategy aimed at interconnecting overland infrastructure corridors with sea route corridors around the world. Cooperation along the Belt and Road has had a profound impact on the energy industry of China.

In terms of international oil cooperation, in accordance with the *World Energy Bluebook: World Energy Development Report* (2018), imports of oil from countries along the Belt and Road account for the large majority of China's total oil imports (76%). In natural gas cooperation, countries along the Belt and Road provided 72% of the import demand of China, which has made these countries important partners of China in international energy trade. As is well known, energy supply is of great importance to a developing country, because a shortage of energy may slow down the process of industrialisation. In this regard, the Belt and Road cooperation is making a great contribution to China's economic and social development. Pipelines play a vital role in satisfying China's demand for energy, especially the three important natural gas pipelines of China–Central Asia, China–Russia and China–Myanmar. In addition to international energy trade, energy cooperation between China and the countries along the Belt and Road includes oil pipeline construction, oil field production, liquefied natural gas projects, and so on.

This is a win-win cooperation. On the one hand, countries along the Belt and Road only contribute 20% of the world's GDP, but possess 44% of the world's total resources. On the other hand, low GDP means great potential for development, and China has enormous demand for oil and gas. Though China possesses abundant domestic oil and gas resources, its geological conditions are too complicated to increase the production and storage of energy and therefore, high dependence on energy imports remains unresolved. Consequently, we believe that the energy investment of Belt and Road will remain one of the main energy policies of China, and it may be expected that China will reinforce its bilateral and multilateral energy cooperation with other countries in the next few years.

Progressing the energy mix adjustment

The Chinese government has announced that the target of China is to develop a "Clean, Low-carbon, Safe and Efficient" energy system in 2017.

In January 2018, the *Notice of the National Energy Administration on the Issuance of Guidelines for Energy Work in 2018* issued by NEA declared that the specific objectives of energy development in 2018 are as follows: reducing non-clean energy consumption and increasing the proportion of non-fossil energy consumption; increasing the total energy supply and the proportion of non-fossil energy production; improving the efficiency of energy; and reducing the energy consumption of domestic production. Meanwhile, the development of a clean energy industry is being encouraged, as well as the construction of nuclear power, wind power and solar power projects. The development and utilisation of new energy sources such as biomass energy are also being supported.

To enhance the clean and efficient development of coal-fired power, NEA issued the *Notice on the Target Task of Super-low Emission and Energy-saving Reform of Coal-fired Power in 2018*. Relevant enterprises are required to carry on their improvement of techniques and equipment so as to lessen the pollution of coal-based power and energy consumption of power production. Additionally, all the emissions of coal-fired machines and energy consumption should comply with national standards. In light of various development levels, this Notice also sets different targets for different regions. Enterprises in the central region are required to reach the standard by 2018 while enterprises in the western region are encouraged to hit the target by 2020. Coal-fired machines which fail to fulfil the standard will be eliminated and eventually closed down.

Apart from updating the equipment and techniques, boosting the natural gas industry is also one of energy policies in China. Natural gas is a high-quality, efficient, green and clean energy with low carbon emissions. China always pays great attention to the exploitation and utilisation of natural gas. In August 2018, *Several Opinions on Promoting the Coordinated and Stable Development of Natural Gas* was issued by the State Council, aiming to encourage and guide the development of the domestic natural gas industry. A key point is to improve natural gas production by encouraging domestic exploration and investing in construction projects for natural gas base installations. Furthermore, modifying the pricing rules regularly, to ensure the stability of the energy market, is also meaningful for the development of natural gas.

Similarly, in connection with the adjustment of the energy mix, the *Notice of the State Council on the Issuance of the Three-Year Action Plan for Protecting the Blue Sky* was published in June 2018. It presents work plans in relation to promoting clean-energy heating, controlling the total control of coal consumption, improving energy efficiency, and accelerating the development of clean energy and new energy.

<u>Promoting the reform of energy enterprises</u>

Energy enterprises carry a lot of weight in the energy reform. Therefore, there is no doubt that the government will pay attention to energy enterprises, giving supervision and guidance on their development.

At the end of 2017, the State Development and Reform Commission, the Ministry of Finance and other 10 departments jointly issued the *Opinions on Further Promoting the Sufficient Transformation and Upgrading of Coal Enterprise Mergers and Acquisitions*. The main purpose of this document was to support mergers and reorganisations among qualified coal enterprises, thereby reducing the number of medium and low-level coal mines, enriching the types of coal products, upgrading the scale of enterprises and creating new operational modes. It is expected that the competitiveness of coal enterprises will be improved through such mergers and reorganisations.

In August 2018, the State Development and Reform Commission and NEA issued the *Notice on Promoting the Standardization of Electricity Trading Institutions*. Since the electric power industry was a monopoly industry in China, the pricing and operation of electricity enterprises are not transparent enough. The aim of this document is to gear up the reform of electricity enterprises and push them to provide standardised and transparent electricity services for consumers.

Developments in legislation or regulation

<u>Enforcement of Nuclear Safety Law</u>

The PRC Nuclear Safety Law of 2018 was enacted for the purposes of guaranteeing nuclear safety, preventing and responding to nuclear accidents, safely using nuclear energy, protecting the safety and health of the general public and workers, protecting the environment, and promoting sustainable economic and social development.

In accordance with the law, first of all, the entry threshold of nuclear facilities operators is relatively high. Nuclear facilities operators are required to have the capability to deal with emergencies and compensate for nuclear damage. Otherwise, the regulator will not approve or issue operating licences to nuclear facilities. Second of all, nuclear facilities operators shall take full responsibility for nuclear safety. Except for wars, armed conflicts, riots and other similar situations, the nuclear facility operator shall be liable for any nuclear accidents and bear the liability of compensation, no matter whether the operator is at fault or not.

Under the PRC Nuclear Safety Law, competent administration departments will supervise on nuclear safety and impose a penalty on those violating this law. The Law also emphasises the manner of nuclear information disclosure and the importance of participation rights of the public. For those major nuclear safety matters impacting public interests, both the government and nuclear facility operating entity shall solicit the opinions of interested parties by holding hearings, discussion meetings, symposia or any other means, and provide feedback in an appropriate form.

Implementation of the PRC Environmental Protection Tax Law and its implementation regulation

The PRC Environmental Protection Tax Law and relevant implementation regulations, which are deemed as the first green tax revenue law, became formally effective from the first day of January in 2018. In accordance with this law, enterprises, public institutions and other producers and operators shall pay environmental pollution tax for producing air pollutants, water pollutants, solid wastes and noise to the environment. The implementation of this law also means that the pollutant discharge fees which had been collected for 38 years are replaced.

The implementation of the environmental protection tax will increase the tax on energy enterprises. However, it will promote technological innovation in energy production and the development of clean energy, which will also accelerate the clean transformation of coal-fired power enterprises.

Amendments of other environment protection laws and regulations

The PRC Marine Environment Protection Law was partially amended at the end of 2017. After amendment, the compensation liability for marine environmental pollution accidents is much stricter. Based on the latest provisions, the penalty for minor or general marine environmental pollution accidents amounts to 20% of direct losses, whilst for major accidents, the penalty will be 30% of the direct loss. Whoever causes serious pollution to the marine environment, or destruction of marine ecology, shall be subject to criminal liability in accordance with the law if a crime is constituted.

The PRC Soil Pollution Prevention and Control Law was issued in August 2018 and will become effective on the first day of 2019. In accordance with this law, land users engaging in activities to develop and utilise land and enterprises, public institutions, and other producers and operators, must take effective measures to prevent or diminish soil pollution and be liable for soil pollution caused. If soil pollution causes damage to the person or property of a person, tort liability shall be assumed as well as penalisation by an administrative department. If there are any civil disputes as a result of soil pollution, the party involved may apply to the ecological and environmental department or any other competent department of local government for mediation, or bring action in the People's Court.

For the energy industry, coal-fired production, construction and operation of nuclear power plant, and the exploration and development of oil, may produce pollutants to the environment. Actually, the excessive exploitation and usage of traditional energies have resulted in serious environmental pollution in China. Under this circumstance, a series of laws on environment protection are issued. The implementation of these laws will force energy enterprises to pay attention to the pollutants they have produced. If they fail to reduce pollution, they shall assume legal responsibilities which could even lead to their inability to survive. On the other hand, they could become the most competitive enterprises in the energy industry if they can improve their technical innovation capabilities and develop clean and low-carbon energy.

Provisions related to Foreign Direct Investment's access to the energy industry

The Special Management Measures (Negative List) for the Access of Foreign Investment (2018) was effective from July 28, 2018, which includes restrictions on energy industry investment by foreign investors. In accordance with the Negative List, foreign investors shall enter into joint ventures with Chinese enterprises if they decide to invest in oil and gas exploration and development.

For the industries of electricity, heat and gas, there are also restrictions in the Negative List. Foreign-invested enterprises may enter into joint ventures with Chinese enterprises to contribute or operate nuclear power plant or gas, heat and water supply systems. But these joint ventures shall be controlled by Chinese enterprises.

Judicial decisions, court judgments, results of public enquiries

Monopoly pricing agreement of direct electricity

In August 2017, the State Development and Reform Commission issued a penalty decision which imposed a fine of over RMB 70 million on 23 enterprises and the Shanxi Electric Power Industry Association. This penalty decision was based on a monopoly pricing agreement for direct electricity entered into and implemented by electricity company and plants, including six state-owned enterprises.

In 2016, the Shanxi Electric Power Industry Association convened a meeting in regard to the direct power supply for large companies, with eight electricity company groups and 15 power plants. During this meeting, they reached an agreement and signed the *Convention on Prevention of Malicious Competition and Protection of the Health and Sustainable Development of the Industry*, stipulating a pricing rule in direct electricity transactions. It was agreed that they would agree to conform the lowest price according to the cost of electricity production and a small profit. In this regard, these enterprises could avoid suffering serious loss in the competition.

The relevant administrative departments opined that 23 electricity enterprises organised by Shanxi Electricity Industry Association had managed to control the transaction price of direct electricity through the monopoly agreement, which was in violation of the provisions of the Anti-monopoly Law. This move also broke the fair competition rule in the energy market, increasing the burden of downstream entities as well as damaging the interests of customers, which was obviously against China's energy strategy. Afterwards, at the request of the relevant departments, the enterprises involved made timely rectification in accordance with the laws and regulations.

This case gives warning to all energy enterprises that buyers and sellers of energy transactions shall determine the price of energy products fairly according to the market, so that a fair, competitive, market environment can be maintained.

At present, there is a relatively high access threshold for energy enterprises in the aspects of technique and money. Thus, the number of energy enterprises is relatively small, and the competition among enterprises is less than other industries. In case these energy enterprises "cooperate" with each other and stop competition, the interests and rights of consumers will be seriously damaged. For this reason, the relevant government departments seek to to strengthen anti-monopoly supervision of the energy industry, and punish those enterprises which break the competition rules.

<u>A pollution case caused by offshore oil operations</u>

In 2011, a major marine oil spill pollution occurred in Penglai 19-3 oilfield in the Bohai Sea, resulting in the pollution of about 6,200 square kilometres of sea water around the oilfield. The Joint Investigation Group of seven administrative organs, including the National Oceanic Administration, held the opinion that ConocoPhillips, as the operator, should be held fully responsible for the accident. After consultation of the relevant departments, China National Offshore Oil Corporation (CNOOC) and ConocoPhillips, ConocoPhillips paid RMB 1 billion for compensation, of which RMB 731.5 million was used to compensate fishermen in polluted areas for their breeding losses. Additionally, ConocoPhillips paid another RMB 1.683 billion for the marine ecological damage. The local government made a compensation standard, and most of the local aquaculture right-holders accepted it and received compensation in accordance with the standard. However, there were 21 fishermen who did not accept administrative mediation and brought a suit against ConocoPhillips in Tianjin Maritime Court. The core contentious issues of this case are the pollution level and the amount of loss caused by 21 oil spill accidents.

After the first instance and the retrial in China, the Supreme Court upheld the verdict in April 2017, maintaining the judgment of the first instance.

The Tianjin Maritime Court hearing the first instance takes the view that, according to evidences in this case, the oil spill accident did cause pollution damage to the plaintiffs and ConocoPhillips should pay for it. However, as CNOOC was not the operator of the oil field at the time of the accident, nor did it control the source of pollution, it should not be liable for compensation. In this case, the burden of proof on the extent and amount of loss belonged to the plaintiff, wherein they failed to give enough proof which could support their claims. Without the Qualification Certificate for the Investigation and Identification of Fishery Pollution Accidents issued by the Fishery Administration and Fishing Port Administration of the Ministry of Agriculture, the company is not qualified to conduct the appraisal.

As a result, the validity of the Technical Advisory Report issued by the appraisal company was not accepted by the court. In view of the fact that the conditions for assessing and appraising the loss of the plaintiff were no longer available during the trial, the pollution degree and the amount of loss should be determined comprehensively in combination with the relevant evidence and facts of the case. Combined with the relevant evidence and the facts of the case, and referring to the compensation standard determined by the local government, Tianjin Maritime Court decided that ConocoPhillips should pay the plaintiffs for their loss of RMB 1,683,464.40. The plaintiffs refused to accept the judgment and appealed, which appeal, however, was dismissed by the Tianjin High Court.

From the legal point of view, the fishermens' right of action will not be divested due to the conclusion of an agreement between the Chinese government (theoretically representing Chinese fishermen) and ConocoPhillips on compensation for fishery losses. But once a fisherman files the suit, in accordance with Chinese law, he/she should bear the burden of proof for the claim. In this case, in light of the fact that the plaintiffs failed to fully prove the extent and amount of the losses they had suffered in the accident, they had to bear the negative consequences of it. Consequently, the court adopted the compensation standard determined by the Chinese government and ConocoPhillips, the amount of which compensation supported by the court was much lower than the plaintiffs' claim.

In addition, in regard to the low fines (no more than RMB 300,000) in the ConocoPhillips oil spill case, China had already modified the relevant articles in the Marine Environmental

Protection Law in 2016. In accordance with the newly revised Marine Environmental Protection Law, the maximum penalty for a marine environmental pollution accident can be up to 30% of the direct losses; if a crime is committed, criminal responsibility shall also be investigated in accordance with laws.

Major events or developments

Electricity power construction accidents

There have been more than 50 power electricity power construction accidents and 62 deaths in the last year, according to a report by NEA. Among these accidents, two major accidents which resulted in personal injuries and deaths, as well as great property damage, were the consequence of the collapse of an electricity tower in a transmission line which was under construction.

In order to reduce frequent accidents, ensure the safe and stable operation of the power system and cut down the number of accidents and losses, NEA issued the *Primary Work Arrangement for Electricity Power Construction Safety* in 2018. For electricity companies, it is required that they should take full responsibility for construction accidents, and ensure construction safety. Strengthening the ability to deal with emergencies is also necessary. On the other hand, the relevant government departments are required to keep an eye on the companies and provide efficient support for emergencies.

Explosion of a natural gas pipeline

In June 2018, an explosion occurred at Jiangbaying in Sanhe Village, Qinglong Shazi Town, Guizhou Province. This accident caused 24 injuries, nine of them serious. It is still under investigation by the relevant authorities. It is shocking that the same kind of accident resulted from a pipeline leakage at the same place and during the same period last year, which killed eight persons and injured 35. It was believed that a mudslide and falling rocks, brought on by continuous heavy rainfall, dislodged and fractured the gas pipeline. As a result, the gas leaked and the pipeline finally exploded.

This oil and gas pipeline, located in the southwest region of China, is significant for China's energy supply. Its explosions drew great attention from the government. For the purpose of avoiding similar accidents, in the last year, the relevant departments have made detailed provisions for the patrol and maintenance of natural gas pipelines. Nevertheless, it seems that the provisions didn't work, as another accident happened again within 12 months. It reveals the neglect of the duty of gas pipeline maintenance by the companies. In addition to making provisions, the government now imposes heavy fines on companies in order to force them to focus on maintenance of pipelines.

Proposals for changes in laws or regulations

Legislation of the Energy Law of PRC

As mentioned above, in the past year, China has made great progress in legislation for the energy industry, but it still has a long way to go. The draft of the Energy Law, as one of the most important laws in the energy industry, has been published for public comment in 2008, but it has not yet been finalised or implemented for various reasons. The draft of the Energy Law has been revised continuously in the past 10 years, due to adjustment of the industrial structure of China and problems that need to be resolved urgently.

The latest draft of the Energy Law will specify that the purpose of legislation is to optimise the energy mix, enhance energy efficiency and safeguard energy safety, according to one of the legal professionals who is responsible for introducing the laws. In addition, the Energy Law will cover the relationship in several aspects, including the energy administration's relationship with government agencies, and the business relationship based on the production and the cooperation relationship with foreign partners. In this draft, it is proposed to set up 10 basic legal systems including a state ownership system, energy safety safeguard system, international cooperation system, etc.

Perfecting the existing regulations

In addition to making the Energy Law, the government may also legislate, amend or even rescind some existing regulations in the energy industry in order to accommodate the continuous changes to the energy mix in China. In terms of oil and gas, making relevant regulations to resolve the participation of domestic private companies in the exploitation of oil and gas will be put on the agenda. At the moment, there are almost 15 kinds of taxes together with six kinds of fees imposed on companies operating in the oil industry, which leads to high market prices.

In these circumstances, to optimise tax policy and structure in the energy industry is a key focus of legislative departments of the Chinese government. In addition, even though the National Energy Administration (NEA) has been established for years, the supervision and administration of coal, oil, gas and electricity has not yet been centralised in NEA. This makes it difficult to reform the legislation, or the legal system of the energy industry, because the interests of different departments have to be reconciled.

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Kehua has experience with a broad range of matters involving M&A and foreign direct investment. In 2017, Kehua acted on behalf of several Chinese companies to make outbound investments in South Africa and Italy, to acquire local companies in the energy industry. And in the past few years, Kehua has assisted his clients to participate in some onshore and offshore new energy projects. Kehua is also very experienced in litigation and arbitration, and relies on his in-depth insight into foreign-related dispute resolution, to help clients navigate complex Chinese juridical procedures and safeguard their reputation. His clients include Iwatani, CNOOC, etc.

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Sizhe is practised in the area of corporate law, foreign investment, international trading and labour law, and is experienced in litigation and commercial arbitration. Sizhe has specialised in corporate law and handled a number of corporate law cases, and has been frequently invited to provide legal opinion on corporate law issues, including corporate governance, compliance and risk control, M&A, corporate restructuring, corporate management, a feasibility study on new business models, due diligence, foreign investment and labour issues. Mr. Huang Sizhe has also many times assisted clients to negotiate with business counterparties, authorities and employees on behalf of clients.

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Cyprus

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Overview

Cyprus is not currently producing any primary sources of energy (other than renewables). It is considered a heavily energy-receiving country, as over 90% 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 90% to the country's gross final energy consumption. In relation to electricity generation itself, approximately 91.6% of it is produced from imported petroleum products. The European Commission has ranked Cyprus as one of the most vulnerable countries in the EU in terms of energy dependency and security of energy supply. The import of petroleum products accounts for approximately 30% of all the country's imports, which is a heavy burden on its balance of payments and reveals its vulnerability to potential macroeconomic imbalances.

Since petroleum products dominate the country's gross final energy consumption, other sources of energy contribute only marginally to the country's energy mix. According to the Energy Service of the Ministry of Energy, Commerce Industry and Tourism, in 2013, renewable energy sources ("**RES**") had, at the time, a share of just over 8% to the country's gross final energy consumption. RES, which are now more significant to the country's energy mix than they used to be five or ten years ago, are used as follows:

1. *Solar energy*: Solar energy is used by domestic and industrial solar thermal systems. It should be noted that Cyprus ranks second in the world in terms of solar water heating collector capacity *per capita*. Photovoltaic grids are also used, and they are either connected to the country's (currently) sole electricity company, or are stand-alone and used in other ways.
2. *Wind energy*: There are currently six wind farms in operation with 157.5 MW installed capacity and they all generate electricity which they sell in its totality to the country's (currently) sole electricity company. Wind energy is also used through wind turbines for water pumping.
3. *Biomass*: The total capacity of biomass plants is insignificant, generated through manure/organic animal waste and, again, sold to the country's (currently) sole electricity company.

In relation to the electricity market of Cyprus, this is currently dominated by the state-owned Electricity Authority of Cyprus (the "**EAC**"), which is the sole generator and supplier of electricity. According to the Cyprus Transmission System Operator of Electrical Energy (the "**TSO**"), around 91.6% of electricity is produced from imported petroleum products, and only around 8.4% from the RES that are mentioned above. Natural gas will be a significant source for production of electricity in the next few years, as will be discussed further in this chapter.

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 for certain non-domestic consumers. In 2009, the electricity market was fully opened in relation to all non-domestic consumers, with a view to 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 generator and supplier of electricity, thereby enjoying a *de facto* monopoly. It should be noted that there have been discussions regarding the denationalisation of the EAC, but there seems to be a low possibility that this will happen any time soon.

Even if Cyprus does not currently produce any primary sources of energy, this is likely to change soon, as it discovered large natural gas reserves in its exclusive economic zone ("**EEZ**") in December 2011. This has been the most significant development in the energy history of Cyprus, and its overall energy policy has been changing rapidly over the last few years due to this. The natural gas discoveries have paved the way for the transition of Cyprus from an energy-receiving country to an energy producer, and potentially exporter.

Changes in the energy situation, the legal regime and government policy

<u>Oil and gas exploration – Legal background</u>

In order to be able to outline the developments in the oil and gas sector, one needs to understand the legal regime behind this.

As a full member of the EU since 2004, Cyprus has to fully comply with EU law. The Regulation on the Jurisdiction and the Recognition and Enforcement of Judgments in Civil and Commercial Matters is directly applicable to Cyprus as an EU Member State. Cyprus is also a member of the New York Convention; it has an excellent network of double tax treaties and bilateral investment treaties, and a very favourable tax system, with its corporation tax rate being the lowest in the eurozone (12.5%).

The legislative regime of Cyprus in relation to hydrocarbons is based on the country's obligations derived under both EU and international law. Cyprus is a party to the United Nations Convention on the Law of the Sea ("**UNCLOS**") which, amongst others, outlines the rights and responsibilities of states in their use of the world's oceans, establishing guidelines for businesses and regulating the territorial waters, contiguous zones and EEZ of states. Cyprus ratified UNCLOS in 1988, and it passed a law defining and regulating its EEZ in 2004. Part of the EEZ of Cyprus is an exploration area of 51,000 square kilometres in the south of the island, which is divided into 13 offshore exploration blocks. The jurisdiction of Cyprus within its EEZ relates to: the exploration, utilisation and management of all natural resources; the waters, the seabed and the soil under the seabed; the production of energy; the utilisation of man-made islands, installations and structures; scientific research; and the protection of the environment.

Agreements on the delimitation of the EEZ of Cyprus exist between Cyprus and respectively Egypt, Lebanon and Israel in relation to the south and south-east of the country. The agreement with Egypt has been ratified and is in force; the agreement with Lebanon has yet to be ratified; and the agreement with Israel has been ratified and is in force (although disputed by Lebanon in relation to the involvement of Israel).

Hydrocarbon exploration and exploitation activities in Cyprus are subject to the Hydrocarbons Law (of 2007 to 2015) and Regulations (of 2007, 2009 and 2014), which were enacted to transpose into national law the EU Directive on the Conditions for Granting and Using Authorisations for the Exploration and Production of Hydrocarbons. Relevant sections of the Hydrocarbons Law stipulate that the ownership of hydrocarbons wherever they are found in Cyprus, including the territorial waters, the continental shelf and the EEZ of the Republic of Cyprus, shall be deemed to be and always to have been vested in the Republic. The powers to determine, within the territory of the Republic and the relevant offshore zones, the areas to be made available for prospecting, exploring for and exploiting hydrocarbons, and to grant authorisations for the prospection and/or exploration and/or exploitation of hydrocarbons in a geographical area, after due process set out in the Hydrocarbons Law, rest with the Council of Ministers.

The Hydrocarbons Law and Regulations set out the criteria for the valuation of the licence applications and provide for three types of licence/authorisation. A prospecting licence is valid for a maximum of one year and involves evaluation of potential by identifying geophysical techniques, and evaluation of offshore potential by carrying out geophysical surveys such as 2D/3D seismic surveys. Prospecting licences do not allow drilling. An exploration licence is granted initially for up to three years, and can be renewed twice for a period of two years for each renewal, providing for a maximum of a seven-year licence. Upon each renewal, 25% of the initial licence area is relinquished. The licensee is permitted to carry out gravity and magnetic surveys, as well as 2D/3D seismic surveys and exploratory drilling. In case of a discovery, the holder has the right to be granted an exploitation licence for that discovery. An exploitation licence is granted for an initial period of up to 25 years, with the possibility for one renewal of up to 10 years. Conditions and requirements contained in the authorisation for exploration or exploitation are stated explicitly in a production-sharing contract ("**PSC**") between the state and the licence holder. An applicant for an exploration licence must carry out an environmental impact assessment, and has several environmental obligations under international and local law upon being granted a licence.

What is notable in relation to the Hydrocarbons Law is its transfer and change-of-control provisions in relation to rights granted under, or deriving from, a licence. In accordance with section 27 of the Hydrocarbons Law, no holder of an authorisation (meaning any type of licence) may transfer an authorisation or assign the rights arising from an authorisation to another entity, except with the consent of the Council of Ministers. The Council of Ministers may grant such consent: (i) if the transfer or assignment does not endanger national security; (ii) if the entity to whom the authorisation is to be transferred, or the rights arising from an authorisation are to be assigned, has sufficient technical knowledge, experience and financial resources to secure the proper exercise of the activities of prospecting, exploring for and exploiting hydrocarbons; and (iii) if such entity undertakes to comply with such other conditions and requirements as the Council of Ministers may deem proper to impose. In accordance with section 28 of the Hydrocarbons Law, no entity may, after the grant of an authorisation thereto, come under the direct or indirect control of a third country, or a national of a third country, without the prior approval of the Council of Ministers.

<u>Oil & gas exploration – Developments</u>

Once Cyprus had defined its EEZ in 2004 and divided the south of the island into 13 offshore exploration blocks, it announced its first licensing round on 5th February 2007. The first licensing round related solely to Block 12, which is located next to the Israeli Leviathan gas field. Houston-based Noble Energy was awarded a three-year exploration licence and a PSC was signed in October 2008. Noble Energy started drilling in September 2011 and announced, in December 2011, that it had discovered a natural gas reservoir ranging from five to eight trillion cubic feet.

The Cyprus government approved the launch of a second licensing round consisting of the remaining 12 offshore blocks (covering an average area of approximately 4,000 square kilometres each). The public announcement was made on 11th February 2012 and expired after a three-month bidding period, on 11th May 2012. Fifteen bids were submitted from five companies and ten consortia, for nine of the 12 blocks. On 30th October 2012 the government announced that it had reached a decision to award Blocks 2, 3, 9 and 11, which are contiguous blocks (lying north and north-east) to Block 12. Blocks 2 and 3 were to be awarded to a consortium consisting of Italy's ENI (80%) and South Korea's KOGAS (20%). Block 9 was to be awarded to a consortium consisting of France's Total (operator), Novatec Overseas Exploration & Production (of Russia) and GPB Global Resources (again of Russia). Block 11 was to be awarded to Total. Despite the above announcement, negotiations in relation to Block 9 (which was thought at the time to be the richest block in natural gas) did not proceed as expected. The government announced on 24th January 2013 that three PSCs had been signed with the ENI and KOGAS consortium in relation to Blocks 2, 3 and 9 (with ENI being the operator). On 6th February 2013 the government further announced that it had signed two PSCs with Total in relation to Blocks 10 and 11. In relation to the signing of PSCs, it should be noted that the Cyprus government had published a model PSC to form the basis of negotiations with successful bidders for its offshore blocks in relation to the second licensing round.

In relation to Block 12, on 11th February 2013, Noble Energy transferred/assigned 30% of its rights in the PSC to Israel's Delek Drilling and Anver Oil and Gas Exploration, which are both subsidiaries of Delek Energy Systems Ltd. In 2016 it further proceeded with transferring/assigning 35% of its rights in the PSC to BG (now owned by Anglo-Dutch Royal Dutch Shell), which resulted (presumably) in certain amendments to the PSC being agreed with the Cyprus government. The rights under the relevant PSC are now held by Noble Energy at 35%, by BG at 35%, and by Delek Drilling and Anver Oil at 15% each. Noble Energy remains the operator.

The drilling of a second appraisal well in Block 12 was completed in October 2013 in order to further evaluate the findings of the 2011 natural gas discovery. The appraisal work confirmed a mean gross natural gas resource of 4.5 trillion cubic feet, in relation to the Aphrodite field. In June 2015, the Ministry of Energy, Commerce, Industry and Tourism announced that Noble Energy, Delek Drilling and Anver Oil, had declared the Aphrodite field to be commercially viable, and the parties to the relevant PSC have now relinquished Block 12 – with, obviously, the exception of the Aphrodite field. The commerciality declaration is a significant milestone to the transition of Cyprus from the hydrocarbons exploration phase to that of exploitation. The consortium has submitted to the Cyprus government a development and production plan in relation to the Aphrodite field and they are currently assessing regional market options for monetising Aphrodite gas.

In relation to Block 9, after conducting two exploratory drills, the ENI and KOGAS consortium failed to identify any exploitable amounts of natural gas. A request to extend its exploration licence was submitted by the consortium to the government in relation to all its blocks, i.e. Blocks 2, 3 and 9. The consortium's exploration licence has now been renewed for two more years, i.e. expiring within 2018.

In relation to Block 11, an agreement was signed in March 2015 in relation to further exploration works in order for Total to further assess the exploitability of Block 11, but with 25% of the block having already been relinquished. In April 2017, Total farmed-out 50% of its rights in Block 11 to ENI, with Total remaining as the operator. On 12th July 2017 it was announced that the Total and ENI consortium had found certain amounts of natural resources at the Onesiphoros West 1 well, but that such amounts were not enough for a standalone commercial development. Despite that, the new findings raise the prospects regarding the geological structures of similar fields and blocks around the Onesiphoros West 1 well.

As far as the remaining blocks are concerned, no licences had been awarded during the second licensing round and the Cyprus government proceeded with the third licensing round for offshore exploration of Blocks 6, 8 and 10, which are carbonate reservoirs similar to the Zohr discovery in Egypt and different to the Aphrodite field in Block 12. Even though Block 10 was previously awarded to Total, the company relinquished the block in 2015 without drilling any wells, hence the Cyprus government proceeded to include this block in the third licensing round.

As far as the third licensing round is concerned, the Cyprus government announced on 27th July 2016 that it had received the following applications: (1) with respect to Block 6, one application from a consortium (50/50) consisting of ENI (as the operator) and Total; (2) with respect to Block 8, two applications, one from a consortium consisting of Capricorn Oil (as the operator), Delek Drilling and Anver Oil Exploration, and one from ENI; and (3) with respect to Block 10, three applications, one from a consortium consisting of ENI (as the operator) and Total, one from a consortium consisting of ExxonMobil (as the operator) and Qatar Petroleum, and one from Statoil. In relation to the signing of PSCs, it should be noted that the Cyprus government had again published a model PSC to form the basis of negotiations with successful bidders for the relevant blocks in the third licensing round.

The results of the third licensing round were announced on 21st December 2016 and respective PSCs were signed in April 2017 with successful bidders. Block 6 was awarded to the ENI and Total consortium; Block 8 was awarded to ENI; and Block 10 was awarded to the ExxonMobil and Qatar Petroleum consortium. It is reported that 12 exploration wells will be drilled in total, with respect to the three third-licensing-round blocks.

In February 2018, the ENI and Total consortium announced a preliminary natural gas discovery in Block 6, the size of which is estimated to be between 4.8 and 8.1 trillion cubic feet. The Block 6 discovery has been significant, as it is adding to the quantities of natural gas in the EEZ of Cyprus, which makes commercial exploitation easier.

Another recent development is Total's interest in acquiring a 50% stake in Block 8 (which is yet to be approved) and the same company's general interest (through speculations mainly) in broadening further its presence in the EEZ of Cyprus through acquiring a share in Block 3, which is licensed to a consortium of ENI and Kogas.

It should be noted that over the years the Cyprus government has signed several agreements in order to facilitate its cooperation with other countries in the field of oil and gas. To name a few recent ones:

- In September 2014, Cyprus signed a memorandum of understanding with Jordan which, amongst others, provides for cooperation between the two countries in exchanging information and expertise with respect to energy matters, and in assessing the possibility of exporting natural gas from Cyprus to Jordan.

- In February 2015, the Cyprus government further signed a memorandum of understanding with Egypt which, amongst others, authorises the Egyptian Natural Gas Holding Company ("**EGAS**") and CHC (as defined below) to examine technical solutions for natural gas transportation via a direct subsea pipeline from Block 12 to Egypt.
- In August 2016, Cyprus further entered into an exchange of letters with Egypt concerning the export of natural gas from Cyprus to Egypt.
- Finally, in April 2017, the respective energy ministers of Cyprus, Israel, Greece and Italy signed a joint declaration, committing to support the application for obtaining EU funding for the construction of the "EastMed" underwater pipeline for the transportation of natural gas between Cyprus and Israel to Greece, and from Greece to Italy (the "**EastMed Declaration**").

<u>Natural gas and the energy/electricity market</u>

The energy policy of Cyprus is harmonised with the energy policy of the EU. The Cyprus Energy Regulatory Authority ("**CERA**") was established pursuant to the Law on Regulating the Electricity Market of 2003, which was enacted for the harmonisation of Cyprus law with the relevant EU directive concerning common law rules for the internal market in electricity. CERA was established, aiming to open the electricity market (which has been, at least legally, fully opened since January 2014), and is the body responsible to ensure that electricity prices determined by (the current monopoly of) the EAC reflect the actual costs of the services offered with a reasonable profit.

In addition to the above, by virtue of the Law Regulating the Natural Gas Market of 2004 (which transposes another EU directive into Cyprus law) concerning common rules for the internal market in natural gas, CERA is responsible for regulating the natural gas market. The TSO was again established pursuant to a decision of the government of the Republic of Cyprus for harmonisation of Cyprus law with another relevant EU directive concerning common rules for the internal electricity market. The main functions and responsibilities of the TSO 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. The TSO ensures access to the transmission system of all producers and suppliers of electricity. Both CERA and the TSO have a significant role to play in the energy market of Cyprus, especially in relation to the electricity market, and their role will be even more significant if electricity companies do break into the Cyprus market in the next few years.

Even before the discovery of natural gas in the EEZ of Cyprus, the Council of Ministers decided to import natural gas for the production of (mainly) electricity. Any power station/unit of considerable capacity should be fuelled with natural gas. Despite the natural gas discoveries, according to commentary, natural gas from the EEZ of Cyprus will not be available to the Cyprus market at least until 2020 (at the earliest) and exports are not expected to commence before 2024. Cyprus therefore needs to import such natural gas if it is to use any natural gas any time soon.

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 (the "**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, amongst 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, be the sole importer and distributor of natural gas in

Cyprus, i.e. making its position a monopoly. It has to proceed with securing the necessary natural gas quantities, at the most favourable commercial terms, in order to cover the needs of Cyprus 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, which 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 €65m, and a €10m 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 €500m.

As the NGPC needs to start importing natural gas into Cyprus before the natural gas from the EEZ of Cyprus is available, it has over the years commenced procedures for expression of interest for the supply of natural gas in Cyprus, but no agreement has ever been reached. It has, however, in 2018 launched two separate tenders, one for the import of LNG (which can be a temporary matter), and one for the infrastructure for the pumping and transportation of natural gas from the vessels to the EAC reception point. The results of the tenders have yet to be released.

<u>Natural gas – what will be done with it?</u>

The above section, which deals partly with the future of natural gas in Cyprus, does not deal with what will be done with the natural gas discovered in the EEZ of Cyprus. The reserves in the EEZ of Cyprus are estimated to be more than enough to cover the national demand in natural gas for over 20 years; hence natural gas will be exported.

In 2013, Cyprus signed a memorandum of understanding with Noble Energy, Delek Drilling and Anver Oil and Gas Exploration, regarding the construction of a liquefied natural gas ("**LNG**") facility. The facility would initially process natural gas from the Aphrodite field into LNG for export and delivery to international markets, but it would also have the ability to expand to accommodate additional natural gas discovered in other blocks in the EEZ of Cyprus, as well as natural gas from neighbouring countries, such as Israel and Lebanon. However, following appraisal work in the Aphrodite field, it seems unlikely that such a project would be financially viable, since the estimated reserve quantities are unlikely to be sufficient to enable the construction of an LNG facility. In light of this, the Noble Energy, Delek and Anver consortium may be considering other options such as a floating LNG facility ("**FLNG**") or a compressed natural gas ("**CNG**") plant, but the government's preferred option is, and has always been, the construction of an onshore LNG facility, if sufficient reserves in other blocks of the EEZ of Cyprus are discovered to make the construction of an onshore LNG facility financially viable.

It should be noted that the construction of a natural gas pipeline to the east, west or south of Cyprus has also been proposed from time to time. No such plans are currently in place, mainly due to geopolitical factors, but also since it is questionable whether any such pipeline would be financially viable. As far as the west is concerned, despite the EastMed Declaration (as defined above), it is questionable whether such project will indeed be financially viable, and parties are still in the initial stages of its evaluation. Regarding the south, however, meaning a pipeline to Egypt, this may indeed be financially viable and the Minister of Energy, Commerce, Industry & Tourism has recently commented that Cyprus, in its capacity as a transit country and future gas producer, will continue to support possible gas export options, such as the EastMed pipeline and a direct line from the EEZ of Cyprus to Egypt. Commentators do suggest that currently, a direct line from the EEZ of Cyprus to Egypt is likely to be the most financially viable option for Cyprus, and the transfer/assignment of 35% of the Noble Energy rights in the PSC for Block 12 to BG (which has substantial interests in Egyptian natural gas) could facilitate a deal between Cyprus and Egypt.

Cyprus Hydrocarbons Company

In accordance with section 16 of the Hydrocarbons Law, the management of the Republic of Cyprus' participation in the activities of prospecting, exploring for and exploiting hydrocarbons may be assumed by the state itself or by a legal person that the Council of Ministers may prescribe. Pursuant to the Hydrocarbons Law, therefore, the Council of Ministers proceeded with the establishment of the Cyprus National Hydrocarbons Company, which later changed its name to the Cyprus Hydrocarbons Company (the "**CHC**"). The CHC is a private limited company and has a sole member, namely the Minister of Energy, Commerce, Industry and Tourism (on behalf of the state) and a seven-member board appointed in accordance with the provisions of the Hydrocarbons Law.

Pursuant to the memorandum of association of the CHC, the company will have the power to perform the following activities:

1. commercial exploitation of hydrocarbons that belong to the Republic of Cyprus;
2. commercial participation in infrastructure which is required for the exploitation of hydrocarbons;
3. participation in the exploration and/or exploitation, production, processing and transportation of hydrocarbons;
4. participation in the management and operational control of the energy infrastructure for the exploitation of hydrocarbons on behalf of the Republic of Cyprus;
5. management and/or supervision regarding the execution of any contracts (in relation to hydrocarbons) that have been in the past, or will be in the future, entered into by the Republic of Cyprus; and
6. safeguarding of the satisfaction (in priority) of local natural gas needs out of the reserves that have been or will be discovered in the territory and/or continental shelf and/or EEZ of the Republic of Cyprus.

It should be noted that following recent developments in the EEZ of Cyprus, the CHC is currently supporting, for example, the government of Cyprus with the review of the submitted development and production plan in relation to the Aphrodite gas field.

Other energy-related developments

RES

Despite the discovery of hydrocarbons dominating the energy sector in Cyprus, there have also been developments in relation to RES. As mentioned in the introduction to this chapter, RES only have a share of less than 9% of the country's gross final energy consumption. The energy policy of Cyprus is, however, 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 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. The abovementioned directive aims at ensuring a 20% share of renewable energy in final energy consumption, and to cut greenhouse gas emissions by 20% as compared to 1990 levels, by 2020 in the EU.

Cyprus is obliged to achieve a share of 13% of RES in its gross final energy consumption (after adjustment for aviation consumption) and a share of 10% of RES in final energy consumption of transport by 2020.

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% 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.

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.

In 2015, the Ministry of Energy, Commerce, Industry and Tourism announced a new scheme for the promotion of the installation of photovoltaic systems, which was amended in 2016, in relation to the following three categories:

1. photovoltaic systems of up to 5kW which are connected to the grid of the EAC via net metering with a total available power of 23MW for: (i) vulnerable households, to which a grant of €900 per kW is given (1.2MW); (ii) non-vulnerable households, without the provision of a grant (8.8MW); and (iii) non-domestic consumers, including businesses in the sectors of agriculture, livestock breeding, fisheries and aquaculture, without the provision of a grant (13MW);
2. auto-generating photovoltaic systems of up to 10MW each in commercial and industrial units, with a total available power of 40MW; and
3. auto-generating photovoltaic systems which are not connected to the grid (where every consumer has a right to submit an application for this category).

Further to the above, the Ministry of Energy, Commerce, Industry and Tourism in 2017 announced a new scheme to install systems which produce electricity from RES for commercial purposes, in order to integrate such systems into the competitive electricity market so that the national target in accordance with the Renewable Energy Directive 2009/28/EC is achieved. This scheme, which was amended in 2018, promotes the installation of photovoltaic systems of up to 8MW each, wind systems of up to 17.5MW each, biomass utilisation systems of up to 5MW each, solar energy storage systems of up to 50MW each, and wave energy utilisation systems of up to 20MW each.

Major economic events and developments

The March 2013, Eurogroup decisions resulted in Cyprus going through its worst economic period since the Turkish invasion of 1974. Severe austerity measures have been imposed, the country's banking sector was forced to shrink, and unemployment rates have risen. The discovery of natural gas in the country's EEZ will play a major role in the island's economic recovery.

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Finland

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Overview of the current energy mix, and the place in the market of different energy sources

According to figures compiled by Statistics Finland for the full calendar year 2017, the Finnish energy mix was as follows:

Total energy consumption by source (TJ) and CO_2 emission (Mt)

Energy source	2017*	Annual change %*	Percentage share of total energy consumption*
Oil	314 169	-3	23
Coal[1]	116 319	-8	9
Natural gas	66 074	-8	5
Nuclear energy[2]	235 367	-3	17
Net imports of electricity[3]	73 532	8	5
Hydro power[3]	52 712	-6	4
Wind power[3]	17 286	57	1
Peat	56 123	0	4
Wood fuels	361 432	4	27
Others[4]	62 693	4	5
TOTAL ENERGY CONSUMPTION	1 355 707	-1	100
Bunkers	43 064	11	.
CO_2 emissions from energy sector	41	-5	.

* =Preliminary

. = Category not applicable

1. Coal: includes hard coal, coke, blast furnace gas and coke oven gas.
2. Conversion of electricity generation into fuel units: nuclear power: 10.91 TJ/GWh (33% total efficiency).
3. Conversion of electricity generation into fuel units: hydro power, wind power and net imports of electricity: 3.6 TJ/GWh (100%)
4. Others: includes exothermic heat from industry, recovered fuels, heat pumps, hydrogen, biogas, other bioenergy and solar energy.

According to Statistics Finland's overview, in 2017, consumption of renewable energy sources accounted for about 6%, and their share of total energy consumption was a record

36%. Consumption of wood fuels increased by 3.5% and remained the most significant single source of energy in Finland, with a 27% share. The growth was due to the increase in by-products of the forest industry and the burning of waste wood. The largest increase of renewable energy sources was wind power, in respect of which production increased by as much as 57%. However, in relation to total energy consumption, wind power is still small, 1.3%. The volume of biofuels used in road transport rose once more, having decreased in 2016.

The use of fossil fuels decreased by 6% compared to 2016 and accounted for 36% of total energy consumption. The consumption of fossil fuels decreased by 8% for coal (including coal, coke, blast furnace and coke gas) and natural gas. Oil consumption fell by 3%, but remained the second-most important individual energy source in Finland with a 23% share of total energy consumption. Peat consumption remained at roughly the same level as the previous year.

Domestic production of electricity in 2017 was 65 TWh, which was about 2% less than in the previous year. Nuclear energy produced about one third of electricity. The share of combined heat and power production was 32%, which was the second-largest share of electricity production. Hydro power accounted for 23% of electricity production. Hydroelectric production declined by 6% in 2017. Wind energy production continued its annual growth rate of 57%, and its share of electricity production last year was up to 7%. Solar power generation grew by preliminary data of 49%, but its share in the production of electricity in Finland was still less than 0.5 *per mille*.

The net import of electricity to Finland was 20.4 TWh, which corresponds to 24% of total electricity consumption. Compared to 2016, net imports of electricity grew by 8%, mainly due to a 44% decline in electricity exports. Finland's largest electricity import countries were Sweden and Russia. The largest amount of electricity was imported from Sweden, totalling 15.3 TWh (5.8 TWh was imported from Russia). Almost all exports of electricity were to Estonia, totalling 1.7 TWh.

Last year, various energy products were imported into Finland worth €8.8 billion, up 21% compared with the previous year. The largest amount of energy was imported from Russia, which accounted for about 61% of the value of imports. Similarly, energy products worth €4.7 billion were exported from Finland, an increase of approximately 20% compared to the previous year.

End-use energy increased by 1%. Of the end-use sectors, industrial usage showed the largest growth at 2%, accounting for 46% of total end-use. Energy used for the heating of buildings was roughly at the same level as for the previous year, corresponding to a 26% share of end-use energy. Energy used in transportation, with a 17% share, was roughly the same percentage as the previous year.

Approximately 27% of Finnish electricity is produced by nuclear power; the figure will rise to about 45% by 2030 when new nuclear power plants are completed. Fennovoima is currently developing the Hanhikivi 1 power plant in Pyhäjoki. The company applied for a building permit in summer 2015. In order to obtain a building permit, the company must be able to demonstrate that the plant is built to meet Finnish safety and regulatory requirements. The goal is to get a building permit by the end of 2019.

In 2017, 153 new wind farms were built in Finland. Wind power capacity grew by 516 MW in 2017, with a combined capacity of 2,044 MW. The acceleration of wind power construction can be partly explained by the closure of a support scheme for wind power ("feed-in tariff scheme") which required new farms to have been entered into the feed-in tariff scheme by January 2018 or miss out on a very attractive feed-in tariff of €83.5/MWh for a fixed 12-year period, representing a significant premium on the Nordpool spot price for the majority of the last few years. The total electricity produced by wind power was 4.8 TWh, which amounted to 7% of Finland's electricity consumption.

According to the National Report 2018 of the Energy Authority, the national energy regulator, the largest share of electricity imports came from Sweden, although imports from Sweden fell slightly compared to the previous year. Imports from Russia grew slightly and net exports to Estonia decreased. The increase in electricity consumption in 2017 was covered by increased net imports, as the level of Finnish domestic electricity generation decreased.

According to the National Report 2018 of the Energy Authority, total installed generation capacity in Finland was about 17,400 MW at the end of 2017. However, all installed capacity is not available during peak load situations. The highest hourly load in 2017 was 14,273 MWh/h. During the peak load situation, the electricity system worked well and there were not any major disturbances in generation and interconnection capacities. Domestic dormant generation capacity was also available. The interconnector capacity between Finland and neighbouring countries is enough to cover the deficit in own-generation capacity during a peak load situation. The limited transfer capacity has restricted the transmission of electricity from Sweden to Finland, which is why wholesale electricity prices in Finland were different from the prices in Northern and Central Sweden in 27% of hours last year. In 2017, Finland and Estonia had the same price in 98% of hours. However, in December 2016, Finnish and Swedish TSOs announced their agreement to build a new AC-interconnector between the two countries by 2025.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

In autumn 2018, the Energy Authority will arrange a subsidy tender for the expansion of electric and gas vehicle charging systems and refuelling stations, with the period for submission of applications running from 1–31 October 2018. The bidding competes in four groups: gas filling stations; local public transport charging systems; high power loading systems for vehicles; and basic vehicle charging systems. This infrastructure support will help to implement the national energy and climate strategy that goes beyond 2030. Support is given to the extension of charging and gas discharge networks investments.

The Finnish Government has decided that the use of coal in energy production will be prohibited by law by 2029. The Government will also prepare an incentives package, amounting to €90 million, for district heating companies that commit to phasing out coal use by 2025. The Government intends to submit its legislative proposal to ban the use of coal to Parliament during the autumn session of 2018.

The aim of the Government is to ensure that the use of coal in energy production will end before 2030, while at the same time promoting indirectly the low-carbon energy system and the use of renewable energy sources. In addition, the aim is to ensure that such power plant or heating investments or replacement investments, which rely on coal energy, are no longer viable. In addition, the aim is to ensure that the provision of security for energy production, security of supply and exceptional situations, are maintained in a cost-effective way.

Developments in legislation or regulation

Renewable energy subsidy scheme

The most important legislative development in 2018 is the implementation of a new support scheme for renewable energy, which has been under discussion for approximately two years.

On 9 November 2017, the Finnish Government published a government bill for renewable energy (175/2017 vp, "the **Government Bill**"), which proposed that provisions on a premium system based on a technology-neutral tender process be added to the Act on Subsidies for Electricity Produced from Renewable Energy Sources (1396/2010) (the "**Act**").

On 23 May 2018, the Finnish Parliament approved the Government Bill regarding the replacement of the renewable energy feed-in tariff system with a new premium-based scheme. Amendments to the Act on Production Subsidy for Electricity Produced from Renewable Energy Sources entered into force by a decree. The amended Act entered into force on 25 June 2018 (the "**Amended Act**").

The main features of the new support scheme:

1. *Technology-neutral support scheme*

   The new support scheme comprises a competitive auction process. According to the Amended Act, the new subsidy scheme will apply to wind power, solar power, wave power, biogas[1] and wood fuel power.[2] Hydro power is explicitly excluded from the support scheme.

2. *Validity of the support scheme and capacity*

   The first auction, and the only round under the new support scheme, will take place between 15 November–31 December 2018. The annual electricity production available for auction is 1.4 TWh.

3. *Preconditions for participating in the auction process*

   An electricity producer must fulfil the following preconditions for participating in the auction process.

   (i) *The power plant must be located in Finland or Finland's territorial waters* (excluding, however, projects located in the Åland Islands).

   (ii) *Each power plant must be completely new, with the exception of the power plant building and its foundations, which may be recycled*. This precondition is dealt with in more detail in the Government Bill, where it is stated that the wind turbine tower is considered as part of the engine, which means that the tower and the engine room must be new in order for the project to be eligible for the subsidy scheme.

   (iii) *It must not previously have received any state aid.* There is, however, an exception from this requirement, based on which re-powering of old power plants, which have previously received state aid, under certain circumstances may be eligible for the new subsidy scheme. The decree, which includes more details on the circumstances under which re-powering is allowed, entered into force on 10 September 2019.

   (iv) *No final investment decision shall have been made by the bidder prior to the auction round*.

   Finally, the Amended Act includes restrictions relating to the size of the projects. Projects with an annual electricity production exceeding the annual electricity production being tendered in the relevant auction round cannot participate in the scheme. Moreover, in order for a project to be eligible for the new support scheme, a total annual output of at least 800 MWh is required. Each bidder may, at its discretion, include several projects and/or power plants in the same bid provided that each power plant included in the bid is of the same technology and has an annual output of at least 800 MWh but no more than 10,000 MWh. It is not required that the grid connection of all power plants is the same or that the power plants are located in the same area. However, the power plants must have a common measurement point, internal grid connection or other technical connection in order to be included in the same bid.

Participation in the auction round requires that the project has all the permits required for construction of the power plant (i.e. that the applicable land use plan (or planning decision (Fi: *suunnittelutarveratkaisu*), as the case may be) as well as the building permit (or deviation decision, as the case may be) are legally binding and remain in force for a sufficiently long period. In addition, a binding grid connection offer (effectively conditional only upon the bidder being successful in the auction process),[3] valid for a sufficiently long time to enable entry into a final grid connection agreement if the bid is successful, is required. A final grid connection agreement is accepted in lieu of a grid connection offer if such agreement has been entered into prior to the entry into force of the act on the new support scheme, or if the bidder can prove that the grid owner has refused to make a required grid connection offer to the bidder.

A participation fee (currently estimated to be €2,500 per bid) is payable in connection with the submission of the bid in the auction process. Since the purpose of the fee is to cover administrative costs caused by the auction system, it will not be refunded even if the bidder is unsuccessful in the auction round.

4. *Support level and duration of support*

The Amended Act contains provisions on support level and duration of support. The support will be determined separately for each bid in a competitive auction process, where the bidders with the lowest offered premium, the aggregate annual electricity production of which does not exceed the annual electricity production allocated to the relevant auction round, are approved into the scheme (pay-as-bid). The maximum duration of the support granted to the project is 12 years. The approval into the scheme is transferable to third parties in connection with the transfer of assets of the relevant project(s).

Based on a floor price of €30/MWh, the bidder will set a premium in its bid not exceeding €53.5,[4] which the bidder requires in excess of the floor price in order to implement its project. This floor price, plus the offered premium, is referred to as the target price.

As stated in the Government Bill, the support scheme is a combination of a sliding and fixed premium. If the market price of electricity, which is determined on the basis of the average Nordpool area price for the relevant calendar quarter, is the floor price (€30/MWh) or less, the support is fixed at the premium offered by the bidder. If the market price of electricity exceeds the floor price, a sliding premium will be applied, where the support equals the difference between the market price and the target price (based on EUR/MWh). In this respect, the Government Bill sets out the following two sample calculations:

Table 1. Sample calculation of aid in accordance with the premium per year (MEUR) for a power plant where the production of electricity is 0.1 TWh per year

	Premium (EUR/MWh)						
Average market price of electricity (EUR/MWh)	10	15	20	25	30	35	40
30	1.0	1.5	2.0	2.5	3.0	3.5	4.0

35	0.5	1.0	1.5	2.0	2.5	3.0	3.5
40	0	0.5	1.0	1.5	2.0	2.5	3.0
45	0	0	0.5	1.0	1.5	2.0	2.5
50	0	0	0	0.5	1.0	1.5	2.0
55	0	0	0	0	0.5	1.0	1.5
60	0	0	0	0	0	0.5	1.0

Table 2. Sample calculation of aid in accordance with the premium per year (MEUR) for a power plant where the production of electricity is 0.25 TWh per year

	Premium (EUR/MWh)						
Average market price of electricity (EUR/MWh)	10	15	20	25	30	35	40
30	2.5	3.8	5.0	6.3	7.5	8.8	10.0
35	1.3	2.5	3.8	5.0	6.3	7.5	8.8
40	0	1.3	2.5	3.8	5.0	6.3	7.5
45	0	0	1.3	2.5	3.8	5.0	6.3
50	0	0	0	1.3	2.5	3.8	5.0
55	0	0	0	0	1.3	2.5	3.8
60	0	0	0	0	0	1.3	2.5

5. *Requirements relating to the bid*

The bid must be made by a due date determined by the Energy Authority using a form to be produced by it and include: (i) the offered premium; (ii) the offered annual production volume of electricity; and (iii) information on the generation unit(s) to be used for the production of electricity (in respect of which it should be noted that there is no requirement to provide information on specific turbine models but rather whether the relevant project is a wind power project, a solar power project or a project for any other eligible technology) as well as the municipality where the project is located. The bidder is not allowed to alter its bid after the due date.

After the due date determined by the Energy Authority, the bidder may not revoke the bid. Neither may the bidder amend the bid regarding the offered premium or the annual production volume of electricity, or the notice of the power plant where the electricity is to be produced after the due date.

In addition to the above, the bid must include information on the bidder, evidence of satisfaction of the preconditions for participation in the auction round as well as the tariff period (which corresponds to the calendar quarter) as of which the support period for the project is requested to commence. The said tariff period must commence within three years from approval into the scheme. According to the Government Bill, the bidder may amend the commencement tariff period by giving notice to the Energy Authority, until the approval decision of the submitted bid has been made by the Energy Authority.

The capacity and the number of generation units, and the construction schedule of the power plant can be updated later, as the bid may only contain a range set by the bidder. However, according to the Government Bill, the final information must be notified to the Energy Authority within three (3) years and two (2) months from approval of the project into the support scheme. The information must be specific and final, and no range within which refinement could take place is allowed thereafter.

There is no possibility of partial approval of a project into the support scheme. This means that if sufficient capacity is no longer available under the scheme in order to approve the entire annual electricity production included in a bid into the support scheme, the bid will be rejected. Furthermore, if there are two bids for the same annual electricity production, but the capacity available under the scheme is not sufficient for the approval of both bids, neither of the bids will be approved into the scheme.

A bidder who has been successful in the auction process is required to complete construction of at least one generation unit and connect it to the grid and start energy production within three years from the approval of the project into the scheme. However, if not all generation units have been constructed and connected to the gird by said deadlines, this would possibly lead to an obligation to pay compensation for underproduction (see below). Moreover, the electricity producer would also lose part of its construction security. In addition, since the commencement date of the subsidy would remain unchanged, the subsidy period would in practice be shortened as an outcome.

It is required that the entire offered capacity is fully constructed and connected to the grid within five years from approval of the project into the scheme. The right to support is forfeited if either of said three- and five-year deadlines is missed.

6. *Bid bonds*

There are two types of security; participation bond and construction security. The participation bond is effectively a bid bond provided to the Energy Authority securing the bidder's participation in the auction round.

The amount of the security will be calculated by multiplying the offered annual production of electricity in MWh by two. For example, if the annual electricity offered by the bidder amounts to 0.1 TWh, the security would amount to €200,000. According to the Amended Act, guarantees issued by financial institutions domiciled in the EEA, cash deposits and policies issued by insurance companies domiciled in the EEA, would be acceptable as security. The Amended Act further provides that the security is released: (i) if the bidder is unsuccessful in the auction; or (ii) upon grant by the bidder of the construction security referred to below. If the bidder is successful in the auction process but does not grant construction security, the Energy Authority will enforce the security and simultaneously the decision on the approval into the scheme will be cancelled.

The participation security shall be valid for six (6) months from the due date determined by the Energy Authority.

If the bidder is successful in the auction process, it shall within one month from approval into the scheme grant a construction security payable to the benefit of the Energy Authority.

The means of providing the construction security accepted are the same as for the participation security. The amount of the security will be calculated by multiplying the offered annual production of electricity in MWh by sixteen (16). For example, if the annual electricity production offered by the bidder amounts to 0.1 TWh, the construction security will amount to €1.6m. The construction security is released if and to the extent the relevant power plants are fully constructed and connected to the grid and producing electricity within three years from approval of the project into the scheme. To the extent that the offered capacity is not producing electricity by said date, the Energy Authority will enforce the construction security.

The construction security must be valid for three (3) years and six (6) months from the date of issue of the security.

7. *Payment of the support*

Under the Amended Act, the 12-year support period commences from the start of the tariff period set out in the relevant bidder's bid (regardless of whether by said date the project has been connected to the grid or not). There is, however, no restriction preventing the bidder from starting production and sale of electricity prior to the commencement of the tariff period from which the right to support starts.

The support is paid on the basis of electricity produced and fed into the grid. Since the support is restricted to the annual electricity production offered in the bid, support is not paid in respect of electricity produced in excess of the offered annual production. Since the electricity production from renewable resources normally varies over time, the Government Bill, however, provides for some flexibility in this respect; the Bill provides that the (annual) production-based cap of the support scheme is calculated as an aggregate cap by applying four-year periods starting from the commencement of the support period for the relevant project(s). Accordingly, any excess production in the first three years will, for example, reduce the support payable in the fourth year.

The support is paid quarterly in arrears. The bidder shall apply for payment within two months from the end of the relevant tariff period. A precondition for the payments is that a monitoring plan for the project(s) is attached to the first application for support payment and, subsequently, approved by the Energy Authority.

8. *Underproduction compensation*

In order to mitigate the risk of the actual production from successful projects being less than the annual electricity production offered in the relevant bids, an underproduction compensation mechanism has been included in the Amended Act. For the purpose of this compensation, the 12-year support period has been split up into three sub-periods of four years each. The underproduction compensation becomes payable if the actual, average, annual electricity production by the relevant power plant is less than: (i) 75% of the average annual electricity production volume offered in the bid during the first sub-period; and/or (ii) 80% of the average annual electricity production volume offered in the bid during the second and third sub-period, respectively.

Notwithstanding the above, the electricity producer would not be obliged to pay the underproduction compensation: (i) where the shortage is attributable to the grid operator; and (ii) for any period during which when the market price of electricity in the power plant's location has been negative. In addition, the Energy Authority may exempt the electricity producer from the obligation to pay the underproduction compensation due to unusual and unforeseeable circumstances beyond the control of the electricity producer, who relies on the circumstances, and who has not had the opportunity to influence the circumstances or avoid the consequences, despite all diligence, and where remedial action has been taken by the producer without delay.

The compensation is calculated by multiplying the MWh deficit in production by the premium approved for the relevant bidder. Accordingly, if the bidder's approved premium is €25/MWh and the deficiency in production is 60,000 MWh, the underproduction compensation equals €1.5m. The Energy Authority is entitled to set off future support payments against the underproduction compensation until it has been paid in full. A more detailed calculation formula may subsequently be included in the Government decree.

New act on the reduction of the life-cycle gas emissions from certain fuels

The Act on the reduction of life-cycle greenhouse gas emissions from certain fuels came into force in March 2018. The Act transposes Article 7a of the Fuel Quality Directive, the FQD, into national law.

The Act provides for the reduction of greenhouse gas emissions from transport fuels. The Act applies to fuels used in motorised vehicles, mobile work vehicles, agricultural and forestry tractors and inland waterway vessels and recreational craft. The law applies to suppliers of the aforementioned fuels that supply more than one million litres of liquid fuels per calendar year or a corresponding amount of gaseous fuels with an energy content.

The Act legislates for the reduction of fuel greenhouse gas emissions from fuels by 2020. According to the obligation, fuel suppliers will have to reduce lifecycle greenhouse gas emissions of their fuels released by consumption by 6% by the end of 2020 compared with 2010 emissions.

According to the Act, fuel suppliers must report to the Energy Authority on the fuel information they have released for consumption per calendar year.

Judicial decisions, court judgments, results of public enquiries

Two Supreme Administrative Court judgments during 2018 of note to the energy sector:

- KHO:2017:87

  Regional State Administrative Agencies had granted permission for a power station project according to the old Water Act. The new river basin management plans had to be taken into consideration while evaluating the conditions to allow the execution of the project. Following complaints made to the Supreme Administrative Court of Finland, it had to resolve among other things, how the information displayed in the new river basin management plans affected the evaluation of the power station project's benefits, injuries and harms according to the Water Act. The complaints had emphasised the power stations' impacts on Kemijoki's fisheries. The Kemijoki river is widely dammed and controlled for the production of hydropower. In this case, there was no grounds on which it could be ruled that the project would reduce the river basin's ecological status so that the river basin management plans considered in accordance with European Union law would lead to a refusal of the application according to the Water Act. The granted permission was therefore upheld with a few changes to the permit conditions.

- KHO 27.7.2018

  The case considered noise levels around windfarms and the harm they cause to close-by residents. The Court weighed the possibility that two windfarms could apply for environmental permits. Even though the noise caused by windfarms does not exceed the limits of the Government Decree on guide values for the outdoor noise level of wind turbines, the noise is at times pulsating. The Supreme Administrative Court of Finland held that windfarm operations must apply for authorisation according to the Environmental Protection Act, because there cannot be a single regulation given to prevent harm and to monitor actions on windfarms under article 180 of the Environmental Protection Act. Because windfarms may cause an unreasonable burden to close-by residents, one must apply for permit on the basis of article 27(2)(3) of the Environmental Protection Act.

Major events or developments

The main market development was the move in wind power towards a market driven largely by private Power Purchase Agreements, currently the hottest topic in the Finnish energy sector.

The first sign of this new development was detectable in May 2018, when TuuliWatti announced the first Finnish 'market-based' wind power project. TuuliWatti's project will consist of five Vestas V150 turbines with a power output of 4.2 MW and a tower height of 175 metres, with a sweep height of 250 metres, which are set to be the highest turbines in the Nordic countries when constructed. According to Tuuliwatti's press release, as the V150 is up to twice as high as previous turbines, the production cost of electricity will remain below €30 / MWh. This project will be in production in 2019 and while it is set to receive Government subsidiaries, Government support will be very marginal, and it will serve mainly as backup funding for the project.

Of potentially greater significance, however, is Google's announcement in September 2018 that it has signed three Finnish Power Purchase Agreements to acquire the whole production of three soon-to-be built wind farms for a duration of 10 years. The collective addition to Finnish electric capacity from wind power will be 190 megawatts (MW), which is a sizeable addition for Finnish wind power as the total capacity constructed during 2017 was 516 megawatts (MW). The windfarm operators that have signed PPAs with Google are long-standing European players: French Neoen; German-based CPC Finland; and Wpd Finland.

The wind farms will be the first in Europe to be built completely without any Government subsidies through the use of Power Purchase Agreements. A PPA-based system has been more common in United States but recently the market has also been moving heavily towards a PPA-based system in Europe. This was presumably the intention of the Government in Finland, since it cut the subsidiary scheme from potentially three rounds to just one round.

Emissions from the Finnish Emissions Trading sector decreased by 2.1 million tonnes in 2017.

The total number of Finnish power plants belonging to the EU emissions trading scheme was 25.1 million tonnes of carbon dioxide in 2017. In 2016, the corresponding emissions were 27.2 million tonnes.

The use of renewable fuels with sustainability criteria in the emissions trading sector increased by about 4.6% compared to the previous year (calculated as the amount of energy). Consumption of hard coal, natural gas and peat fell compared to the previous year.

The Baltic Connector's completion by the end of 2019 is designed to reduce Finland's isolation by connecting the Finnish gas market to Estonia and opening up to Finnish gas operators the opportunity to buy gas from the joint Finnish-Baltic market.

According to the 2018 National Report, the most significant generation investment project in Finland is the construction of nuclear power plant unit Olkiluoto 3. The completion of the building of this 1,600 MW unit has been delayed for several years. Originally, the new unit should have been commissioned by the end of 2009. According to the latest estimates, it will be in operation in September 2019.

In addition, Fennovoima Oy is planning to build a new nuclear power plant in Pyhäjoki. The project has received a decision-in-principle from the Finnish Government and the Parliament and awaits a construction permit, which is expected to be granted in 2019. The unit has a planned capacity of 1,200 MW and it is planned to be in operation in 2024.

Metsä Group's new pulp mill started its operation in 2017. The power production capacity is 260 MW and the total net capacity is around 160 MW.

Most of the condensing power plants are already closed in Finland and currently many CHP producers are considering whether they should invest for CHP or just heating capacity in the future. Capacity adequacy is a challenge in Finland, and it will be a challenge also in the future. Controllable generation capacity has been decreasing and at the same time intermittent renewable capacity is increasing.

Proposals for changes in laws or regulations

An amendment to the Emissions Trading Directive took effect on April 2018. The amendment mainly concerns changes to the emissions trading scheme for the next trading period starting in 2021. Member States will have to make the amendment to the Emissions Trading Directive by 9 October 2019. In Finland, this requires the amendment of the Emissions Trading Act 311/2011. In addition to the implementation of the Directive, the legislative amendment will bring improvements that have been found necessary at national level on the basis of the current trading period.

* * *

Endnotes

1. In order to qualify as a biogas plant, at least 85% of electricity produced in the plant has to be produced by biogas.
2. Wood fuel power refers to combined heat and power plants that are fuelled by wooden, side or waste products from the forest industry. In fuel power plants, 85% of the energy has to be produced with different fuel than wood chips; 15% of the energy can be produced with other fuels than wood.
3. A template for such offer is currently being prepared by Finnish Energy (Fi: *Energiateollisuus*).
4. According to the Government Bill, the maximum level may be reduced by a Government decree.

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Overview of the current energy mix and the place in the market of different energy sources

German energy policy continues to promote and implement the so-called "*Energiewende*" (***Energy Transition)*** by expanding the capacity of electricity generation from renewable sources and phasing-out nuclear and fossil energy while improving energy efficiency.

At the same time, conventional energy sources still constitute the major part of Germany's energy supply:[1] coal-fired power plants accounted for 36.6% of gross electricity production in 2017 using both lignite (22.5%) and hard coal (14.1%). Natural gas contributed 13.2%, mineral oil and other sources 5.1%. The share of nuclear energy decreased to 11.7% of gross electricity production in 2017, as compared to 14.2% in 2015, due to the shutdowns forced by law under section 7 (1) (a) Atomic Energy Act (*Atomgesetz*).

However, the Energy Transition is showing its effect: in 2017, approximately 36.2% of the gross electricity production came from renewable energy sources, compared to 29% in 2016. The remarkably strong increase within just one year can be explained by the substantial expansion of wind energy plants (both off- and onshore, see below) and unusually strong winds.[2]

Wind energy provides about half of the electricity derived from renewable energies. Its production increased from 80 TWh in 2016 to 107 TWh in 2017, and contributes 16.2% of the gross electricity production (13.6% onshore, 2.7% offshore).[3] In 2017, the capacity increase of onshore wind totalled 5.5 GW, significantly exceeding the yearly target of 2.8 GW under the Renewable Energies Act 2017 ("*Erneuerbare-Energien-Gesetz 2017*", ***EEG 2017***) and reaching a total installed capacity of approximately 50 GW.[4] It can be assumed that this particular increase in 2017 is partly due to existing "*grandfathering*" rules that still ensure remuneration without prior successful participation in an auction. Offshore wind capacity increased by 1.2 GW to a total of 5.4 MW.[5]

The shares of electricity generated from solar energy (6.1%, derived from a total installed capacity of 42.3 GW), from biomass and waste energy (7.9%) and from hydro power (3.1%) have remained approximately the same as in the year before.

Notably, the government's annual targets for new solar and biomass energy capacity (2.5 GW and 100 MW respectively) were not reached in 2017.[6]

Developments in government policy/strategy/approach

In the coalition agreement between the ruling parties CDU/CSU and SPD of 12 March 2018 (***Coalition Agreement***[7]), the newly elected government set its agenda and raised the target for renewable energy's share in the mix to 65% by 2030. More generally, the new government reaffirmed the importance of a successful Energy Transition as Germany's long-term energy and climate strategy. It aims to further advance the three pillars of the Energy Transition: (i) reduction of greenhouse gas emissions; (ii) expansion of renewable energies; and (iii) increasing energy efficiency.

The Coalition Agreement emphasises the importance of increasing energy production from renewable energy sources less than in previous legislative periods, but particularly the synchronisation with required grid-enhancement and sector-coupling. The government further announced the development of an "*Energy Efficiency Strategy*", laying down the principle of "*efficiency first*" and aiming to cut total energy consumption by 50% by 2050.

However, the Coalition Agreement also envisages an extraordinary tender for offshore wind capacities addressing concerns that the rigid goals implemented by the Offshore Wind Energy Act 2017 ("*Windenergie-auf-See-Gesetz*", ***WindSeeG***) might overburden the offshore industry in Germany. Also, additional 4GW each of wind and solar energy capacities shall be tendered for. The auctions will take place in 2019 and 2020.[8]

The Coalition Agreement also states that the Federal Government intends to develop a comprehensive blockchain strategy and promote an appropriate legal framework for trading cryptocurrencies and tokens at both European and international level, in order to "*exploit the potential of blockchain technology and prevent misuse*". The Federal Government plans to test such innovative technologies in order to examine their use for government work. The aim of such pilot projects is to gather information so that a legal framework can be created on the basis of these experiences. These intentions of the Federal Government reflect the growing attention to the relevance of blockchain technology also at EU level. The European Commission recently set up the "*EU Blockchain Observatory and Forum*".[9] Additionally, on 10 April 2018, 22 European countries, amongst them Germany, signed a Declaration on the Establishment of a "*European Blockchain Partnership*".[10] This focus does justice to the potential of blockchain technology's ability to enhance real-time energy management with billions of interconnected devices.

Developments in legislation or regulation

Offshore regional plan

As determined by the German legislation for offshore wind projects, especially the WindSeeG, the Federal Maritime and Hydrographic Agency (*Bundesamt für Seeschifffahrt und Hydrographie*, ***BSH***) in consultation with the Federal Network Agency (*Bundesnetzagentur*, ***BNetzA***), has initiated the procedure to set up the offshore regional plan ("*Flächenentwicklungsplan*", ***FEP***).

The FEP contains, in particular, determinations of areas and sites for the construction and operation of offshore wind energy plants. It also sets out the time sequence in which the areas will be subject to tender processes under the so-called central model of the WindSeeG until 2030. Under the central model, anyone can apply for the right to build and receive a remuneration on the same pre-assessed area. Previously, developers still applied with areas for which they had undertaken the pre-development work.

The determinations of the FEP are now particularly relevant, as certain special rights exist only for those projects whose area is tendered until 2030: the developer who had previously obtained rights on the respective area has a step-in right under section 39 WindSeeG if he does not win in the tender process. Therefore, a determination that an area will be subject to a tender before 2030 is the only way such previous rights still bear value.

In May 2018, the BSH published the preliminary draft of the FEP.[11] A public hearing took place in June 2018. Besides the specific sites and their sequence of tendering, *inter alia* the maximum generation per km² in the future, and elements of the timing and interpretation of the WindSeeG, were subject to controversy. The BSH is expected to publish the draft of the FEP in the autumn, which will then be subject to another hearing.

New guideline for feed-in management measures

In June 2018, the BNetzA published the new version 3.0 of the Guideline for Feed-In Management ("*Leitfaden zum Einspeisemanagement, Version 3.0*"; ***Guideline 3.0***).[12] Even though the Guideline 3.0 has no legally binding effect, it has high practical relevance. The Guideline 3.0 contains the opinion of the BNetzA on how feed-in management measures ("*Einspeisemanagement*"), in particular prioritisation and curtailment, shall be conducted and when the operator receives compensation from the grid operator. If not stipulated in the Guideline 3.0, a compensation payment is unlikely, unless enforced in court.

The Guideline 3.0 first of all contains provisions for the calculation and structure applied to receive a curtailment compensation, depending on the type of plant (wind, biomass, solar or combined heat and power (***CHP***)) and, in case of a renewable energy installation, the marketing method (direct marketing or feed-in remuneration). Secondly, it contains provisions on how to compensate additional expenses which arise due to the acquisition of balancing power.[13] Thirdly, it stipulates the feed-in of CHP units.[14] The Guideline 3.0 states how to conduct the priority feed-in of high-efficiency CHP power, provides for sweeping and peak accounting procedures as well as data for power plant deployment planning, and states how to compensate CHP units that are subject to curtailment. Finally, the Guideline 3.0 contains provisions accounting for various installations which utilise a joint measuring device.[15]

Modernisation of the grid fee structure

In July 2017, the government adopted the Act on the Modernisation of the Grid Fee Structure ("*Netzentgeltmodernisierungsgesetz* – ***NEMoG***"), which aims at lowering the grid fees and distributing the remaining costs more fairly. From 2019 to 1 January 2023, the grid fees charged for the use of transmission grids will be incrementally harmonised across the entire country in five equal steps. Thereby, regional disparities in grid fees, and thus effective electricity prices for final customers, will be reduced.[16]

The NEMoG also provides for the successive removal of the privilege of so-called "*avoided grid fees*", i. e. payments for costs that are avoided due to feed-in at the decentralised (distribution) level. Since the original assumption that locally generated electricity would be consumed at a local level, without using the higher-voltage grid, proved to be false yet the avoided grid fees have risen significantly in subsequent years, the NEMoG provides for a phase-out in three steps:

(i) the calculation basis for avoided grid fees for controllable electricity generation installations will be frozen at the 2016 level;

(ii) volatile electricity generation installations, i.e. from wind and solar energy, that start operating as of 2018, do not qualify for payments any more; and

(iii) payments will further be stopped for controllable electricity generation installations that will be put into operation on or after 1 January 2023.

Additionally, avoided grid fees for existing volatile electricity generation installations are to be successively reduced once a year from 1 January 2018, by an amount of one third of the initial value.

The NEMoG also introduced regulation regarding the so-called special network utilities (*besondere netztechnische Betriebsmittel,* ***bnBm***) in section 11 (3) ("*Energiewirtschaftsgesetz*", ***EnWG***), while simultaneously deleting section 13k EnWG (*grid stability units*). It stipulates that transmission system operators *may* provide bnBm, if short-term measures are necessary in order to restore the safety and reliability of the electricity supply system in case of an actual local breakdown of one or more utilities. The law does not contain guidelines for the technical nature of the bnBm, and the European Commission has demanded any according tenders to be technology-neutral. By the nature of the requirements, however, in particular newly constructed gas power plants come into question as bnBm. Pursuant to section 11 (3) EnWG, third parties have to be commissioned with the operation of bnBm, whereas such third party must be chosen by way of competitive tendering, involving the BNetzA. The first tendering procedure has just been started at the end of June 2018 in order to meet the need of three TSOs for an active power of 1,200 MW, divided into 12 batches of 100 MW that are, again, divided by region into four lot groups.

Tenant Energy Act

On 25 July 2017, the so-called Tenant Energy Act ("*Gesetz zur Förderung von Mieterstrom und zur Änderung weiterer Vorschriften des Erneuerbare-Energien-Gesetzes – Mieterstromgesetz*[17]) came into force and was approved by the EU Commission under State aid rules in November 2017. Tenant energy models are envisaged to stimulate additional investment in solar parks and enhance active participation of tenants in the Energy Transition. The Tenant Energy Act introduces a so-called "*tenant energy surcharge*", applicable to units up to in total 100 kW and received by the landlord, provided that the electricity is consumed by an end user within this building (the tenant) or in direct spatial connection. It constitutes an additional revenue component for electricity produced from renewable sources pursuant to the EEG 2017, besides market premium and feed-in tariff. In line with the structure of the feed-in tariff model, the overall tenant energy surcharge is computed from the statutory funding level minus 8.5 ct/kWh. It is subject to the so-called flexible cap ("*atmender Deckel*"), which means that the remuneration flexibly decreases depending on added capacity.

Although the potential for tenant consumption energy in Germany is estimated to reach 3.8 million households, the Tenant Energy Act has failed so far: bureaucratic obstacles, tax risks, and complex metering requirements have prevented a significant impact. Hence, an improvement of the existing law seems inevitable.

New bid structure for balancing energy

As of 8 May 2018, the BNetzA decided on an adaption of the bid structure regarding secondary control power (matter no.: BK6-18-019) and minutes reserve (matter no.: BK6-19-020), which entered into force on 12 July 2018. According to the new rules, the award of an offer for secondary control power or minutes reserve shall be based on a mixed price method: the surcharge value proportionally shall take into consideration the energy price besides the capacity price. This is new, as to date the award was granted solely on the basis of the offered capacity charge. An adjustment factor determines how strongly the energy price enters into the surcharge value. Such adjustment factor complies with the average likelihood of capitalisation of bids of the respective type of balancing energy, and shall be calculated quarterly on the basis of the past 12 months.

The intention of the new award mechanism is to ensure that bids for the energy price will be competitively taken into consideration when procuring balancing energy. The changes are likely to change the offer-merit order of the participants of the balancing power market and thus reduce the margins, and ultimately reduce the value of participating assets. Consequently, a market participant filed a complaint before the Higher Regional Court of Düsseldorf that was rejected, apart from an extension of the transposition period until 15 October 2018.[18]

Market coupling: XBID Market Project

Intraday markets are an important tool for market parties to keep positions balanced as injections and/or off-take may change between the day-ahead stage and real-time operations. The growth of intermittent generation capacity has increased the importance of efficient intraday markets. Consequently, the EU Commission has established a "*Target Model for Intraday*", based on continuous energy trading where cross-zonal transmission capacity is allocated through implicit continuous allocation. This model has been enshrined in the "*Framework Guidelines for Capacity Allocation and Congestion Management (CACM)*",[19] the cornerstone of a European single market for electricity. The European Power Exchanges EPEX SPOT, GME, Nord Pool Spot and OMIE (***PXs***) have responded to the needs of the market by establishing a transparent and efficient continuous intraday trading environment to enable market parties to easily trade out their intraday positions.

In order to help to realise this goal, the PXs, together with the transmission system operators from 11 countries, have launched an initiative called the Cross Border Intraday Market Project (***XBID***) to create a joint integrated intraday cross-zonal market. The purpose of XBID is to enable continuous cross-zonal trading and increase the overall efficiency of intraday trading on the single cross-zonal intraday market across Europe. XBID is based on a common IT system with one Shared Order Book, a Capacity Management Module and a Shipping Module. It allows for orders entered by market participants for continuous matching in one bidding zone to be matched by orders similarly submitted by market participants in any other bidding zone within the XBID solution's reach, as long as transmission capacity is available.[20]

The wider XBID solution will create one integrated European intraday market. Since going live in mid-June 2018, the number of trades in XBID has exceeded 2.5 million.[21]

Judicial decisions, court judgments, results of public enquiries

Decision of the Higher Regional Court

The Higher Regional Court of Düsseldorf on 6 December 2017 ruled that compensation claims of an offshore wind farm operator according to § 17e EnWG must be calculated on the basis of the best available data.[22]

It thereby deviated from the BNetzA's according guideline[23] and previous decision which held that an offshore wind farm operator had to accept massive reductions from its compensation for delayed grid connection under § 17e EnWG if the wind-data gathered on the top of each turbine was inaccurate. Based on a very literal interpretation of the law, the BNetzA had assumed that data gathered otherwise could not be used, even if it had been proven to be more accurate. Besides its relevance for the business case and financing of offshore wind farms, it is notable that the court held the refusal to pay the compensation by the transmission system operator as abusive, even though this was in line with the BNetzA's guidelines and decisions. The latter may have a significant impact on the reliability of the core regulator's authority in the industry.

EU Commission decisions under State aid rules

Within the last 12 months, the EU Commission decided on a number of cases[24] regarding the compatibility of German regulation with European State aid rules, *i.a.*:

Back in 2014, the EU Commission approved exemptions from the EEG surcharge (essentially a charge imposed on electricity consumers to refinance subsidies for renewable energy plants) for existing self-suppliers of electricity under the EEG 2014 for a transitory period, as Germany committed to examine how the surcharge could be imposed on existing self-suppliers in the future.[25] In December 2017, the EU Commission approved the progressive application of the EEG 2017 surcharge regime for self-suppliers that had entered into operation before August 2014.[26]

In February 2018, the EU Commission approved the capacity reserve mechanism under section 13e EnWG, as it is considered necessary to ensure the stability of the electricity market during the ongoing Energy Transition.[27] The approval is applicable to a reserve capacity of up to 2GW and covers three two-year contracting periods from 2019 until 2025.

As of 28 May 2018 and after a five-year lasting in-depth investigation, the EU Commission concluded that the exemption for certain large electricity users in Germany from network charges in 2012–2013 violated EU State aid rules.[28] There were no grounds to fully relieve those users from paying network charges. Consequently, Germany has to recover the illegal aid, whereas it is not yet clear how such reversal shall take place. Between 2011 and 2013, electricity users that had an annual consumption above 10 GW/h, and particularly stable electricity consumption, were fully exempted from paying network charges under German law (Section 19 para. 2 of the German Network Charges Ordinance – *Stromnetzentgeltverordnung, **StromNEV***). In 2012, thanks to this provision, these users avoided paying an estimated €300 million in network charges. These costs were instead financed by a special levy imposed on final electricity consumers (the so-called §19-surcharge), which Germany introduced in 2012.

In August 2018, the EU Commission approved the German plans to reduce the EEG surcharge for new highly efficient CHP installations used for the self-supply of electricity and heat, which entered into operation after August 2014.[29] Operators of installations with an output range below 1MW or above 10MW are only obliged to pay 40% of the EEG surcharge. Regulations for installations with an output range between 1MW and 10MW are complex, but reduce the EEG surcharge in general.

Major events and developments

Results of renewable energy auctions

The first auction rounds for funding of electricity from renewable energy sources showed that the competition-based auction scheme introduced by the EEG 2017 works well in practice.

Under the new auction scheme, plant operators receive payments according to their individual bids, the funding rate being the price quoted in the successful bid and bids being accepted from the bottom up until the available volume has been exhausted.

Auctions regarding solar energy have taken place since April 2015. They resulted in an overall high competition level, unexpectedly low prices and an average quota of realisation of 95%.[30] The average volume weighted price of successful bids decreased from 9.17 ct/kWh in April 2015 to 4.33 ct/kWh in February 2018, with the lowest accepted price being 3.86 ct/kWh.[31]

The first two auction rounds regarding offshore wind energy were open to well-advanced projects and showed a high competition level. Accordingly, five bids of 0 ct/kWh were accepted; these projects, while not receiving funding under the EEG, will, however, benefit from free grid access.[32] The average volume weighted price of successful bids was 2.3 ct/

kWh; the highest price accepted was 9.83 ct/kWh.[33] The 10 projects that were awarded a total of 3,100 MW are expected to be realised between 2021 and 2025.

The first auction rounds, of a total of 2,800 MW, for onshore wind energy in 2017, showed very high demand and significantly falling prices. The average volume-weighted price fell from 5.71 ct/kWh in May 2017 to 3.82 ct/kWh in November 2017.[34]

The vast majority (95%) of the awards granted in 2017 were for citizens' energy undertakings (so-called "*Bürgerenergiegesellschaften*"). These projects enjoyed privileges under the EEG 2017 in terms of, *inter alia*, longer implementation periods and the possibility to participate in auctions for government funding prior to having obtained an emission permit.

As a result, the government identified a certain discontinuity risk regarding the expansion of the onshore wind energy sector. It expects a delayed realisation of these projects, negatively affecting the expansion of onshore wind energy plants in 2019 and 2020 as well as project developers, suppliers, and producers.[35] As a first reaction, the government suspended the aforementioned privileges for *Bürgerenergiegesellschaften* in July 2017[36] for the auction rounds of February and May 2018, and prolonged the suspension in June 2018 for all further auction rounds until May 2020.[37] Subsequently, the first auctions in 2018 showed a lower competition level, with prices rising back to the level of the first auction round in May 2017.[38]

In 2018, the BNetzA conducted the first joint auction, of 210 MW, for onshore wind energy and solar power installations. The pilot project under the *EEG 2017* provides for a direct competition between different technologies for the years 2018–2020. The results of the first round show a high competition level, but also a clear dominance of solar power projects, since only bids for solar power stations at an average volume-weighted price of 4.67 ct/kWh were accepted in the first round. The BNetzA holds the successful reduction of costs for solar energy projects in previous auctions responsible for the dominance.[39]

The first auction for CHP-plants in December 2017 showed a very high level of competition and a volume-weighted average price of 4.05 ct/kWh.[40] The bids totalled 82 MW; the lowest price accepted being 3.19 ct/kWh, and the highest price accepted being 4.99 ct/kWh.

Big merger: E.ON to acquire Innogy

In March 2018, E.ON SE (***E.ON***) and RWE AG (***RWE***) announced that E.ON is to acquire innogy SE (***innogy***), the renewable energy business, from its controlling shareholder RWE, as well as a series of asset swaps. By this, E.ON will become a company purely focused on providing energy networks and services to retail customers, while RWE will acquire E.ON and innogy's renewables businesses and take a 16.76% stake in E.ON. The Federal Cartel Office ("*Bundeskartellamt*") is currently examining the envisaged merger and will closely cooperate with the European Commission on this matter.

Grid-acquisition by Chinese investor blocked

The government recently decided that a 20% share of the German TSO 50Hertz, which was up for sale in 2018, should temporarily be acquired by the Kreditanstalt für Wiederaufbau (***KfW***, a government-owned development bank) on behalf of the Federal Republic of Germany. It considered 50Hertz, one of four TSOs in Germany, supplying about 18 million people, to be a key player in the implementation of the Energy Transition in Germany. The government defined the protection of the transmission system, a critical energy infrastructure under the Act on the Federal Office for Information Security, as a national security interest, since citizens and the business community expect a reliable energy supply.[41] The action was preceded by a bid by the leading Chinese grid operator

SGCC, and is no more than a temporary measure in order to protect one of the country's most crucial infrastructures from foreign influences.

Power Purchase Agreements

The determination of the level of funding received for electricity generated from renewable sources via tendering procedures pursuant to EEG 2017 and the WindSeeG caused a price erosion. This is why market participants, in particular plant operators, are more than ever forced to think about new business models and remuneration concepts for the electricity generated from renewable sources beyond the subsidy scheme of the EEG 2017. This is where Power Purchase Agreements (PPAs) come into play, an already well-established business model in other European countries, such as the Netherlands or Scandinavia. They can provide stability and long-term savings, for both the generator as well as the off-taker.

At present, a state-of-the-art PPA template complying with German law does not (yet) exist. In general, three different types of PPA exist: (i) on-site PPA; (ii) off-site PPA; and (iii) synthetic PPA (Contract for Difference). It is to be expected that such long-term PPAs will replace the existing legal subsidy scheme for most technologies, all the more considering that the 20-year EEG-funding period for numerous renewable energy facilities is about to end in the near future.[42] A start has been made: recently, Greenpeace Energy as well as Statkraft Markets announced the conclusion of PPAs with onshore windfarm operators, enabling the latter's further operation of their wind farms after expiry of the EEG-funding.[43] Turbine producer Enercon GmbH, via its subsidiary Quadra Energy GmbH, is also offering long-term PPAs to old installations dropping out of EEG funding.

Digitalisation in business

As mentioned above, the energy sector is considered to be a high-potential area for blockchain technology. It is therefore not surprising that various energy supply companies as well as startups have started working on the development and testing of blockchain solutions for the energy sector within the last year. Just to name a few, TenneT TSO GmbH together with sonnen GmbH is currently using decentralised home storage facilities, which are connected via a blockchain, to stabilise the electricity grid. The aim is to test the extent to which emergency measures in the event of network shortages, such as regulating wind farms, can be reduced. Another notable blockchain project is Essen-based blockchain startup Conjoule GmbH (a JV of Innogy and Tepco), offering a digital peer-to-peer trading platform, enabling blockchain-processed transactions of electricity between consumers and prosumers directly in the neighbourhood. It will be interesting to see how blockchain will affect the German energy market, all the more considering that the legislator is about to adapt the legal framework in this regard.

Proposals for changes in laws or regulation

100 Day Law

A first legislative project to implement the Coalition Agreement was promoted with a draft law to amend the EEG, the Combined Heat and Power Act and further provisions of energy law ("*Entwurf eines Gesetzes zur Änderung des Erneuerbare-Energien Gesetzes, des Kraft-Wärme-Kopplungsgesetzes und weiterer Bestimmungen des Energierechts*"; so-called "*100 Tage-Gesetz*", ***100 Day Law***[44]). This draft aimed to adapt the law to recent auction results and to accommodate the EU Commission's requirements under State aid rules.

The draft, *inter alia*, envisages stipulating maximum remunerations ("*Höchstwerte*") for onshore wind (5.7 ct/kWh) and solar (6.5 ct/kWh) to be granted in auctions. It further amends the WindSeeG to provide for a framework to permit offshore wind projects that are not connected to the grid without a tendering procedure.

Initially, the enactment was scheduled for summer 2018. Due to different views within the Coalition, however, the enactment of the 100 Day Law was postponed. It is assumed that the legislative process will resume in autumn 2018.

Coal Commission

In order to further decarbonise its electricity mix, the government is considering phasing out its coal-fired power plants faster than previously envisaged. Due to the high public sensitivities, it has established a "Commission on Growth, Structural Change and Employment" ("*Kohlekommission*") with the aim of defining a phase-out date and finding solutions for a swift and non-disruptive phase-out. The Commission has not yet published its results, even though according to public debate, coal phase-out shall possibly take place between 2035 and 2038.

Electricity Grid Action Plan

In order to accelerate grid expansion and upgrade the existing grids, the Federal Minister for Economic Affairs and Energy recently presented the "*Electricity Grid Action Plan*".[45]

The grid expansion is to be accelerated by improved internal auditing, including target agreements for all parties involved, and streamlined planning procedures. The government plans the revision of the Grid Expansion Acceleration Act ("*Netzausbaubeschleunigungs gesetz*") in autumn 2018, providing for simplified and accelerated planning procedures, e.g. by dispensing with federal planning where an existing powerline is used. It aims to optimise the existing grid infrastructure, especially by using yet unused capacities as well as new technologies and operating systems, and tackling bottleneck issues.

Electronic market communication (MaKo 2020)

In June 2018, the BNetzA launched a consultation process in order to amend the current requirements for electronic market communication (so called ***MaKo 2020***), in compliance with the requirements of the Act on the Digitalisation of the Energy Transition ("*Gesetz zur Digitalisierung der Energiewende*"). The consultation covers the adaption of business processes for the supply of customers with electricity (GPKE), the market processes for generating market locations (MPES), change processes in the field of metering (WiM), as well as the market rules for the performance of balance group accounting (MaBiS). The BNetzA intends to declare the changes of the market communication binding as of 1 December 2019. The period for comments has expired; it remains to be seen how the BNetzA will take into consideration the numerous comments received from the industry.

* * *

Endnotes

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Ghana

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Overview of the current energy mix, and the place in the market of different energy sources

Industry regulators and players

Ghana's current energy mix comprises: (a) electrical energy as produced from hydro, thermal and renewable sources; and (b) petroleum comprising crude oil and natural gas. The Ministry of Energy is the sector Ministry with responsibility for policy formulation, implementation, monitoring and evaluation.

Key players in the electricity sector are the: (a) Energy Commission, which is the licensing authority of electricity utilities with further statutory responsibilities for setting technical standards; (b) Public Utilities Regulatory Commission (PURC), which has responsibility for regulating and providing the rates chargeable for utility services; (c) Ghana Grid Company (GRIDCo), which has responsibility for the transmission functions of the electricity sector; (d) Electricity Company of Ghana (ECG) and the Northern Electricity Distribution Company (NEDCo), which have responsibility for the distribution of electricity throughout the country; and (e) various state-owned and independent power producers, the biggest and longest-standing of which is the Volta River Authority (VRA).

The Petroleum Commission and the National Petroleum Authority respectively, regulate the upstream and downstream petroleum industries. Ghana has one gas processing plant located at Atuabo in the Western Region operated by the Ghana National Gas Company (Ghana Gas). Ghana Gas is, formally, a subsidiary of the Ghana National Petroleum Corporation (GNPC), a state-owned entity tasked to reduce the country's dependence on imports through the development of the country's own petroleum resources. The GNPC is partner in all petroleum agreements in Ghana. The Tema Oil Refinery (TOR) is the country's major petroleum refinery[1] with a capacity of 60,000 barrels per day. The Bulk Oil Storage and Transportation Company Limited (BOST), with its network of storage and pipeline infrastructure, is a wholly state-owned company authorised to, among others, own, manage and develop a national network of oil pipelines and storage depots throughout the country.

In 2016, the increasing debt of state-owned energy operators such as TOR, VRA, NEDCo, and the ECG resulting from low collection rates and below-cost recovery pricing, caused the Government to establish ESLA PLC, a public limited liability company charged with issuing long-term bonds to pay energy sector debts due to banks and trade creditors. The securities issued by ESLA are backed by receivables emanating from the Energy Sector Levy which is imposed under the Energy Sector Levies Act, 2015 (Act 899).[2]

Electricity

There are currently three hydro-electric dams, all on the Volta River and all state-owned, with a combined installed capacity of 1,580MW contributing to the country's generating capacity: (a) the Akosombo dam is owned and operated by the Volta River Authority (VRA), established in April 1961; (b) the VRA also operates the plant at Kpong; and (c) the nation's other hydro power generation plant is located at Bui and owned by the Bui Power Authority (BPA).

The first thermal generation plant, the Takoradi thermal power plant, came on stream in 1997. Currently, the VRA owns a number of thermal plants located in Aboadze near Takoradi and within the Tema enclave, with a combined generation capacity of 1,292MW. These thermal facilities operate on a combined cycle and include: the 330MW Takoradi Thermal 1 (T1) Power Plant; the 340MW Takoradi Thermal 2 (T2) Power Plant, which is a Joint Venture (JV) between VRA and TAQA from Abu Dhabi; a 110MW Tema Thermal 1 Power Plant (TT1PP); a 80MW Mines Reserve Plant (MRP); a 49.5MW Tema Thermal 2 Power Plant (TT2PP),; a 38MW Tema Thermal 2 Plant Expansion (TT2PP-X); and a 220MW Kpone Thermal Power Plant (KTPP).[3] Due to the energy sector reform embarked on by the country from 1994,[4] there are also other independent power producers contributing to the energy generation capacity of the country. Notable among them are Ameri, Karpower, Sunon-Asogli and Cenit.[5]

With the passage of the Renewable Energy Act in 2011, the focus was shifted to encouraging the production of electricity from renewable sources. The Renewable Energy Act requires an electricity distribution utility or bulk customer to procure a specified percentage of its total purchase of electricity from renewable energy sources and provides in terms of incentives, a guaranteed feed-in tariff to renewable energy producers for 10 years. The policy objective of the country is stated to be to source at least 10% of its energy requirements from renewables.[6] Currently, two solar power plants, VRA Solar and BXC Solar, are operational, contributing about 0.22% to the total electric energy mix of the country. The contribution of renewable energy to the mix was bolstered by the commissioning of a 20MW solar plant at Gomoa Onyadze in the Central Region of Ghana on 15 September 2018.

In Issue No. 28 of the Energy Commission's Ghana Wholesale Electricity Market Bulletin of April 2018, the sources of Ghana's power mix are reported to comprise: (a) Hydro – 35.56%; (b) Thermal – 63.48%; (c) Renewable – 0.22%, all of which are generated locally; and imported power from Côte d'Ivoire – 0.74%. Of the generated power, 42.85% is state-owned while 56.42% is owned by independent power producers. At the end of 2017, the country's total installed capacity was 4,398.5 MW. The country is reported to have an excess capacity of about 1,700MW (±3%). This situation has been partly attributed to self-generation plants which have been installed as alternatives or back-up to the grid supply. These are estimated to represent about 500MW.[7] At the height of the energy crisis, non-residential and industrial consumers began to depend on diesel-operated generators as a more reliable and, in some cases, cheaper alternative to power supplied from the national grid.

Oil and Gas

Ghana discovered crude oil in commercial quantities in 2007 and commenced the commercial production of crude oil and gas in 2011. The country currently has three major oil fields: Jubilee, SGN and TEN. The Public Interest and Accountability Committee (PIAC) is a statutory body set up under the Petroleum Revenue Management Act, 2011 (Act 815) with a mandate to promote transparency and accountability in the management of petroleum revenues. In its report on the Management of Petroleum Revenues for 2017, the country's total crude oil production for 2017 was reported to be 58,658,063.54 barrels: Jubilee Field produced 32,749,975 barrels, representing 56% of total production, whilst TEN and SGN produced 20,452,577 (35%) and 5,455,511.54 (9%) barrels, respectively. This represented an 82% increase on the 2016 figure of 32,298,638 barrels.

The report further indicates that a total of 77,294.44 million standard cubic feet (MMScf) of associated gas was produced from the Jubilee, TEN and SGN fields in 2017. Jubilee produced 42,261.35 MMScf, while TEN produced 26,818.33 MMScf. Gas production from the SGN field commenced in May 2017 and totalled 7,214.76 MMScf for the year.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Two developments are worthy of mention:

In the 2017 report of PIAC on the Management of Petroleum Revenues, it is noted that the Government of Togo or its authorities are making adverse claims concerning its maritime boundary with Ghana in respect of the East Keta Ultra Deep Block. This could have an adverse impact, at the very least, on the development of the block and in effect, the total future revenues of the country. The report urges the Government to initiate urgent steps to delimit the country's maritime boundary with Togo. In this context, attention ought to be paid to the reported collaboration between Togo and Benin on maritime boundary issues.

The Government has at different fora expressed concern about the feed-in-tariffs agreed to in the various power purchase agreements (PPAs) negotiated between 2012 and 2015, at the height of the power crisis in the country.[8] To this end, it initiated a review of these PPAs. Some of the findings from the review were that the feed-in-tariffs were excessive, with some ranging upwards of US$ 0.18 per kilowatt hour.[9] The Government's stated policy is to renegotiate these PPAs with a view to, among other things, reducing the feed-in-tariffs to US$ 0.10 or less.

Among the entities whose PPAs were renegotiated is Karpower Ghana Company Limited. The results of the renegotiation were an extension of the duration of the PPA from 10 to 20 years and the relocation of the plant from Tema to the naval base in Takoradi. The expressed idea for the relocation is to make use of the country's gas resources from the Western Enclave by converting the plant from reliance on heavy fuel oil (HFO) to the relatively cheaper natural gas available in Takoradi. Further, future PPAs are also to be subject to a process of competitive bidding where prospective power producers are required to bid for power projects proposed by the Government. This is to engender competition and, hopefully, provide the country with cheaper power. Closely aligned to this policy is the Government's decision to renegotiate the timelines for the commencement of generation of power under the various PPAs signed with the ECG. The review found that production of power under most of the PPAs was scheduled to commence at about the same time, with the result that the country would have increased its generating capacity without the commensurate demand.

Developments in government policy/strategy/approach

<u>National Fuel Quality Policy</u>

A draft National Fuel Quality Policy (Draft Policy) has been developed[10] to amongst others, improve air quality and provide a framework for the development of guidelines, standards and regulations on the quality of petroleum products produced or imported into Ghana.[11] Its stated strategy for achieving these goals is to reduce or eliminate toxic compounds in fuels that have a negative impact on the environment and public health; and to review existing standards every five years or develop new standards, as well as enact new laws and regulations to address policy drifts.[12]

The Draft Policy notes that the average sulphur levels in petrol and diesel have in recent times soared to 1,000ppm and 1,500ppm respectively. In 2017, the maximum sulphur levels for Ghana were set at 50ppm for both gasoline and diesel.[13] The NPA has granted a waiver for local refineries to continue to produce fuels up to 1,500ppm maximum sulphur content until 2020, when their products will be required to meet the current specification of 50ppm.[14] Consequently, local refineries need to raise the required capital to upgrade their facilities to meet the set limits, failing which they will not be permitted to sell their products on the domestic market.[15] Penalties, to be determined by the NPA, will be imposed for non-compliance and the entity will be forced to shut down.[16]

Further, local refineries have the responsibility to ensure that the quality of fuels is maintained and copies of the quality certificates are made available to the NPA, which is required to periodically sample and test products destined for the market to ensure compliance to national standards.[17] In relation to imported fuels, samples of the fuels shall be taken from the vessel for conformity assessment by the Ghana Standards Authority (GSA) or any accredited laboratory before discharge and upon receipt of a satisfactory quality certificate, the NPA shall grant the final approval for discharge of the fuels into the various storage facilities.[18]

Inauguration of the Electricity Market Oversight Panel (EMOP)

The Electricity Market Oversight Panel (EMOP), which was established by the Energy Commission, as mandated by Regulation 16 of the Electricity Regulation, 2008 (L.I. 1937) to supervise the operation and administration of the Wholesale Electricity Market (WEM) and to carry out its functions independent of the Transmission Utility, was officially inaugurated with the 11-member panel sworn into office by the Minister for Energy on 22nd December 2017. At the inauguration, the Minister tasked the EMOP to ensure the finalisation of the various manuals and other governance documents of the WEM, and work hard to restore confidence in the power sector of Ghana to attract the needed investment.[19]

Addressing the overcapacity situation in power generation

The approach adopted by the Government to address the current overcapacity in power generation is seen in its renegotiation of existing PPAs to change their commencement date to different future dates (as detailed under section 1 above). Thus, going forward, it is likely that any new PPA contemplated by the Government may be set to commence at a future date, taking account of existing PPAs.

Developments in legislation or regulation

Energy Commission (Local Content and Local Participation) (Electricity Supply Industry) Regulations, 2017 (L.I. 2354)

The expressed objectives of the Energy Commission (Local Content and Local Participation) (Electricity Supply Industry) Regulations, 2017 (L.I. 2354)[20] include to: (i) promote use of local financial capital, expertise, goods and services to create employment for Ghanaians, promote businesses in the electricity supply industry and retain the benefits in Ghana; (ii) promote development initiatives for local stakeholders; and (iii) achieve a minimum local content of 60% and local participation of 51% in the Electricity Supply Industry.[21] The Regulations are applicable to persons engaged or intending to engage in the electricity supply industry[22] (i.e. any activity that requires a licence under the Energy Commission Act, 2011 (Act 541) and the Renewable Energy Act, 2011 (Act 832); and related to manufacture of electrical equipment, electrical appliances or renewable energy equipment in respect of the projects for the development and utilisation of renewable energy resources).[23]

The local participation levels required under L.I. 2354 are as follows:[24]

	Wholesale Power Supply	**Renewable Energy Sector**	**Electricity Distribution**	**Electricity Sales Services**	**Brokerage Services**	**Electricity Transmission Infrastructure**
Ownership	*Initial level*: 15% *Target level:* 51% in 10 years	*Initial level*: 15% *Target level:* 51% in 10 years	*Initial level*: 30% Minimum *Target level:* 51% in 10 years	*Initial level*: 80% Minimum *Target level:* 100% in 5 years	*Initial level*: 80% Minimum *Target level:* 100% in 5 years	*Initial level*: 15% *Target level:* 49% in 10 years

The local content levels required under L.I. 2354 are as follows:[25]

	Wholesale Power Supply	**Renewable Energy Sector**	**Electricity Distribution**	**Electricity Sales Services**	**Brokerage Services**	**Electricity Transmission Infrastructure**
Engineering and Procurement[26]	*Initial level*: Minimum of 30%[27] *Target level:* 50% in 10 years	*Initial level*: Minimum of 70%[28] *Target level:* 100% in 10 years	*Initial level*: Minimum of 70% *Target level:* 80% in 10 years	100% to Ghanaian owned companies	*Initial level*: Minimum of 90% *Target level:* 100% in 5 years	*Initial level*: Minimum of 30% *Target level:* 50% in 10 years
Construction Works – Installations	*Initial level*: Minimum of 60%[29] *Target level:* 80% in 10 years	*Initial level*: Minimum of 60% *Target level:* 80% in 3 years; 90% in 6 years	*Initial level*: Minimum of 70% *Target level:* 80% in 10 years	100% to Ghanaian owned companies	*Initial level*: Minimum of 100% *Target level:* 100% in 5 years	*Initial level*: Minimum of 60% *Target level:* 80% in 10 years
Post Construction Works Supplies	*Initial level*: Minimum of 70%[30] *Target level:* 80% in 5 years	*Initial level*: Minimum of 70% *Target level:* 100% in 10 years	*Initial level*: Minimum of 80% *Target level:* 100% in 10 years	*Initial level*: Minimum of 80% *Target level:* 100% in 5 years	*Initial level*: Minimum of 80% *Target level:* 100% in 5 years	*Initial level*: Minimum of 60% *Target level:* 80% in 10 years
Services	Minimum level for: Catering – 100%; Janitorial Services – 100%; Vehicle Maintenance – 100%; Equipment Servicing – 70% *Target level:* 100% in 10 years	Minimum level for: Catering – 100%; Janitorial Services – 100%; Vehicle Maintenance – 100%; Equipment Servicing – 70% *Target level:* 100% in 10 years	Minimum level for: Catering – 100%; Janitorial Services – 100%; Vehicle Maintenance – 100%; Equipment Servicing – 70% *Target level:* 100% in 10 years	Minimum level for: Catering – 100%; Janitorial Services – 100%; Vehicle Maintenance – 100%; Equipment Servicing – 70% *Target level:* 100% in 5 years	Minimum level for: Catering – 100%; Janitorial Services – 100%; Vehicle Maintenance – 100%; Equipment Servicing – 70% *Target level:* 100% in 5 years	Minimum level for: Catering – 100%; Janitorial Services – 100%; Vehicle Maintenance – 100%; Equipment Servicing – 70% *Target level:* 100% in 10 years
Management	*Initial level*: Minimum of 60%[31] *Target level:* 90% in 5 years	*Initial level*: Minimum of 60% *Target level:* 90% in 5 years	*Initial level*: Minimum of 90% *Target level:* 95% at all times	*Initial level*: Minimum of 90% *Target level:* 95% in 5 years	*Initial level*: Minimum of 90% *Target level:* 95% in 5 years	*Initial level*: Minimum of 80% *Target level:* 100% in 5 years

Operations and Staff Maintenance Staff	*Initial level*: Minimum of 60%[32] *Target level:* 80% in 5 years	*Initial level*: Minimum of 70% *Target level:* 80% in 5 years	*Initial level*: Minimum of 90% *Target level:* 100% in 5 years	*Initial level*: Minimum of 95% *Target level:* 100% in 5 years	*Initial level*: Minimum of 95% *Target level:* 100%	*Initial level*: Minimum of 80% *Target level:* 100% in 10 years
All Other Staff	*Initial level*: 100% Ghanaian at all	*Initial level*: 100% Ghanaian at all	*Initial level*: 100% Ghanaian at all	*Initial level*: 100% Ghanaian at all	*Initial level*: 100% Ghanaian at all *Target level:* 100%	*Initial level*: 100% Ghanaian at all
Operations and Maintenance Contract	-	*Initial level*: Minimum of 50%[33] *Target level:* 80% in 5 years	*Initial level*: Minimum of 90% *Target level:* 100% in 5 years	*Initial level*: Minimum of 95% *Target level:* 100% in 5 years	*Initial level*: Minimum of 90% *Target level:* 100% in 5 years	*Initial level*: Minimum of 100%

For purposes of implementing the Regulations, there is established thereunder the Electricity Supply Industry Local Content and Local Participation Committee[34] whose functions include: (i) supervising, coordinating, administering, monitoring and managing local content and participation development; (ii) appraising, evaluating and approving local content plans and reports; and (iii) assisting service providers and Ghanaian companies in capacity development.[35]

Petroleum (Exploration and Production) (Data Management) Regulations, 2017 (L.I. 2257)

The Petroleum (Exploration and Production) (Data Management) Regulations, 2017 (L.I. 2257)[36] set out the format, contents and standards for reporting and management of petroleum data.[37] L.I. 2257 imposes on contractors and the GNPC, the requirement to submit to the Energy Commission information on the production and sale of petroleum[38] as well as an annual report containing information on production of the field.[39] Licensees, contractors and the GNPC are required to keep data acquired or provided to them by the Energy Commission confidential.[40]

Petroleum (Exploration and Production) (Health, Safety and Environment) Regulations, 2017 (L.I. 2258)

The Petroleum (Exploration and Production) (Health, Safety and Environment) Regulations, 2017 (L.I. 2258)[41] expresses itself as seeking, amongst others, to prevent the adverse effects of petroleum activities on health, safety and the environment; provide minimum health, safety and environment requirements for contractors, sub-contractors, licensees, the GNPC or persons engaged in petroleum activities; and promote high standards for health, safety and environment in carrying out petroleum activities.[42]

L.I. 2258 requires that contractors, sub-contractors, licensees, the GNPC or persons engaged in petroleum activities put in place and submit to the Energy Commission a health and safety plan adapted to their petroleum activity, and endeavour to improve the plan in accordance with technological development, applicable laws and best international practice;[43] and also prepare and submit to the Energy Commission a Safety Case[44] no later than six months before the commencement or operation or decommissioning of a petroleum facility.[45]

L.I 2258 further requires that contractors, sub-contractors, licensees, the GNPC and persons engaged in a petroleum activity take steps to eliminate or reduce risks or hazards to people, the environment or assets, in accordance with the Regulations and in compliance with best industry practice.[46] An operator is required to immediately notify the Energy Commission of any "high-potential near-miss",[47] pollution, hazardous situation or accident[48] and ensure that necessary measures are taken as soon as possible during a hazardous and "accident"[49] situation.[50]

Judicial decisions, court judgments, results of public enquiries

Benedict Kanose and 1001 Others & Public Utilities Workers Union (PUWU) v. Electricity Company of Ghana Limited, the Attorney-General and Millennium Development Authority – Suit No. IL/0115/2017 (High Court, Accra)

Pursuant to the Millennium Challenge Compact dated 5 August 2014, the Millennium Challenge Corporation (MCC) is assisting the Government of Ghana to reorganise the power sector through private sector participation and key policy and institutional reforms that are expected to enhance power production in Ghana. In relation to the Electricity Company of Ghana (ECG), it requires the bringing-in of a private sector operator.[51] There has been some agitation from employees of ECG against the implementation of the Millennium Challenge Compact, due to an apprehension that the project threatens to affect their employment with ECG. On 3 October 2017, 1,002 employees of ECG and the PUWU instituted an action against ECG, the Attorney General and the Millennium Development Authority seeking, amongst other things, a perpetual injunction against the defendants from continuing with the reform of the electricity distribution sector of Ghana. They also applied for an interlocutory injunction restraining the defendants from engaging individual workers of ECG, including the Plaintiffs, with a view to bargaining their redundancy package with them individually. On 31 October 2017, the High Court dismissed the interlocutory injunction application on the basis that the Respondents would suffer greater hardship if implementation of the Compact were halted. The action has also now been discontinued by the employees.

Seadrill Ghana Operations Limited v. Tullow Ghana Limited [2018] EWHC 1640

Tullow Ghana Limited ("Tullow Ghana") hired from Seadrill Ghana Operations Limited ("Seadrill Ghana") an ultra-deep water semi-submersible rig, West Leo. The contract, initially entered into on 3 November 2011, was for one year but a three-year contract was later agreed with an option to increase by a further two years. That option was exercised by Tullow Ghana on 15 December 2012 so that the three-year contract was amended to a five-year contract. Pursuant to the contract, Tullow Ghana was obliged to pay a daily operating rate of hire of the order of US$600,000.

In October 2016, Tullow Ghana sent a notice of *force majeure* to Seadrill Ghana in respect of the West Leo contract. Tullow Ghana claimed that the field the rig had been hired for was subject to a drilling moratorium by the Government of Ghana. The moratorium was in place due to proceedings before the International Tribunal for the Law of the Sea (ITLOS) to determine the delineation of the disputed maritime boundary between Ghana and Côte d'Ivoire in the Atlantic Ocean. The moratorium was pursuant to the Provisional Measures Order of the Tribunal that "Ghana shall take all necessary steps to ensure that no new drilling either by Ghana or under its control takes place in the disputed area." Tullow Ghana unilaterally terminated the Rig Contract in December 2016.

The High Court in England held that Tullow Ghana was not entitled to terminate its West Leo rig contract with Seadrill Ghana by invoking the contract's *force majeure* provisions. The Provisional Measures Orders of ITLOS did not disable Tullow from fulfilling its obligation by providing a drilling programme to Seadrill in relation to the Greater Jubilee Fields, which were not part of the disputed area. The unwillingness of the Government of Ghana to approve the Greater Jubilee Plan was not an event of *force majeure* given the limits that the contractual provision imposed on the meaning of that term.

Major events or developments

<u>Maritime boundary dispute</u>

The maritime boundary dispute between Ghana and Côte d'Ivoire, which arose following Ghana's oil discoveries in 2007 and had been a matter of keen national and international interest, has eventually been determined.

On 23 September 2017, the special chamber of the International Tribunal for the Law of the Sea (ITLOS) ruled in favour of Ghana on its maritime dispute with Côte d'Ivoire. The tribunal accepted Ghana's argument for the adoption of the equidistance method of delimitation of the maritime boundary between it and Côte d'Ivoire. The effect of the ruling of the ITLOS was to confirm substantially Ghana's version of the disputed boundary where it had granted petroleum concessions. According to the 2017 PIAC report on the Management of Petroleum Revenues, "[t]his has de-risked the uncertainty of the area and has led to the intensification of exploration by upstream petroleum companies in the previously contested area".

Further, Ghana, by the ruling of the tribunal, avoided paying compensation to Côte d'Ivoire for the concessions that were existing and producing oil from the disputed area. The Africa Energy Intelligence No. 802 Paris, October 10, 2017 publication indicates that "[t]he hardest-hitting outcome of the sea court's decision is that all the revenue from the TEN deposits now goes to Accra. As a result, Ivory Coast has no claim to any amounts outstanding from Tullow Oil".

Subsequent to the decision of the special chamber of ITLOS, Ghana and Côte d'Ivoire set up a joint committee to oversee implementation of the decision. The joint committee has held two separate sets of meetings in relation to implementing the decision of the special chamber. The first of these meetings was held in May 2018 in Abidjan, Côte d'Ivoire. On 9 and 10 August 2018, the second set of meetings were held in Accra, Ghana. It is reported that Ghana and Côte d'Ivoire have now jointly plotted the coordinates to determine the maritime boundary in accordance with the ITLOS decision, and have agreed to execute a document evidencing the plotted maritime boundary at the next meeting scheduled for October 2018 in Côte d'Ivoire.[52]

<u>Ameri BOOT Agreement</u>

On 10 February 2015, Africa & Middle East Resources Investment LLC ("Ameri Group") and the Government of Ghana entered into a Build, Own, Operate and Transfer Agreement ("BOOT Agreement") in relation to the supply, financing, installation, operation and maintenance of 10 new GT TM 2500 aero derivate gas turbines. Ameri Group assigned the BOOT Agreement to Ameri Energy Power Equipment Trading LLC ("Ameri Energy"). The agreement was signed as an emergency power agreement to help reduce the power supply deficit at the time and the project was expected to be delivered within 90 days after the fulfilment of conditions precedent.

Ameri Energy was to build the power plant, own and operate it for five years before transferring it to the Government of Ghana at a total cost of US$510m. However, after the new Government came into power, on 1 February 2017 it set up a committee to review the BOOT Agreement. The committee found the BOOT Agreement to be grossly unfair and not in the best interests of Ghana. It also found that the project was executed and financed by a Turkish registered company at a price that was considerably lower than that agreed between the Government of Ghana and Ameri Energy under the BOOT Agreement. The committee recommended a renegotiation of the Agreement or, failing that, its repudiation.[53]

Following the committee's recommendation, it is reported that the Energy Ministry embarked on a revision of the Ameri deal. On 26 July 2018, when the revised agreement was to be considered by Parliament, it had to be withdrawn for further consideration as the proposal was opposed by members.[54]

Sankofa Gas Project

Vitol, an energy and commodities company which holds a 35.56% stake in the Sankofa Gas Project, on 20 August 2018 announced via a press release that Offshore Cape Three Points (OCTP) had commenced delivery of gas from the Sankofa field to the GNPC. The estimated net cost of gas to Ghana will be less than US$4.5/MMBtu, significantly reducing Ghana's fuel costs compared to liquid fuels or imported gas.[55] The OCTP Integrated Oil and Gas Project is aimed at developing offshore natural gas located in deep water 60km offshore of Western Ghana, and is estimated to generate US$7.9 billion of investment in Ghana over its full life. The project is expected to improve the reliability of power services in Ghana, replacing the current use of expensive, heavy fuel with cleaner and more affordable gas resources. The gas from the project is expected to fuel up to 1,000MW of domestic power generation.

Proposals for changes in laws or regulations

The Land Bill, 2018 which is currently before the Parliament of Ghana, proposes to "…revise and consolidate the laws on land, with the view to harmonising those laws to ensure sustainable land administration and management, effective land tenure and to provide for related matters". To that end, it proposes to repeal most of the major legislation relating to land including the Lands (Statutory Wayleaves) Act, 1963 (Act 186).

Significantly, the Bill proposes to do away with the right of users as exists under the Lands (Statutory Wayleaves) Act, 1963 (Act 186) and provides for lands required in the public interest to be compulsorily acquired by the State. The Bill further requires that provision is made to the satisfaction of the Lands Commission for the payment of compensation and related costs of the acquisition in an escrow account prior to undertaking the acquisition. It introduces a statutory timeframe of two years within which the process of compulsory acquisition must be completed, and the requisite compensation paid. Under the Bill, a registered interest in land is made subject to the overriding interests of a right of way, right of entry, an electric supply line and dam erected, constructed or laid in pursuance or by virtue of a power conferred by an enactment. The right of way need not be registered to have such effect.

* * *

Endnotes

1. Platon Gas Oil Ghana Limited and Akwaaba Link Investments are privately owned mini-oil refineries operating in the country.
2. www.eslaplc.com/pages/about-us#company-profile.
3. http://www.vra.com/about_us/profile.php.
4. Edjekumhene, Ishmael; Amadu, Martin Bawa; Brew-Hammond, Abeeku. "Power Sector Reform in Ghana: The Untold Story", January 2001.
5. http://www.ecgonline.info/index.php/about-the-power-sector-in-ghana.html.
6. The Energy Commission. "National Energy Policy Paper", 2010.
7. Energy Commission Ghana, "2018 (Energy Supply and Demand) Outlook for Ghana", April 2018.

8. www.myjoyonline.com/politics/2017/april-17th/review-of-power-agreements-has-saved-ghana-300m-bawumia.php.
9. https://www.myjoyonline.com/news/2018/September-16th/1d1f-akufo-addo-commissions-20mw-solar-plant-project-at-gomoa.php.
10. By a Committee formed by the Ministry of Energy with representation from the NPA, Environmental Protection Agency, Ghana Standards Authority, Energy Commission, Tema Oil Refinery, BOST, Association of Oil Marketing Companies and the Chamber of Bulk Oil Distributors. The draft is currently under review by the individual entities having representation on the Committee.
11. https://www.mofep.gov.gh/sites/default/files/pbb-estimates/2018/2018-PBB-MoEn.pdf at p.12; Sections 1.4 and 8.2 of the Draft Policy.
12. Section 8.3
13. Section 2.2.3
14. Section 2.4
15. Section 2.4
16. Section 2.4
17. Section 9.3.2
18. Section 9.3.2
19. http://www.energycom.gov.gh/emop.
20. Gazetted on 17 November 2017 and came into effect on 22 December 2017.
21. Regulation 1
22. Regulation 2
23. Regulation 82
24. First to Sixth Schedule
25. First to Sixth Schedule
26. of the value of the project other than machinery shall go to Ghanaian Companies.
27. of the value of the project other than machinery shall go to Ghanaian Companies.
28. of the value of the project shall go to Ghanaian Companies.
29. of the cost of construction works of the project shall go to Ghanaian Companies.
30. of the value of all supplies shall go to Ghanaian owned Companies.
31. of management staff shall be Ghanaians at the beginning of the business operations.
32. of operation and maintenance staff shall be Ghanaians at any time in the lifetime of the business.
33. of the value of all operation and maintenance contracts shall be awarded to indigenous Ghanaian Companies.
34. Regulation 9
35. Regulation 10
36. Gazetted on 16 November 2017 and came into effect on 21 December 2017.
37. Regulations 1 and 2
38. Regulation 36
39. Regulation 37
40. Regulation 38
41. Gazetted on 16 November 2017 and came into effect on 21 December 2017.
42. Regulation 1
43. Regulation 33(1) and (2)
44. Means a document produced by the operator of a facility which identifies the hazards and risks, describes how the risks are controlled and safety management system in place to ensure the controls are effectively and consistently applied (see Regulation 80).

45. Regulation 10
46. Regulation 9
47. Means any accident that could in other circumstances have realistically resulted in one or more fatalities, significant damage to the environment or major asset damage (see Regulation 180).
48. Regulation 159
49. Means an uncontrolled event which has resulted in loss of human life, personal injury, damage to the environment or loss of assets and reputation (see Regulation 180).
50. Regulation 160
51. https://www.mcc.gov/where-we-work/program/ghana-power-compact.
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Kweki Quaynor Ahlijah has been active in the corporate and commercial, banking and finance and energy practice of Reindorf Chambers since 2011. She has been involved in advising on financing and equity transactions, business set-up and issues relating to various relevant laws and regulatory compliance, approvals and consents. She provided key support for advising on a US$450 million and US$75 million financing of a major power generation company, as well as a €10,750 financing of the construction of a 230MW simple cycle power plant. She has also been involved in advising on a US$ 6 million equity and debt investment through a joint venture for the development phase of a petroleum storage terminal project in Ghana.

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Nana Takyiwa joined Reindorf Chambers in September 2013 and has since been involved in the firm's energy and natural resources, corporate and commercial, dispute resolution and finance practice. She has, among other things, been instrumental in providing advice to a power company in relation to the development of a liquefied natural gas project in Ghana, and providing advice to a bulk petroleum products distribution company in relation to a front-end engineering design services contract for 750km of Buried Pipeline Build-out in Ghana. She has also assisted in providing legal advice to a commodity trading and logistics company in relation to permitting requirements in connection with the operation of an offshore oil vessel within the Free Zone (located within Ghanaian territorial waters) and related matters.

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Guatemala

Gabriela Roca
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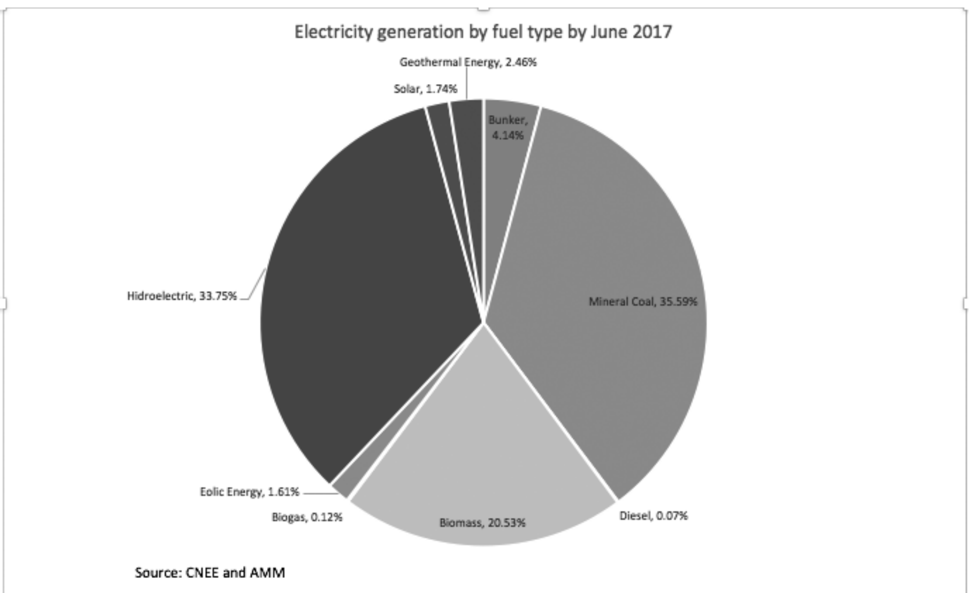
Overview of the current energy mix, and the place in the market of different energy sources

The Guatemalan electricity sector has an installed capacity of 4,204.9 MW, comprising a combination of technologies. The major energy generation sources for supplying demand are: 1,417 MW of Hydroelectricity; 675 MW Sugar Mills' Cogeneration; 545 MW Coal-fired turbines; and a combination of wind farms and solar plants.



All generation sources sell energy through the wholesale market, either by bilateral contracts with purchasers or on the spot market. Generation is dispatched daily, based on a weekly programme that allows the wholesale market to optimise the sources for better pricing and more reliable power.

The Guatemalan electricity sector has evolved: back in the 1990s, it was a nationalised and centralised system; then came legal reform in 1996 with the General Electricity Act which created a framework allowing private sector, national and international entities to invest in all four major activities of the electricity market, which are generation, distribution, transmission and commercialisation. From only 4 out of 10 Guatemalans having access to electricity back in the 1990s, Guatemala has shifted to 9 out of 10 of its citizens gaining access to electricity recently.

Also, stability in the tariffs is a result of continuous investment for the last 18 years, and the coexistence of regulation and private investment has been a great success for the country.

The major difference between energy sources is the products that each source is allowed to sell. Capacity and Energy are two products that may be contracted, but not all generation sources may sell both. Solar and wind generation, as well as hydropower plants with no reservoir, may only sell energy, as opposed to other sources such as thermic and hydropower plants with reservoirs that may also sell capacity. By law, demand should be covered with capacity contracts in order to be considered a firm demand.

In 2018, maximum demand has been 1,621 MW, less than half of the available installed capacity. Prices have been going down constantly in recent years due to: excessive installed capacity; reverse auctions as the system used by distribution companies to buy energy for their regulated demand; and prices of fuels.

The Guatemalan government through the Ministry of Energy and Mines has the obligation to plan for national electric policies, and to plan ahead for the expansion of generation and transmission systems.

Transmission is a regulated activity that allows for private entities to participate in bid processes for expanding the system and recover the investment through a Transmission Tariff (CAT for its definition in Spanish) that gets paid by all users of the system.

Distribution is also a regulated activity, where private entities bid for certain areas (not exclusive) and get a VAD (Distribution Added Value) in return; distribution companies are the largest Capacity and Energy purchasers. Guatemala has three major distribution companies, two for rural Guatemala and one for the central area.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

The Ministry of Energy and Mines is the State body responsible for development and coordination policies, plans and programmes related to the sector.

The National Electric Energy Board (CNEE – *Comision Nacional e Energia Electrica*) is the regulatory agency of the subsector responsible for ensuring compliance with General Electricity Law and sector regulations. It has a planning role and is in charge of the bidding process for new-generation projects and the process for expanding the transmission system.

Finally, the Wholesale Market Administrator (AMM – *Administrador del Mercado Mayorista*) is a private non-profit agency created by law with the purpose of managing the products and services that are bought and sold on the market in accordance with law and regulations.

The Guatemalan electric system interconnected with Mexico in the year 2010, although agreements have been in place since 2003. Initially, such interconnection was only used for importing energy to Guatemala, but recently, in 2017, and due to new Mexican electricity regulations, Guatemala has been exporting to Mexico as much as 10% of its national energy demand. This new market has opened a new perspective and opportunities to local generation.

It is also important to consider that Guatemala is part of the Central American electricity Market (MER) with other Central American countries, *per* international agreement reached more than 20 years ago. Due to differences in the political, regulatory and commercial approaches, real integration has not been reached, but transactions between countries are incrementally increasing each year using the regional interconnected system.

Recently Guatemala has been embroiled in a conflict with the Regional Operator and Regional Regulator for the interconnection facility with Mexico, where the regional authorities consider this to be a regional facility while Guatemala sees it as a national facility, the interconnection of which is not to be ruled by Central American regulations. This conflict has raised several issues between countries but Guatemala has a strong position due to its geographic location and also its interpretation of bilateral agreements between a country member of the regional market and non-members of such market.

Guatemala has good opportunities to increase demand for energy due to good prices and diverse sources of generation, but has to solve some political issues such as Municipalities charging a high rate for street lighting, or technical losses due to theft of energy by some conflict groups.

The diverse group of agents participating in the different activities of the sector makes this a well-balanced sector with enough competition.

Developments in government policy/strategy/approach

As mentioned previously, the Guatemalan electric sector as well as the country is facing litigation with regional entities, but Guatemala is also entering into more detailed and open agreements with Mexico's electric authorities to expand commercial activities between both countries.

Back in 2003, the Guatemalan Congress approved a bill to incentivise renewable generation with some fiscal benefits such as VAT exemption, as well as import duties exemption; also during the first 10 years of operations, no Income tax will be applicable to renewables projects. Due to such fiscal incentives and recent bidding processes promoted by the distribution companies in coordination with the Regulator, an increase of renewable generation projects is anticipated; not only large-scale but also minor-scale projects.

Due to the interest in developing minor-scale generation projects, the Regulator issued the regulation to authorise the possibility of minor-scale renewable projects connecting to the distribution grid without charge and selling the energy to distribution companies through bidding processes.

The Guatemalan Government through the Regulator (CNEE) has developed different expansion plans, such as the Transmission System Expansion Plan for the years 2018–2032, and the Generation System Expansion Plan for the years 2018–2032.

The main goals of the Expansion Plans are:

(a) Assured electricity supply at competitive prices.

(b) Assured fuel supply at competitive prices.

(c) Exploration and exploitation of fuel reserves with the intention of local supplies.

(d) Sustainable and efficient use of energy.

(e) A reduction in the use of wood as a fuel in the country.

It is important to note that Guatemala is a signatory to the Sustainable Development

Goals of the United Nations, and in accordance with Goal No. 7, non-contaminating energy should be sought by government. Access to energy in remote communities is still a pending issue for Guatemala and its electric system which should be addressed in the next few years. Ironically, in the areas with more renewable resources, there is less access to electricity due to difficulties accessing the transmission system and land access rights.

The specific objectives of the Plan are:

(a) Diversification of energy sources, prioritising renewable sources.

(b) Reaching 80% of electric energy produced by renewable sources by the year 2027.

(c) Offering the assurance of energy supply at competitive prices.

(d) Reducing national emissions.

(e) Complying with obligations acquired by COP21 in regard to emission reductions.

The Guatemalan Government has ratified a number of international commitments, where sustainable development is highlighted as a transversal approach for all plans.

In spite of the differences between Guatemala and the regional authorities, Guatemala has a regional policy that calls for positioning the country as the leader of the Regional Electricity Market and expanding operations. There has always been the intention to create regulation that will allow for long-term regional power purchase agreements, since the actual regulation is not clear and strong enough to back such investment.

Judicial decisions, court judgments, results of public enquiries

Important events happened recently in the judicial sector which had impacts on the electricity sector. In June 2017, an environmental NGO filed an *Amparo* (constitutional claim) against the Government (Ministry of Energy and Mines) for issuing a mining licence for an international company without having consulted indigenous communities in the impact area of the project. Such claim is not isolated; in the last five years, NGOs have filed several claims, with requests for suspension of the projects, including generation and transmission projects.

Until 2017, no project had been suspended by a Court injunction due to a claim against the Government for not having consulted by the ILO 169 Agreement. Guatemala doesn't have a consultation law that would allow not just companies, but the Government too, to have a clear and agreed implementation process. This definitely affects the energy sector, primarily because although generation does not need governmental authorisation, the use of water for generation projects does, and the Hydropower plants are being challenged by this type of claim. The Oxec and Oxec 2 projects (two projects that add up to around 86 MW) were suspended for more than 90 days based on the claim, but after a Court resolution, they were able to go back to operations and the Government conducted a consultation process. This topic has raised a lot of concern between national and international investors, banks and other stakeholders, increasing risk and credit constraints to the projects.

Due to this situation, the private sector and Government have for the past four years been discussing a Bill to be approved by the Congress to regulate the consultation rights for indigenous communities and coexistence with development projects. It is important that local or international investors consider plans that the Government should conduct a consultation process in accordance with ILO Agreement and Court resolutions before issuing a permit that may affect indigenous communities.

Major events or developments

Since 2013, Guatemalan distribution companies, with the support of CNEE, have launched three major bids for purchasing more than 900MW of energy for regulated users. Such processes were a complete success and provoked an intensive wave of investment in different generation sources. For the last four years, new facilities have been installed in Guatemala on a continual basis, introducing wind farms and solar plants.

Although there is a concern in the electricity sector due to low prices of energy and excess installed capacity, distribution companies are committed to continue with the bidding process, in accordance with their obligation to provide firm capacity contracts to meet projected increased demand.

Guatemala is a good country to invest in the energy sector; it is open for foreign investment by not imposing limitations on foreign companies' ownership of generation, distribution and transmission companies. There is no specific tax imposed on electricity activities other than income tax and VAT.

In June 2017, the US State Department launched a strategy that is focused on the protection of American citizens by addressing the security, governance and economic drivers of illegal immigration and illicit trafficking, while increasing opportunities for U.S. and other business. As part of that strategy, the U.S. Government is supporting the Alliance for Prosperity Initiative (A4P). The U.S. assistance will promote economic growth, energy security, poverty reduction, workforce development, education and training, and greater regional integration that will increase jobs for Central Americans. Guatemala is part of this Plan, so this is also seen as an opportunity for the electricity sector, specifically in respect of expanding access to energy in more remote communities and promoting industry in the country.

Proposals for changes in laws or regulations

As mentioned, there is an intention – and a Constitutional Court order – to approve a bill to regulate the consultation process. Also, for the last couple of years there have been different bills proposed to regulate the Municipality charge for public lighting and other regional issues. In light of the current political situation in the Congress, it is unlikely any changes will result from the same in the short-to mid-term. The main regulations in the electricity sector are not likely to change, due to acceptance of the bill by the sector and the Government. No changes are needed at this time, neither are any such changes desirable with regard to the electrical energy sector, since this framework has proven to be a straightforward framework for investment in Guatemala.

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Gabriela Roca is a founding partner at QIL+4 Abogados, where she leads the Energy and Infrastructure practice. She advises associations representing the private sector which, in turn, provides guidance to investors in matters of Business and Human Rights to standardise ethical behaviour within their organisations and with local stakeholders and communities.

Her practice is focused on the development, financing, acquisition and operation of energy, fuel and infrastructure projects for foreign and local companies. She has advised an important number of companies interested in investing in greenfield projects, cross-border acquisitions of ongoing projects, mergers, sale and financing of equipment through export credit agencies and other investments in relation to the energy business.

Her experience and expertise in the negotiation of construction turnkey contracts is highly appreciated, and valued highly by developers and construction companies.

As a project lawyer, she has developed a strategic litigation practice in defence of the rights of investors related to the implementation of ILO Convention 169 in Guatemala. Recently, she has also been working actively in various associations that work to achieve the implementation of ILO Convention 169 by the Government.

Recently and due to a claim brought up by an environmental NGO against a mining licence and suspension of operations of the project, she is temporarily acting as Corporate Affairs Director of Minera San Rafael as part of the special task force dedicated to bringing back the project to operations in accordance with the laws.

As part of the QIL+4 Abogados team, she has participated with the litigation team, in various proceedings before the country's highest Courts to reinstate investors' rights, including foreign investors.

Gabriela has been counsel to development groups using different technologies for power generation (thermo, hydro, solar, wind and geothermal power projects), and also to local and foreign banks in financing such types of projects. She also has experience in legal due diligence processes for financing and acquisition of companies. She holds an active chair in the wholesale electricity market administrator that oversees and regulates all commercial and technical aspects of the wholesale electricity market's transactions. She is a founding member and Vice President of the Guatemalan Chapter of the Vance Center Women in the Profession Program (WIP) – *Transforma Abogadas en Guate* (local name). The Guatemalan Chapter was launched in 2016 as an initiative in Guatemala to enhance diversity and inclusion at all levels in the legal profession. She is also Director of the Women's Justice Initiative in Guatemala.

Gabriela has a Master in Laws (LL.M.) from the Pontificia Universidad Católica de Chile and graduated as an attorney at Universidad Rafael Landivar.

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India

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Overview of the current energy mix, and the place in the market of different energy sources

With the advent of the 21st century and even prior to it, there has been large-scale industrialisation in India. Our lives have become vastly dependent on machines, various types of gadgets and electronics, and it is almost impossible to imagine a world without it. For the purpose of enjoying the fruits of this industrialisation, the generation of power, energy and electricity is essential. In India there are broadly three kinds of participants in the Power Generation Sector; namely the Central Sector, State Sector and Private Sector.

The total installed capacity of Power Generation Stations/Utilities in India as of 31.05.2018 was 343,898.39 MW, of which the Private Sector is the highest contributor with an installed capacity of 155,511.02 MW (45%); the State Sector has an installed capacity of 103,760.75 MW (30%); and the Central Sector has an installed capacity of 84,626.63 MW (25%). The installed capacity at the end of the 12th five-year plan ending on 31.03.2017 was 319,606.30 MW; therefore, the increase in installed capacity in the past 14 months has been 24,292.09 MW. Furthermore, there has been an increase in the PLF (Plant Load Factor) percentage across India, whereby it has gone up from 63.55% in May 2017 to 65.34% in May 2018, which is indicative of the fact that India is focusing not only on increasing the capacity for generation but also on optimal utilisation of the existing capacity.

Being a country spread across a total area of approx. 3,287,263 sq km, India is gifted with a variety of renewable natural resources. This enables the country to generate power through not only thermal sources but other means as well. The pan-Indian breakdown of installed capacity, in terms of modes, is as follows:

1. Thermal Utilities: 222,692.59 MW
   a) Coal Utilities: 196,957.50 MW
   b) Gas Utilities: 24,897.46 MW
   c) Diesel Utilities: 837.63 MW
2. Nuclear Utilities: 6,780 MW
3. Hydro Utilities: 45,403.42 MW
4. Renewable Energy Sources Utilities: 69,022.39 MW (as on 31.03.2018)
   a) Small Hydro Power Utilities: 4,485.81 MW
   b) Wind Power Utilities: 34,046 MW
   c) Biogas-Power Utilities: 8,700.80 MW
   d) Waste to Energy Utilities: 138.30 MW
   e) Solar Power Utilities: 21,651.48 MW.

Each region in India generates electricity through various modes as mentioned above; wherein the resources available to each region vary because of the wide expanse of the country. The Western Region has the highest installed capacity of Coal Utilities, i.e., 70,608.62 MW and Gas Utilities, i.e., 10,806.49 MW; Southern Region has the highest installed capacity of Diesel Utilities, i.e., 761.58 MW, Renewable Energy Utilities, i.e., 34,369.28 MW and Nuclear Utilities, i.e., 3,320 MW; and Northern Region has highest the installed capacity of Hydro Utilities, i.e., 19,653.77 MW.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction of policy

Power generation through thermal and hydro sources can be traced back to the formation of India as an independent country. However, nuclear power stations have been established since 1974, and the first renewable energy power station was established in 1990. The growth in installed capacity of Renewable Energy Utilities in 2017 as against 2016 is about 11,320 MW. The growth in installed capacity of Hydro Utilities in 2017 as against 2016 is about 1,696 MW. The overall increase in electricity generation from 2015–16 to 2016-17 through renewable energy generation plants is 16,088 Gigawatt hours (referred to as "**GWh**", for short). The increase in electricity generation from 2015–16 to 2016–17 through hydro generation plants is 1,001 GWh.

The generation of electricity from renewable sources has increased to 8,444.5 Million Units (for short, referred to as "**MU**") in April 2018, as against 6,917.1 MU in April 2017. This is a consequence of the increase in generation from bagasse-based and solar plants, whereby generation has increased to 1,263.94 MU in April 2018 as against 644.57 MU in April 2017 for the former, while in the latter case generation has increased from 1,752.64 MU in April 2017 to 3,178.88 MU in April 2018. However, there has been a decrease in generation from sources like wind, biomass and small hydro.

The energy requirement in India for the period April 2018 to May 2018 was 216,429 MU, out of which 214,983 MU was supplied, as against 209,856 MU energy requirement and 208,455 MU energy supplied for the period April 2017 to May 2017; however, for both years there is a deficiency of merely 0.7%. The Peak Demand for power supply for the period April 2018 to May 2018 was 171,973 MW, of which 170,765 MW was met, as against the Peak Demand of 159,816 MW for the period April 2017 to May 2017, of which 158,393 MW was met. The deficiency in the previous year was 0.9%, which this year has been reduced to 0.7%.

The above data, inclusive of data under the previous heading, is based on reports of the Central Electricity Authority, and on analysing the same, it can be seen that there has been an increase in the generation of power and energy, with the emphasis on generation of electricity from renewable energy sources; primarily solar and waste-to-energy plants. Furthermore, as the generation of and the need for energy continues to grow, and with the private sector being actively involved as the highest contributor to the generation of electricity in India, the regulation of the same becomes critical.

Developments in government policy

With the increase in demand for energy along with the threat of climate change, it is pertinent that the development in electricity generation is sustainable and does not adversely affect the environment; hence various schemes have been launched and continued by the Government of India to promote generation primarily from renewable sources like waste-to-energy.

The main objectives of these policies are: firstly, to promote sustainable development; secondly, promotion of non-conventional sources of energy and bringing them at par with conventional sources; and lastly, to bring about betterment in the day-to-day lives of the citizens of the country by meeting their energy requirements and demands.

Thus, the policies introduced by the Central Government in 2017–18 in lieu of generation from renewable sources, along with meeting the energy requirements, are discussed below:

(a) *Concessional Custom Duty Certificate (Waste-to-energy)*

In the light of the current scenario in the country, where the amount of waste generated by citizens and demand for energy are increasing at a similar pace, policies encouraging the setting-up of waste-to-energy plants have proved to be an effective measure to utilise waste for the generation of electricity.

The Ministry of Finance had issued various Notifications for concessions on the procurement of machinery required for initial setting-up of a project for the generation of power or compressed bio-gas ("**Bio CNG**") using urban and industrial wastes of a renewable nature. Post- the implementation of the GST regime, the issuance of Excise Duty Exemption Certificates ceased to operate from 01.07.2017; whereas the issuance of a Custom Duty Concession Certificate is continued by virtue of the Office Memorandum dated 07.03.2018 of the Ministry of New and Renewable Energy. This will act as an incentive to set up waste-to-energy plants and thereby encourage generation from such sources.

(b) *New National Biogas and Organic Manure Programme 2018–2020*

Earlier, the National Biogas and Manure Management Programme ("**NBOMP**") was introduced, with the aim of setting up family-type biogas plants for providing biogas as a clean cooking fuel and a source of lighting, which continued until 31.03.2018. Pursuant to that scheme, about 4.96 million household-size biogas plants have been installed to date.

For the period 2018–20, a New National Biogas and Organic Manure Programme ("**NNBOMP**") is introduced as a Central Sector Scheme. One of the many objectives of this Programme is to provide clean cooking fuel for kitchens, lighting and meeting other thermal and small power needs of farmers/dairy farmers/users including individual households, and to improve organic manure systems based on bio slurry from biogas plants in rural and semi-urban areas by setting up biogas plants. For the purpose of achieving the objective of the Programme, Central Financial Assistance is provided under various headings, namely:

A. Central Subsidy Rates Applicable.

B. Additional Subsidy for cattle dung-based biogas plants if linked with sanitary toilets, only for individual households.

C. Turnkey Job Fee for construction, supervision, commissioning, and free O&M warranty for five years' trouble-free operations of plant including quality control at all levels.

D. Administrative Charges – for physical target achievement range of biogas plants.

E. Support for Training Courses including skills-development programme for Biogas Mitras.

F. Biogas Development & Training Centres ("**BDTCs**"). Financial support for set functions and roles of BDTCs would be provided towards staff, conducting training courses, skills-development courses, pilot plant demonstration, consumables and contingencies as per allocated targets.

G. Support for Communication & Publicity, as per the physical achievement range of biogas plants.

H. Incentive for Saving Fossil Fuels (diesel, petrol, kerosene, electricity, etc.) to farmers by using biogas in 100% biogas engines.

I. Further additional incentives are also given to Rural Development Departments.

(c) *National Policy on Biofuels*

The Central Government approved the National Policy on Biofuels on 16.05.2018. The policy categorises biofuels as: first generation (1G), producing ethanol from molasses and bio-diesel from non-edible oil seeds; second generation (2G), producing ethanol from municipal waste; and lastly third generation (3G) fuels like bio-CNG. The policy expands the scope of raw material for ethanol production by allowing the use of: sugarcane juice; sugar containing materials like sugar beet, sweet sorghum; and starch containing materials like corn, cassava, etc. The policy also allows blending of ethanol produced from damaged food grain, rotten potatoes and tomatoes.

The objective of this programme is to support R&D, pilot plant and demonstration projects leading to commercial development of 2G biofuels. In pursuance thereof, the policy provides a viability gap funding scheme indicated for 2G bio-ethanol refineries valued at Rs. 50,000 Million in six years to give special emphasis to advanced biofuels.

(d) *Scheme to Support Promotion of Biomass-based Cogeneration in Sugar Mills and Other Industries in the Country (up to March 2020)*

In order to support Biomass-based Cogeneration Projects in Sugar Mills and Other Industries for power generation in the country, this scheme has been implemented. The programme will provide Central Financial Assistance ("**CFA**") at the rate of Rs. 2.5 Million/MW for bagasse co-generation projects and Rs. 5 Million/MW for non-bagasse co-generation projects. The CFA will be back-ended and released in one instalment after successful commissioning and commencement of commercial generation and performance-testing of the plant. The Central Government has also directed to give incentives to the state nodal agencies at Rs. 0.1 Million/MW (maximum of Rs. 1 Million per project) towards post-installation monitoring of projects. The total CFA outlay is Rs. 1.7 Billion and the physical target to be achieved for the period 2017-18 to 2019–20 is of 740 MW.

(e) *National Wind-Solar Hybrid Policy 2018*

India has the fourth-largest wind power installed capacity in the world after China, United States and Germany. To further boost this segment along with solar power, the Government of India has announced a national wind-solar hybrid policy, which seeks to promote new projects as well as hybridisation of the existing ones.

The main objective of the Policy is to provide a framework for promotion of large grid-connected wind-solar PV hybrid systems for optimal and efficient utilisation of transmission infrastructure and land, reducing the variability in renewable power generation and achieving better grid stability and to encourage new technologies, methods and way-outs involving combined operation of wind and solar PV plants.

To encourage development of the said wind and solar hybrid projects, all fiscal and financial incentives available to wind and solar power projects will also be made available to hybrid projects.

(f) *Jawaharlal Nehru National Solar Mission (JNNSM)*

JNNSM aims to promote the development of solar energy for grid-connected and off-grid power generation. The primary objective is to make solar power competitive with conventional energy by 2020–2022. The commissioned capacity of grid-connected solar plants in India as of March, 2016 is 5,834 MW. The policy has set a target of producing 20,000 MW solar power by 2022.

Various schemes have been announced by Ministry of Natural and Renewable Energy ("**MNRE**") and State Governments to promote grid-connected and off-grid solar rooftop projects. In order to promote solar rooftops, Rs. 50,000 Million has been approved for implementation of the Grid Connected Rooftops system over a period of five years up to 2019–2020 under the National Solar Mission.

Various projects of total 356 MW capacity have been sanctioned and projects of 84 MW capacity have been tendered in January 2017 for Indian defence and paramilitary forces using solar cells and modules manufactured in India.

(g) *Information and Public Awareness Program*

Taking into consideration the growing concerns of energy security and environmental sustainability of energy use, and in order to percolate the benefits and usage of renewables to the masses, the Government of India has decided to continue the Information and Public Awareness Program for the period 2017–18 to 2019–20. A total outlay of Rs. 660 Million has been sanctioned by the Government for the wide-ranging programme which seeks to span print media, digital media, television and radio so as to reach a large number of audiences, which would in turn fulfil the wide-ranging objectives of the programme, the main objectives of which are as follows:

A. to popularise and create awareness about new and renewable energy systems and devices highlighting their benefits;
B. to create mass awareness about technological developments and promotional activities taking place in renewables from time to time in the country, with special focus on rural areas;
C. to make people aware about the availability of renewables including their proper use, repair and maintenance facilities, etc.;
D. to expand and promote the market for renewable energy systems and devices; and
E. to raise awareness about renewables among students, teachers, scientists and the public at large.

(h) *Clean Environment Cess*

In addition to the above schemes and policies, the Clean Energy Fund was proposed in the Budget 2016–2017. The Clean Environment Cess on coal, lignite, peat has been doubled from Rs. 200 per tonne to Rs. 400 per tonne to promote the use of renewable energy. This has the effect of deterring, or rather discouraging, the generation of electricity from sources such as coal, lignite and peat and consequently promotes generation through renewable sources.

(i) *Saubhagya Scheme or Pradhan Mantri Sahaj Bijli Har Ghar Yojana* (English Equivalent: Prime Minister's Easy Electricity in Every Household Scheme)

Another key development for encouraging the generation of electricity is this scheme, with the motto of providing/supplying electricity in every household. The project was announced in September 2017 with the aim to complete the electrification process by

December 2018. The total outlay of the project is Rs. 163,200 Million, while the Gross Budgetary Support ("**GBS**") is Rs. 123,200 Million. The scheme aims to provide electricity free of cost to the un-electrified poor households of the country so that 87% of Indian households will received electricity access as of 15 June 2018.

The abovementioned are various Schemes, Policies and Missions of the Government of India which primarily focus on the generation of power from renewable sources, along with supplying electricity to rural areas and unelectrified poor households. With respect to conventional sources of generation, on 17.05.2017 the Cabinet Committee on Economic Affairs approved the Scheme for Harnessing and Allocating Koyala (Coal) Transparently in India. The main objective of this scheme is to ensure adequate supply of fuel to power plants, which will thereby tackle the long-term challenge of lack of coal linkages.

Judicial decisions

The role of the Indian Judiciary in regulating the Energy Sector is not limited to curbing malpractice of private companies but rather extends to setting boundaries to the powers of the statutory authorities including, but not limited to, regulatory commissions. Furthermore, there have been instances of anti-trust violations by Government companies and the same have been recognised by the Courts in India. The following cases highlight some of the major decisions taken by the Hon'ble Supreme Court of India along with the Competition Commission of India.

- In the case of *Gujarat Urja Vikas Nigam Limited v. Solar Semiconductor Power Company (India) Private Limited and Ors.* [AIR 2017 SC 5372], the Hon'ble Supreme Court decided on the issue of "Whether Electricity Regulatory Commission has power to extend control period under tariff order and whether Commission has power to amend tariff despite the terms of Power Purchase Agreements." The Hon'ble Court held that the Commission, being a creature of statute, cannot assume to itself any powers which are not otherwise conferred on it. Therefore, it was held that the extension of the control period is outside the purview of the inherent power of the commission. The Hon'ble Supreme Court further notes that this judgment shall not stand in the way of Respondent No. 1 taking recourse to the liberty available to them for re-determining tariff if it is otherwise permissible under law. Therefore, the above case limits the powers of the Commission and holds that the terms of the Power Purchase Agreement cannot be varied by the Commission under the garb of inherent jurisdiction.
- The Hon'ble Supreme Court of India, in the case of *The State of Himachal Pradesh and Ors. v. Gujarat Ambuja Cements Ltd. and Ors.* [(2017) 9 SCC 601], further put an end to the dispute in relation to reimbursement of Peak Load Exemption Charge (hereinafter referred to as "PLEC"). The issue relates to Incentive Rules framed under the Industrial Policy wherein a "power tariff freeze" was granted for a four-year period from commercial production date by way of reimbursement of the excess tariff charged during the said period. It was observed by the Hon'ble Court that the question is how the word 'tariff' is to be understood in the context of the case; it is not one of whether PLEC is a part of the tariff within the natural meaning of 'tariff'. It was noted that during peak hours, the normal supply of electricity to which the normal tariff applied was discontinued, and the supply of electricity was an act of special dispensation and upon payment of PLEC, which was in the character of a surcharge. In view of this, it was held that the writ Petitioners would not be entitled to reimbursement towards PLEC, pursuant to the Incentive Rules.

- The case of *Nabha Power Ltd. v. Punjab State Corporation Ltd. and Ors.* [2017 (12) SCALE 241] is another leading case in the Energy Sector whereby the Hon'ble Supreme Court has held that the explicit terms of contract are always the final word with regard to the intention of the parties. A Power Purchase Agreement was entered into by the parties for the supply of 1,200 MW of power from Rajpura Thermal Power Project. The issue pertained to the cost of washing of coal and the entitlement of the Appellant to recover the same from Respondents. It was held that since, in terms of contract and the clarification issued by the Respondents, it is clear that the supply of washed coal is a necessity and hence, the Appellant is entitled to the cost of washing of coal under the terms of the Power Purchase Agreement.
- The Hon'ble Competition Commission of India (hereinafter referred to as "CCI") dealt with an issue related to Abuse of Dominant position by Gujarat Energy Transmission Corporation Limited (hereinafter referred to as "GETCO"), Stated Load Dispatch Centre, GETCO and Paschim Gujarat Vij Company Limited, being the Opposite Party (OP) Nos. 1, 2 & 3 in case of *HPCL-Mittal Pipelines Limited v. GETCO & Ors.* [2018 Comp LR 215 (CCI)]. The abuse of dominant position was alleged on the basis of the denial of open access by the OP 2 to the Informant, i.e., HPCL-Mittal Pipelines Limited. It was noted that by denying open access, the OP 2 had curtailed the demand for open access electricity and thereby restricted the production of electricity and provision of supply of open access electricity. Furthermore, it was observed that there is *prima facie* a denial of market access whereby the Informant and OP 3 (OP3 is a group entity of OP 2) are competitors. Lastly, a case of leveraging dominant position can also be made out, as OP 2 has leveraged its dominant position in the relevant market to adversely affect the competition in the downstream market. It was therefore held by the CCI that *prima facie* there is contravention of Section 4(2)(b)(i), 4(2)(c) and 4(2)(e) of the Competition Act, 2002 and thereby the Order of Investigation by the Director General under Section 26(1) of the said Act was passed. The Director General will submit its report to the CCI and a final Order *re*. abuse of dominance will then be passed by the CCI.

Major events or developments

The major events in India in the past 12 months include the Union Budget 2018–2019, which was tabled on 01.02.2018 and is said to have impacted the Renewable Energy Sector adversely; the other event is that the Union of India has entered into various MoUs with other countries with respect to the Energy Sector, which have been elaborated hereunder.

a) *Union Budget 2018–2019*

This Budget was presented by the Finance Minister, Mr. Arun Jaitley, on 01.02.2018 whereby on the one hand, incentives were given for the generation of electricity from renewable sources like solar, wind, etc. and on the other hand, custom duty, etc. was increased which adversely affects the Renewable Energy Sector. The highlights of the Budget 2018–19 in regard to the Energy sector are:

- The MNRE has been allocated Rs. 99 billion under Internal and Extra Budgetary Resources ("**IEBR**").
- The Solar Energy Corporation of India ("**SECI**") has been allocated Rs. 2.17 billion under IEBR.
- The custom duty on solar tempered glass or solar tempered (anti-reflective coated) glass for the manufacture of solar cells/panels/modules has been reduced from 5% to NIL, which has no significant impact as this duty was not effective earlier as well.

- The tariff rate of customs duty for Lithium-ion batteries has been increased from 10% to 20%. In the Government's bid to thrust the "Make in India" movement and to discourage imports, the budget has increased the custom duty on imported goods; this is likely to have an impact on the Energy Sector.
- Abolition of the Education Cess and Secondary and Higher Education Cess on imported goods. However, the same is replaced by the Social Welfare Surcharge at 10%, as against the Cess which was a mere 3%.
- Increased budget allocations to various schemes like the Saubhagya Scheme.

b) *Memoranda of Understanding (MoU)*

- India has been promoting the cause of renewable energy for quite some time now, and the same has been recognised by fellow countries. In lieu thereof, various countries have extended their hand and collaborated with India in the promotion of renewable energy whereby those countries take up joint research and development, establish institutional linkages and other mechanisms to extend cooperation. The various MoUs entered into by the Ministry of New and Renewable Energy in the past year are mentioned below:

A. Ministry of New and Renewable Energy, India and the Ministry of Energy and Mining, Peru (*Signed on 11 May 2018*)

The scope and forms of cooperation under the said MoU include: exchange and training of scientific and technical personnel; exchange of available scientific and technical information and data; organisation of workshops, seminar and working groups; know-how and technological transfers in non-commercial terms; exchange of information on regulatory aspects of renewable energy; and other forms of co-operation.

B. Ministry of New and Renewable Energy, India and the Ministry of Energy, Mines and Sustainable Development, Morocco (*Signed on 10 April 2018*)

The areas of cooperation under this MoU focus on the development of new and renewable energy technologies, *viz*. solar energy, small hydro, bio-energy and capacity-building. The modalities of cooperation under the said MoU include: exchange and training of scientific and technical personnel; exchange of scientific and available technical information and data; organisation of workshops, seminar and working groups; transfer of equipment, know-how and technology on non-commercial terms; development of joint research or technical projects on subjects of mutual interest; and other modalities.

C. Ministry of New and Renewable Energy, India and the National Solar Energy Institute, France (*Signed on 10 March 2018*)

This MoU is entered into primarily to work on various areas of solar energy comprising: solar photovoltaic; storage technologies; transfer of technology; and collaborative activities to include expanding the mapping of Indian solar energy resources, identifying optimal sites for large-scale solar projects in India, common R&D programmes, capacity-building, specialised training and the like.

D. Ministry of New and Renewable Energy, India and the Ministry of Public Infrastructure, Guyana (*Signed on 30 January 2018)*

The areas of cooperation under this MoU will focus on development of new and renewable energy technologies, *viz*. solar energy, wind energy, bio-energy, small hydro and capacity-building. The modalities are the same as those of the MoU between India and Morocco.

E. Ministry of New and Renewable Energy, India and the Ministry of Environment and Energy, Greece (*Signed on 27 November 2017*)

The areas of cooperation and the modalities used are the same as those of the MoU entered into with Guyana.

F. Ministry of New and Renewable Energy, India and the Ministry for the Environment, Italy (*Signed on 30 October 2017*)

The areas of cooperation under this MoU include new and renewable energy development, innovation in the field of energy, i.e., storage, and any other area of cooperation that the parties may decide. For the purposes of the MoU, there will be: promotion of investment and business activities in the field of energy; establishment of joint projects on technical and innovation cooperation; capacity-building through training and education cooperation; and various other like steps will be taken.

Proposals for changes in laws and regulations

The Ministry of Power, Government of India is planning to bring amendments to the Electricity Rules, 2005 (referred to as the "**Rules**", for short), whereby the proposed amendments pertain to Captive Generating Plants. The draft amendments were proposed and circulated among the stakeholders on 06.10.2016 and on the basis of comments received from various stakeholders, the Ministry of Power issued a modified draft on 22.05.2018.

The said amendment states that the Appropriate State Commission shall certify a generating station or power plant to be a Captive Generating Plant. This status of Captive Plant shall be cancelled by the Appropriate Commission, on request of the Authority, if the report of generation and consumption is not submitted on time, as required.

Furthermore, on commencement of the amendment, any generating station set up as an Independent Power Project shall not be considered for the benefits of a Captive Generating Plant which is subject to various provisos. For instance, if an Independent Power Project has not been availing of any benefit as an Independent Power Project and does not have a Power Purchase Agreement, it may be considered for benefits as a Captive Generating Plant.

The status of being a Captive Generating Plant entitles one to certain incentives and exemptions and thereby the same shall not be granted simply. Therefore, to make the process stringent and to monitor the Captive Generating Plants, these amendments to the Rules have been proposed.

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Ireland

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Overview of the current energy mix, and the place in the market of different energy sources

2017 saw a continuation of the main trend in Irish energy infrastructure: namely, strong development, financing and construction activity in onshore wind farms, as Ireland makes its contribution to decarbonisation. In Ireland and Northern Ireland, renewable energy is predominantly sourced from wind. Other sources include hydroelectricity, solar photovoltaic, biomass and waste.

Approximately 310MW of renewable generation was connected to the Irish electricity grid during the year. The island of Ireland has 346 connected wind farms with a total installed capacity of 4,625MW. Of this, 264 connected wind farms are located in the Republic of Ireland which account for 3,458MW of installed capacity. The 2017 annual connection figure represents a slight decrease from the 350MW that was connected in 2016. On 25 January 2017, the record for highest instantaneous amount of all-island wind generation was achieved at 3,088MW.

According to the Sustainable Energy Authority of Ireland's December 2017 Annual Report, the contribution of renewables to gross final energy consumption in 2016 was 9.5%, working towards the 2020 target of 16%. This replaced €342 million of fossil fuel imports. The amount of renewable electricity generation in Ireland was 27.2% (normalised) of gross electricity consumption in 2016, working towards the 2020 target of 40%. The highest ever annual level of wind installations were installed, with approximately 400MW installed. This saw wind generation account for 22.3% (normalised) of the electricity generated in 2016 and was the second-largest source of electricity generation after natural gas.

Ireland's overall primary energy consumption in 2016 was 14,413 ktoe broken down to: fossil fuels and non-renewable wastes as 92% of all energy used in Ireland (coal use 9.5%, peat 5%, oil 48%, natural gas 29% and non-renewable wastes 0.5%); and renewable energy at 8% (hydro and wind at 50.8%, biomass use 28.9%, and other renewables 20.3%).

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

<u>Commission for Regulation of Utilities</u>

Ireland's independent energy regulator was renamed the Commission for Regulation of Utilities (CRU) to reflect the extension of its mandate to include the regulation of water services. It also received, in April 2017, enhanced statutory powers to better facilitate the enforcement of the licences that it issues in relation to the generation and supply of electricity. Whereas previously the CRU's primary tool of energy licence enforcement had been the binary threat of licence revocation, the new powers now allow the CRU to impose tailored financial penalties on errant licence-holders.

National Energy Efficiency Action Plan

Pursuant to the EU Renewable Energy Directive, for 16% of the country's total energy consumption to come from renewable energy sources by 2020, the Irish government has set a 40% target for renewable electricity. The Sustainable Energy Authority of Ireland has reported that in 2016, 27.2% of Ireland's gross electricity consumption was generated from renewable sources, indicating that in order for Ireland's 2020 renewable electricity target to be met, the market penetration of renewable electricity generators needs to increase significantly from its current level.

The Irish government is also seeking to reduce the amount of power that is consumed, through the implementation of the National Energy Efficiency Action Plan that Ireland maintains, pursuant to the EU Energy Efficiency Directive. The 2020 energy efficiency target equates to a 20% reduction in final overall energy demand based on the average energy demand during the period 2001 to 2005, with the public sector expected to play an exemplar role by working towards a 33% reduction target – although it should be noted that these targets apply to overall energy demand, and not just the demand for electricity.

Brexit

The exit of the United Kingdom from the EU, which is scheduled to occur on 29 March 2019, remains a pressing issue by reason of its timing and its potential disruptive effect, at least in theory, on assets and activities, such as Single Electricity Market (SEM), that span the UK-EU border.

Ireland's energy markets are closely connected to those in the UK and to date, the regulatory regimes in both countries have worked well together. This is largely because a significant amount of the applicable energy regulation, in both the UK and Ireland, derives ultimately from EU legislation. Brexit may not change this immediately, but over time we may see the regulatory regimes diverging, with implications for our energy markets.

Energy and infrastructure connections between Ireland and the UK, especially Northern Ireland and Wales, may be affected by Brexit, in particular because:

- the electricity generated and consumed in Ireland and Northern Ireland currently passes through a common wholesale electricity market, the Single Electricity Market;
- a 500MW sub-sea electricity interconnector has been built between Ireland and Wales;
- EirGrid, the transmission system operator on the island of Ireland, is planning to build a 400MW cross-border transmission line across the border between Ireland and Northern Ireland, to supplement the small number of lower-voltage power lines that already cross the border; and
- much of Ireland's natural gas is imported through two sub-sea pipelines running from Scotland, and a "South-North pipeline" runs from Gormanston, Co. Meath, to Belfast.

Brexit, of itself, may not have an immediate impact upon the continued smooth operation of these energy markets and assets. Nor should Brexit disturb the extent to which the Irish elements of these arrangements continue to comply with European law.

Under the I-SEM project, which "went live" on 1 October 2018, the Single Electricity Market was modified for the primary purpose of aligning it more closely with the "target model" that is favoured by the European Union. This project has aligned the Irish wholesale market more closely with that of Great Britain, and should facilitate enhanced electricity exports between the two markets. The I-SEM project therefore has merit, even if Northern Ireland is no longer obliged to pursue it for reasons of compliance with European law. At this time, therefore, we do not expect that the Single Electricity Market, as modified by I-SEM, will be a casualty of any Brexit. The implementation of I-SEM is considered further below, under the heading "Developments in legislation or regulation".

It is to be hoped that the Brexit negotiation process delivers clarity as to potential impact on this sector, however, at the time of writing, the regulatory consequences of this event for the Irish energy sector have not been settled.

Developments in government policy/strategy/approach

Renewable Electricity Support Scheme (RESS)

The previous support scheme for the generation of electricity from renewable sources (Renewable Energy Feed-in Tariff (REFIT) scheme) has closed for applications, and projects holding REFIT 2 offer letters have until 31 March 2020 to meet the connection deadlines. REFIT's successor was revealed in July 2018 with the announcement by the Department of Communications, Climate Action and Environment of its intention to establish a new Renewable Electricity Support Scheme (RESS), and the publishing of a high-level design paper (the "High Level Design"). RESS is intended to operate by allocating long-term two-way contracts for difference to projects that are successful in RESS auctions. The High Level Design anticipates that in order to be eligible to participate in auctions, projects will need to satisfy community participation requirements, and to hold planning permission and a grid connection offer.

The first RESS auction is anticipated to occur in 2019 in respect of 1GWh of electricity from "shovel ready" renewable projects (RESS-1), and a series of subsequent auctions out to 2025 (for project delivery by the end of 2030) are expected. There will be no single technology cap for the first auction, but this may change for subsequent actions.

RESS is to be procured by MWh (output) rather than MW (export capacity), and therefore the capacity factor of technology will be relevant to determining the extent of the MWh awarded in the auctions. Separately, it appears that flexibility will be afforded in relation to the expected duration of the RESS contracts from auction to auction to potentially enable different technologies to succeed, with careful consideration being applied such that varying contract lengths do not negatively affect competition within the auctions.

In RESS 1 it is anticipated that successful applicants will be required to achieve energisation and connection to the grid by the end of 2020.

Significant further design work is required, in addition to State aid approval, before the scheme could be regarded as ready for its scheduled first deployment in 2019. However, the publication of the High Level Design indicates that the regulatory environment in Ireland for the development of renewable electricity is moving in the right direction in providing a successor to REFIT.

Enduring Connection Policy (ECP-1)

On 27 March 2018, the CRU introduced a new grid connection policy (ECP-1) in order to streamline the connection process and address a bloated 36GW list of generators seeking capacity (on a system that has 10.8GW installed, and a historical peak demand of only 5.1GW). Applications to qualify for this new policy opened on 27 April 2018 and closed on 28 May 2018.

On 31 August 2018, the list of applicants for new connection capacity that have been deemed "eligible for processing" under the 2018 iteration of the ECP-1 capacity allocation regime was released, known as the "2018 batch". A 1GW tranche of connection capacity was announced as part of this batch. The round was oversubscribed by 3.2GW of applications. Each listed applicant can be assured the system operators will process its application and eventually schedule a connection offer date, provided that the applicant pays the next instalment of the required connection application fees.

Of the 1GW tranche, 400MW was to be prioritised in ECP-1 for applications related to projects that will be capable of supplying the DS3 fast frequency response and primary operating response products. DS3 projects in this category did not require planning permission in order to apply for connection capacity. However, they must meet grid code standards and must use proven technology. Battery storage technology was the major winner within the DS3 tranche, accounting for 351MW out of the 371MW allocated.

Given the extent of the applications received, the remaining capacity in the ECP-1 was allotted by order of priority, having regard to a project's planning status. Projects with soon-to-expire planning permissions were given priority, with the effect that among the successful applicants, the last planning permission expiry occurs in Q3 2023. No projects with planning permissions expiring after that date have been included. To reflect the practicalities of construction, minimum periods of planning permission validity were also included in the ECP-1 process: expiry no earlier than 28 May 2020 (where a planning permission had been extended), or 28 May 2019 (where no extension had been received).

The non-DS3 component of the ECP-1 batch comprises 67 projects that have a total export capacity of 591MW.

In addition to the ECP-1 batch, there are:

1. 21 projects totalling 842 MW which already had live connection applications (sitting outside the earlier group processing regime), but which opted to be processed alongside the ECP-1 batch ("fold-in" applications). Of this, 841.5 MW is solar; and
2. 34 projects totalling 436MW, where either capacity is being relocated or technology is changing.

The interplay between ECP-1 and Ireland's new RESS, will be crucial in determining the delivery of Ireland's next phase of renewable electricity generation projects. The ECP-1 announcement neither refers to RESS nor includes any commitment from the System Operators as to the timing of connection dates relative to the RESS deadlines.

A number of the projects in receipt of ECP-1 connections have planning permissions which expire during the course of 2019, 2020 and 2021. Therefore, based on the selection criteria, it is likely that these projects will be given connection dates that will enable them to compete for inclusion in RESS-1.

Ireland 2040

2018 saw the announcement of Ireland 2040, the Irish State's much-needed infrastructure investment plan which guides public and private investment and aims to accomplish 10 strategic outcomes.

The plan makes specific reference to the North-South interconnector and EirGrid's continued assessment of opportunities for interconnection with other electricity markets, including the Celtic Interconnector to France, at an estimated cost of €1 bn.

The plan also references €8.5 bn to be invested by Irish Water in order to deliver efficient and robust infrastructure and services.

Developments in legislation or regulation

Integrated Single Electricity Market (I-SEM)

The Commission for Regulation of Utilities, Water and Energy (CRU) announced on 31 August 2018 that the I-SEM wholesale market project, the redesign of the wholesale electricity market on the island of Ireland, will "go live" on 1 October 2018.

I-SEM is a wide-ranging change to the rules, practices and hardware of the SEM, the wholesale electricity market for the island of Ireland that has been trading since 2007.

It is intended to satisfy the requirements of EU Regulation 2015/1222, which set out the measures that were required to be introduced by EU Member States in relation to the cross-border electricity flows between them, in order to achieve a fully functioning and interconnected internal EU energy market. In recognition of the work that would be required, the Regulation allowed Ireland and Northern Ireland a dispensation until the end of 2017; however, this deadline had to be extended to facilitate measures for the changes required.

During the course of 2017, substantially all of the industry codes that will support the amended market were finalised.

One notable element of the amended market is the new arrangements for the remuneration of generating capacity, and the first auction under these arrangements was held in December 2017 in preparation for the October 2018 go-live.

A key feature of I-SEM is the choice of temporal markets upon which a market participant can trade electricity. It is now possible for participants to price and sell their electrical output in the "day ahead" and "intraday" markets, each of which close before the time at which the output is generated. Any imbalances between the traded position and the actual output are required to be settled in a "balancing" market, on which large projects are required to trade.

In June 2018 it was confirmed that the REFIT support scheme, under which many RoI wind farms receive financial support, would not insulate supported projects from the financial consequences of these imbalances. In order to optimise their revenues, REFIT generators therefore need to forecast their output (based on historical wind turbine performance and expected wind conditions), trade accordingly in the new I-SEM markets, and stand ready to take corrective trading actions as and when inaccuracies in their forecasts are revealed.

Major efforts were made across the Irish electricity sector in order to meet the challenges presented by balance responsibility. In particular, a range of local, European and global trading houses have entered the Irish market to assist in mitigating the new risks.

I-SEM go-live is likely to be the most significant single event to occur in the Irish energy sector during 2018.

Strategic infrastructure developments and judicial review

The Planning and Development Act 2000, as amended, provides for a special planning application process for strategic infrastructure development (SID). This procedure allows for the local planning authority to be bypassed entirely and the application to be made directly to An Bord Pleanála, the Irish State planning appeals board. SID status is afforded to developments which are considered of strategic importance to the State. They most commonly consist of energy infrastructure, transport infrastructure, large housing development and environmental infrastructure projects.

Due to the fact that often, these developments are large in scale and complexity, decisions of An Bord Pleanála are challenged on a frequent basis by way of judicial review. Applications for consent to launch a judicial review must be made to the High Court.

In February 2018, the President of the High Court issued a Practice Direction concerning judicial review applications relating to SIDs. From 26 February 2018 onwards, all applications for consent to launch a judicial review of permissions or decisions concerning strategic infrastructure developments may only be made to an assigned judge in the Commercial Court. Applications can be made at 10.30am every Thursday and must comply with filing requirements.

Where an applicant is granted permission to launch a judicial review, the judge will provide the parties with all necessary additional directions with a view to ensuring a fair, just and expeditious hearing of the matter.

<u>New planning process for data centres</u>

The Seventh Schedule to the Planning and Development Act 2000 was amended by Section 49 of the Planning and Development (Amendment) Act 2018 which provides that certain data centre planning applications can be made directly to the Strategic Infrastructure Division of An Bord Pleanála. We mention data centres due to the common perception of them as the major new source of electricity demand in Ireland, and therefore very relevant to Irish energy policy.

The Planning and Development Act 2000, as amended, provides for a special planning application process for Strategic Infrastructure Development (SID). Data centres consisting of one or more than one structure, the combined gross floor space of which exceeds 10,000 square metres, will have SID status.

Section 49 of the Planning and Development (Amendment) Act 2018 has not yet commenced. Once it is commenced, applications for data centres will benefit from a fast-tracked planning process. Also as detailed above, all applications for consent to launch a judicial review of permissions or decisions concerning strategic infrastructure developments may only be made to an assigned judge in the Commercial Court.

Data centres of the size envisaged under the Planning and Development (Amendment) Act 2018 are large users of power, generally with demand greater than 20MVA, thatrequire a connection to the transmission system in order to meet their energy needs. This means planning approval for a connection to the electricity transmission system may be required and, if so, an application directly to An Bord Pleanála for this transmission infrastructure may also be required.

Judicial decisions, court judgments, results of public enquiries

We describe below some of the recent planning related decisions which are relevant to the energy sector in Ireland.

<u>*Connelly v An Bord Pleanála & Ors* [2018] IESC 31</u>

The Supreme Court in, *Connelly v An Bord Pleanála & Ors* [2018] IESC 31 decided on an appeal in relation to the whether adequate reasons were given by the An Bord Pleanála in its decision (the Decision). The Decision was in relation to an application for the development of a six-turbine, on-shore wind farm. In the Decision, the Board stated that it was satisfied that the information before it was adequate to undertake an Environmental Impact Assessment (EIA) and an Appropriate Assessment (AA) for the proposed development.

The Supreme Court observed that the legal requirements which relate to different types of decisions can vary significantly depending on the circumstances. In certain decisions, a decision-maker may be required to determine whether very precise criteria are met, while other decisions will involve much broader considerations and a level of judgment on the part of the decision-maker.

The court identified two separate but closely related requirements at national law regarding the adequacy of any reasons:

1. any person affected by a decision is at least entitled to know in general terms why the decision was made; and
2. a person is entitled to have enough information to consider whether they can or should seek to avail of any appeal or to bring judicial review of a decision. Also, the reasons provided must be such as to allow a court hearing an appeal or reviewing a decision to actually engage properly in such an appeal or review.

The application of these requirements will vary greatly from case to case.

In a case to which the environment impact assessment (EIA) regime applies, even though the general principle remains the same, the decision must be sufficiently clear to enable any interested party to consider whether they may have grounds to challenge the decision on the basis that an adequate EIA had not been conducted. This requires that the decision, or other relevant and connected materials available to any interested party, must demonstrate that an EIA was carried out and that the decision-maker properly had regard to the results of the EIA in coming to its conclusion.

In order for a valid appropriate assessment (AA) to have been conducted, there must be a precise identification of the potential risks and precise scientific findings to allay any fear of those risks coming to pass.

This aspect is not, strictly speaking, a reasons issue. The issue concerns the validity of an AA decision which gives jurisdiction to the Board to grant permission. There must be complete, precise and definitive findings and conclusions which support the ultimate conclusion.

The Supreme Court held that neither the Decision itself nor any other materials which were expressly referred to in the Decision, or must be taken by necessary implication to form part of the process leading to the ultimate determination of the Board, can be shown to contain the sort of complete, precise and definitive findings which would underpin a conclusion that no reasonable scientific doubt remained as to the absence of any identified potential detrimental effects on a protected site, having regard to its conservation objectives. Findings such as these are a necessary pre-condition to the Board having jurisdiction to grant development consent in a case where it is determined that an AA is required.

<u>Case C-461/17: Reference for a preliminary ruling from High Court (Ireland) made on 28 July 2017 – *Brian Holohan & Others v An Bord Pleanála*</u>

The Court of Justice of the European Union (CJEU) answered the Irish High Court's request for a preliminary ruling on questions relating to the Environmental Impact Assessment Directive (85/337/EEC) and Habitats Directive (92/43/EEC), stemming from a High Court case on the approval of planning permission for a ring road. The case clarified what must be contained in a Natura impact statement, an Environmental Impact Assessment (EIA) and an Environmental Impact Statement (EIS).

This case has clarified a number of questions in relation to the Habitats and EIA Directives, particularly: what level of detail is provided in the Natura impact statement; what can be decided in a development post-consent; the reasons an authority must give when granting consent; what are "significant" effects; what constitutes a main alternative; and the reasons relating to environmental effects a developer must provide which guide them when choosing an option. It is important that these are considered by the developers of any energy infrastructure in Ireland which requires a Natura impact statement.

Major events or developments

North-South Interconnector Project

Continued progress was made in relation to the North-South Interconnector Project for the all-island electricity grid, a major electricity transmission line planned for construction across the border between Ireland and Northern Ireland. EirGrid plc, the developer of the line in Ireland, published a tender notice for works on the project in September 2017.

In November 2017, the Planning Appeals Commission in Northern Ireland issued its recommendation to the Department for Infrastructure in relation to the Northern Irish element of the project. Three judicial review applications were brought during 2017 in relation to the Irish planning decision, with one of these challenges dismissed and another struck out. The North-South Interconnector Project is one of the three major electricity interconnectors being developed in Ireland, the others being the Greenlink Interconnector and the Celtic Interconnector, all of which will play a significant role in Ireland's electricity market once completed.

Proposals for changes in laws or regulations

Maritime Area and Foreshore (Amendment) Bill 2013

The Maritime Area and Foreshore (Amendment) Bill 2013 was proposed to streamline the development consent process for the foreshore including the integration of certain parts of the foreshore consent process (under the Foreshore Act 1933) with the existing on-land planning system. Amendments to the Planning and Development Acts 2000–2012, to the Foreshore Acts 1933–2012 and to the Dumping at Sea Acts 1996–2012 are proposed.

The heads of the Bill were approved on 23 July 2013, and pre-legislative scrutiny was undertaken in February 2014. Since then there has been engagement with the Marine Coordination Group, and a number of workshops and bilateral meetings with relevant policy Departments and the Office of the Attorney General throughout 2017 and early 2018. Legal advice from the Office of the Attorney General will be available shortly, which will inform the further drafting of the legislation. This Bill is currently on the list of Government Priority Legislation for Publication for the Spring/Summer Session 2018, however it has yet to be presented to the Dáil Éireann for discussion.

Fossil Fuel Divestment Bill 2016

On 12 July 2018, the Fossil Fuel Divestment Bill was passed by Dáil Éireann as part of the first stage of enacting the bill.

This Bill amends the investment mandate of the Ireland Strategic Investment Fund (ISIF) to both prevent it investing in, and requiring it to divest from, fossil fuel undertakings over the next five years. This is a show in global leadership, as Ireland would be the first country to do so, and would be a huge move away from fossil-fuel investment dependency. If a sufficient number of other countries follow, this will stimulate investment in renewable and sustainable alternatives.

Before the Bill is enacted into law, the *Seanad* will debate the principles of the Bill; amendments are suggested, these amendments are considered, and finally final statements on the Bill are made. Once this has occurred, the Bill may be signed into law by the President.

Wind energy development guidelines

In June 2017, the Minister for Housing, Planning, Community and Local Government, in conjunction with the Minister for Communications, Climate Action and Environment, announced a preferred draft of the approach to address the key aspects of the review of the 2006 Wind Energy Development Guidelines. The approach taken is the application of a more stringent noise limit, in tandem with a new robust noise monitoring regime. The key aspects of the preferred draft approach are:

- new noise restriction limits of a relative rated noise limit of 5dB(A) above existing background noise within the range of 35-43dB(A) for both day and night, with 43dB(A) being the maximum noise limit permitted;
- for visual amenity purposes, each turbine should be set back from the curtilage of a residential property by a distance of at least four times its tip height, subject to a mandatory minimum setback of 500 metres;
- the adoption of technology that will shut off each wind turbine automatically to eliminate any shadow flicker;
- a Community Report, which describes how the proposed wind farm was designed in response to consultation with communities, will have to be submitted along with each planning application;
- the applicant will need to offer a form of community dividend, that will ensure the project is of enduring economic benefit to the communities concerned; and
- from a visual amenity aspect, grid connections to wind farms should be underground.

The proposed approach will be further supported by the Good Practice for Wind Energy Development Guidelines, issued in 2016 by the Department of Communications, Climate Action and Environment.

A Strategic Environmental Assessment (SEA) of the draft approach to the revised guidelines will be undertaken before they are finalised. Following the completion of the SEA, the guidelines will be finalised and issued under section 28 of the Planning and Development Act 2000 and will apply to planning applications for future wind energy development proposals.

Carbon reduction

In July 2018, the Irish government published its National Mitigation Plan strategy, including a number of mitigation measures designed to address the carbon-reduction challenge to 2020 and to prepare for the EU targets that Ireland will take on for 2030. The plan focuses on the electricity generation; built environment; transport; and agriculture, forest and land use sectors.

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Japan

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Overview of the current energy mix, and the place in the market of different energy sources

Since the wake of the first oil shock in 1973, Japan has sought to decrease its dependency on oil by promoting nuclear power, natural gas and coal as alternative energy resources. As a result, in FY 2010 Japan had successfully diversified primary energy sources (i.e. coal (22.5%), natural gas (19.2%) and nuclear (11.1%)) and dependency on oil as a primary energy source was significantly reduced to 40.3% from 75.5% in FY 1973. However, as a result of the Great East Japan Earthquake and nuclear accident at Fukushima Daiichi Nuclear Power Plant ("**Fukushima Nuclear Accident**") in March 2011, imports of fossil fuels as power sources as an alternative to nuclear power have increased, resulting in dependency on fossil fuels as primary energy sources surging again significantly (i.e. 91.6% in total in FY 2012 from 82% in FY 2010). On the other hand, due to the restart of several nuclear power plants and increase of renewable energy (particularly solar power), demand for fossil fuels as primary energy sources has gradually decreased in the last few years, reaching 88.9% in FY2016.

Although the FY 2017 figure is not available for now, the following tables show the latest status of the primary energy domestic supply and power source mix.

Table 1: Primary Energy Domestic Supply (FY2012–2016)

Year	Oil	Coal	Natural Gas	Nuclear Power	Hydro Power	Renewable Energy (excluding hydro power)	Unutilised Energy
2012	44.5%	23.6%	23.5%	0.7%	3.2%	2.1%	2.5%
2013	42.8%	25.2%	23.3%	0.4%	3.2%	2.5%	2.6%
2014	41.2%	25.2%	24.5%	0.0%	3.5%	3.0%	2.7%
2015	40.7%	25.8%	23.3%	0.4%	3.6%	3.6%	2.7%
2016	39.7%	25.4%	23.8%	0.8%	3.3%	4.1%	2.9%

(Source: Agency for Natural Resources and Energy, *Energy demand and supply result in FY 2016 (confirmed report)* dated April 2018)

Table 2: Power Source Mix (FY2012–2016)

Year	Oil	Coal	Natural Gas	Nuclear Power	Hydro Power	Renewable Energy (excluding hydro power)
2012	17.5%	31.0%	40.1%	1.5%	7.1%	2.9%
2013	14.5%	32.9%	40.8%	0.9%	7.3%	3.6%
2014	11.1%	33.4%	42.9%	0.0%	7.9%	4.7%

Year	Oil	Coal	Natural Gas	Nuclear Power	Hydro Power	Renewable Energy (excluding hydro power)
2015	9.8%	34.1%	40.8%	0.9%	8.4%	5.9%
2016	9.3%	32.3%	42.2%	1.7%	7.6%	6.9%

(Source: Agency for Natural Resources and Energy, *Energy demand and supply result in FY 2016 (confirmed report)* dated April 2018)

Energy mix plan

In April 2014, the 4th Strategic Energy Plan ("**Previous Strategic Energy Plan**") was approved by the Japanese Cabinet for the purpose of setting the future direction of Japanese energy policy after the Fukushima Nuclear Accident in March 2011. The Previous Strategic Energy Plan was affected by the significant impact on Japan's energy environment caused by the Fukushima Nuclear Accident. For example, under the 3rd Strategic Energy Plan approved in June 2010, it was described as the target for FY 2030 that zero-emission power sources consisting of nuclear powers and renewable energies amounted to approximately 70%.

However, given the tremendous disaster caused by the Fukushima Nuclear Accident, Japan reconsidered its energy strategy from scratch and the Previous Strategic Energy Plan declared that Japan will minimise its dependency on nuclear power. Furthermore, the Previous Strategic Energy Plan confirmed so-called "3E + S" policy, meaning that Japan will pursue "*Energy Security*" (i.e. to ensure stable supply of energy), "*Economic Efficiency*" (i.e. to realise low-cost energy supply by enhancing efficiency), "*Environment*" (i.e. to make maximum efforts to pursue environment suitability), and "*Safety*".

In July 2015, based upon targets established to realise "3E + S" policy confirmed in the Previous Strategic Energy Plan, the Ministry of Economy, Trade and Industry ("**METI**") publicised the Long Term Energy Supply and Demand Outlook ("**2015 Outlook**") where the primary energy supply structure and the electric power supply-demand structure in FY 2030 were declared as follows:

Table 3: Primary Energy Supply in FY 2030

Oil	LPG	Coal	Natural Gas	Nuclear Power	Renewable Energy
30%	3%	25%	18%	10–11%	13–14%

Table 4: Power Source Mix in FY 2030

Oil	Coal	LNG	Nuclear Power	Renewable Energy (22-24%)				
				Hydroelectric Power	Solar	Wind	Biomass	Geothermal Power
3%	26%	27%	20-22%	8.8-9.2%	7.0%	1.7%	3.7-4.6%	1.0-1.1%

As you can see from the above, it was expected in the 2015 Outlook that as a source of electricity generation, renewable energy would be significantly increased from around 12.6% in FY 2014 to around 22–24% in FY 2030, while it was also expected that the dependency on nuclear power, which was around 30% before the Great East Japan Earthquake, would decrease to around 20 to 22%. As a result, it is expected that zero-emission power sources consisting of nuclear power and renewable energy in FY 2030 should be approximately 44% in total, and the base load rate consisting of hydropower, coal-fired thermal power and nuclear power, etc. will be around 56% in total.

As three years have passed since the Previous Strategic Energy Plan was approved in 2014, formal review of the Previous Strategic Energy Plan started in August 2017 at the Advisory Committee for Natural Resources and Energy, where the energy mix target at FY 2030 was also discussed and re-reviewed based upon the last three years' developments. However, as discussed below, while various issues had been discussed by this Advisory Committee, it was finally determined that the energy mix declared in the 2015 Outlook would be maintained as it is.

5th Strategic Energy Plan discussion

The most important development in energy policy in Japan for the last year has been the revision of the Strategic Energy Plan.

As discussed above, formal review of the Previous Strategic Energy Plan had started in August 2017 at the Advisory Committee for Natural Resources and Energy. While various issues had been discussed between August 2017 and May 2018 at the Advisory Committee and the draft 5th Strategic Energy Plan was finally proposed to the Cabinet based upon the result of the Advisory Committee's discussion, it seems that the most controversial issues discussed there were: how to realise the energy mix target for renewable energy (i.e. 22–24%); and nuclear power (i.e. 20–22%).

Issues discussed in connection with the renewable energy target

After introducing the Feed-in Tariff system in Japan in July 2012, the volume of power produced through renewable energy has steadily increased, from 10% in 2010 to 15% in 2016. However, as a result of such 10% increase, 2 trillion yen per year would be required for the purchase cost in the Feed-in Tariff system, while a 9% additional increase (i.e. from 15% to 24%) is targeted with only 1 trillion yen increase per year as the purchase cost. As a result, how to further increase renewable energy capacity in an economically efficient manner is one of the important issues to be resolved.

Secondly, for the initial five years, it seems that the input of solar power has disproportionately increased compared with other renewable energy sources which require a longer lead time due to regulatory and other hurdles (e.g. environmental impact studies are generally required for offshore wind, geothermal and hydroelectric). Therefore, it was confirmed that regulatory hurdles shall be rebalanced to foster other types of renewable energy sources.

Thirdly, the vast majority of the increase of renewable energy capacity is expected to rely on naturally fluctuating power sources (e.g. solar power and wind power), which requires base load capacity (e.g. coal-fired thermal power or nuclear power) and/or storage batteries to adjust the power output fluctuations of those renewable energies.

Finally, as many of solar and wind power facilities are expected to be installed in rural areas, how to increase grid capacity to accommodate needs for decentralised power was also identified as one of the challenges to increase renewable energy going forward.

Issues discussed in connection with nuclear power

The energy mix target for nuclear power in 2030 was set at 20–22% in the 2015 Outlook and to achieve such target, it is generally considered that around 30 nuclear power plants will need to resume their operations. However, it was reported that as of the end of March 2018, only seven nuclear power plants have resumed their operations; seven nuclear power plants have obtained permits to resume their operation under the new regulatory standard; and eight nuclear power plants are currently under review and inspection by the Nuclear Regulation Authority based on the new regulatory standard. As a result, some members of the Advisory Committee strongly criticised that the energy mix target for nuclear power is unrealistic, unless replacement of those plants or new plant constructions are contemplated, but it seems that no discussion in detail was actually conducted in connection with replacement and new constructions.

On July 3, 2018, by taking into various discussions at the Advisory Committee, the 5th Strategic Energy Plan was finally approved by the Cabinet. Note that one point highlighted in the 5th Strategic Energy Plan is that renewable energy was cited as a "major power source" in order to achieve such target, which is good evidence that the Japanese government has shifted to drive an increase in renewable energy capacity, although as mentioned above, there are a lot of issues to be resolved to achieve this target. I will explain the details of the measures adopted in Japan with a view to promoting renewable energy.

Development of Feed-in Tariff system in Japan

Introduction of Feed-in Tariff system

To achieve the target raised in the energy mix plan declared in the 2015 Outlook, one of the key factors is how to introduce and expand renewable energy to the maximum extent while minimising the public burden. As the driving force for promoting renewable energy, the Feed-in Tariff system was introduced in Japan in July 2012 and many issues have been identified and many counter-measures to adjust the system have been implemented since then. The details of these developments of the Feed-in Tariff system in Japan are set out below.

A Feed-in Tariff system for renewable energy power plants (solar, wind, hydro, geothermal and biomass) came into effect in Japan on July 1, 2012 under the Act on Special Measures Concerning Procurement of Renewable Electric Energy by Operators of Electric Utilities ("**Old Feed-in Tariff Act**"). For a power producer to be entitled to sell electricity at a certain fixed price (the "**Tariff**") for a certain period ("**Tariff Period**") under the Old Feed-in Tariff Act, it was generally required to: (i) obtain certification of power generation facilities from METI ("**Facility Certification**"); (ii) apply for grid connection to a general transmission and distribution operator and enter into the grid connection agreement[1] with them; and (iii) enter into a power purchase agreement with an electricity retailer.

Under the Old Feed-in Tariff Act, METI could set different tariffs and tariff periods annually or semi-annually, depending on the renewable energy category, installation method and scale of the generation facilities, by taking into account various factors (e.g. (i) costs to be ordinarily incurred by power producers on the basis that renewable energy is supplied in an efficient manner, (ii) whether renewable energy power producers can obtain an appropriate level of profits, (iii) volume of supply of renewable energy-based electricity nationwide, and (iv) public burden (i.e. amount of surcharge)).

Issues identified during the initial phase of the Feed-in Tariff system

As a result of introduction of the Feed-in Tariff system in Japan, renewable energy generation increased by more than 2.5 times during the initial four years. However, total purchase costs for renewable electricity under the Feed-in Tariff system had reached 2.3 trillion yen in FY2016, while the total purchase cost in FY 2030 targeted under the energy mix plan declared in the 2015 Outlook was around 3.7–4.0 trillion yen. Therefore, how to introduce renewable energy in a cost-efficient way was highlighted as the major issue under the Feed-in Tariff system in Japan.

In addition, the introduction of additional capacity of renewable energy during the initial four years had been heavily tilted toward solar power generation, as 90% of capacity certified under the Feed-in Tariff system was solar power. However, unlike geothermal, hydro and biomass, which can be operated stably in any weather conditions and therefore can be expected to replace nuclear power as base load capacities, solar power, which fluctuates greatly in output depending on the natural conditions, is required to be accompanied by base load capacity (e.g. coal-fired thermal power or nuclear power) as the adjusting power source. Accordingly, diversification among various types of renewable energy has been recognised as the most important factor to achieve the energy mix plan declared in the 2015 Outlook.

Furthermore, it was reported that around 340,000 solar power projects having Facility Certifications issued during FY 2012 and 2013 had not started commercial operation as of December 31, 2015, while those non-operating projects were keeping priority over grid connection rights, which may cause opportunity losses by other projects with high potential. In addition, as Japan's grid system had been developed for a long time on the basis that the locations of power sources were centralised (e.g. thermal power and nuclear power, whose locations are relatively concentrated in certain limited areas), rapid expansion of renewable energy power, whose locations are de-centralised nationwide, have caused many issues for the grid system, including limitation of capacity. As a result, how to prevent such non-operating projects from holding up grid capacity, and how to make future investment in the grid system in an efficient manner, had also been highlighted as material issues to be resolved under the Feed-in Tariff system.

<u>New Feed-in Tariff Act</u>

In response to various issues identified during the initial phase of the Feed-in Tariff system, in order to introduce renewable energy to the maximum extent while curbing the public burden, revisions to the Old Feed-in Tariff Act were submitted to the Diet in February 2016 and passed the Diet on May 25, 2016 (such revised Feed-in Tariff Act hereunder, "**New Feed-in Tariff Act**"). The New Feed-in Tariff Act came into force as from April 1, 2017. The main purposes to revise the Old Feed-in Tariff Act were:

(a) establishment of a new approval system where (i) existing non-operating projects can be eliminated, (ii) non-operating projects can be prevented going forward, and (iii) introducing a system to ensure only feasible projects can obtain certification;
(b) introducing additional renewable energy in cost-efficient manner by (i) starting an auction system for large-scale solar power generation, and (ii) setting mid- and long-term target for the tariff;
(c) introduction of power sources with a long lead time required for development, such as geothermal, wind and hydro power, by announcing the multi-year tariff in advance, thus providing better visibility about the future applicable tariff for power sources with a long lead time; and
(d) change of the purchaser of electricity under the Feed-in Tariff system from electricity retailers to transmission and distribution business operators.

The details of the measures introduced under the New Feed-in Tariff Act to realise the above purposes are set out below.

<u>Introduction of new approval system</u>

Under the New Feed-in Tariff Act, METI shall grant certifications to "business plans" (not to the facilities) ("**Business Plan Certification**") for renewable energy-based power projects. For this purpose, METI shall confirm whether: (i) a business plan complies with certain prescribed standards; (ii) the contemplated business will be smoothly and certainly implemented; and (iii) specification of the renewable power facility is appropriate from the viewpoint of stable and efficient power production.

For example, in connection with (i) above, METI will confirm whether it is contemplated in the business plan to properly install a system enabling maintenance check-up and O&M, and whether the business plan includes a plan for disposal of the facility upon the end of the commercial operation. In connection with (ii) above, METI will examine if: (a) the grid connection agreement has been executed with a general transmission and distribution operator; (b) the land has been secured (or is certain to be secured) for the installation of the facility; and (c) the applicant has checked applicable laws and local ordinances with the relevant local government.

Even after Business Plan Certification is issued, METI will monitor the project on an ongoing basis to check if the project is properly developed and operated pursuant to the certified business plan and if any violation is identified, METI can issue an instruction and an order for improvement to a power producer and eventually cancel the Business Plan Certification if such power producer does not follow the said instruction/order. Note that the Agency for Natural Resources and Energy published guidelines for a business plan with respect to each category of power source (i.e. solar, wind, hydro, geothermal and biomass) in March 2017 (and revised in April 2018) and, if power producers fail to follow the rules to be observed under the guideline, METI may issue an instruction or an order for improvement. If a power producer still fails to follow such instruction/order, the Business Plan Certification may be cancelled. Accordingly, power producers should carefully check and follow the applicable guideline.

On the other hand, a power producer with Facility Certification issued under the Old Feed-in Tariff Act may be "deemed" to have Business Plan Certification as from April 1, 2017 by keeping the applicable Tariff granted under the Old Feed-in Tariff Law as long as such power producer entered into the grid connection agreement with the operator of the transmission line (e.g. a general transmission and distribution operator) by March 31, 2017.[2] The whole purpose of requiring execution of the grid connection agreement was to prevent non-operating projects surviving under the New Feed-in Tariff Act.[3]

Note that a power producer with a "deemed" Business Plan Certification shall submit its business plan to METI by September 30, 2017 to keep its status as the holder of the Business Plan Certification. METI should confirm the completion of a "transitional process" for such operators to the new system under the New Feed-in Tariff Act if their business plans are duly submitted by those power producers, with the evidence showing that the grid connection agreements were executed by March 31, 2017. In case a power producer fails to submit its business plan to METI by the said deadline, METI may rescind the "deemed" Business Plan Certification after holding a hearing (*chomon*).

In order to reduce non-operating projects as much as possible, the rule for deadline of the commercial operation was newly introduced for solar power projects with an output capacity of more than 10kW, as long as such solar power project entered into the grid connection agreement with the operator of the transmission line (e.g. a general transmission and distribution operator) on or after August 1, 2016. Under this new rule, if a power producer fails to commence commercial operation within three years from the date when the Business Plan Certification is granted (or from April 1, 2017 in case of the project originally having Facility Certification and being transited to the new system under the New Feed-in Tariff Act), the purchase period shall be shortened by the days corresponding to the period starting after the end of the said three years until the date of commercial operation of its project.

Introduction of auction process

Under the New Feed-in Tariff Act, in case an auction process could be deemed to be useful in order to decrease the amount of surcharge to be imposed on the consumer public, METI can designate the category and the scale of powers subject to the auction process.

At this moment, solar power projects having an output capacity of 2MW or more,[4] and certain types of biomass projects having an output capacity of 10MW or more, are subject to the auction process.[5]

Mid- and long-term targets concerning the price level

Under the New Feed-in Tariff Act, with a view to decreasing the public burden by encouraging business operators' efforts and industry innovation, it is contemplated to set mid- and long-term targets concerning the price level applicable to each category of powers. In response to this requirement, the Procurement Price Calculation Committee announced the following targets for each category of powers:

(a) *Solar power*:

Pursuing independence from the Feed-in Tariff system by achieving the following targets.

- Non-residential use:

  Power generation cost should be JPY 14 / kWh at FY 2020; and

  Power generation cost should be JPY 7 / kWh at FY 2030.

- Residential use:

  Applicable Tariff at FY 2019 should be equivalent to electric rates for home use; and

  Applicable Tariff after FY 2020 should be equivalent to market price at electricity market.

(b) *Wind power*:

- Onshore wind with the capacity of 20kW or more:

  Power generation cost should be JPY 8–9 / kWh by pursuing independence from the Feed-in Tariff system by FY 2030.

- Small wind with a capacity of less than 20kW:

  Pursuing independence from the Feed-in Tariff system on a mid- and long-term basis by encouraging decrease of costs, while assessing the trend of introduction of small wind power.

- Offshore wind:

  Pursuing independence from the Feed-in Tariff system on a mid- and long-term basis by promoting improvement of the environment for the introduction of offshore wind power.[6]

(c) *Geothermal power*:

For the time being, in addition to the Feed-in Tariff, facilitating development of large-scale projects through promoting understanding from local communities and accelerating the Environmental Impact Assessment process; and

On a mid- and long-term basis, pursuing independence from the Feed-in Tariff system by reducing development risk and costs through technical innovation.

(d) *Mid- to small-sized hydro*

For the time being, in addition to the Feed-in Tariff, facilitating development of new places, while trying to decrease risk through research on the flow of water; and

On a mid- and long-term basis, pursuing independence from the Feed-in Tariff by reducing costs through technical innovation.

(e) *Biomass*

Pursuing independence from the Feed-in Tariff in collaboration with the policy where procurement of materials is streamlined.

Multi-year tariff

Under the New Feed-in Tariff Act, it is possible to set a multi-year tariff in advance to increase foreseeability by power producers. Especially with regard to power sources requiring a long lead time (e.g. wind, geothermal, hydro and biomass), it is appropriate to set a multi-year tariff. For example, many large-scale wind power projects and geothermal power projects are likely to trigger Environmental Impact Assessments, in which case it used to take around three to four years in total before obtaining Facility Certifications after a power producer commenced its initial step for an Environmental Impact Assessment (i.e. process for Preliminary Environmental Impact Consideration) under the previous METI practice, although the period required for the whole process should shorten, as METI has recently[7] changed its former practice and permitted applications for Facility Certification/Business Plan Certification to be accepted at a relatively earlier stage (i.e. commencement of Scoping Document process). By taking into account these regulatory environments as well as the necessity of coordination with local society, METI decided to announce a multi-year tariff for a period of three years in connection with large-scale wind power[8] and geothermal power.

On the other hand, with regard to mid- to small-sized hydro and biomass, it takes around two years before obtaining Facility Certifications/Business Plan Certifications after a power producer starts development work. However, given the possibility of requiring a longer period for coordination with local society and clearance of applicable regulations, METI also announced a multi-year tariff for a period of three years in connection with mid- to small-sized hydro and biomass.

Finally, with regard to solar power for residential use (with a capacity of less than 10kW), though the lead time itself is very short, a multi-year tariff for a period of three years was also announced for the purpose of promoting reduction of costs by presenting the tariff requiring the level of reduction on system costs for a top-runner.

Change of purchaser of FIT Electricity

Under the Old Feed-in Tariff Act, purchasers of electricity under the Feed-in Tariff system were electricity retailers. However, under the New Feed-in Tariff Act, the purchaser has been changed to transmission and distribution business operators.[9] In order to promote expansion of renewable energy in the future through nationwide operation of the grid system (e.g. demand and supply adjustment nationwide), it was considered that transmission and distribution business operators who are responsible for operation of the grid system and demand and supply adjustment are most appropriate to assume the obligation to purchase electricity generated under the Feed-in Tariff system. Power producers who need to enter into power purchase agreements with transmission and distribution business operators pursuant to the New Feed-in Tariff Act shall enter into such agreements pursuant to adhesive terms and conditions of the relevant transmission and distribution business operators.[10]

Additional change after New Feed-in Tariff Act came into force

After the New Feed-in Tariff Act took effect as from April 1, 2017, additional amendments were introduced pursuant to the new FIT Law Enforcement Ordinance[11] and the new

Notification for the Feed-in Tariff Price[12] as from August 31, 2017. Such revisions are targeted only to solar power projects, and the most relevant changes thereunder which may significantly affect existing projects are that the following changes[13] could trigger the change in the applicable tariff:

(a) change of panel manufacturer, category of panels or panels causing a decrease of conversion efficiency;[14]

(b) increase of output capacity;

(c) decrease of output capacity by 20% or more;[15]

(d) increase of the total DC capacity of solar panels by 3 kW or more; and

(e) decrease of the total DC capacity of solar panels by 20% or more.

In addition to the above changes related to panels, the following change could also trigger the change in the applicable tariff:

(f) change in "major items" requiring the consent of the relevant transmission and distribution business operator in connection with interconnection with the grid system maintained and used thereby.

According to METI's website,[16] "major items" means important matters which constitute the basis of the grid connection agreement, including the following, and once the grid connection agreement is re-executed as a result of a change of such "major item", the applicable tariff could be lowered:

(i) In case the grid connection agreement is re-executed after the termination thereof due to reasons such as that: (i) a power producer fails to pay a certain part of the construction cost required for construction by the transmission and distribution business operator; or (ii) the power producer fails to satisfy the output curtailment requirement pursuant to the output curtailment rule.

(ii) In case the grid connection agreement is re-executed after a new study of interconnection is conducted due to the power producer's request of any of the following:

- change of transmission system (network) to which the power generation facility is interconnected;[17]
- change of method of installation of the transmission line by the power producer from overhead line method to underground cable method, and *vice versa*; and
- change of the constructor of the transmission line from the power producer to the transmission and distribution business operator.

Addendum

As discussed above, the 5th Strategic Energy Plan was adopted in July 2018, when renewable energy was identified as a "major power source" to achieve the energy mix plan in 2030, while many issues under the Feed-in Tariff system were also identified thereunder. As the Feed-in Tariff system is the key driver to expand renewable energy going forward, we need to pay close attention to further developments of the Feed-in Tariff system.

* * *

Endnotes

1. "Grid connection agreement" comprises an agreement to interconnect with the grid point and an agreement to bear the construction costs required for the construction conducted by the operator of the transmission line.
2. There are two exceptions to the deadline for entering into a grid connection agreement. Firstly, if a power producer obtained its Facility Certification after July 1, 2016, the deadline will be nine months from the date of such Facility Certification. Secondly, in the event that a power producer participates in an auction process for certain joint enhancement construction projects related to the grid system and/or facilities thereof, such power producer shall enter into the grid connection agreement within six months after the said auction process is completed, and the deadline for submission of its business plan is six months after the grid connection agreement is executed.
3. Once the grid connection agreement is executed, a power producer owes an obligation to bear a certain part of the construction cost required for the construction conducted by the operator of transmission line. Accordingly, it seems that many non-operating solar projects with low feasibility of successful completion of development abandoned entering into grid connection agreements before March 31, 2017 and therefore, Facility Certification thereof should have been cancelled.
4. Existing solar projects whose capacity becomes 2MW or more as a result of increase of their capacity shall also be subject to this auction process.
5. In order to foster offshore wind projects, the new bill providing the occupancy rights scheme for general waters was submitted to the ordinary Diet session in 2018. Although the Diet was unable to vote on this new bill during such ordinary Diet session for reasons of scheduling, it seems that once such bill is enacted, the projects to which occupancy rights are granted thereunder shall be also subject to the auction process. We believe that this bill will be re-submitted to a future Diet session.
6. For the purpose of increasing visibility on the regulatory aspects for developers of offshore wind projects, the Agency for Natural Resources and Agency published the Guideline for Land Use Control over General Territorial Water on March 31, 2017. In addition, as discussed in note 5, the new bill providing the occupancy rights scheme for general waters was submitted to the ordinary Diet session in 2018. These are good evidence showing that METI is supportive of offshore wind projects in the course of diversification of renewable energy sources.
7. METI announced this new practice on December 5, 2016.
8. Small-scale wind powers with a capacity of less than 20 kW are excluded.
9. Provided that power producers who entered into power purchase agreements with electricity retailers can keep such agreements even under the New Feed-in Tariff Act.
10. As a result, the so-called METI form of power purchase agreement was abolished.
11. The Enforcement Ordinance of Act on Special Measures Concerning the Procurement of Renewable Electric Energy by Operators of Electric Utilities (METI Ministerial Ordinance No. 46 of 2012, as amended).
12. Notification related to determine the FIT Price etc. pursuant to the Act on Special Measures Concerning the Procurement of Renewable Electric Energy by Operators of Electric Utilities (METI Notification No. 35 of 2017, as amended).
13. As an illustration, we summarise the events triggering change in the Feed-in Tariff Price in connection with projects which: (i) have been deemed "Certified Business Plans" as of April 1, 2017; (ii) are not subject to the Three Years Rule; and (iii) have not started commercial operation.

14. Except for the case where a panel change is required as a result of a panel manufacturer's cessation of manufacturing panels originally contemplated under the old certification.
15. Except for the case where such decrease is required due to the result of the system impact study conducted by the transmission and distribution business operators.
16. http://www.enecho.meti.go.jp/category/saving_and_new/saiene/kaitori/fit_point.html.
17. Except for "relocation". Relocation means change of the location of the point of interconnection after commercial operation, and is limited to cases with unavoidable reasons such as house-moving.

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Korea

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Overview of the current energy mix and different energy sources in Korea

In line with the international trend of increasing focus on green energy sources under the present climate system and the effects of potential climate change, Korea is currently introducing new policies regarding the energy mix and the usage of different energy sources. The recently proposed policies in Korea mainly focus on two basic elements: (i) a reduction in reliance upon its primary energy sources such as fossil fuels and nuclear energy; and (ii) the promotion of renewable energy sources with regard to developing energy efficiency, with a consistent energy supply and eco-friendly policies to prepare for possible changes in the global climate.

With respect to global climate change concerns, the world has been taking a somewhat more straightforward and aggressive stance to protect the world environment. For instance, whereas the 1997 Kyoto Protocol imposed obligations on advanced economies such as Europe and North America to reduce greenhouse gas, the 2015 Paris Agreement, which replaced the Kyoto Protocol, imposed obligations for the reduction of greenhouse gases on all 195 countries signatory to the Agreement. In this regard, the proportions of fossil fuels and nuclear energy are currently in decline as the proportion of eco-friendly energy sources conversely increases in the global energy market. The Korean energy mix has been established in line with such energy transition in the global sphere, described as "a fundamental structural change in the energy sector of a certain country, like the increasing share of renewable energies and the promotion of energy efficiency combined with the phasing-out of fossil fuel energy".[1]

South Korea's incumbent Moon Jae-in government has implemented energy policies aimed at the gradual expansion of new and renewable energy, while phasing out nuclear and fossil fuel plants, which currently account for more than 80% of the energy mix in Korea. In order to achieve this long-term goal, there must be conspicuous developments in terms of the government policy, legislation, and judicial decisions – not only to strengthen the new energy policy itself, but also to balance it with environmental concerns and public safety. In this chapter, we will examine how the Korean government has moved towards a new energy mix, and the resulting implications and concerns.

Structure of Korean energy policy, strategy, and approach

In 2006 and 2010, the Korean government passed the Energy Basic Act (later the Energy Act) and the Framework Act on Low Carbon and Green Growth (the "**Framework Act**") as the basic principles to drive its energy policies. Pursuant to Article 6 of the Energy Basic Act and Article 41 of the Framework Act, the government is required to establish national energy roadmaps for every five years, over a planning period of 20 years in accordance with basic principles for policies on energy. In addition to the national energy roadmap on general energy issues, the Minister of Trade, Industry, and Energy is required to formulate a basic plan for electricity supply and demand (the "**Electricity Supply-Demand Basic Plan**", or the "**Basic Plan**") to stabilise the supply and demand of electricity according to the Electric Utility Act (the "**EUA**") passed in year 2000.[2] This Basic Plan must include: (i) matters concerning the basic direction-setting for the supply and demand of electricity; (ii) matters concerning the long-term outlook for the supply and demand of electricity; (iii) matters concerning plans for generation installation and plans for major transmission and substation facilities; (iv) matters concerning the management of electricity demand; (v) matters concerning the evaluation of preceding basic plans; and (vi) other matters deemed necessary for the supply and demand of electricity.[3]

The Basic Plan should be revised every two years[4] to enable frequent developments, depending on the then-current energy situation in Korea; in this regard, it is highly significant for the government to plan and implement a well-structured Basic Plan not only to execute better energy policies but also to show the government's strong political will to demonstrate how it will develop the energy industry in the future.

Historical background and national energy roadmap

In the past, before the year 2000 in particular, Korea concentrated on providing low-cost and stable energy sources, with a preferential focus on industrial development and price stability. However, since the early 2000s, the government has changed its authoritative stance towards the energy industry by reducing direct interventions into the energy markets, not only to restructure the electric power system in Korea but also to revitalise competition among the various energy sectors. Then, in 2008, the government took the plunge into the energy market again, through the so-called the 'National Energy Roadmap'. The National Energy Roadmap has been designed as the most fundamental model to establish the legal system relevant to energy policy in Korea, including a variety of sub-plans such as Electricity Supply-Demand Basic Plan and the Basic Plan for Development and Use of New and Renewable Energy Policy. In this regard, the National Energy Roadmap has been developed and advanced in the following chronological order:

- <u>The 1st National Energy Roadmap (2008–2030)</u>

  The 1st National Energy Roadmap in 2008 established both mid-term and long-term energy policies that simultaneously and collectively considered: (i) energy security; (ii) economic efficiency; and (iii) the environment. The 1st National Energy Roadmap, however, resulted in an energy-guzzling trend by consumers along with the unequal utilisation of energy sources, particularly centered on coal and nuclear energy. This phenomenon occurred due to the policy's prioritising energy efficiency and offering low electricity rates to consumers.

- <u>The 2nd National Energy Roadmap (2014–2035)</u>

  As a supplementary measure of the 1st National Energy Roadmap, the government implemented the 2nd National Energy Roadmap in January 2014. The new plan provided blueprints for energy plans with specific focus on the following: (i) the conversion of energy policies towards demand management for consumers; (ii) the establishment of a distributed power generation system; (iii) seeking harmonisation with environmental and safety factors; (iv) strengthening energy security and stabilising the energy supply in general; (v) establishment of specific plans for stabilising supplies of each different energy source; and (vi) the active promotion of energy policies to energy consumers in order to increase public awareness. In December 2018, the Moon Jae-in government, whose energy agenda has been to phase out and gradually abandon coal and nuclear power generation facilities, finally established the 8th Basic Plan, which basically included: (i) a refreshed plan for the stabilisation of power supply and demand, based on new and renewable energy sources; and (ii) plans for growing the capacity of new and renewable energy sources in line with environmental protection concerns.[5]

In the same way, the incumbent government is also encouraging energy suppliers to comply with: the Renewable Portfolio Standard (RPS), which obligates such suppliers to provide certain amounts of new and renewable energy; Feed-In Tariffs (FIT),[6] designed to promote the use of new and renewable energy; and Renewable Fuel Standard (RFS), which obligates fossil fuel suppliers to provide a certain percentage of new and renewable energy together with their fossil fuel supply. It is anticipated that the new energy policy regarding new and renewable energy sources may lead to the acceleration of the plant-decommissioning industry, as well as the elevation of gas power generation, in line with the government's policy to avoid nuclear energy altogether.

- The 3rd National Energy Roadmap (2019–2040)

  The 3rd National Energy Roadmap is scheduled to be released in 2019 and is expected to conspicuously stimulate the development of new and renewable energy sources to replace fossil fuels and nuclear energy as primary sources of energy in Korea.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Energy mix and future expectations: Gradual shift to new and renewable energy

In 2017, coal power generation accounted for 43% of total power generation in Korea, the largest proportion among all energy sources. Furthermore, according to the 8th Basic Plan proposed by the government, it is still expected that coal generation will account for the largest proportion of all energy sources until the year 2030.[7]

In terms of installed capacity, the proportions of energy generation among the various energy sources are as follows:

- Year 2017: LNG (31.9%), Coal (31.6%), Nuclear (19.3%), New and Renewable Energy (9.7%), Others* (7.5%).

  (* Where 'Others' includes petroleum thermal power.)
- Year 2030 (Expected): LNG (27.3%), Coal (23.0%), Nuclear Plant (11.7%), New and Renewable (33.7%), Others (4.3%).

Below is the percentage of the actual amounts of electricity generation for each energy resource:

- Year 2017: Coal (45.3%), Nuclear (30.3%), LNG (16.9%), New and Renewable Energy (6.2%), Others (1.3%).
- Year 2030 (Expected): Coal (36.1%), Nuclear (23.9%), LNG (18.8%), New and Renewable Energy (20.0%).

In spite of the government's energy policies aimed towards discontinuing the use of nuclear and coal plants, coal and nuclear power still account for a significant proportion of installed capacity due to two factors: (i) first, the current Basic Plan intends to implement 'phased reductions' of energy facilities which are already installed and operating; and (ii) second, through this Basic Plan, the government has scheduled 'partial shutdowns' of nuclear or coal facilities, and not drastic shutdowns of the same, in order to ensure energy security for supply and demand. In this regard, the government intends to accomplish the gradual shift of energy sources into new and renewable energy without impairing the current power generation system.

Current electricity rate system and relevant legal matters

In Korea, the electricity rate system consists of three different categories, namely: industrial use; general use; and household use. In addition, the applicable rates are composed of two-part tariffs – with basic rates (minimum rates) and rates based on the amount of electricity actually used. However, in general, overall electricity costs are much lower in Korea than in other OECD countries, due to the low cost of electricity generation, based on greater reliance on nuclear and coal power generation, which are deemed more economically efficient compared to other energy sources, and low transmission and distribution costs without additional environmental costs included within the rates.[8]

A recently heated issue regarding the electricity rate system related to excessively burdensome rates being imposed only on household electricity use under the 'progressive billing system'. The progressive billing system was designed to encourage frugal energy consumption among household consumers by charging higher rates for higher electricity use. The progressive billing system is composed of a three-stage progressive rate structure, creating payment differences in electricity rates. Under the current system, the unit price of the first stage for those of who use below 200 kWh per month is KRW 93.3 per kWh (equivalent to US 9 cents), which drastically rises to KRW 187.9 per kWh (US 18 cents) for the second stage, which ranges between 201 kWh and 400 kWh. The third stage is set at KRW 280.6 (US 27 cents) for those household consumers who use over 400 kWh of electricity per month.

The controversy arising from this progressive billing system is that it only applies to household electricity rates, and not industrial rates. Industrial power consumption accounts for 56% of total electricity use in Korea, whereas household consumption accounts for only 13%. Therefore, household electricity consumers are inevitably deterred from using electricity especially during the summer months with their intense heat waves in recent years. In this regard, the ratio of household electricity consumption compared to other electricity consumption in Korea is just over half of that of other OECD countries, the latter averaging 18.8%, whereas the ratio for Korea is just 10.9%.[9]

Due to the unprecedented heatwave directly striking the Korean Peninsula in the summer of 2018, there arose heated controversy as to whether the progressive billing system should be modified. As a result, the government decided to temporarily adjust the billing system to ease the burden on households. Under the adjusted billing system, the ceiling for the first stage rose up to 300 kWh, and that of the second stage rose to 500 kWh, albeit only for two months – July and August 2018.

The progressive electricity billing system has become one of major social issues of concern. The temporary adjustment of the billing system cannot be the ultimate resolution to soothe consumer discontent. In fact, at the time of this writing there is a pending civil lawsuit before the Supreme Court of Korea in which the Plaintiffs have claimed the return of unjust gains received by KEPCO (the Korea Electric Power Corporation) under the progressive electricity billing system, which should be invalidated in accordance with Article 6 of the Act on the Regulation of Standardized Terms and Conditions, which stipulates that "any clause in any standard terms and conditions which is not fair or contrary to the principles of trust and good faith shall be null and void".

The final judgment of the Supreme Court regarding the foregoing case will have a great impact not only on the progressive billing system *per se*, but also on electric power systems in terms of their economic feasibility. Considering the foregoing, the government is now obligated to implement more concrete roadmaps to further develop efficient power generation systems, while simultaneously satisfying household consumers with a fair and reasonable electricity rate system.

Developments in legislation or regulation

The 8th Basic Plan: Shifts in energy policy

Article 3 of the EUA, amended in March 2017 and begun to be enforced in June 2017, sets specific guidelines for the government with respect to the efficient use of energy, environmental protection, and public safety. So now, when the government reviews the Electricity Supply-Demand Basic Plan, it must comprehensively take into account the economic feasibility of electric installations and their impact on the environment and public safety.[10] In this regard, the 8th Basic Plan, established in December 2017, has been implemented for the development of energy market policies closely aligned with environmental and public safety concerns, as per the EUA. The 8th Basic Plan focuses on producing more power from new and renewable energy sources while gradually reducing the use of fossil fuels and nuclear power. To be specific, the 8th Basic Plan consists of three major objectives, as further discussed below:

- *Reduction of coal and nuclear energy and expansion of new and renewable energy*

First, the government will shift the primary energy source from fossil fuels and nuclear energy to new and renewable energy. Through the 'New and Renewable Energy Plan 3020', the Korean government has targeted the expansion of new and renewable energy sources to 20% by 2030, through various measurements which will be discussed in detail later in this article. Considering the fact that the renewable energy industry must undergo a certain period of stagnation due to its relatively expensive costs for installation, a drastic reduction in the use of coal energy and nuclear power by 2022 will not occur due to the need to ensure energy continuity and safety.

However, as the government increases its investments in technological developments for new and renewable energy sources, and encourages technological competition in relation to same, this is highly likely to lead to considerable growth in these energy sources in the long term. Also, through tax adjustments, the government is aiming to reduce the rate differences between new and renewable energy and existing primary energy sources, in order to increase the cost-competitiveness of the new and renewable energy sources. In addition to the Basic Plan, the government will also concentrate on restructuring the energy system via the New and Renewable Energy Plan 3020, in order to actualise the long-term plan for replacing fossil fuels and nuclear energy with new and renewable energy sources.

- *Power supply system with environmental and safety standards*

Secondly, the 8th Basic Plan, based on the recently added provisions of the EUA aimed at ensuring environmental and safety standards are maintained during energy generation, aims at expanding new and renewable energy sources which inflict zero harm on the environment. According to the 8th Basic Plan, in terms of installed capacity, the energy mix forecast for new and renewable energy sources will drastically increase to 3.5 times larger than at present, from 9.7% in 2017 to 33.7% by 2030, in proportion to the reduction of the coal, nuclear, and LNG energy mix. In this regard, the actual amount of electricity generated in 2030 will be expected to increase by 20% as well.

In order to expand new and renewable energy sources in practice, the Korean government has acknowledged the necessity of calculating the cost of power generation by taking into account environmental costs such as emissions trading costs, with the end-goal of curbing environmentally unfriendly power systems. In addition, the government is enforcing a policy of strengthening emission standards along with imposing emission costs thereon. To legally enforce the imposition of emission costs, the external effects of environmental pollution caused by coal power plants and nuclear power plants must be meticulously reassessed to set and clarify the standards for such environmental costs in advance. For example, in order to cope with the 'fine dust' problem generated by the operation of coal power plants, the government has implemented a policy to impose specific restrictions on coal power plant operators whenever such restrictions are deemed necessary to protect air quality in accordance with the Clean Air Conservation Act. In addition, the government will introduce a system to restrict coal power generation, particularly in the spring when fine dust especially pervades the surrounding air. The national government, in consultation with provincial governments, is now planning to establish the standards for enforcing such policies, and the proper procedures to cease all forms of thermal power generation.

Lastly, public safety must be guaranteed during the proposed energy transition. The energy transition process inevitably deals with decommissioning nuclear power plants, as the government has promised the shutdown of most aging nuclear generation facilities. The Fukushima nuclear accident in Japan strongly aroused widespread public awareness of the significance of nuclear safety and management. In July 2017, the Moon Jae-in government proclaimed the new Nuclear Safety Act ("**NSA**") to regulate the safety of nuclear energy development and use. The NSA was established to provide for matters concerning safety management during the research, development, production and use of nuclear energy, in order to maintain public safety and to ensure the prevention of future disasters resulting from radiation leakage.[11]

- *Demand-side management*

As its third major objective under the 8th Basic Plan, the Korean government will take measures to reduce total electric power generation by 12.3%, and total power consumption by 14.5%, by 2030. To fulfil this goal and manage demand-side matters, the government plans to implement and expand: (i) new types of electric energy businesses; (ii) the Demand Response ("**DR**") system; (iii) Energy Efficiency Resource Standards ("**EERS**"); and (iv) the 'Energy Champion System'.

Through further amendments of the EUA, it will be possible to officially register new electric businesses such as an 'electric vehicle charging business' or 'small-scale electric brokerage business' into the market, so that those who are interested in such businesses may operate them easily and directly transact within the electric power market, thereby promoting investments into these burgeoning energy businesses. In this case, the 'new energy' market will not only expand in terms of size, but also diversify supply and energy generation methods.

The purpose of the DR system is to provide companies which intend to cut down their usage of electricity with an opportunity to enter into reimbursement contracts with 'demand management' companies. Under such contracts, if the relevant company uses less electricity than its current consumption amount, then the remaining amount of electricity will be sold to KEPCO and the company and the demand management company will share the proceeds. In this regard, the DR system may be used as an efficient tool to reduce energy demands without any particular intervention into the energy market directly.

Through the EERS, the government sets certain standards for energy reduction goals, and energy suppliers promote certain activities in order for consumers to achieve energy efficiency improvement goals. The EERS is designed to promote a self-regulating system to control demand-side management in the long term. In this regard, the Korean government also plans to grant rewards to those energy suppliers who actively cooperate in the government's demand-side management measures, through the so-called Energy Champion System as well.

<u>New and Renewable Energy Plan 3020 – Moon Jae-in government's support</u>

The Moon Jae-in government separately disclosed its policy stance regarding new and renewable energy matters through its New and Renewable Energy Plan 3020 ("**Plan 3020**"). Plan 3020's specific goal is to increase the electricity generated by new and renewable energy sources up to 20% by 2030. In particular, by 2030, more than 95% of new power generation capacity will be supplied by clean energy sources such as solar power (63%) and wind power (34%), and the targeted amount provided by these energy sources will be 12.4 GW each year in the earlier stages (years 2018–2022), and 36.3 GW each year in the later stages (years 2023–2030).[12]

What is most noteworthy among the major implementations as mentioned above is the expansion of new and renewable energy businesses centering on solar power systems. In reality, the Korean solar photovoltaic industry has recently been suffering from overseas market conditions such as trade protection measures against Korean solar photovoltaic cells and subsidy reductions by the Chinese government, in particular. In this regard, the Korean government changed its policy direction originally targeted at overseas market expansion, to the domestic solar photovoltaic cell businesses.

Plan 3020 elevates photovoltaic cells and wind as core resources to fulfil its energy implementation plans, aiming to achieve the supply of new and renewable energy by initiating large-scale photovoltaic cell and wind power projects. These large projects will be conducted in close collaboration with Renewable Portfolio Standard (RPS) suppliers and public institutions. Specifically, these projects are expected to include the following features: (i) the expansion of urban-style photovoltaic power for houses and buildings (2.4 GW); (ii) small-scale project support through cooperative associations (7.5 GW); (iii) rural photovoltaic activation (10 GW); and (iv) large-scale projects with idle land previously used for nuclear power plants and coal development sites (28.8 GW).

In order to achieve the foregoing goals, the government will expand the supply of new and renewable energy and increase the relevant financial budgets by more than 50% (51.7%), starting from 2019. In this regard, by 2030, Plan 3020 expects the government to input costs of KRW 92 trillion (roughly equivalent to US$ 90 billion), composed of KRW 51 trillion from the public sector (including a government budget equal to KRW 18 trillion), and KRW 41 trillion from the private sector.[13] With Plan 3020, the government is showing its determination in building a foundation for the further development of new and renewable energy sources.

Major events or developments

<u>Nuclear power phase-out</u>

As mentioned above, the Moon Jae-in government promised to phase out nuclear power, while increasing new and renewable energy by 20% by 2030. The phase-out plan for nuclear power plants has been planned as follows: (i) all new construction plans will be cancelled; (ii) aging nuclear plants will be shut down within the next decade; (iii) nuclear energy technology gained through the construction and operation of nuclear plants will be maintained through the government's nuclear export policy; and (iv) the government will focus on controlling the nuclear decommissioning market, using advanced technology in close alignment with security concerns.

Growing concerns over nuclear power

- *Nuclear security*

Since the 2011 Fukushima nuclear accident in Japan, there have been ever-growing concerns over nuclear plant safety, which has led to the implementation of the Moon Jae-in government's nuclear power phase-out policy. Electricity consumers have become much more sensitive to the safety of nuclear power plants and have sought more concrete legal solutions in line with current social attitudes. In other words, consumers have exercised their rights to ensure nuclear power safety more strongly and have sought new legislation to reflect their new policy needs.

For instance, in 2012, ordinary people living within the proximity of nuclear power plants filed a constitutional appeal for the government's lack of effective preventive measures to avoid critical accidents similar to the Fukushima nuclear accident. Such constitutional appeal was raised to ensure "the right to pursue happiness", and "the right to life and human dignity" of the people living near the nuclear facilities. The Constitutional Court of Korea dismissed the appeal, ruling that "since the government has prepared efficient policies in case of critical nuclear power plants accidents through the Atomic Energy Commission and applicable guidelines, the applicants' rights cannot be seen to have been violated due to the government's lack of relevant policies". In spite of the foregoing decision, however, the appeal clearly reflects the Korean people's growing concerns over nuclear safety.

- *How to proceed with the nuclear phase-out*

As discussed earlier, Korea plans to limit its nuclear power generation gradually by cancelling the plans for extending the life of certain aging plants, as well as completely shutting down new construction plans. However, as Korea has already sunk significant costs into developing nuclear energy technology and accumulated know-how as to the construction and operation of nuclear power plants, the government plans to make its best efforts to maintain such technology.

In this regard, the government plans to export its nuclear technology and know-how to other countries such as the UAE, Saudi Arabia, Poland and Great Britain. The UAE's US$ 20 billion nuclear power plant construction project is almost complete and is expected to be operational by 2020 (such project being initiated by the former government). KEPCO actively promoted its nuclear export policy in order to win a nuclear power plant bid requested by Saudi Arabia. In the meantime, Korea plans to export small and medium-sized nuclear reactors to Saudi Arabia, hoping to participate in the 'King Abdullah City for Atomic and Renewable Energy' in Riyadh.

Also, KEPCO was selected in December 2017 as the preferred bidder for Toshiba's NuGen unit, which was to build a nuclear power plant at Moorside in Great Britain (although its preferred bidder position was terminated last July due to funding issues). Currently, the government is fully supporting KEPCO in its efforts to maintain its bargaining position in ongoing negotiations, and to finally recoup its financial investment in due time. In this regard, the nuclear industry expects the government to ascertain the best way to save this project in order to maintain Korea's leading edge technology for future nuclear power plant construction and operation.

The Korean government is taking steps to minimise technological losses as well as manpower losses possibly caused by the nuclear power phase-out policy. Besides the nuclear export policy, the current situation demands legislative and administrative measures not only to guarantee the job security of workers who will inevitably lose their jobs, but also to establish nuclear decommissioning safety. In this regard, the government and related authorities in Korea are using their best efforts to successfully usher in a soft landing during the nuclear phase-out.

Appraisals and expectations

Following the shutdown of its nuclear generation capacity, Korea is anticipated to experience a reduction of electricity supply. This raises concerns that the country may experience blackouts along with massive hikes in electricity rates. Considering the foregoing, it will be important to install new and renewable energy sources to establish sufficient supply as soon as practicable, in order to prevent any possible shortages of electricity.

In addition, some people regard the 8th Basic Plan as going against the intentions of the National Energy Roadmap, thereby raising questions of whether the expected supply will fail to meet demand due to the nuclear phase-out. In reality, to build photovoltaic power plants or wind power plants, one must undergo a process involving numerous approvals (such as environmental assessments, land transaction approvals, alteration of land quality and geography, and the like) which delay electricity generation from these energy plants. In this regard, the government may have to establish both legislative and administrative measures to facilitate more rapid construction and operational processes for new and renewable energy plants.

In the end, the Korean government is making its best efforts to achieve both economic as well as safe energy usage, in line with environmental protection and public safety goals. In order to achieve these objectives and in collaboration with other public organisations, the government will help improve the quality of alternative energy sources by constant innovation of mechanisms to fulfil energy demands. It is also anticipated that the government will maintain a strong focus on developing its energy Basic Plans, which properly reflects the current energy situation with flexibility, in order to cope with any problems arising therefrom.

* * *

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Kosovo

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Jurisdiction particularities of the Republic of Kosovo

Until 2008, Kosovo was administered by the United Nations Interim Administration Mission in Kosovo (UNMIK). The mandate of UNMIK was established by the Security Council in its resolution no. 1244 (1999), [https://unmik.unmissions.org/united-nations-resolution-1244] aiming to help ensure the conditions for a peaceful and normal life for all inhabitants of Kosovo and to advance regional stability in the Western Balkans.

Kosovo declared independence on 17 February 2008 and adopted its constitution on 15 June 2008. The Constitution of the Republic of Kosovo (art. 143) makes reference to the Comprehensive Proposal for the Kosovo Status Settlement of 26 March 2007 produced by the Special Envoy, Mr. Martti Ahtissari, in line with UN Resolution no. 1244 (1999) [http://www.kuvendikosoves.org/common/docs/Comprehensive%20Proposal%20.pdf].

The Parliament of the Republic of Kosovo enacted the Law on Publicly Owned Enterprises (law no. 03/L-087 as amended), which paved the way for the privatisation of publicly owned enterprises (POE).

Serbia challenged the independence of Kosovo before the International Court of Justice but, according to the Court's opinion, Kosovo's declaration of independence did not violate any applicable rule of international law.

Privatisations and unbundling of distribution and supply of electricity

From October 2006 until 8 May 2013, the generation, distribution and supply of electrical energy in Kosovo was owned, controlled and carried out by Korporata Energjitike e Kosoves SH.A / Kosovo Energy Corporation J.S.C. (KEK), incorporated in 2005 as a fully integrated, state-owned company. All energy assets on the territory of Republic of Kosovo, including assets in the northern part of Kosovo, were transferred to KEK upon its incorporation.

The Government of the Republic of Kosovo and KEK completed the unbundling of the distribution system operation and supply functions into Kompania Kosovare per Distribuim dhe Furnizim me Energji Elektrike SH.A. / Kosovo Electricity Distribution and Supply Company J.S.C. (KEDS), which shares were acquired in a competing privatisation process by a consortium of two Turkish private groups, Limak and Çalik. This process was successfully finalised on 8 May 2013.

On 1 January 2015, the licensed supply activities were transferred from KEDS to Kosovo Electricity Supply Company J.S.C. (KESCO), a company newly established by the same consortium, Limak and Çalik. Functional unbundling was completed by the adoption of a compliance programme by Kosovo Energy Regulator Office (ERO) in July 2015 and the appointment of a compliance officer.

Therefore, KEDS operates only as a distributor system operator (DSO) licensed to carry out its activity covering the entire territory of the Republic of Kosovo.

Opening of the energy market

Kosovo* together with Albania, Bosnia and Herzegovina, FYROM, Georgia, Moldova, Montenegro, Serbia and Ukraine, is a member of the Energy Community (an international organisation founded under the Treaty establishing the Energy Community signed in October 2005 in Athens, Greece, in force since July 2006). The key objective of the Energy Community is to extend the EU internal energy market rules and principles to countries in South East Europe, the Black Sea region and beyond, on the basis of a legally binding framework.

Kosovo has reached a high level of compliance in the electricity sector legal framework.

In June 2016, the Parliament of Kosovo adopted:

(i) the Law on Energy (Law No. 05/L-081), transposing partially Directive 2009/72/EC on common rules for the internal market in electricity, the Regulation No. 714/2009/EC on conditions for access to the network for cross-border exchanges in electricity, and Directive No. 2009/28/EC concerning promotion of the use of energy from renewable energy sources;

(ii) the Law on Electricity (Law No. 05/L-085), transposing partially the Directive No. 2009/72/EC on common rules for the internal market in electricity and the Regulation No. 714/2009/EC on conditions for access to the network for cross-border exchanges in electricity; and

(iii) the Law on Energy Regulator (Law No. 05/L – 084), transposing partially the Directive 2009/72/EC on common rules for the internal market in electricity, the Regulation No. 714/2009/EC on conditions for access to the network for cross-border exchanges in electricity, Directive No. 2009/73/EC on common rules of the internal European natural gas market Regulation No. 715/2009/EC on conditions of access to natural gas transmission networks, and Directive No. 2009/28/EC concerning promotion of the use of energy from renewable energy sources.

In addition to the above, the secondary legislation necessary for opening of the market was also adopted.

The Law on Electricity sets common rules for the generation, transmission, distribution, supply, trade and organised market, as part of the regional and European electricity markets, and establishes rules for: the access of parties in the market; public service obligations; consumer rights; and competition conditions. The law transposes the requirements for ownership unbundling of the transmission system operator in line with the *acquis*. Therefore, the Government of Kosovo owns the generation company KEK, while the Parliament controls the transmission system operator Operator Sistemi, Transmisioni dhe Tregu – KOSTT SH.A. As mentioned above, the unbundling of the distribution system operator KEDS from supply activities has been already completed.

According to the Law on Electricity, all customers are eligible to freely choose a supplier of their choice. The law establishes general principles of supplier switching based on which ERO adopted the relevant rules in October 2016.

In addition, the law limits regulation to supply prices for household and small customers under universal service. ERO reassesses annually the price methodology, the level of prices and the need for further regulation.

In January 2017, ERO issued a guideline for liberalisation of the market, which terminated regulation of the generation price on 31 March 2017. The guideline also includes an action plan for the deregulation of retail prices. Transmission and distribution system operators have started to procure electricity for network losses at non-regulated prices.

ERO started to issue supply licences, resulting in three licensed suppliers so far. By the decision of ERO, KESCO was entrusted with universal supply obligations and remunerated based on tariffs approved by ERO.

A tender for the appointment of a supplier of last resort was announced by ERO in accordance with the Law, however, it appears that no application has been submitted so far.

It also appears that the rules are reflected properly in the paper, nevertheless it remains to be seen whether new players entering the market will benefit from the opening.

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Nigeria

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Overview of the current energy mix, and the place in the market of different energy sources

Introduction

Nigeria is extremely rich in energy resources. It is the largest oil producer in Africa and the 6th largest in the world. Nigeria has an estimated oil reserve of about 37 billion barrels,[1] thereby making exports of fossil fuels the country's major income-generation mechanism since the discovery of oil in large deposits in 1956.[2] One would assume that with the identified large deposits of resources in Nigeria, the country would have been able to harness these resources for the development of the country. To date, however, about 60–70% of the Nigerian population does not have access to electricity.[3]

Despite the country's strong inclination towards non-renewable energy exportation and consumption, Nigeria boasts generous renewable energy resources such as Solar, Wind, Biomass, and Small hydropower potential. The country presently uses a synergy of renewable and non-renewable energy resources in the generation of the country's power.

The primary sources of energy for the production of electricity in Nigeria remain Coal, Oil, Water and Gas. Nevertheless, the Nigerian market remains primed towards the exploitation of other energy sources to meet with the country's ever-increasing demand to cater for its population of over 196 million.[4] Presently, Hydroelectric power and Gas-fired systems take precedence in Nigeria's current energy mix.[5]

The energy sources in Nigeria can be broadly categorised into Renewable & Non-renewable energy.

Non-renewable energy

The predominant non-renewable energy resources in Nigeria comprise Fossil Fuels which include Coal, Oil and Natural gas. These components of fossil fuels are used for the provision of energy, with crude oil being the most widely used in Nigeria.[6] Crude oil has historically accounted for ninety per cent (90%) of Nigeria's foreign exchange earnings. The country's annual budget has always been benchmarked to oil price projections and the number of barrels sold. Daily average oil production had grown, since its commercial discovery in 1956, to around 2.5 million barrels per day in 2012 (notwithstanding the periodic price shock in between those dates), effectively signalling an over-extended oil boom.

The Nigerian National Petroleum Corporation (NNPC) is the apex oil regulatory body in the country. It oversees the operation of all the subsidiaries in the Upstream, Midstream and Downstream sectors and regulates the marketing and distribution of crude oil. The NNPC was commercialised into 12 strategic business units which cover the entire oil industry operations.[7] These operations include: exploration & production; gas development; refining; distribution; petrochemicals engineering; commercial investments; and product transportation.[8]

Additionally, the industry is regulated by the Department of Petroleum Resources (DPR), which regulates the operations of the Oil industry, issues licences and ensures compliance with industry regulations, as well as establishing and enforcing environmental regulations.[9]

Another key regulator in the Oil & Gas industry is the National Petroleum Investment Management Services (NAPIMS), the investment arm of the NNPC. It is charged with the responsibility of managing the Nigerian Government's investment in the Upstream sector of the Oil & Gas industry and administering the NNPC's Joint Venture Operations.[10]

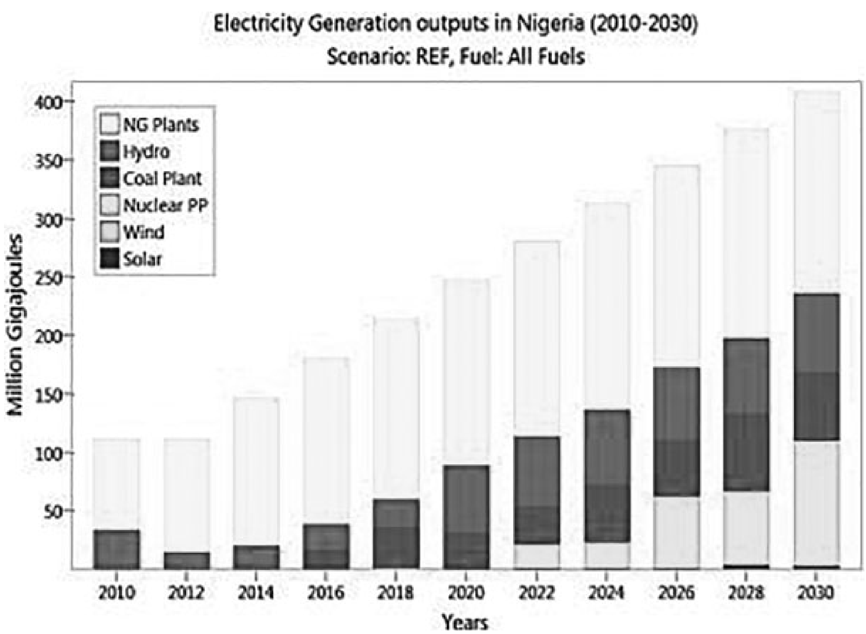
Nigeria's market for oil & gas

Nigeria's market for oil & gas has mainly been for external consumption. The petroleum sourced in Nigeria has been termed "Light" and "Sweet".[11] This is because the oil is purportedly free of Sulphur. Nigeria is the largest producer of "Sweet" oil in the Organisation of the Petroleum Exporting Industries (OPEC).[12] Nigeria has six (6) Petroleum Export Terminals in the country owned by Shell, Mobil, Chevron, Texaco and Agip.

It is estimated that the demand for, and consumption of petroleum in Nigeria is growing at a rate of 12.8% annually. Nevertheless, petroleum products remain unavailable and expensive to most Nigerians, due to the fact that crude oil extracted in Nigeria is refined overseas and imported back to Nigeria for distribution in limited quantity.

From the foregoing, it is evident that local consumption of the crude oil derived is at a historic low in comparison to the amount exported to other countries.

The DPR reported that despite the meagre amount of petroleum products imported back into Nigeria for local consumption, 78% of total energy consumption in Nigeria is still derived from Oil & Gas.[13] Thus, the recent dip in oil prices in March 2018 has left in its path a rekindled understanding by the Nigerian Government of the need to shift total reliance on crude oil exports and utilisation in the generation of power to cheaper and more environmentally friendly sources of energy generation.[14]



Renewable energy

The predominant renewable energy sources in Nigeria are Wind, Solar, Hydro and Biomass energy. These energy sources have been gravely under-utilised due to the heavy reliance on fossil fuel for power generation in Nigeria for the past 45 years.

Hydroelectric power systems and Gas-fired systems are the two main power-generating systems used presently in Nigeria. The power sector has generated electricity through a mix of both Thermal and Hydro systems, but the amount of power generated from these sources has reduced over time due to lack of infrastructure and poor maintenance of turbines and power-generation mechanisms.

By the year 2020, Nigeria aims to generate an excess of 40,000 Megawatts (MW), with an energy mix that constitutes 69% Thermal, 17% Hydro, 10% Coal and about 4% Renewable energy.

In recent years, there has been a shift in focus towards solar power generation, and this is as a result of the climate in Nigeria. Over the past year, the country has invested more than $20 billion in Solar Power projects, seeking to boost the capacity of the National grid and reduce reliance on it by building "Mini-Grids" in rural areas without mains electricity.[15] A $350 million World Bank loan will be used to build 10,000 solar-powered Mini-Grids by 2023 in rural areas, bringing power to hospitals, schools and households, according to the MD of the Rural Electrification Agency.[16]

Furthermore, Nigeria has set a target of expanding electricity access to 75% of the population by 2020, and 90% by 2030. It aims to generate 30% of its total energy from renewable sources by 2030.

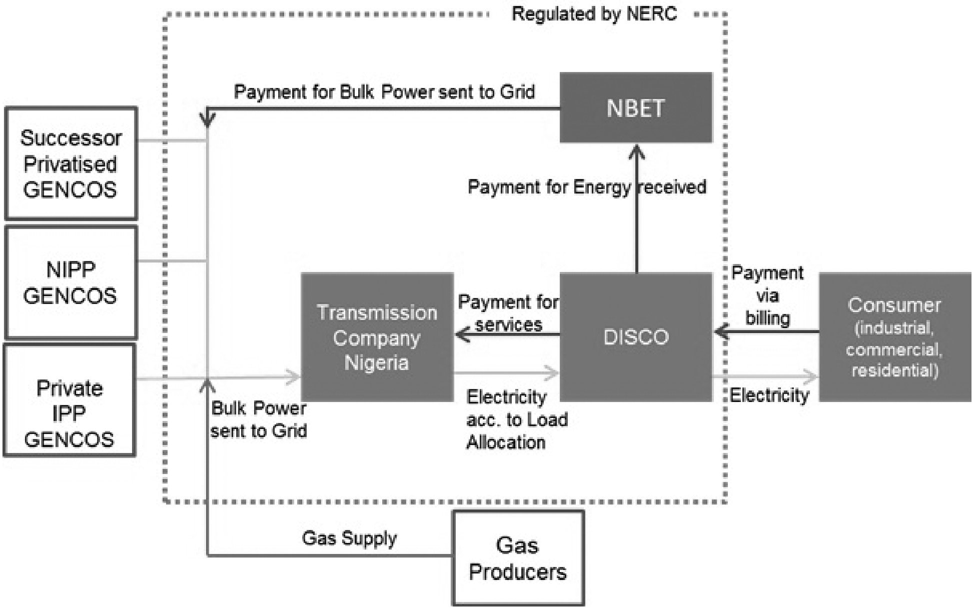
The aim of Nigeria's power sector over the years has remained to ensure effective transmission of power to all parts of the country, despite the apparent lack of an institutional and regulatory framework to streamline the sector's progress and development. The constant need to progress and provide uninterrupted power supply to Nigerians has led to the privatisation of the nation's power sector and the termination of the monopoly status of the Nigerian Electricity Power Authority (NEPA), which was the sole governing body of the entire Power sector in Nigeria between 1972–2005.[17]

NEPA was transformed into the Power Holding Company of Nigeria (PHCN) as a holding company for NEPA's assets, liabilities, employees, rights and obligations pursuant to the passage of the Electric Power Sector Reform Act (EPSRA) in March 2005. This Act was established to drive the process of reforming the Power sector.

Pursuant to the Act, 18 new successor companies comprising six Generation companies (GenCos), the Transmission Company of Nigeria (TCN) and 11 Distribution companies (DisCos) were incorporated. New agencies were also created to drive the institutional and regulatory framework of the privatised sector. These agencies are composed of: the National Electricity Regulatory Commission (NERC); the Nigerian Electricity Liability Management Company (NELMCO); and the Nigerian Bulk Electricity Trading Plc. (NBET).

Despite several attempts by the public and private agencies to promote the adoption of alternative energy sources in Nigeria, the cost of setting up renewable energy generation components remains prohibitively high. The lack of technological expertise and skilled labour for the implementation and running of wind farms, thermal stations and hydroelectric renewable energy facilities, is another challenge being faced in Nigeria.

Figure 2, on the next page, gives a pictorial overview of how power is generated in Nigeria.



Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

<u>The imposition of import duty on solar panels</u>

The Nigerian Customs Service (NCS) imposed a 5–10% import duty on solar panels in March 2018, despite a Government directive that classifies solar panel importation as exempt from duty tariff.

Solar energy is adopted in Nigeria as a Renewable Energy (RE) source and has tremendously reduced noise and air pollution due to the displacement of diesel and petrol generators. The introduction of an import duty will increase the price of importation and sales of solar energy to uncompetitive levels. Globally, the cost of solar energy has declined, leading to increased adoption by home and business owners. Therefore, if the import duty is imposed, Nigeria will stand to lose out on RE development since it does not currently have the capacity to manufacture solar panels and performs limited assembly, in volumes that cannot meet more than 10% of market demand, hence its recourse to importation while growing capacity locally.

Additionally, the tariff will increase the acquisition cost of solar panels in Nigeria which are currently heavily delayed in rural areas where purchasing power is low, and could derail Nigeria’s plan to generate 30% of electricity through renewable energy by 2030. Inadvertently, it would affect the ease of doing business in Nigeria and decrease energy access to 70 million people with inadequate access to power.

<u>The N701bn Payment Assurance Guarantee</u>

This initiative was created by the current Government to give comfort to investors in the power-generation arm of the value chain, to enable them to get a sizeable percentage of their money when they deliver power to DisCos through the Transmission Company of Nigeria (TCN). GenCos can now feel more confident that they will invest and realise money, which will enable them pay their gas suppliers, and also enable the gas suppliers to pay their banks.[18]

Since implementation of the Payment Assurance Guarantee in 2017, recovery of payments by GenCos has increased from 20% to 80%, and power supply capacity has also improved from 4,000 MW to 7,000 MW, according to the Minister of Power, Works and Housing.[19]

According to the Minister, the Geregu I and Geregu II gas turbine power plants[20] had only one turbine running in each of them out of three turbines combined, making a total of six. Therefore, there was minimal capacity. Subsequently, following implementation of the policy, all three turbines are running at each plant due to improved gas supply.

Now, is the policy perfect? Certainly not. But one can say the GenCos will profit from it, considering the fact that they can now obtain more money for the power they produce, as opposed to when they got below 30% of the value of their invoices.

Developments in government policy/strategy/approach

National Renewable Energy Actions Plans (NREAP) 2016

In 2016, several Ministries, Departments, Agencies and Representatives of the 36 states of the Federal Government developed the NREAP. It details plans to increase the use of alternative energies such as solar, wind and biomass. Through the NREAP, the Government has made a commitment to incentivise large-scale adoption of Renewable Energies (RE) in Nigeria.[21]

The policy commits Nigeria to achieving 16% of its national electricity consumption from RE by 2030 with the following proportion of energy consumption in the electricity sector coming from renewables: Small Hydropower (7.07%); Solar (5.90%); Biomass (2.78%); and Wind (0.25%). This compares to only 0.8% of Renewable Energy consumption in 2012.[22]

The Government has pledged to encourage the Nigerian Bulk Electricity Trading Plc (NBET) and DisCos to buy the electricity offered to the electricity market from Renewable Energy sources. However, this will be done at a rate fixed by the Nigerian Electricity Regulatory Commission (NERC), which will be responsible for the promotion and issuing of licences to RE operators.[23]

Additionally, the NREAP offers tax incentives to GenCos who adopt renewable energy. The policy promises to grant financial aid, loans and grants for RE projects and Feed-In-Tariff for Solar, Wind, Biomass & Small Hydro.

A hindrance to the adoption of RE in Nigeria is the continued subsidy of fossil fuel energy. The Renewable Energy Association of Nigeria (REAN) has complained that the subsidy of fossil fuel energy is an unfair economic policy to importers and manufacturers of RE. Therefore, the Government should provide a level playing field for all energy sources to compete economically. This would encourage and make RE competitive with fossil fuel energies such as Oil & Gas.

In stark contradiction to its clean energy commitment, the Federal Government (through the Ministry of Mines and Steel Development) recently announced plans to issue coal mining licences to companies set-up for the sole purpose of power generation. In this regard, such companies would ordinarily have been granted power generating licences prior to their application for a coal mining licence. This turnaround in policy direction indicates Government's commitment to providing electricity regardless of the environmental and climate implications, considering the steep financing required for clean energy financing, and the reluctance of funding agencies to be involved in coal-related projects.

Partnership with international organisations

Asteven Group, a green energy solution provider, launched a Renewable Energy Academy in Ogun State, Nigeria in February 2018. The Academy aims to train students to become vendors, developers, installers, technicians and service providers of renewable energy technologies.[24]

The Academy falls under efforts to help expand Nigeria's RE portfolio to secure its energy supply against growing demand. Furthermore, the initiative will contribute to increasing access to affordable and clean energy to under-served consumers currently not connected to the main grid, in addition to helping Nigeria reduce its carbon footprint.[25]

Additionally, the Nigerian Government, Power for All, US Global Development Lab, Power Africa, USAID-Nigeria, as well as FHI360, announced a partnership to drive access to modern, clean and affordable electricity.[26] The launch comes after Asteven Group installed approximately 20 MW of renewable energy capacity, avoiding 20,744 tonnes of carbon emissions per year, in Nigeria. The group was formed to identify and implement a stakeholder approach to expedite the end of energy poverty in Nigeria. This is in line with the goals and vision of the Nigerian Government's commitment towards increasing power access in Nigeria and increasing the rate of electrification of rural areas.

Meter Asset Provider

Another recent policy is the Meter Asset Provider (MAP), which was introduced to address the meter supply gap, relieve DisCos of the financial burden of meters, allow entrepreneurs to take up meter-supplying as a business, and diversify the sources of meter supply. The Regulations and Conditions for its operation were issued by the NERC on March 8, 2018.[27] The new MAP regulation provides for third-party financing of meter production and supply, under a permit issued by the NERC, with a 10-year period to pay back the cost.

Additionally, the Minister of Power, Works and Housing stated recently that Government intervention in this regard is part of its role of enabling businesses to be effective, and explained that the policy does not relieve the DisCos of their contractual obligation to provide meters. He stated that on the contrary, the policy seeks to help them perform their contracts.[28]

Developments in legislation or regulation

Paris Climate Agreement

Nigeria is experiencing adverse climate conditions with adverse effects on the welfare of millions of people. Persistent flooding and droughts, dry spells and off-season rains have sent growing seasons out of orbit, in a country dependent on rain-fed agriculture. This results in lower water supplies for agricultural use, hydro power generation and other uses. The cause of all this havoc is climate change. An estimated 62% of Nigerians rely on wood fuel for their entire energy needs, resulting in massive deforestation and dangerous emissions which add to pollution and climate change.

To combat and address this climate change devastation, Nigeria became a signatory to the Paris Agreement (PA) in December 2015 which came into force on October 5, 2016. The PA sought to cut carbon emissions by reducing dependence on fossil fuels and increase the use of renewables. Many countries have been required to fulfil a key requirement in the agreement by formulating their Nationally Determined Contributions (NDCs). The NDCs represent the countries' efforts to achieve climate-change goals.

The majority of African countries have delayed measures to prioritise climate-change development activities, especially in economic sectors such as Energy and Agriculture. The NDC ambition under the Climate Change Accord would cost an estimated $142 billion to meet the 2030 target. However, an innovative means of achieving this goal is through the issuance of "green bonds", which have gained recognition as a means of acquiring finance for climate-friendly purposes. Consequently, the Federal Ministry of Environment and Federal Ministry of Finance issued N10,690,000 in green bonds between December 18–20, 2017.

Eligible Customer Regulation 2017

The Regulation was issued by the NERC on November 1, 2017.[29] The purpose of the Regulation was, amongst others, to improve the distribution of electricity to industry and facilitate better power supply to consumers who consume up to 2MW of power.

The regulation stated four (4) categories of eligible customers in the Nigerian Electricity Supply Industry (NESI). The directive, which permits electricity customers to buy power directly from the GenCos rather than DisCos,[30] is in line with the provisions of Section 27 of the Electric Power Sector Reform Act 2005.

As of August 2018, the Ministry of Power, Works and Housing reported that the policy has started yielding results, with five industrial customers presently buying electricity directly from GenCos and a list of 26 industrial customers who are seeking to benefit from the policy.[31]

This policy is resisted by the DisCos, as they argue that it seeks to deny them their mega customers and contradicts the law establishing the DisCos. The Minister appeased the DisCos by issuing directives to the NERC to work out and implement Competition Transition Charges, as provided by law, to safeguard them from any loss.

Lagos State Electric Power Sector Reform Law 2018

The Lagos State Government launched a "Lagos State Embedded Power Programme" (LSEPP) initiative with the objective of generating and distributing an additional 3,000 MW off-grid power from private sector-sponsored projects within a six-year timeline. It was immediately approved by the NERC and, in order to implement and legalise the initiative, the Lagos State Governor recently assented to the Lagos State Electric Power Sector Reform Law (the Law).

The overall aim of the Law is to increase electricity supply and power generation through enactment of the LSEPP, criminalise energy theft offences, and enforce Consumer Rights and Obligations, among others.

The LSEPP aims to improve the supply of electricity within Lagos through embedded power generating plants/projects. NERC licensed companies (Embedded Power Providers (EPPs)) will generate and sell power to DisCos within Lagos State. Additionally, the Law recognises organisations that would supply feedstock to the EPPs (the "Feedstock Suppliers") and licensed entities to be appointed by the state to procure and aggregate feedstock from the Feedstock Suppliers and execute feedstock supply agreements with the EPPs (the "Feedstock Merchants").

Under the Law, the Lagos State Electricity Board will be established as the authority of LSEPP. The powers and responsibilities of the Board include providing support to EPPs to obtain licences, permits and approval for the transmission and distribution of electricity to areas not covered by the national grid, among others.

The Energy Theft Offences Act introduces offences such as unlawful connection of electricity lines or cables, meter-tampering, supplying electric power without a licence, and other offences. Additionally, it provides punishment, fines and prison sentences for violation of the offences. The Law also establishes a power task force to enforce the provisions of the Law.

Nigerian Electricity Regulatory Commission-Uniform System of Accounts Regulations 2018

On March 8, 2018, the NERC issued the Uniform System of Accounts (USoA) with the main objective of enacting the Uniform System of Accounts Guidelines 2014 in the Nigerian Electricity Supply Industry (NESI). The regulatory framework seeks to achieve a uniform accounting format or template for the filing of all accounting reports required by the NERC based on information extracted from the accounting ledgers of Licensees.

The main goal of this regulation is to foster accountability and transparency in the accounting framework of NESI through the effective monitoring of financial flows by the NERC. The USoA applies to all NERC-licensed organisations such as GenCos, DisCos, transmission and system operators who, by virtue of the USoA, are required to file Regulatory Accounting Reports (RARs) in accordance with the format prescribed by NERC. All Licensees are required to file RARs periodically, and section 8 of the USoA prescribes a uniform financial year-end for all licensees to prepare their statutory financial statements in compliance with the Companies and Allied Matters Act (CAMA). Additionally, the Licensees are to appoint auditors, in line with the provisions of CAMA.

With many stakeholders having doubts as to the transparency of the finances and accounts of NESI, the USoA indicates a determined effort by NERC to improve transparency in NESI.

Petroleum Industry Bill

The main objectives of the (Petroleum) Industry Governance Bill are to improve transparency, attract investors, increase growth and government revenues.[32] The Bill will entrust the Minister of Petroleum Resources to set policies and direction for the petroleum industry as a whole.

The National Petroleum Regulatory Commission will be charged with regulating the entire petroleum industry and replace the current Department of Petroleum Resources (DPR), the Petroleum Inspectorate and the Petroleum Products Pricing Regulatory Agencies (PPPRA).[33] Further, it will create a new body, the Nigeria Petroleum Assets Management Company (NAPAMC) which will be responsible for managing the assets and interests of the Government and shall take over the role of the NNPC. NAPAMC will be a company limited by shares to be held by the Ministry of Petroleum Finance and the Bureau of Public Enterprise and governed by the provisions of CAMA.[34]

Among the provisions of the Bill is that the Federal Government shall endeavour to honour international environmental obligations and shall promote energy efficiency, the provision of reliable energy, and a taxation policy that encourages fuel efficiency by producers and consumers.

Judicial decisions, court judgments, results of public enquiries

Nigerian Electricity Regulation Commission v Barrister Toluwani Yemi Adebiyi LPELR-429032 (CA) 2017

The public outcry on estimated billing and the NERC's proposed increment of the electricity tariff in 2015 brought about an action by human rights lawyer Mr Toluwani Yemi Adebiyi, who challenged the increment. In his originating summons, Mr Adebiyi sought the following reliefs, amongst others:

(a) An order restraining the NERC, its Distribution Companies and their Agents from foisting further hardship and unjustifiable increase of the electricity tariff on Nigerian citizens without a meaningful power supply.

(b) An order mandating the NERC to make prepaid meters available to all consumers within a reasonable time of maximum of two years, as a way to stop indiscriminate estimated bills.

The Court made an interim order that the *status quo* be maintained in the suit, which in effect barred the NERC from increasing the tariff. The NERC filed a motion on notice seeking to discharge the interim order, but it was dismissed. The NERC successfully appealed this ruling in July 2017. The case has been re-assigned to another Court and Nigerians await the outcome of this new case, which could mean an increase in the already exorbitant tariff rates.

Ernest Nwoye v Abuja Electricity Distribution Company Unreported Suit No: CV/1256/15 (2017)

In this case the Plaintiff, a resident of the Federal Capital Territory, sued the Abuja Electricity Distribution Company for breach of his duty of care when they ignored the Plaintiff's complaints over illegal, unfair and exorbitant bills imposed on him. The Plaintiff also sought the installation of an electric meter in his house as the Defendant has a duty of care to provide all customers with a meter and, pending that installation, an estimated bill in accordance with the NERC's method of estimated billing.

This method is based on the weighted average cluster load; it involves the subtraction of the entire metered load from the energy supplied to the feeder (33kv or 11kv) and the application of an appropriately determined availability factor and correction of losses, which is aggregated among the various numbers and classes of customers supplied by the feeder. The Defendant in this case could not prove that the plaintiff's estimated bill was generated using the above method. The Court therefore held that the Defendant owed a duty of care to the Plaintiff and must discharge that duty by installing a meter at the Plaintiff's house. This judgment, delivered in December 2017, is a victory for Nigerians as it shows that electricity distribution companies owe all customers a duty of care (to provide a meter) and must use the approved method for estimated billing.

Major events or developments

The Power Sector Recovery Implementation Plan (PSRIP)

This was approved by the Federal Executive council of Nigeria which was prepared in consultation with the World Bank Group (WBG). The PSRIP is a set of policy actions, operational and financial interventions, to be implemented by the Federal Government to attain financial viability of the power sector. The objectives of this plan include the elimination of the payment deficit which had accumulated in recent years, i.e. 2015 and 2016. The recovery implementation plan is estimated to require approximately US$ 1,500,000,000 annually for the next five years (2017–2022) in order to achieve sector viability. This would equally ensure performance and implementation of credible business continuity plans by the DisCos and the TCN. Equally instructive is the effort to ensure that cost-reflective tariffs are achieved over five years and there is increased electricity access through the implementation of off-grid, renewable power solutions. The implementation of the PSRIP is expected to introduce significant additional funding to ensure liquidity in the NESI.

Final issuance of the Mini Grid regulations

These regulations were previously issued in draft form in 2016 and subsequently adopted on May 24, 2017 by the NERC. The Mini Grid regulations provide a regulatory framework in Nigeria for the establishment and development of Mini Grids, which are peculiar to small-scale electricity distribution. The Mini-Grid regulations were issued to accelerate electrification in areas without existing distribution infrastructure (Unserved Areas) as well as areas with existing but poorly electrified or non-functional distribution facilities (Underserved areas). They are intended to act as a catalyst for stimulating the desired improvements along the electricity value chain.

Despite their importance, the Mini-Grids are not without their shortcomings, which include the lengthy period of processing an application for a permit, particularly the requirement of developers of an interconnected Mini-Grid to execute a tripartite contract with a community connected with a DisCo.

With the focus of the Federal Government on the supply of power to rural and Unserved Areas in Nigeria, it is expected that proactive ideas in the design and implementation of power projects in these areas will yield amazing results.

<u>Liberalisation of power generation and distribution</u>

Pursuant to the Communique on the liberalisation of power generation and distribution between the Federal and state Governments at the 18th monthly Power Sector and stakeholders' meeting held in Kumbotso, Kano State, Nigeria, on August 14, 2017, where the Minister affirmed the right of state governments in Nigeria to generate their own power independent of the Gencos, DisCos, the TCN, and other operators in the NESI. The communique is aimed at underpinning the free-enterprise stance of the Act and liberating the power industry in the country from the grip of inefficient supply monopoly.

Though the affirmation has no force of law, it is believed that the NERC will treat applications from state governments that are financially buoyant to generate their own power for the development of power projects. It was pursuant to this affirmation that the Lagos State Electric Power Reform Law 2018 was passed. What this invariably means is that there is an opportunity for stakeholders and potential investors to collaborate with viable state governments for the development of power solutions that are independent of current transmission and distribution systems.

Proposals for changes in laws or regulations

<u>The Energy Commission Act (Amendment) Bill 2018</u>

This Bill seeks to amend the Energy Commission Act (Amendment) of Nigeria 1989, whose statutory obligation is to ensure strategic planning and co-ordination of national policies in the Energy sector. The Bill seeks to confer power on the Commission to accord priority to promote, regulate and standardise development and utilisation of RE. This Bill equally seeks to make the Commission the national focal point for RE conservation for sustainable development.

<u>The Electricity Power Sector Reform Act (Amendment) Bill 2017</u>

This Bill seeks to amend the Electricity Power Sector Reform Act No. 6 of 2005. The Bill proposes to empower the NERC with an effective supervisory role over distribution companies through the provision of regulations for tariff increments, consumer education and alternative energy sources for a sufficient power supply.

<u>The National Energy Bill 2016</u>

The Bill seeks to ensure that diverse energy resources are available in sustainable quantities and at affordable prices to the economy, in support of the economic growth and poverty-alleviation initiative of the Government. Furthermore, the Bill seeks to provide energy planning, increased generation and consumption of renewable energies. The Bill proposes to provide access to energy infrastructure and establish an institution to be responsible for the promotion of efficient generation and consumption of energy and energy research.

The Federal Competition and Consumer Protection Bill 2016

Previous Nigeria competition laws have been grossly inadequate. Despite the provisions of the Electric Power Sector Reform Act 2005 which regulates sector-based competition, the passing of the proposed Competition Bill into law will provide a codified set of laws that would govern competition in the overall marketplace. This Bill seeks to develop and promote fair, efficient and competitive markets in the Nigerian economy. The scope of application of this bill is holistic, thus its adoption will affect all activities across all sectors in Nigeria.

Acknowledgments

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* * *

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Portugal

Mónica Carneiro Pacheco & João Marques Mendes
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Overview of the current energy mix, and the place in the market of different energy sources

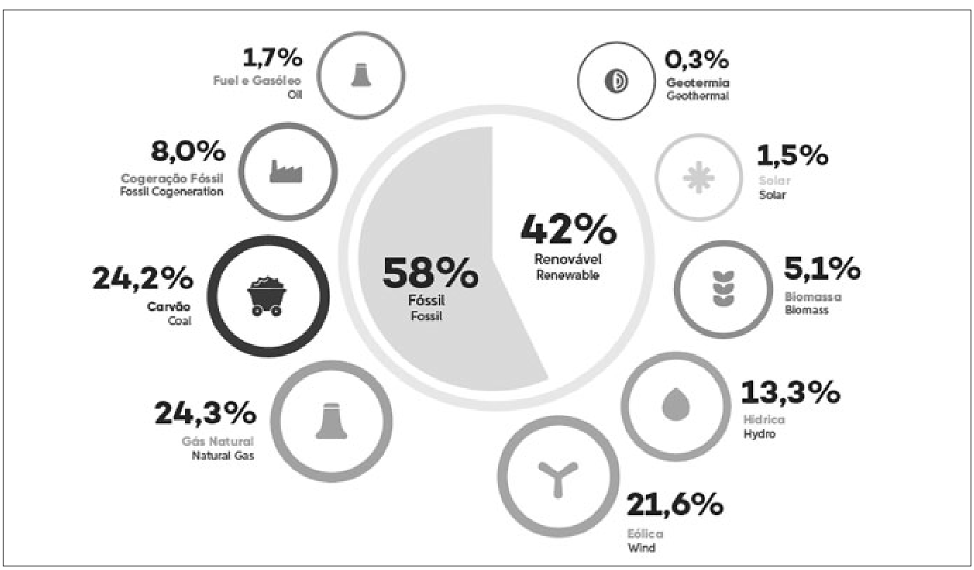
Portugal's dependence on imported energy has been historically high, since the country does not produce oil or natural gas. However, due to an increasing amount of renewable energy in the generation mix, total energy dependence has been declining.

In 2017, energy was produced from biomass (5.1%), hydro (13.3%), wind (21.6%), solar (1.5%) and geothermal (0.3%). Wind and hydro power have been the main drivers in growing energy production in Portugal. Solar power is expected to be the main driver in the future.

National production decreased (54.52 TWh) compared to 2016. The main reason was that 2017 was characterised by a lack of precipitation. The hydrological index was 0.47 (the historical average being 1), which means that the production of electricity from hydro power steeply reduced. Additionally, the wind index decreased by 0.03%.

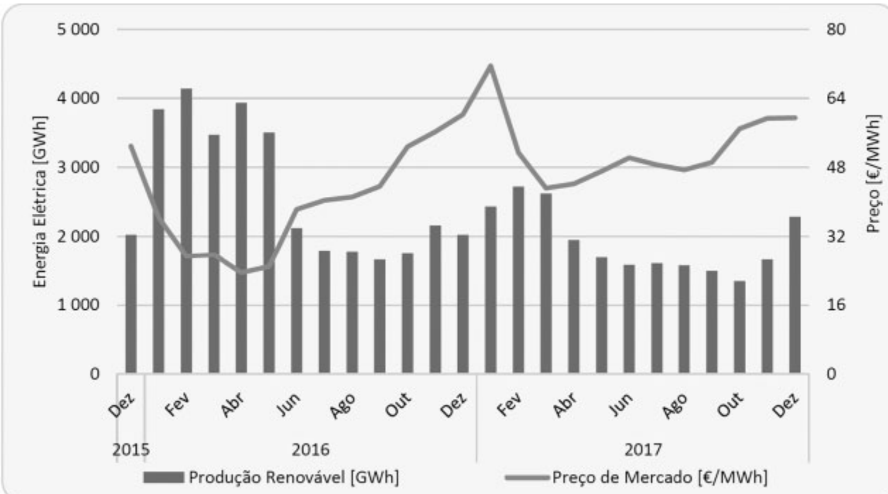
However, the export balance was one of the best ever (since 1999) with a significant value of 2.684 GWh (only surpassed in 2016 – 5.082GWh).

<u>Production of electricity by source 2017</u>[1]



The low representation of renewable sources resulted in an increase in the average annual price of electricity in the wholesale market, which was €52.45/MWh (in 2016, according to the Portuguese Renewable Energy Association, it was €39.4/MWh). Still, Portugal recorded 122 non-consecutive hours on 100% renewable electricity energy sources.

Correlation between renewable energy generation (*produção renovável*) and market price (*preço de mercado*), December 2015 to December 2017

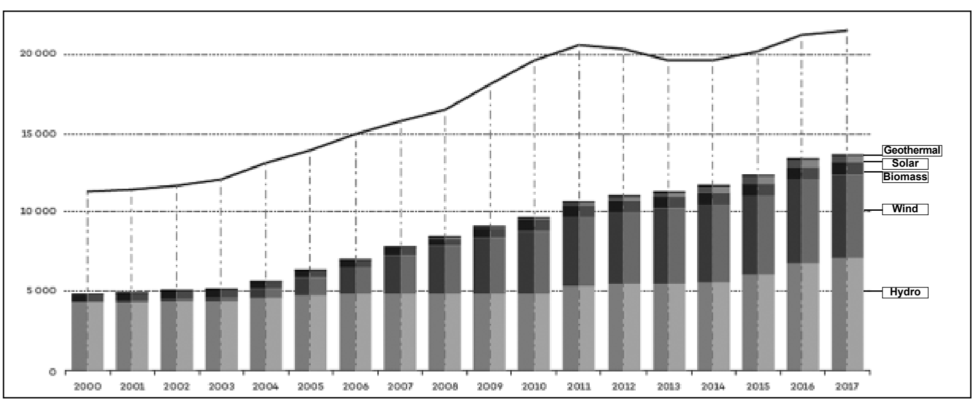


Source: OMIE, REN; Analysis APREN

Installed power in the national electricity system continued to grow. Since 2000, installed power increased from 3.9 GW to 13.7 GW, with average growth of 8% per year. The increase in renewable power was especially noticeable between 2004 and 2011, with the commencement of operations of several wind farms. Since 2011, fossil power capacity has been declining in turn.

Among the new power plants entering into operation in 2017 were: the Foz Tua hydroelectric plant (263 MW); the Pico Alto geothermal power plant (4.5 MW); and large-scale photovoltaic solar power plants (14 MW), in addition to several PV units covered by the self-consumption schemes (UPAC and UPP). On the other hand, the remaining renewable technologies, biomass and wind, have remained practically stagnant.

Evolution of the installed capacity (MW) of the different sources of electricity generation in Portugal between 2000 and 2017



Source DGEG; APREN's analysis

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Solar energy projects have increased in the past year, with a significant increase in capacity-licensing requests. Many investors continue looking to this sector despite there being no applicable feed-in tariff or other subsidies.

This is happening despite the implementation of some measures by the current Government which assumed, as a priority, a reduction of the electricity price and the tariff deficit and the burdens of future costs overruns. These measures have included:

- termination of the concession contracts for exploration, research, development and production of oil in the Algarve's offshore areas;
- revision of the power guarantee mechanism (a new scheme, not yet implemented since it awaits a decision from the European Commission regarding State aid) on availability of services;
- a return to the National Electric System of alleged "excessive" amounts received due to the accumulation of feed-in-tariffs and public support funds (determined by Ministerial Order 69/2017 which has not yet materialised);
- revocation of a legal provision which allowed the change of the source of primary energy for generating centres to which the former law was applied;
- limitation of authorisation of over-equipment of power plants to a consultation of the Regulator on the impact on the National Electric System termination of the exemption of excise duty on coal-fired power plants, plus payment of an additional rate over CO2 emissions (starting from 10% up to 100% in 2022); and
- transference of responsibility for payment of social tariff for the supply of natural gas to network operators and suppliers.

These measures notwithstanding, the government is also committed to de-carbonising the economy. The growth of solar capacity is in line with this target.

Micro-generation (self-consumption and small production units) is another area where some developments have occurred, with different schemes being implemented.

Developments in government policy/strategy/approach

<u>Boom in solar photovoltaic projects</u>

Portugal is witnessing a proliferation of new renewable energy projects, sourced by solar photovoltaic energy. This is together with the promotion of lithium concessions, and measures to reduce energy prices and the tariff deficit, the main vector of this Government's current energy policy.

Many solar photovoltaic plants are being licensed, some of which are already at the construction stage. It is expected that, by 2021, Portugal will grow from the current 572 MW of installed capacity of this energy source to around 1,600 MW, with more than 30 power plants being built.

These projects will be enabled by power purchase or similar agreements freely negotiated with energy traders and suppliers, pursuant to which generators put their electricity at the disposal of a buyer which will then resell it (or sell it on behalf of the generator) in organised markets (notably, in the spot market) or by bilateral agreements. Generators will receive a price per MWh agreed with these buyers.

These projects represent a turning point from the old paradigm of the remuneration of renewable energy projects through feed-in-tariffs set by law or regulation.

Electro-mobility and rush to lithium concessions

Portugal has been active in promoting investment in the electro-mobility sector. A legal framework is in force and a network of charging points of electric vehicles is in place and expanding. At the same time, the Government has also been encouraging the renewal of the fleet of vehicles of the Public Administration by gradually replacing conventional cars with electric vehicles.

In the year 2018, the Government approved the acquisition of 200 more electric vehicles by the Public Administration and the installation of more 250 charging points.

At the same time, Portugal is witnessing a lithium rush, given the growing utilisation of this mineral for the production of batteries used in electric vehicles and in electricity storage. Several companies (mostly multinational companies) have been requesting rights for the research and exploration of lithium. In the period ranging from 2016 until now, more than 30 requests were made for the granting of research and exploration rights of mineral deposits including lithium, in the North and Centre of Portugal.

Due to this volume of requests, the Government has already announced that it will launch public tenders for the granting of rights to research and explore lithium, likely until the end of 2018. However, complementary legislation on these tenders is still awaiting approval.

Developments in legislation or regulation

Regime of prevention of market distortions

In 2013, a legal framework was created with a view to eliminating windfall profits received by Portuguese generators due to the taxes then approved in Spain and which elevated wholesale electricity prices in the Iberian market.

Portugal would afterwards approve its own taxation measures to electricity generators, but would determine that the impact of such measures should be offset against the impact of Spanish measures when measuring windfall profits to be eliminated.

In the second semester of 2017, the current Government has, however, declared this offsetting to be illegal, due to allegedly exempting generators from the cost of Portuguese taxation measures (notably the extraordinary contribution to the energy sector and the burden of social tariffs, which is supported by these generators).

Annulment of possibility of modification of primary energy source of RES

In 2015, the Government approved a regime which allowed for promoters of renewable energy power plants, the installation of which was rendered impossible by reasons not attributable to the promoter, to request the modification of the primary energy source of their installation.

This regime was approved by the previous Government and was seen as a way to allow producers to whom the State had given – through public tender – rights to install mini hydro power plants against the payment of a fee and who, for reasons beyond their control, could not obtain all necessary licences for such installation, to have another way of installing such power (shifting e.g. to solar power, and still receiving a feed-in-tariff, although with a discount to previously set feed-in-tariffs), and for the State to avoid having to return the fees paid.

This regime was frowned upon by the current Government, as it would enable solar photovoltaic power plants receiving feed-in-tariffs at the same time that many solar photovoltaic projects are being licensed in a market-price regime, and two different remuneration schemes would then coexist at the same time.

In this context, the current Government decided on 31 August 2017 to declare such regime illegal, due to allegedly violating legal principles, such as principles of legality and competition, due to allowing the installation of a different power plant (of a different primary source) than that which was awarded by the public tender. This prevented procedures of shifting of primary sources of licences being successfully concluded.

Attribution of production licences for the generation of electricity from renewable sources

The Ministerial Order no. 62/2018 of March 2, following Law no. 114/2017 of December 29, established that licences for the production of electricity from renewable sources (notably, solar) shall be assigned through a draw when there are applicants whose requests, globally, exceed the injection capacity in the relevant network area.

A first draw was organised and launched by the General Directorate for Energy and Geology (DGEG), the state department responsible for the energy sector, in April 2018. Meanwhile, through Decree-Law no. 57-A/2018, of 13 July, the competence to organise the draw was transferred to the Energy Services Regulatory Entity, which was also bestowed with the power to issue a binding opinion as to the grid connection of new power plants.

The issuance of a production licence or acceptance of prior communication shall be immediate and automatic after the draw, up to the limit of the capacity available in the network zone or set of network areas.

New rules for the licensing of electrical networks

Since 2010, the approval of a regime establishing the maximum levels of human exposure to electromagnetic fields was foreseen in law. However, the complementary decree-law was never approved by the Government.

On 4 May, through Law no. 20/2018, the Assembly of the Republic commissioned the Government to approve legislation establishing these limits to human exposure to electromagnetic fields, applicable to high- and very-high-voltage networks and installations, in a six-month term. Such limits shall be defined in line with the guidelines of the World Health Organization and best practices of the European Union.

The establishing of these limits shall abide by the principle of precaution, avoiding, beyond any doubt, the causing of risks to human health. Also, when minimum distances of electrical networks to households and other buildings cannot be ensured, the possibility of installation thereof underground shall be considered.

This new regime also requires municipalities to issue an opinion as to the network layout before the project is approved.

Social tariff of supply of natural gas

Together with the liberalisation of the natural gas market in Portugal, a social tariff was created in 2011 with a view to providing a discount to the final price of natural gas for supply to especially vulnerable consumers. This discount, which is currently set to 31.2% of the total grid access tariffs paid by these consumers, was hitherto financed by all the clients of natural gas, in the proportion of their consumed energy.

The State Budget Law for 2018 transferred the burden of financing this social tariff to the companies engaged in transportation activity and suppliers of natural gas, in the proportion of the gas delivered the previous year.

Due to poor wording of the law, it is not clear if the reference to the transportation activity only includes the activity of exploitation of transmission networks. According to an opinion of the Advisory Council of the Republic's General Attorney's Office, this burden shall be considered to have been imposed not only on the transmission network operator but also on distribution grid operators, also construed to be encompassed by the concept of "*transportation*" in a broad sense.

Postponement of power guarantee auctions

A power guarantee legal scheme exists in Portugal in order to ensure security of supply in the electricity sector. This scheme aims to do this by ensuring, through payments to the mostly backup electricity generators (or aggregators of generators), such as coal or gas-fired stations, that they are permanently available to commence producing when there is a reduction of renewable energy production, creating the risk of supply not being able to meet demand. As Portugal relies a lot on hydro and wind energy production, which is weather-dependent and volatile, this scheme is a way to eliminate this dependence and volatility.

In 2017, this scheme was amended so as to include an auction mechanism to select chosen generators, in order for the remuneration of the availability service to reflect the market value of this service. An auction was launched for the year 2017.

However, for the year 2018, the Government decided to postpone the auction to select the providers of the power guarantee until the European Commission confirms the compatibility of this mechanism – which was already approved by the Government in 2017 – and for which state-aid provides.

Protection of consumers – new rules for gas bottles

The current Government has been trying to promote competition and transparency in the oil products sector, in order to protect consumers. New measures were taken this year regarding gas bottles.

According to Decree-Law no. 5/2018, of 2 February, new rules were approved for selling, collecting and exchanging bottled Liquefied Petroleum Gas (LPG). These new rules make it mandatory for petrol stations to sell gas bottles and approve mechanisms which facilitate the exchange thereof, requiring any supplier or retailer of liquefied petroleum gas to receive and exchange any gas bottle, irrespective of each brand or original seller. This law prohibited all discriminatory treatment of gas bottles on the basis of their brand.

The new law also subjected retailers of gas bottles to compliance with the legal provisions applicable to essential public services, which until then were only applicable to piped gas.

A 'solidary' tariff for the supply of bottled LPG was also created. The application of this tariff – which will depend on the will of municipalities – will allow the reduction of LPG prices for especially vulnerable consumers.

Judicial decisions, court judgments, results of public enquiries

Components of windfarms not considered as real estate for property tax purposes

Judgments of the Supreme Administrative Court of 10.01.2018 (case no. 01284/17 and case no. 01280/17) considered that each individual component of windfarms cannot be considered real estate for property tax purposes.

The court concluded that each component of a windfarm (wind turbine, rotor, etc.) does not have economic autonomy from the windfarm in its entirety, and cannot therefore be subject to evaluation and taxation individually (i.e. in the absence of the full windfarm).

Therefore, the court annulled the settlement of the property tax for the wind turbines of a given windfarm individually. However, the reasoning of these judgments will not prevent windfarms (in their entirety) being considered real estate and subject to property tax.

Major events or developments

Transference of regulation of the oil sector to the Energy Services Regulatory Entity (ERSE)

Pursuant to Decree-Law no. 57-A/2018, of 13 July, the sector of oil products, biofuels and LPG become subject to ERSE's regulation. This change was anticipated since it was foreseen in the State Budget Law for 2017.

Thus, ERSE, which is the regulatory entity for the electricity and natural gas markets, will acquire these duties with the regulation of the oil sector (downstream), including oil products, LPG and biofuels.

It is unclear if this change of competent authority will be accompanied by a material change in regulatory activity itself, notably if a more active and intense regulation will follow. Although the listing of ERSE's new competences in this sector, as well as its vocational and customary approach (its intervention occurs in economically regulated sectors, such as electricity and natural gas), point in this direction, the legal framework of the development of downstream activities of the oil sector, was not amended with this change. According to this legal framework, activities in the oil sector – including transportation, storage and distribution activities developed in infrastructure qualified as being of public interest – are not public activities developed under a concession, nor strictly regulated as the regulated activities of the electricity and natural gas sectors.

This decree-law also provides for the creation of a new advisory body to advise ERSE on carrying out its functions in the oil sector.

Proposals for changes in laws or regulations

Overpowering of windfarms

In the last few years, windfarms existing in Portugal have carried out overpowering actions, through the installation of additional wind turbines and injection of additional energy to the grid, according to the existing legal framework.

There were also some overpowering projects carried out in Portugal before 2017. The existing legal framework allowed for the overpowering of windfarms up to a limit of 20% of their connecting power, surplus electricity produced being remunerated at €60 / MWh.

However, in August 2017, the Government determined that any overpowering shall not have negative effects for the National Electrical System, and that this evaluation shall be carried in each case by the regulator (ERSE). The approval of a new legal regime for the overpowering of windfarms, replacing the existing one, is foreseen and may happen in 2019.

The approval of a legal framework regarding the repowering of renewable energy power plants – modernisation of power turbines, by replacing old wind turbines with new wind turbines with more efficient technology, capable of generating more electricity and at much lower cost – is still expected in this sector, in order to provide legal certainty to investors in windfarms reaching the end of their lifespan.

Consumers to be exempt of subsoil occupancy charges?

Currently, part of the price of natural gas supply to final consumers in some municipalities is formed by subsoil occupancy charges, a type of charge levied by municipalities for the installation and passage of pipelines in subsoil of their public and private domain.

These charges are primarily charged to distribution network operators and are passed thereon to suppliers and, finally, to end consumers.

In its struggle to lower energy prices, the current Government has already tried to prevent companies passing on this charge to consumers and has even approved legislation for that purpose. However, it seemed to hesitate later, and such legislation was never applied. In fact, this legislation runs the risk of incentivising municipalities which do not yet levy this charge (or levy it in small amounts) to charge it, as the possible dissatisfaction of consumers is the main disincentive for their collection of high values.

However, the Government has already announced that it intends to review existing legislation on subsoil occupancy charges with a view to achieving a balance in the levying of these charges and prevent end consumers having to pay them.

Tenders for concession of low-voltage distribution networks

Tenders for the new concession agreements of low-voltage distribution networks are also expected to be launched in 2019.

In principle, tenders shall be launched at the intermunicipal level. However, municipalities may launch separate tenders if they can demonstrate that there are powerful reasons, technically or economically, which support or recommend it, and this does not result in global losses of efficiency, equity or territorial cohesion.

* * *

Endnote

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Russia

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Overview of the current energy mix, and the place in the market of different energy sources

Russia's energy sector is strategic for the county, insofar as energy is the driver of Russian economic growth and the main source for replenishing the state budget.

Russia's energy sector consists of the following key subsectors:

- oil industry;
- gas industry;
- coal industry; and
- electric-power industry (atomic power, hydropower).

As one of the world's dominant suppliers of energy resources, Russia occupies a confident place on the international energy market. BP analysts think that over the next 20 years, Russia will continue to be one of the largest energy-exporters in the world, satisfying more than 5% of global demand for primary energy resources by 2040. Russia is also predicted to remain one of the world's leading producers of fossil fuels, accounting for 14% of global oil & gas production. For example, by 2040, Russian oil production will grow by 2 mln bpd (to 13 mln bpd), while Russian gas production will climb by 29% (to 72 bln SCFD) by 2040 against a backdrop of growing demand on the global markets.

Russia's total energy resources can be broken down according to the consumption level of primary energy resources in 2016: oil (22%); gas (52%); coal (8%); atomic power (7%); hydropower (6%); and renewable resources (2%). BP analysts forecast only a slight change in the aforementioned breakdown in the period through 2040.

Changes in the energy situation over the last 12 months that are likely to have an impact on future direction or policy

<u>Oil industry</u>

In 2017–2018, Russia's position on the oil market has seen a marked improvement. The main factor driving such an upturn is almost certainly the deal to cut oil production struck between OPEC members and other petroleum-producing countries. In January 2018, the Joint Technical Committee (JTC) of OPEC countries and non-member states agreed on achieving the goal of reducing oil production by all member countries by 107%. Consequently, as a result of the collective action taken by OPEC members and a number of other countries, oil supply on the global market was restricted, which had a favourable impact on rising oil prices. That said, the countries pledged to OPEC to keep 2018 oil production at 2017 levels. For this reason, it should be expected that one of the key drivers of increasing supply on the 2017 global oil market will disappear some time in 2018.

According to the RF Ministry of Energy, Russian oil production in 2017 amounted to 546.7 mln tons, which is 0.6 mln tons less than in 2016. In 2017, growth in oil production was mainly posted by independent petroleum companies and Gazprom Neft. Reduction in oil production was observed among such companies as Surgutneftegas, Lukoil and Rosneft. The contraction in oil production by Russian companies was predicated on the need to honour the obligations that had been made to OPEC. That said, Russian oil companies' 2017 reduction in oil production was mainly a result of their declining activity at old oil fields – mostly in Western Siberia, which is characterised by low flow rates and meagre profitability.

However, the slight production drop in 2017 didn't stop Russian oil companies from increasing their exports. According to the RF Ministry of Energy, oil exports in 2017 amounted to 256.7 mln tons – 3 mln tons more than the previous year. Against the backdrop of climbing petroleum prices, growth in Russian oil exports led to an increase in budgetary receipts.

An important export trend in 2017 was the reallocation of export flows of Russian oil, including the Urals brand, in favour of consumers in the Asia-Pacific Region. This was made possible thanks to the OPEC+ deal. Prolongation of the OPEC+ deal until year-end 2018 would likely cause Russian oil production for 2018 to drop to 2017 levels.

Finally, it's worth mentioning that in 2018, oil shipments to the East ticked up thanks to the effective start in January 2018 of a five-year agreement between Rosneft and CEFC China Energy for a total volume of 60.8 million tons of oil.

According to BP analysts, by 2040, Russian oil production will grow by 2 mln (to 13 mln bpd). In terms of the production of liquid hydrocarbons, Russia will lag behind only the USA and Saudi Arabia.

Gas industry

In 2017–2018, Russia has continued to consolidate its position on the global gas market. For the Russian gas sector, these two years have passed on a high note. Despite the ratcheting-up of sanctions pressure, Russian companies have consistently expanded their presence on the world's leading commodity markets, including China's. According to BP analysts, by 2040 Russia will be the world's second-largest gas producer after the USA. This phenomenon is predicated, *inter alia*, on the following factors.

Gazprom is actively preparing to enter the Chinese market. Over the past several years, China has been pursuing a policy of improving air quality and replacing coal with gas in virtually all of its industrial sectors, prompting Russia's serious intentions to conquer the Chinese gas market.

In May 2014, Gazprom and China's CNPC signed an agreement on supplies of Russian gas to China along the Eastern route. The agreement was concluded for a term of 30 years and envisions an annual supply of 38 billion cubic metres of Russian gas to China via the Power of Siberia pipeline. Deliveries are slated to start on December 20, 2019. The pipeline will span a total length of roughly 4,000 kilometres, and its operation will be supported by eight compressor stations with a total capacity of 1,331 MW.

As of September 2018, Gazprom reports that it has built 93% of the Power of Siberia. The announcement indicates that "2,010 kilometers of pipe have been welded and laid on the Power of Siberia pipeline section running from Yakutia to the Russian-Chinese border, accounting for 93% of its total length." Consequently, in 2018–2019, the Power of Siberia gas-construction project will be completed and deliveries of Russian gas to China will commence by year-end 2019.

Nor is Russia sparing any effort to conquer the European gas market. Another Russian project, Power of Siberia-2, has already secured a full set of permits for construction and operation of the gas pipeline in Germany, Finland and Sweden. On June 7, 2018, the RF Ministry of Construction, Housing and Public Utilities issued a construction permit for the Russian section of the pipeline. Yet to be obtained in Russia is a permit for the construction of submerged pipeline sections in Russian territorial waters.

The Nord Stream 2 gas pipeline will run through the Baltic Sea, connecting suppliers in Russia with consumers in Europe and spanning a total length of more than 1,200 km. Throughput capacity will amount to 55 bln cubic metres of gas per year. Construction of this pipeline is critical to ensuring uninterrupted supplies of gas to Europe, insofar as transit supplies through Ukraine could come to an end in just a couple of years, and Russia needs to have alternate supply routes in place by that time.

Finally, Russia is successfully moving forward with the development of supplies through the Eastern European region. On May 7, 2017, construction of the TurkStream gas pipeline commenced in the Black Sea, with the work starting off on the Russian coast. The TurkStream project envisions a gas pipeline running from Russia to Turkey through the Black Sea and terminating at the Turkish border with neighbouring countries. The first strand of the pipeline is intended for the Turkish market; the second, for the countries of Southern and Southeastern Europe. The throughput capacity of each strand is expected to be 15.75 bln cubic metres of gas per year. Construction of the pipeline's marine section will be handled by South Stream Transport B.V. Company; management has been tasked with actively continuing work on the implementation of the TurkStream project in 2018 in order to ensure that it can be commissioned according to schedule – by year-end 2019.

The above-described development thrusts should be enough to ensure growing volumes of Russian gas production. For example, according to BP analysts, Russian output is expected to increase by 29% (to 72 bln SCFD) by 2040.

Coal industry

Russia is a world leader in coal production – the country is sixth in terms of total coal-mining volume after China, the USA, India, Australia and Indonesia (with Russia accounting for roughly 4.5% of global coal output).

As a result of the privatisation of coal assets, which occurred as part of the overall restructuring of the country's coal industry, virtually all coal production is now carried out by privately-owned joint-stock companies. As of spring 2018, Russia's stock of operating coal-mining companies comprised 170 individual enterprises.

Russia's coal companies have posted good results in 2017–2018 thanks to the following factors.

In the summer of 2017, coal prices went up. This largely occurred because in 2016, China – simultaneously the world's largest coal producer and consumer – closed 1,000 old and unprofitable mines and slashed the number of work days at coal enterprises from 330 to 276 a year in order to reduce output volumes. As a result, the Asian markets experienced an acute shortage of coking coals. Consequently, prices for them shot up, hitting their peak level in November 2016 – $320/ton.

On top of everything else, in March 2017 the Australian coast was battered by Severe Tropical Cyclone Debbie, leading to the months-long shutdown of coal production at mines in Queensland – the world's largest export-coal basin. All of this resulted in serious coal-shipment disruptions.

Against the backdrop of these events, Russian enterprises ramped up both their production and supply volume of coal.

Electric-power industry

In terms of the total volume of electric-power production and consumption, Russia is the world's fourth-largest energy market after China, the USA and India. In 2017, Russia's actual consumption of electric power amounted to 1,059.7 bln kWh (per the Unified Energy System (UES) of Russia – 1,039.9 bln kWh), which is higher than actual 2016 consumption by 0.5% (per UES of Russia – by 1.3%). Russia dispatches some of its electric power (21.6 bln kWh) to its closest neighbours. The main receiving countries of this electric power were Finland (accounting for 26% of in-kind electric-power export structure), China (15.3%), Belarus (12.5%), Ukraine (12.5%) and Lithuania (10.3%).

There were no significant changes on the electric-power market in 2017–2018. Noteworthy is the overall stable condition of the Russian market, achieved thanks to the structural changes that occurred in 2001–2011 when the Russian authorities implemented a series of sweeping reforms on the electric-power market aimed at increasing competition. Based on the results of these reforms, Russia's electric-power sector was divided into the following main segments: power generation; power transmission and distribution; power sales; and final consumption.

Generation		**Transmission & Distribution**	
Competitive Segment		**Regulated Segment**	
Public	RusHydro PJSC, Gazprom Energoholding LLC, Inter RAO PJSC, Rosenergoatom Concern JSC	Rosseti PJSC Group – Russian grid companies	Federal grid company
Russian private	EuroSibEnergo PLC, T Plus PJSC, and others		Interregional distribution grid companies
Foreign private	Unipro PJSC, Fortum PJSC*, Enel Russia PJSC		Regional grid companies
	Private – other	BESK JSC, SUENKO PJSC and others	

* *Fortum is expected to acquire Unipro (the transaction is currently being considered for approval by the RF Federal Antimonopoly Service)*

Sales	Power Consumption
Competitive-regulated segment	
	Industrial companies
Guarantee suppliers	Infrastructure facilities
Independent utilities	Population

As shown in this diagram, generating suppliers deliver the electric power that they produce either to the grid or directly to major industrial enterprises. From there, grid companies deliver the electric power to end-consumers, who conclude power-supply agreements with guarantee suppliers or independent utility companies.

According to current forecasts, Russia's production of electric power is expected to reach 1,112 bln kWh by 2023. That said, no significant fluctuations on the market are anticipated.

Developments in government policy/strategy/approach

Oil

In 2018, the Ministry of Energy of Russia faces the task of preparing changes in the legislation of the Russian Federation with a view to introducing a new system of taxation in the oil industry, depending on the economic efficiency of field development (the tax on added income).

Gas

The State Duma proposes to create a special executive body that will be responsible for the development of the Arctic zone and the Russian North. The powers of such a ministry will include issues of development of the Arctic energy resources.

The seriousness of this idea depends on the intensity of development of Arctic energy resources by Russia.

The year 2017 became important for the development of Arctic projects; in December, the Yamal LNG natural gas liquefaction plant was launched. According to industry experts, the year 2018 will be even more crucial for the industry, because in exactly this year in Russia and around the world events will take place that will determine the development of the entire oil and gas sector in the medium term.

2018 will be a year of careful monitoring of the "Yamal-LNG" plant's operation, as it is possible that it will operate in a competitive mode with the Russian gas network in Europe. And after that, the issue of the feasibility of implementing another project for liquefying gas – "Arctic-LNG" should be resolved.

In addition, Russia is now discussing projects aimed not only at raising the level of gas production and export, but also at increasing the level of gas consumption. The Ministry of Energy of the Russian Federation set the task of a multiple increase of automobile gas filling stations within 5–10 years. According to the Deputy Minister, today the country has built about 370 methane refueling stations in 70 regions, with half of the infrastructure for refuelling gas engine fuel concentrated in 10 entities. "We are now engaged in precise calculations, but in our opinion, if every year about 200 methane fuel stations and about 30 LNGs appear, in the next five years a serious infrastructure will be created in the top 25–30 regions of our country," he added.

Coal

According to the forecast of BP analysts, the level of coal consumption in Russia by 2040 will decrease from 13% to 8%. This phenomenon is due to several factors which are as follows:

"In the world, the reduction of coal is due to environmental and climatic reasons dictated by the Paris Agreement," the Deputy Energy Minister of the Russian Federation, Anatoly Yanovsky, has said.

Russia also has another specific feature – the replacement of coal fuel with cheap gas, long distances of transportation of coal products, and infrastructural restrictions. Another threat to the coal industry is the volatility of the conjunction of coal markets. In Russia, coal regions are very far from the main ports and trans-shipment points.

The problems described, both international and national, intimate that the Russian authorities will be determined to develop gas and oil industries in the first place, rather than coal. This is due to the long-term prospects of coal as an energy resource.

Power

The Ministry of Energy of Russia faces the task of developing a concept for the development of retail electricity markets, with the possibility of greater participation of retail consumers in the purchase of electricity in the wholesale market.

Developments in legislation or regulation

Energy legislation in the Russian Federation is represented by the following list of regulatory acts that carry both general-legal and special significance:

1. Civil Code of the Russian Federation (Part II), governing relations among subjects of law with respect to power-supply agreements (paragraph 6, Chapter 30);
2. RF Federal Law No. 35-FZ dated 26.03.2003 "On the Electric-Power Industry" establishes the legal foundations of economic relations in the sphere of the electric-power industry and defines the authorities of bodies of state power in the regulation of these relationships, as well as the main rights and obligations of electric-power-industry subjects under the performance of activity in the sphere of electric power and engaging with its consumers;
3. RF Federal Law No. 69-FZ dated 31.03.1999 "On Gas Supply in the Russian Federation" determines the legal, economic and organizational foundations of relations in the area of gas supply in the Russian Federation and is aimed at ensuring satisfaction of the state's need for strategic energy resources;
4. RF Federal Law No. 190-FZ dated 27.07.2010 "On Heating Supply" establishes the legal foundations of economic relations arising in connection with the generation, transmission and consumption of thermal power, thermal capacity, coolant featuring the use of heating-supply systems and the creation, functioning and development of such systems, and also defines the authorities of bodies of state power and local self-government bodies responsible for population centres and urban districts in terms of regulation and control in the sphere of heating supply, and the rights and obligations of heating-supply consumers, heating-supply organisations and heating-grid companies;
5. RF Federal Law No. 147-FZ dated 17.08.1995 "On Natural Monopolies" determines the legal foundations of federal policy with respect to natural monopolies in the Russian Federation and is aimed at achieving a balance of interests among consumers and natural-monopoly entities ensuring the affordability of the goods sold by the latter to consumers as well as the efficient operation of the natural-monopoly entities themselves;
6. RF Federal Law No. 135-FZ dated 26.07.2006 "On the Protection of Competition" determines the organisational and legal foundations for the protection of competition for the purposes of ensuring the unity of the economic space, the free movement of goods, the freedom of economic activity in the Russian Federation, the protection of competition and the creation of conditions for the efficient functioning of the commodity markets;
7. RF Federal Law No. 261-FZ dated 23.11.2009 "On Conserving Energy, Improving Energy Efficiency and Amending Certain Legislative Acts of the Russian Federation" regulates relations in the area of energy conservation and improving energy efficiency with the aim of creating the legal, economic and organisational foundations for the stimulation of energy conservation and improvements to energy efficiency;
8. RF Law No. 2395-1 dated 21.02.1992 "On Subsoil" governs relations arising in the area of the geological exploration, use and conservation of subsoil resources, the use of the waste generated in the extraction of mineral deposits and related refining operations, specific mineral resources (the brine of estuaries and lakes, peat, sapropel and others), underground waters, including associated waters (waters extracted from the subsoil together with raw hydrocarbon deposits) and waters used by subsoil users for their own production and technological needs;

9. RF Federal Law No. 225-FZ dated 30.12.1995 "On Production-Sharing Agreements", adopted in the furtherance of Russian Federation legislation in the area of subsoil use and investment activity, establishes the legal foundations of relations arising in the process of the making of Russian and foreign investments in the surveying, exploration and extraction of raw minerals in the territory of the Russian Federation, as well as on the continental shelf and (or) within the exclusive economic zone of the Russian Federation on production-sharing-agreement (PSA) terms;
10. RF Federal Law No. 116-FZ dated 21.07.1997 "On the Industrial Safety of Hazardous Production Facilities" determines the legal, economic and social foundations of ensuring the safe operation of hazardous production facilities and is aimed at preventing accidents at such facilities and ensuring the preparedness of legal entities and individual entrepreneurs operating hazardous production facilities (hereinafter also referred to as "hazardous-production-facility operators") for the localisation and liquidation of the aftermath of such accidents;
11. RF Governmental Resolution No. 1178 dated 29.12.2011 "On Pricing in the Area of Regulated Prices (Tariffs) in the Electric-Power Industry" establishes the main principles and methods of price (tariff) regulation in the electric-power industry;
12. RF Governmental Resolution No. 1075 dated 22.10.2012 "On Pricing in the Area of Heating Supply" defines: the main principles and methods for determining the tariffs for thermal power (capacity) and coolants; tariffs for the services involved in the transmission of thermal power and coolants; the procedure for establishing regulated prices (tariffs) in the area of heating supply; as well as the terms and procedures for adopting decisions on the deregulation of tariffs and the re-regulation of tariffs following their deregulation;
13. RF Governmental Resolution No. 1172 dated 27.12.2010 "On Approval of the Rules for the Wholesale Electric-Power and Capacity Market and the Amendment of Certain Acts of the Government of the Russian Federation Concerning the Functional Organization of the Wholesale Electric-Power and Capacity Market" establishes the legal foundations for the functioning of the wholesale electric-power and capacity market, including the regulation of relations associated with the turnover of electric power and capacity on the wholesale market, as of January 1, 2011;
14. RF Governmental Resolution No. 442 dated 04.05.2012 "On the Functioning of Retail Markets for Electric Power, the Full and (or) Partial Restriction of Electric-Power Consumption Mode", establishes the legal foundations for the functioning of electric-power retail markets; and
15. RF Federal Tariff Service Order No. 20-e/2 dated 06.08.2004 "On Approval of the Methodology Instructions for the Calculation of Regulated Tariffs and Prices for Electric (Thermal) Power on the Retail (Consumer) Market" is intended for the calculation, using the economically-justified cost method, of the levels of regulated tariffs and prices on the retail (consumer) market for electric power (capacity) and thermal power (capacity).

The above list is not exhaustive but reflects the basic foundation of federal law in this area. At the same time, despite the rather serious regulatory framework that governs the sector, it would not be accurate to say that the current system of laws regulating the energy sector is ideal or sufficient to allow its administrators, including judges, to effectively apply the proper laws and sub-statutes in the course of their professional activity.

Judicial decisions, court judgments, results of public enquiries

It is hardly possible to highlight any notable changes in the jurisprudence of Russian courts in 2017–2018. At the level of higher courts, only two Reviews were adopted, which, one way or another, dealt with energy law issues.

The Presidium of the Supreme Court of the Russian Federation issued the Review of Judicial Practice of 16.02.2017 No. 1 (2017), in which problematic issues of the application of legislation on energy supply are considered. Particularly, the Review gives the following theses: "In the event of damage to the property of the Consumer that occurred as a result of the voltage drop in the power grid, the burden of proof confirming the proper performance of obligations under the energy supply contract is assigned to the energy supply organization" (The Supreme Court Ruling No. 26- KG16-12).

The Presidium of the Supreme Court of the Russian Federation has issued the Review of Judicial Practice No. 1 (2018) of March 28, 2013, which considers, among others, the problematic issues of the application of legislation on energy supply. Particularly, the Review states the following theses:

- Paragraph 18 of the Review: "The amount of regulated rent for the use of a land plot owned by a territorial entity of the Russian Federation and used for the operation of electricity, gas supply facilities, heat supply facilities, main hot water supply systems, cold water supply and (or) of regional or local significance, from March 1, 2015 cannot exceed the amount of rent set for the corresponding land plots that are in the federal ownership" (The Supreme Court Ruling No. 305-ES17-12788).
- Paragraph 23 of the Review: "The Customer under the agreement on the implementation of technological connection has the right to refuse the contract on the basis of the provisions of Art. 782 of the Civil Code of the Russian Federation" (The Supreme Court Ruling No. 305-ES17-11195).
- Paragraph 24 of the Review: "Under an uncertain range of consumers for the purposes of the application of Part 1 of Art. 10 of RF Federal Law No. 135-FZ dated 26.07.2006 "On the Protection of Competition" should be understood as the multiplicity (not the singularity) of the number of consumers whose rights and legitimate interests may be affected by the actions of the person occupying a dominant position in the market" (The Supreme Court Ruling No. 310- KG17-12130).

Major events or developments

The most important change in the legal regulation may affect the tax sphere. It is about introducing a new tax on added income (TAI). Under the plan, the TAI will be extended to four groups of deposits:

- The first group includes new deposits in Eastern Siberia with depletion of less than 5%.
- The second group includes the fields which enjoy the export duty exemption.
- The third group consists of operating fields in Western Siberia with depletion of 10% and a total production volume of no more than 15 million tons per year as of January 1, 2017.
- The fourth group includes new deposits in Western Siberia with depletion of less than 5% and aggregate reserves of no more than 50 million tons per year.

The tax base will be determined as the estimated cash flow from operating and investment activities for the exploration and production of hydrocarbons in the subsoil plot. The

TAI will be deducted from the income tax base; additionally, in all other cases the current procedure for calculating the income tax will remain.

The implementation of the TAI will additionally involve up to five billion tons of oil in development by 2025 to maintain the production levels achieved, increase the oil recovery factor and increase industry tax revenues.

Proposals for changes to laws or regulations

In conclusion, it should be noted that current legal regulation of the fuel-and-energy complex is patchwork in nature and predicated on the lack of an overarching law (on energy) that would establish the basic principles and approaches to regulating relations in the electric-power, nuclear-industry, coal-industry and oil & gas industry complexes.

Each sector in the broader fuel-and-energy complex is governed by its own separate law (laws) and the sub-statutory acts adopted in its (their) furtherance. This approach to legal regulation creates conditions for the uneven application of the requirements of these laws, and consequently – to the non-achievement or only partial achievement of the goals and objectives envisioned thereby.

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Slovenia

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Overview of the current energy mix, and the place in the market of different energy sources

Due to the recovery of the Slovenian economy over recent years (a 5.1% growth in GDP for 2018 has been recently forecast by the Slovenian Institute of Macroeconomic Analysis and Development), the country's overall energy demand is increasing and this is reflected in all energy markets.

In 2017, 14,984 GWh of electricity was delivered to the transmission and distribution systems, which is 249 GWh less than in 2016. The delivery from generating plants using renewable energy sources was 4,479.1 GWh, which is 616 GWh less than the previous year; generating plants using fossil fuels contributed 4,539 GWh or 176 GWh less than the year before. Nuclear power plant Krško, Slovenia's only nuclear facility, delivered 5,966 GWh to the transmission system, or 543 GWh more than in 2016. Half of the electricity produced at Krško (approximately 2,983 GWh) was transmitted to the Republic of Croatia based on the bilateral treaty, yet the plant still supplied 40% of all the electricity generated in Slovenia; renewable energy sources contributed 30% (hydro power, wind power, solar power, biomass); and fossil fuels provided 30% of generated electricity. Domestic production covered 82.9% of Slovenian electricity consumption and the country's import dependence was 17.1%.[1] Total consumption of electricity amounted to 14,558 GWh and increased by 2.7% in comparison to 2016.[2]

Since Slovenia does not have its own sources of natural gas, storage of natural gas or LNG terminals, the wholesale natural gas market is limited by imports of natural gas through neighbouring transmission systems from Austria, Italy and Croatia. Due to market liberalisation, the long-term contracts with producers from Russia are being replaced by short-term contracts concluded at gas hubs, power exchanges and other points in the EU. In 2017, 75% of natural gas was imported from Austria.[3] Natural gas amounting to 2,114 million Sm^3 (or 22,745 GWh) was transferred through the transmission system in 2017, which is almost 2% less than in 2016. The consumption of natural gas increased for the third consecutive year and amounted to 900 million Sm^3 (or 9,677 GWh). The supply of natural gas is reliable and was not affected by the explosion in December 2017 at Baumgarten gas hub, when supply at the Ceršak entry point on the Slovenian-Austrian border was disturbed for several hours.[4]

The Slovenian electricity and natural gas markets are transparent and well-integrated in the wholesale energy markets. In 2017, 69,130 consumers switched their electricity supplier, which is 6.7% less than in 2016 when the market reached a record number of switches (945,442 or approximately 7% of all electricity consumers), and 6,054 consumers switched their natural gas supplier, which is 4.3% less than in 2016. A significant majority of switches were performed by the group purchasing action of the Slovenian Association of Consumers "*Switch and save #2*", in which more than 13,000 consumers switched their electricity supplier (19% of all switches), more than 12,000 consumers switched their electricity and natural gas suppliers, and 2,765 consumers switched their natural gas supplier (46% of all switches).[5]

As a Member State of the European Union, Slovenia has committed itself to promoting the use of renewable sources for energy consumption, and especially for electricity generation. The use of renewable energy sources (hereinafter: "**RES**") has an important role in the national energy policy. Energy efficiency improvements and increased use of energy from RES bring significant direct and indirect benefits: reduced greenhouse gas emissions; improved security of supply; technological development and innovations; and opportunities for employment and regional development. The EU Renewable Energy Directive 2009/28/EC[6] sets a mandatory national target for each Member State, stating the overall share of gross energy consumption that must come from renewable energy sources by 2020. For Slovenia, this target has been set at 25%. In 2017, 21.8% of estimated gross energy consumption in Slovenia came from renewable energy sources.[7]

Developments in government policy/strategy/approach

The RES and cogeneration of heat and electricity ("**CHP**") support scheme

The national legal basis for the RES and CHP support scheme is regulated by the Energy Act, the Decree on the method of determining and calculating the contribution for ensuring support for the production of electricity from high-efficiency cogeneration and renewable energy sources,[8] and the Decree on support for electricity generated from renewable energy sources and from high-efficiency cogeneration.[9] The support scheme had to be harmonised with the EU legislation on state aid and was successfully notified and approved by the European Commission decision SA.41998 of October 10, 2016[10] as a permitted form of state aid.

By the end of 2017, more than 2,500 producers with 3,864 production facilities were included in the support scheme (85% of them solar power plants). Most of these production facilities involved in the support scheme fall under the terms which were in force before the enforcement of the Energy Act, while four producers were selected in the first public tender.[11]

Under the initial support scheme (approved by European Commission decision no. SA.28799), operators of eligible installations were automatically entitled to the support. However, after January 1, 2017, all beneficiaries must be selected through a competitive tender.

Beneficiaries under the support scheme for RES installations include: energy potential of watercourses; wind energy used in generating plants on land; solar energy used in photovoltaic power plants; energy from biogas obtained from biomass and biodegradable waste; energy from landfill gas; energy from gas obtained from sludge produced in wastewater purification plants; energy from biodegradable waste; and, most recently, operators of wood biomass installations that are depreciated and would otherwise not be eligible under the support scheme if, owing to the price of wood biomass, their production costs exceed the market price for electricity.[12] For CHP installations, aid may only be granted to high-efficiency cogeneration installations as defined in the Guidelines on state aid for environmental protection and energy 2014–2020 (hereinafter: "**EEAG**").[13] Eligible beneficiaries under the Energy Act are limited to a maximum nominal installed capacity of 50 MW for wind installations, 20 MW for CHPs and 10 MW for all other RES.

The beneficiaries are selected based on a two-phase tender. In general, the first round allocates between 70–90% of the overall available budget in any given year and is open to new installations falling into two 'pots'. Pot 1 is available for RES generators operating technologies based on the exploitation of resources, which do not need to be purchased (*i.e.* non-fuelled technologies including solar, wind and hydropower), and pot 2 for technologies which are less competitive or bear higher risks during the preparation phase (*i.e.* fuelled or less competitive technologies, including CHP, biomass, biogas and geothermal). Projects from both pots which fail to be selected in the first round are eligible to compete in the second round. If the number of applicants in pot 1 and/or pot 2 is insufficient to use all of the funding allocated to that pot, any unused budget is added to the budget for the second round. The second round is open to all projects including renovated installations and depreciated wood biomass facilities that are otherwise too old to be deemed eligible under the scheme if, owing to the price of wood biomass, their production costs exceed the market price for electricity. This round is run on a technology-neutral basis with the most cost-effective projects.

The first public tender for the support scheme, with available funding in the amount of €10 million, was completed in June 2017 by funding 78 projects (of which 30 were hydroelectric plants, 28 internal combustion engines, two steam backpressure extraction turbines, seven solar power plants and 11 wind power plants) with total rated electrical power of 61.36 MW.[14]

The second public tender for the support scheme, with available funding in the amount of €10 million, was completed in January 2018 by funding 93 projects (of which 11 were hydroelectric plants, 26 solar power plants, 37 wind power plants, one wood biomass power plant, one biogas power plant and 17 CHPs) with total rated electrical power of 98.03 MW.[15]

On February 23, 2017, the Energy Agency published the third public tender for the support scheme, again with available funding in the amount of €10 million, which was completed in June 2018 by funding 41 projects (of which two were hydroelectric plants, 15 internal combustion engines, 13 wind power plants and 11 solar power plants) with total rated electrical power of 129.4 MW.[16]

The completed public tenders for the support scheme show high interest of potential investors to invest in RES and CHP production facilities. The projects funded by the support scheme are encouraging for the further development of such electricity production. On the other hand, however, the number of funded wind power projects is worrying, as the construction of wind power plants in Slovenia is very complex with respect to their geographic location, and time-consuming. Currently the wind power plants contribute only approximately 3 MW of rated electric power in the support scheme.[17]

Installations with a nominal installed capacity up to 500kW may continue to receive the feed-in tariff as approved in the European Commission decision SA.28799 of November 26, 2009. For installations exceeding this threshold, support will be paid in the form of a market premium on top of the market price. The market premium awarded to projects which succeed in tender is based on the difference between the reference costs of electricity and the actual market price of electricity (calculated on the basis of the reference market price).

With respect to wood biomass facilities which, due to their age, would not ordinarily qualify for support, these installations are still remunerated via a market premium, but the quantum of that premium will only take into account the 'variable' aspect of the reference costs, excluding any investment costs which, owing to their age, would be expected to have already been recouped through operation.

The support scheme for eligible RES and CHP producers is funded through the imposition of a "para-fiscal" levy on electricity consumers in Slovenia. The funds are paid as lump sum payments on connection.

At the level of individual beneficiaries, the aid is granted for a period of 15 years for RES installations. CHP installations using biomass are granted aid for 15 years, and those using biogas for 10 years. Furthermore, for renovated installations, the period of support is shorter, with the deduction of the period of time which has elapsed since the renovation from the applicable period for support (10 or 15 years, as applicable).

The Ministry of Energy acts as granting authority. The eligibility for aid is assessed by the Energy Agency, which is also responsible for ensuring compliance with the cumulating rules.

The funds to provide support to the RES and CHP support scheme are sourced from a combination of:

- the RES and CHP contributions paid by all final consumers of electricity, natural gas, and other gases used in grid and district heating;
- contributions levied on solid and liquid fossil fuels, liquid petroleum and liquefied natural gas and heat from district heating systems; and
- revenues which the Centre for RES/CHP Support receives through the sale of electricity it is obligated to purchase from recipients of the feed-in tariff.

The expected budget for new RES and CHP installations under the support scheme over the lifetime of the scheme is estimated at €600 million and, for the reductions in RES levies granted to energy-intensive users, to total €242.5 million over the lifetime of the scheme.[18]

Developments in legislation or regulation

In 2017 and 2018, the adoption of further key acts for implementation of the Energy Act[19] (and implementation of the EU Third Package of energy legislation)[20] continued, *inter alia*, by adopting the following acts:

- Rules amending the Rules on the balancing of the electricity market,[21] which govern organisation, membership and participation on the balancing market, reports and notifications and financial settlement of the transactions on the balancing market;
- a Decree establishing the infrastructure for alternative transport fuels,[22] which governs alternative transport fuels and the provision of infrastructure for alternative transport fuels;
- Legal Act on the methodology determining the regulatory framework and network charge for the electricity distribution system;[23]
- Legal Act on the methodology for determining the regulatory framework of the gas distribution system operator,[24] which governs the methodology for the regulatory framework for eligible costs and cost recovery; and
- Legal Act on the methodology for determining network charge for the natural gas distribution system,[25] which determines tariffs, separately charged services, calculation of network charge and method for charging the network charge and other services.

Simultaneously with the development of smart grids, an adequate level of cyber security of the electricity system must be ensured. The cyber security and measures for the security of networks and information systems, essential for undisturbed functioning of the state, are governed by the Act on Information Security,[26] transposing the Directive (EU) 2016/1148 of the European Parliament and of the Council of 6 July 2016 concerning measures for a high common level of security of network and information systems across the Union.[27]

The Act on Information security, which entered into force in May 2018, imposes obligations with respect to information security upon the operators of essential services, *inter alia*, in the energy sector. The operators of essential services, such as companies in the energy sector, must: (i) take appropriate and proportionate technical and organisational measures to manage the risks posed to the security of network and information systems; (ii) take appropriate measures to prevent and minimise the impact of incidents affecting the security of network and information systems; and (iii) notify, without undue delay, the competent authority or the CSIRT (Competent authorities or the Computer Security Incident Response Teams) of incidents having a significant impact on the continuity of the essential services they provide.

Judicial decisions, court judgments, results of public enquiries

Compatibility of the support scheme for RES with the state aid rules

The operation of the electricity support scheme, "*Support for production of electricity from renewable energy sources and in co-generation installations*", which was approved by European Commission decision SA.28799,[28] achieved approximately 21% of renewable energy by the end of 2014, and it is expected that the amended version of the electricity support scheme will allow the 25% target to be reached. The Slovenian authorities notified an amendment to a support scheme to the European Commission on May 27, 2015 pursuant to Article 108(3) of the Treaty on the Functioning of the European Union (hereinafter: "**TFEU**").[29]

The most significant amendment to the scheme is the **introduction of a tender process** to select beneficiaries to receive support under the support scheme and determine the appropriate level of that support. In particular, Slovenia has introduced a two-round public tender process designed to increase competition between potential beneficiaries and ensure that support is granted to the best-value projects. This change is in line with the EEAG, which requires that, from January 2017, such aid is granted on the basis of a clear, transparent, non-discriminatory competitive bidding process open to all producers of renewable electricity.

The European Commission has assessed the notified aid scheme on the basis of Article 107(3) TFEU and the EEAG and concluded that the measure is compatible with the internal market pursuant to Article 107(3)(c) TFEU (decision SA.41998 of October 10, 2016).[30] The notified measure will expire on December 31, 2019.

Merger controls

In 2017, the Slovenian Competition Protection Agency (hereinafter: the "**CPA**") cleared three notified concentrations of the companies from the energy sector. On May 11, 2017 the CPA issued a clearance for the concentration of five distributors of electricity (Elektro Ljubljana d.d., Elektro Maribor d.d., Elektro Celje, d.d., Elektro Primorska d.d. and Elektro Gorenjska, d.d.) with Informatika d.d., a company for business IT solutions, as it found that Informatika d.d. already provided its services to the distributors of electricity before the concentration and that many alternative providers of IT services are present on the market.[31] In February 2018, the CPA cleared the concentration of Adriaplin d.o.o. and Mestni plinovodi, d.o.o., both active in the distribution of natural gas.[32] In March 2018, the CPA also cleared the concentration of Petrol d.d., Ljubljana (hereinafter: "**Petrol**"), a company active in the energy sector with a focus on the wholesale and retail distribution of petroleum products, and Megaenergija, d.o.o., a producer of electricity from CHP installations.[33]

In November 2017, the notifying parties HSE, d.o.o., Elektro Celje, d.d., Elektro Gorenjska, d.d. and Elektro Primorska, d.d. notified the concentration with ECE d.o.o. and E3 d.o.o. to the CPA. According to the CPA's assessment, the concentration will increase its market shares on the retail market of electricity, which could raise serious concerns on its compatibility with the competition rules in relation to the presence of notifying parties on the vertically linked markets of production and wholesale of electricity. With the resolution of May 11, 2018, the CPA thus initiated the investigation of the concentration and invited the notifying parties and any third parties to submit any information, which could be relevant for its decision on the notified concentration.[34]

Finally, the European Commission cleared the concentration of Petrol and Geoplin d.o.o. Ljubljana (hereinafter: "**Geoplin**") by way of acquiring sole control over Geoplin by Petrol, which had an EU dimension within the meaning of Article 1(2) of the Council Regulation (EC) No. 139/2004 of 20 January 2004 on the control of concentrations between undertakings.[35,36] In its investigation, the European Commission found that Petrol was perceived by several market participants as an independent supplier of natural gas in the wholesale market; there are, however, sufficient alternative sources of supply and the respective concentration is unlikely to significantly impede effective competition in the market. Additionally, there are no significant barriers for domestic retailers and wholesalers to source natural gas abroad. As the retail customers are not dependent for natural gas supplies on Petrol nor Geoplin, the relevant concentration would have no (or limited) competitive impact on the Slovenian retail natural gas market.

Even the minority shareholdings of Petrol and Geoplin in their retail competitors (Adriaplin d.o.o. and GEN-I, d.o.o.) are unlikely to result in unilateral or coordinated effects, especially because: these minority shareholdings do not entitle Petrol or Geoplin to exercise any specific influence over the strategic decisions; the size of these minority shareholdings is limited; there are numerous established suppliers on the retail market; and Petrol's indirect minority shareholding was in the process of being divested at the time of the decision.

Major events or developments

Baumgarten incident

On December 12, 2017, there was an explosion followed by fire at the Baumgarten gas hub on the Austrian-Slovakian boarder, which disturbed the supply of natural gas at Ceršak entry point for several hours. In the absence of storage facilities, Slovenia's gas supply is largely dependent on the natural gas transferred from Austria through the Ceršak entry point. On the day of the explosion, the volume of natural gas transferred through Baumgarten dropped and Slovenia reacted by importing gas from Italy (the technical capacity of the Šempeter entry point reaches only 20% of the Ceršak entry point).

One third of the Russian gas transferred to Western Europe passes through Baumgarten, so the explosion caused confusion on the market with significant price hikes. Italy, which is dependent on the Russian flows for almost one third of its demand, faced almost double the price in comparison to the previous or the following days, and declared a state of emergency. The incident increased Slovenian import costs by the combined effect of higher-priced imports from Italy on the day of the explosion and the need to buy more expensive within-day capacities the day after. The estimated extra costs due to this incident amounted to approximately €120,000.[37]

The natural gas supply of consumers was not disturbed, the gas transmission system worked properly, and the Energy Agency declared a so-called level of early warning. However, this incident raised considerations regarding the security of supply; if the supply through the Ceršak entry point would be disturbed for a longer period, the operator of the transmission system or gas suppliers would have to adopt respective measures under the Regulation on the emergency plan for natural gas supply[38] and, as a last resort, limit the consumption of natural gas.[39]

Cross-border market coupling as a step towards a single integrated European power market

Market coupling is the use of an implicit auctioning system, where transmission capacity represents an input parameter in the exchange of offers between two or more power exchanges. In 2016, BSP SouthPool Energy Exchange, designated as a nominated electricity market operator[40] for the trading area of Slovenia, in cooperation with other European Power Exchanges and system operators, successfully implemented a project of day-ahead market coupling on the Slovenian–Italian and Slovenian–Austrian borders.

Finally, on June 19, 2018, the coupling of the Slovenian and Croatian market was also successfully implemented. With the implementation of implicit allocation of day-ahead cross-border capacities on the last non-coupled Slovenian electricity border (the Hungarian power exchange HUPX is not included in the multi-regional coupling and the Slovenian and Hungarian markets are not linked through interconnector), the Slovenian bidding zone is fully coupled and integrated in the single European electricity market. The latter primarily brings a benefit for end-consumers derived from more efficient use of the power system and cross-border infrastructure as a consequence of a stronger coordination between energy markets. We can expect that the fully integrated Slovenian bidding zone will give an additional liquidity boost to the Slovenian spot power market. Considering the large volumes of available cross-zonal capacity on the Slovenian–Croatian border, it will also strengthen the Slovenian electricity price index SIPX.[41]

Proposals for changes in laws or regulations

On November 30, 2016, the European Commission presented the so-called Winter Package of eight proposals to facilitate the transition to a clean-energy economy, which will have a strong impact on all EU Member States. The European Commission aims to provide a stable legislative framework to facilitate the clean energy transition, thereby taking a significant step toward the Energy Union. The package has three main goals: (i) putting energy efficiency first (EU level binding target of at least 30% energy efficiency by 2030); (ii) achieving global leadership in renewable energies (at least 27% renewables in the final energy consumption and emissions cut by at least 40% by 2030); and (iii) providing a fair deal for consumers (clean energy transition needs to be fair for sectors, regions or vulnerable parts of society affected by such a transition; all consumers are entitled to generate electricity, store it, share it, consume it or to sell it to the market).[42]

The proposals can be grouped into three categories: proposals amending existing energy market legislation (third package of electricity market liberalisation measures); proposals amending existing climate change legislation (measures aimed at aligning and integrating climate change goals); and proposals for new measures (risk-preparedness in the electricity sector and governance of the Energy Union).[43]

* * *

Endnotes

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4. Report on the energy sector for 2017, of the Energy Agency, pp. 110 and 159.
5. Report on the energy sector for 2017, of the Energy Agency, p. 98 and pp. 154–155.
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7. Report on the energy sector for 2017, of the Energy Agency, p. 24.
8. Official Gazette of the Republic of Slovenia, no. 46/2015.
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10. http://ec.europa.eu/competition/elojade/isef/case_details.cfm?proc_code=3_SA_41998.
11. Report on the energy sector for 2017, of the Energy Agency, p. 31.
12. Article 4 of the Decree on support for electricity generated from renewable energy sources and from high-efficiency cogeneration.
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14. https://www.agen-rs.si/web/portal/-/izbor-prijavljenih-projektov.
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18. Commission decision SA.41998, paras. 70 and 71.
19. Official Gazette of the Republic of Slovenia, no. 17/14 *et seq*.
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23. Official Gazette of the Republic of Slovenia, no. 46/18.
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31. Decision of the CPA, no. 3061-30/2016 of May 11, 2017.
32. Decision of the CPA, no. 3061-32/2017 of February 23, 2018.
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37. Self-assessment and development options for the Slovenian gas wholesale market, report prepared in April 2018 by REKK Energiapiaci Tanácsadó Kft. for the Slovenian Energy Agency, pp. 35–36.
38. Official Gazette of the Republic of Slovenia, no. 43/14 *et. seq*.
39. Report on the energy sector for 2017, of the Energy Agency, p. 159.
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South Africa

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Overview of the current energy mix, and the place in the market of different energy sources

The energy mix

The South African energy mix in South Africa is made up of renewables, gas, coal, hydroelectric and nuclear. Electricity generation is undertaken by state-owned power company Eskom and independent power producers. The transmission of electricity is undertaken by state utility Eskom and electricity distribution is the final deliver of electricity to end users, currently undertaken by Eskom together with municipalities.

South Africa is heavily reliant on coal, which comprised 39,126 MW of the country's 51,981 MW installed capacity in 2018 – approximately 75%. Existing hydro, pumped storage, PV and wind sits at approximately 4%, 5.5%, 2,8% and 3.8% respectively, while nuclear remains an auxiliary power contributor, providing 1,860 MW (3.5%).

Energy costs – a growing concern

South Africa has experienced significant increases in consumer-side energy costs, most notably through the increase in fuel and electricity prices. The National Energy Regulator approved a 5.23% average price increase in April 2018 for customers who purchase electricity directly from Eskom (the parastatal energy company), and a 7.32% average price increase for customers who purchase energy from municipalities. Petrol prices have increased over the last 12 months by almost 25% (from R12.37 in 2017 to a high of R16.02 in 2018).

Increases are primarily due to the global resurgence of the oil price (assisted by a decision from OPEC nations in November 2017 to cut production by 2%), with South Africa relying on the import of crude oil for the majority of its domestic fuel needs.

Indigenous oil and gas has the potential to relieve the pressure of import costs – in particular, through South Africa's potential shale gas reserves. The U.S. Energy and Information Administration (EIA) estimates the Karoo Basin's "technically recoverable shale gas resource" at 390 trillion cubic feet, making it the eighth largest in the world and second largest in Africa.

Developments in government policy/strategy/approach

Legislative uncertainty

Legislative and policy uncertainty in South Africa have served as a significant barrier to investment in the energy sector. The planned Gas-to-Power Independent Power Purchase Programme has been delayed pending finalisation of long-awaited energy, electricity and resources plans. Similarly, exploration and production of indigenous oil and gas has now been delayed as a result of the long-awaited Mineral and Petroleum Resources Development Act Amendment Bill, 15 of 2015, (MPRDA Bill) and, more recently (in respect of shale gas), by delays in the publication of the Technical Regulations for Petroleum Exploration and Production (Fracking Technical Regulations).

The newly appointed president, Cyril Ramaphosa, has been tasked with revitalising a stagnating economy, creating jobs and ensuring that all South African have access to electricity. Under his leadership we have already seen development to provide regulatory and policy certainty, such as the publication of the draft Integrated Resource Plan and the withdrawal of the MPRDA Bill.

<u>Draft Integrated Resource Plan published for public comment</u>

On 6 May 2011, the Department of Energy released the Integrated Resource Plan 2010–2030 (IRP 2010) in respect of SA's forecast energy demand for a 20-year period from 2010 to 2030. To date, the Department of Energy has implemented IRP 2010 by issuing Ministerial Determinations in accordance with section 34 of the Electricity Regulation Act, No 4 of 2006. The IRP 2010 is a living plan intended to be updated by the Department of Energy, but it has not been updated. A review has been necessitated by a number of changes in the assumptions utilised in the IRP 2010 and the publication of the Draft IRP for public comment. The Draft IRP has been formulated on a least-cost-plan basis. The much-awaited and long overdue draft Integrated Resource Plan 2018 (Draft IRP) was released by Minister of Energy, Jeff Radebe on 27 August 2018 for comment by the public. Comments on the Draft IRP are to be submitted by interested persons by 26 October 2018.

The SA integrated resource plan is an electricity capacity plan which sets out an indication of the country's electricity demands, how this demand is to be addressed and the cost thereof. The primary enabling legislation in South Africa is the Electricity Regulation Act, No 4 of 2006 (ERA). In terms of the ERA, the National Energy Regulator of South Africa (NERSA) is required to issue rules designed to implement the Integrated Resource Plan. The IRP hence provides insight into the development of the nation's energy mix.

The Draft IRP contemplates the following additional capacity:

- 1,000 MW of coal;
- 2,500 MW of hydro;
- 5,670 of solar PV;
- 8,100 MW of wind; and
- 8,100 MW of gas.

It is notable that the Draft IRP includes capacity allocation for solar photovoltaic, wind (onshore), embedded generation and gas. It excludes nuclear and solar CSP and any new coal generation capacity.

Coal

The Draft IRP includes 1,000MW of coal-to-power in 2023–2024 based on the two procured and announced coal projects under the Coal Baseload IPP programme. Although South Africa is committed to the management of the efficient use of its coal through the employment of clean coal technologies, these two projects may find reaching financial close and implementation fraught with funding and environmental challenges.

Renewable energy

South Africa's renewable energy industry is in its infancy, but growing. South Africa has successfully implemented four rounds under its renewable independent power producer programme. After waiting for close on two years for the power purchase agreements under the South African Renewable IPP programme rounds 3.5 and 4 projects to be finalised, the Minister of Energy, Jeff Radebe signed the 27 PPAs on 4 April 2018. Financial close of the round 4 and 4.5 projects were reached on 31 July 2018. This has provided much-wanted investment in SA and will reignite the construction industry, as construction will soon begin on the 27 projects.

The Draft IRP contemplates renewable capacity coming online, with solar PV and wind in 2025 clearly indicating a delay in the scale and pace with which the bid windows have been implemented to date. The Draft IRP recommends a least-cost plan for the implementation of renewable energy capacity, with the retention of annual build limits to provide a smooth rollout and help sustain the industry. It is anticipated that the comments to the Draft IRP to be submitted by 26 October 2018 will see the sector requesting earlier build-outs, considering that the assumptions on which the Draft IRP has been developed are being questioned.

Gas

It is clear from the Draft IRP that gas will be a significant part of the energy mix in the future: 8,100 MW of new additional capacity is projected to be procured, with a total contribution of 11,930 MW by 2030. Gas will account for approximately 16% of installed capacity mix by the year 2030.

Embedded generation

The Draft IRP has allocated 200 MW per annum to embedded generation for own use of between 1 MW and 10 MW, commencing in 2018. A generation licence will be needed to undertake the activities listed in Appendix E to the Draft IRP. NERSA will need to allocate this licence.

Hydro

Hydro is allocated in the year 2030 to honour the RSA–DRC treaty on the Inga Hydro power project. This is in line with SA's commitments set out in the National Development Plan to partner with regional countries.

Nuclear

New additional capacity for nuclear has not been included in the Draft IRP. The 1,800 MW of nuclear power generation from the Eskom Koeberg plant is expected to reach end-of-life between 2045 and 2047

<u>MPRDA Amendment Bill and New Petroleum Bill</u>

The MPRDA Bill was originally published for public comment in 2012, as a further amendment to the Mineral and Petroleum Resources Development Act, 28 of 2002, and subsequent amendment of 2008.

Following passage through the South African National Assembly on 16 January 2015, the President of South Africa at the time, acting in terms of section 79(1) of the Constitution, referred the Bill back to the National Assembly due to reservations the President had as to the constitutionality of the Bill (including that inadequate public participation had been provided for in its publication).

Accordingly, and in order to remedy the defects identified by the President, the National

Council of Provinces Select Committee on Land and Mineral Resources (the Select Committee) held an extensive public participation process during 2017 which involved public hearings on the Bill held in every province in the country, and which allowed for the submission of written submissions by members of the public in respect of the Bill.

In the latter half of 2017, each provincial legislature was afforded the opportunity to consider the proposed amendments to the Bill and was required to present Negotiating Mandates to the Select Committee indicating which amendments that province would like to see included in the Bill. The Negotiating Mandates received were voted on by the Select Committee (amendment by amendment) to form a final draft of the Bill, which was to be voted on in the National Assembly before the close of Parliament in 2018.

On 20 September 2018, the Minister of Mineral Resources announced his decision to withdraw the MPRDA Bill from parliament and to fast-track the development of a new Bill which will regulate the upstream petroleum industry separately from the mining industry. This has widely been regarded as a positive development as it allows for the development of clear and certain legislation without the issues and concerns which are specific to the mining industry, and which have significantly contributed to the delay of the MPRDA Bill.

The draft Petroleum Bill is currently being drafted on the basis of the amendments to the MPRDA Act which affected the petroleum industry, and is expected to be published (in draft form) in the first quarter of 2019.

Judicial decisions, court judgments, results of public enquiries

Nuclear

In April 2017, the Western Cape High Court declared unlawful and set aside the nuclear procurement processes. The Western Cape High Court declared the government's attempts to secure 9.6 GW of nuclear energy to be unlawful, including the initial determination to procure nuclear energy in 2013, the cooperation agreements signed with Russia, the US and South Korea, as well as former energy minister Tina Joemat-Pettersson's decision to hand over the procurement of nuclear energy to Eskom late last year. President Cyril Ramaphosa confirmed in late July 2018 that: "the South African economy cannot afford the nuclear build programme in its energy mix right now, as the country has other urgent priorities".

We note that the Draft IRP excludes nuclear as part of the proposed capacity allocation.

Fracking technical regulations

In October 2017, the Eastern Cape High Court set aside the publication of the Regulations for Petroleum Exploration and Production (Fracking Technical Regulations) in terms of section 107 of the Mineral and Petroleum Resources Development Act, 28 of 2002 (MPRDA), on the basis that such publication was unlawful. The court ruled that the Minister of Mineral Resources had not been authorised by the applicable empowering provisions to make the Technical Regulations, and further that the decision to do so had been procedurally unfair. As a result, and in terms of section 8(1)(c) of the Promotion of Administrative Justice Act ('PAJA'), the Court set aside the Technical Regulations and remitted the matter to the Minister for reconsideration.

It has been reported that this decision has been challenged by the Department of Mineral Resources, and an appeal is expected to be heard in due course.

It is interesting to note that in a second case which considered the validity of the Fracking Technical Regulations (brought at the same time by a different applicant), the High Court in Pretoria found that the Minister had been duly authorised to make the Fracking Technical Regulations. This may have some bearing on the pending appeal.

Major events or developments

Moratorium on granting of new applications for oil and gas technical co-operation permits, exploration rights and production rights

Despite the positive development in relation to the IRP and the MPRDA Amendment Bill, the Minister of Mineral Resources imposed a moratorium on the granting of new applications for technical co-operation permits, exploration rights and production rights in terms of the Mineral and Petroleum Resources Development Act, on 28 June 2018.

The restriction has immediate effect, and will run until the Minister publishes notices for invitation to apply for specific rights or permissions. The restriction will not, however, affect the processing of applications for reconnaissance permits, technical co-operation permits and exploration and production rights received before implementation of the restriction, nor will it affect renewals or transfers.

While it is understood that this is an interim measure to allow for the transition from the current legislative regime to the anticipated Petroleum Bill/Act, the moratorium has caused concern due to the possibility that it may limit the right to apply for exploration or production rights over discoveries made under technical co-operation permits and exploration rights at the end of their tenure exclusively to existing permit-holders. While the Department of Mineral Resources has indicated that this is not their intention, the wording used in the legally binding moratorium is ambiguous.

Absolute certainty of the right to develop a discovery is essential for the industry to make the investments necessary to conduct oil and gas exploration. As such, this issue is of great significance, and all eyes are on how the Department will resolve it.

Proposals for changes in laws or regulations

Draft Financial Provisioning Regulations

In addition to the proposal for new legislation which will regulate the upstream oil and gas industry separately from the mining industry (see the discussion on this point under 'Developments in legislation or regulation', above), the amended draft National Environmental Management Act: Financial Provisioning Regulations (Financial Provisioning Regulations) have been published for public comment.

First published in November 2017, the draft Financial Provisioning Regulations replace the existing 2015 version of the Financial Provisioning Regulations, and regulate the obligation on parties engaged in oil and gas exploration to provide financially for anticipated environmental liability arising from their activities.

The new draft provides for a flexible, risk-based approach to financial provisioning which will allow parties engaged in exploration to reduce the financial obligation to provide for anticipated liabilities by taking proactive measures to reduce risks associated with exploration. The draft regulations also expand the list of approved financial vehicles available to make provision, and introduce many long-awaited improvements and efficiencies to the process.

Conclusion

While legislative uncertainty remains a significant roadblock to development of the South African energy sector, there have been several positive developments in the course of the last year which point to a renewed focus from government to address this pressing issue. While it will take time to effect the change which is necessary to encourage investment and growth, indications are positive that Government and the regulators understand what is needed and are working towards achieving this outcome.

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Spain

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Overview of the current energy mix, and the place in the market of different energy sources

The Spanish energy market has gone through some marked changes, which can be well illustrated in a series of snapshots:

- A prominent headline of the current energy mix could very well be that the data available for 2017 in Spain indicate a pronounced decrease in the consumption of hydroelectric energy (by 49.1%) and a considerable increase (20%) in electricity generation from coal. The primary energy mix would be: oil 46.7%; natural gas 19.8%; renewables 11.3%; coal 9.7%; nuclear energy 9.5%; and hydroelectricity 3%.
- Regarding the demand for electricity in Spain, in 2017 it was 268,140 Gwh, up 1.1% on the previous year (and 4.6% lower than in 2008).
- The maximum point of instantaneous power was recorded on January 18 at 41,381 MW, which is 2.2% higher than the maximum of the previous year. (The historical maximum was 45,450 MW in December 2007).
- The installed capacity is currently at 104,122MW, which is 0.5% less than the previous year and can be attributed to the closure of Santa Maria de Garoña nuclear power plant which supplied 455MW. Of the total installed capacity, 46.3% corresponds to renewable energy facilities and 53.7% to non-renewable technologies.
- Regarding electricity generation, 33.7% corresponds to renewable energy and 66.3% to non-renewable energy. The mix stands at: nuclear 22.4%; coal 17.1%; combined cycle 13.6%; cogeneration 11.3%; pump turbines 0.9%; and non-renewable waste 1%.
- In terms of renewable energy, wind energy makes up 19.1%; hydraulics 7.4%; photovoltaic solar 3.2%; solar thermal 2.2%; other renewable energies 1.5%; and renewable waste 0.3%.
- The most noteworthy development from the point of view of consumption is an increase in the consumption of less-clean energy in Spain, creating an increase in carbon dioxide emissions back to the level they were in 2012 and placing Spain in fifth place in the European Union.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Among the most striking legislative or regulatory developments in recent times are the auctions called by the government during 2017 to establish a specific remuneration scheme to encourage production from renewable energy sources, high-efficiency cogeneration and waste, in order to meet the energy objectives established by Community regulations, or when their introduction into the market involves a reduction in energy costs and dependence on external energy sources.

These auctions were convened by two royal decrees approved by the existing administration at that time and following those held in 2016. The decrees assigned the following megawatts:

The first auction was held in May 2017, and 3,000 MW of power were awarded, 2,979 MW of which went to wind facilities, 1 MW to photovoltaic facilities and 20 MW to other energy sources. Thus, the first auction was dedicated largely to the wind energy sector, which bid by mostly offering the highest possible discount, thereby leaving out other technologies.

The facilities corresponding to this first auction will have to start operating before 2020. In this sense, it must be considered that the auction required the provision of a guarantee of €60.- for each Kw that was will bid at the auction.

On the other hand, approximately 5,000 MW of power were awarded in the auction of July 2017, 3,909 MW of it to photovoltaic technology and the rest to wind technology.

These projects must also be operational before 2020, having had to provide identical guarantees to those provided in the first auction in 2017.

In this sense, and given the large number of megawatts awarded and the lack of need to identify bidders in the auction procedures for the projects that supported these offers, it will be interesting to follow up on the development of this topic in order to verify which of the awardees are able to comply with the term limit established in the auctions' governing regulations.

An additional auction was initially foreseen for 2018, given the success in the level of participation in the auctions of the previous two years, however with the arrival of the new government administration, plans have been put on hold. In any case, the new administration has indicated its intention to re-launch them.

Developments in government policy/strategy/approach

In fact, the change of government in Spain in June of this year, which we have touched on above, has been the most significant change and the new administration brings with it a new energy policy.

In this sense, the new administration has announced a series of measures aimed basically at, on the one hand, reducing carbon dioxide emissions to the atmosphere and, on the other, accelerating fulfilment of the objectives marked by the European Union with regard to market penetration of renewable energies.

The strategy set by the new administration also includes the progressive decarbonisation of the Spanish electricity system as well as the closure of thermal power plants.

In principle, the beneficiaries of this new strategy would mainly be the global photovoltaic and wind sector (i.e. manufacturers, builders, developers and producers) given that, according to the data published by the Ministry itself, the fulfilment of the objectives set for the European Union implies installing 40,000 MW in addition to the existing capacity by the year 2030.

In any case, it will be necessary to follow up on these developments and their possibility of being implemented, given that in the case of decarbonisation of the system, the data of the energy mix of 2017 are still a desirable target, indicating Spain's dependence on this power source.

Developments in legislation or regulation

On the other hand, a notable short-term development will occur in terms of production facilities through renewable energy sources. Namely, in accordance with current legislation and effective January 1, 2020, the remuneration parameters of the production facilities will be up for revision. In particular, changes are expected in relation to the reasonable profitability renumeration, which all the sources of the sector anticipate will be decreased from its current rate, at 7.398%, to between 4% to 5%.

In this sense, it will be necessary to pay attention to the newly lowered rate that is finally established, which will have important economic and financial consequences for the holders of these facilities and may lead to a new period in which the secondary market is activated, favouring transactions of this type of facility.

Judicial decisions, court judgments, results of public enquiries

<u>International arbitration against the government of Spain regarding the reform of the renewable sector by virtue of Royal Decree Law 9/2013 and Royal Decree 413/2014</u>

Spain established the feed-in tariff system to support renewable energies through Royal Decree 661/2007. Since then, the regulations have undergone several modifications until the approval of Royal Decree 9/2013 and Royal Decree 413/2014, by means of which the previously existing regime was amended in its entirety and replaced by another one whereby each installation is reimbursed with a reasonable profitability. This is on equal terms for all technologies based on a standard installation with standard revenues and costs, depending on the technology, power and year of installation.

The said regulation implied a decrease in the economic support that the government provided to the facilities and promoters, which caused a great majority of them to bring unsuccessful claims against the Spanish government, challenging mainly the retroactivity of the regulation on the basis of unconstitutionality.

Foreign investors also brought claims against the Spanish government, but using international arbitration instead of the Spanish judicial system. Spain has signed the European Energy Charter Treaty ("ECT") and, as a member state that receives investment, has an obligation to offer fair and equitable treatment to all investors.

As a result, Spain has been sued in approximately 30 arbitrations for an approximate amount of €7,500 million. In four of these 30 arbitrations, unfavourable judgments have been issued against the Spanish State. The procedures have been initiated by the investment funds Eiser, Masdar, Antin (awards issued by a court of the ICSID) and Novenergia (Stockholm Chamber of Commerce Court).

In general terms, the Arbitral Award argues that, although every investor must have the expectation that any legal regime can be subject to evolution and modification, especially in a regulated sector such as electricity, they are entitled to receive fair and equitable treatment, meaning there cannot be a radical modification of the regulation that would deprive investors of the value of their investment in an unpredictable way.

To avoid the execution of arbitration awards, Spain has presented two legal arguments:

i) In accordance with Community legislation, the Court of Justice of the European Union (CJEU) is the exclusive interpreter of European law. In these procedures, an arbitral tribunal is allowed to hear matters that could affect European law, without the CJEU having any control.

As a consequence, it could be argued that the award is null and cannot be executed as it would contravene public order (New York Convention of 1958 and grounds for nullity provided for in the UNCITRAL model law and in national legislation on arbitration in general).

There are some precedents to this, including the *Achmea* case. The CJEU has ruled that matters that are regulated or affected by European law cannot be submitted to arbitration. Otherwise, the court would be deprived of its exclusive interpretative power of the treaties. The decision of the CJEU was based, originally, on a question referred by the *Bundesgerichtshof* (German Supreme Court).

ii) The Spanish government has argued that the execution of any award that agrees to indemnify foreign investors in Spain would imply an aid that is prohibited by Community regulations.

This argument has its basis. With regard to the state aid investigation procedure SA-40348, the European Commission ruled in its decision of November 10, 2017, that the remuneration regime established in 2013 and 2014 by Spain entailed an infringement of the Treaty on the Functioning of the Union European Union, since it implies the granting of unauthorised aid. Thus, the execution of any award that compensates investors for modifying such regulation would suppose an aid against European law.

<u>The Court of Justice of the European Union confirms the compulsory exemption of the tax on hydrocarbons for the energy products used in the production of electricity even when used for the combined generation of electricity and heat</u>

Law 15/2012, of December 27, on fiscal measures for energy sustainability, which entered into force on January 1, 2013, abolished the exemptions in the Hydrocarbons Tax for the products identified as taxable that were for the production of electricity and/or the cogeneration of electricity and heat in cogeneration plants.

In the explanatory memorandum to the aforementioned law, reference is made to the revision of the tax scheme on electricity generation activities from fossil fuels and, therefore, the need to eliminate this exemption in accordance with the provisions of article 14.1.a) of Directive 2003/96/EC, which refers to energy products used to produce electricity, and article 15.1.c) of the same directive, which refers to the combined generation of heat and electricity.

The High Court of Justice of the European Union, recently (7 March, 2018) ruled in favour of a company that had challenged the French legislation, confirming that the exemption established in the community regulations should be of obligatory application to the energy products used by a cogeneration facility for the production of electricity. Among other reasons, this decision was based on the understanding that double taxation could occur, and because there are no environmental reasons to justify the exemption.

For this purpose, the Court's conclusion is clear and leaves no room for doubt when it states literally that "the compulsory exemption provided for in [article 14(1)(a)] applies to energy products used for electricity generation, when such products are used for the combined generation of electricity and heat within the meaning of Article 15(1)(c) of that directive…"

This interpretation is extensive to the Spanish legal system, so it could be interpreted that Spanish legislation should apply the exemption from the tax on hydrocarbons, which is intended to tax the supply of fuels destined for the production of electricity and/or cogeneration of electricity, and heat in cogeneration plants with respect to the electricity part.

All this implies the possibility on the part of the cogeneration facilities to claim a refund of the tax in the amount paid for those hydrocarbons used by the cogeneration facility to produce electricity (and not with respect to those used to produce heat or gases).

Tax on the Value of Electric Power Production (IPVEE 7%)

On January 1, 2013, the tax on the value of electricity production approved by Law 15/2012, of 27 December, on fiscal measures for energy sustainability, came into force. The aforementioned tax involves the liquidation of 7% on income obtained by electricity production, regardless of the technology used.

The stated purpose of Law 15/2012, inspired by the principle of environmental protection established in Article 45 of the Constitution, seeks to transfer environmental costs to contaminating agents or entities. However, the formulation of the tax calls into question the pursuit of the stated purpose, insofar as the same tax rate is applied equally to all energy sources that pollute the environment, regardless of the intensity and impact of pollution, including renewable energies.

There were therefore doubts about the constitutionality of the tax. On June 14, 2016, the Third Chamber of the Supreme Court ruled to elevate to the Constitutional Court several constitutional issues against various articles of Law 15/2012, on tax measures for energy sustainability, stating their doubts about the constitutionality of three taxes regulated in the said norm, including the tax on the value of electric power production (known in Spanish as the IVPEE) set at 7%.

According to a note issued by the Judicial Council, "In all three cases, the Chamber has doubts about the environmental aim of these taxes, which the magistrates understand could be taxing the same taxable event or the same wealth already taxed by other taxes, which is why they believe that the Constitutional Court must clarify whether these taxes violate Article 31.1 of the Constitution."

Numerous facilities and promoters claimed the refund of the tax, alleging the unconstitutionality thereof.

On June 20, 2018, the Constitutional Court settled the issue with a decision of non-admission. In short, the ruling states that double taxation *per se* is only proscribed in the case of an Autonomous Region tax in relation to state or local taxes, but not in a case of a state tax (IVPEE) and a local tax (IAE). Therefore, this situation of double taxation generated by the degree of similarity of the taxable event between both taxes would not be grounds for unconstitutionality.

Therefore, based on this ruling of non-admission, it is foreseeable that in the coming months the Supreme Court will dismiss the appeals filed by the obliged parties, linking this ruling to the rest of the operators.

Major events or developments

The decrease in consumption of fuels and fossil fuels is a reality that will continue into the future. We are moving towards a society that makes more and more use of electricity (self-consumption, electric cars, storage, etc.) and there is a real commitment to renewable energies and the sustainability of the system. This implies that traditional oil companies are moving strategically towards the business of electric utilities, including the generation, distribution and commercialisation of electricity directly to the consumer.

Strategic movements stand out on the part of companies historically linked to fossil fuels that, in recent times, are diversifying their activity and entering into new energy businesses.

Thus, some have penetrated the market of electricity commercialisation, offering electricity and gas supply along with fuel in all their commercial networks of service stations.

Others have opted for the acquisition of companies in the electricity sector that generate more than 2,300 MW of electricity, in addition to their own cogeneration. With transactions like this, these historically fossil-fuel based companies will acquire a market share that can increase in the coming years and place them alongside other important players in the sector.

Additionally, other companies have recently closed the acquisition of photovoltaic projects of more than 250 MW with estimated investments of around €200 million, betting therefore on renewable generation.

Proposals for changes in laws or regulations

As we have had occasion to point out previously, the recent formation of a new government in Spain has led to the announcement of some legislative changes that would directly affect the energy sector.

One striking announcement from the new administration is that they will to try to eliminate before the end of the year what is known in Spain as the *Impuesto al Sol*, or tax on the sun. Under this tax, the self-consumption facilities have the obligation to pay fees to connect to the distribution network, and this has been one of the reasons that self-consumption in Spain in recent years has not developed at the same rate as in other countries around us.

Likewise, and as part of this initiative to favour self-consumption facilities, the administration has also announced it will eliminate bureaucratic procedures that hinder installation of these facilities.

This initiative has the support of a large part of the sector and of the parliamentary groups, so we will have to follow it closely to see if it finally materialises in the short term.

Likewise, as a measure to try to reduce the price of electricity, which in September of this year has reached historic highs, the administration has just announced plans to temporarily suspend application of the abovementioned IVPEE. This measure, which had also been sought by the opposition parties, will directly influence the price of electricity, resulting in a 2–4% decrease in electricity bills, according to government estimates.

Likewise, and in line with the objectives of reducing carbon dioxide emissions into the atmosphere (which increased significantly in 2017), the new administration has also announced that it is studying the creation of a new tax that will tax diesel consumption, and thus equate taxation of this fuel with that of gasoline. In any case, it will be necessary to pay attention to the development of this announcement, given the impact it would produce both on individuals and on professionals in the transport sector.

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Sweden

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Overview of the current energy mix, and the place in the market of different energy sources

Swedish energy production is – and has been for a fair amount of time – dominated by carbon dioxide-free energy sources, mainly hydropower and nuclear power. Statistics gathered up until 2016 reveal that 58% of electricity produced stems from renewable sources such as hydropower, biofuels, wind power, and solar installations. Moreover, around 80% of Sweden's total electricity demand is met through hydro- and nuclear power. Hydropower is the dominant energy source, accounting for around 40% of the total supply. Furthermore, a fair share of the energy demand is met by imported energy, mostly for electricity production in nuclear reactors, but also fossil fuels.

Total energy use in Sweden has seen a general decrease since the year 2000. This is mostly a result of the decommissioning of several nuclear reactors, which has decreased energy losses in the nuclear energy domain. However, the total energy input amount shows notable stability over time and has, since the mid-80s, hovered between 550 and 600 TWh. In 2016, the total domestic energy supply was 564 TWh. Sweden's energy use is commonly divided into three different user sectors: the industrial sector; the transportation sector; and the residential and service sector. Out of Sweden's total energy use, the industrial sector accounts for around 40%, whereas the transportation sector represents 25%. The industrial sector primarily relies on electricity and biofuel, while the transportation sector is dominated by fossil fuels. Energy usage within the residential and service sector is dominated by district heating, electricity, oil and biofuels.

A long-standing endeavour of Swedish energy policy, which during the last decade has cemented itself as commonplace, is to actively promote the use of renewable sources. As a corollary to this overarching pro-renewables approach and concurrent rapid technological development, Sweden has managed to establish a relatively low fossil-fuel dependency. During the course of the last two decades, total fossil-fuel usage has decreased significantly, especially so in the residential sector. The latter can, to a noteworthy degree, be attributed to the transition to geothermal solutions for residential heating, as opposed to traditional oil furnace heating. Geothermal or district heating now accounts for almost 90% of energy usage for the heating of apartment buildings.

Furthermore, within the industry sector, fossil fuel utilisation has decreased from 37% to 19%. This notwithstanding, and as noted above, fossil fuels still play a conspicuous role within the transportation sector. Nonetheless, we have witnessed a clear trend, even in transportation, of shifting to renewables. In 2016, the use of biofuels (predominantly biodiesel) in the transportation sector accounted for 19% of the total energy use. Moreover, and as will be elaborated further below, the current legislative environment will most likely further accelerate this already rapid development going forward.

The palpable pro-renewables wave is leaving its mark also in the realm of electricity production by paving the way for a forceful shift towards a wider range of green solutions. During recent years, we have witnessed a notable increase in wind farms built and, as of today, Sweden constitutes one of Europe's larger markets for wind power. By the end of 2016, the total amount of wind turbines amounted to around 3,400. Likewise, wind power accounted in 2016 for 15.5 TWh, or around 10% of the total net electricity production.

The 2016 numbers nonetheless reveal a decrease in wind power-produced electricity from previous years which, however, likely can be attributed to yearly variations. Now the wind power market is booming again and earlier this year, the Swedish Wind Energy Association declared that the amount of wind power capacity planned to be installed is at a record high. In 2017, press releases regarding the development of wind farms with an aggregate capacity of more than 2,000 MW, corresponding to almost 40% of currently installed capacity, were issued. The interest among foreign investors to invest in Swedish wind power has been massive and they underwrite almost 90% of the new wind power projects currently under development. In addition to the wind power development, extensive solar power installations are taking place in Sweden on a continuous basis. Between 2016 and 2017, the number of solar cell facilities connected to the power grid increased by around 50%. Solar power facilities now account for an installed capacity of around 231 MW.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

The Swedish energy system has traditionally rested on large-scale and centralised electricity production, stemming primarily from hydropower and nuclear power. A steady and controllable flow of electricity between consumers and producers has characterised the market. However, as noted above, more solar- and wind-power installations have been put in place during recent years, and currently account for a larger amount of total electricity production. As a consequence, the total amount of decentralised and intermittent electricity production has increased.

This, in conjunction with the fact that total base load generation has decreased as a result of the decommissioning of nuclear power plants, necessitates a well-balanced energy output. In light of this, the need to achieve a rational balance between production and consumption renders higher demands of flexibility in the system than used to be the case. The issue of system flexibility interlinks with the necessity of creating adequate delivery reliability among providers of electrical energy. To achieve this end, the legislator imposes fairly strict demands on network operators to ensure timely delivery, with minimum downtime.

The applicable rules entail, *inter alia,* that power losses occurring as a result of grid failures may not last longer than 24 hours. Additionally, more than 11 power failures for one and the same customer during the course of one year, is to be considered as poor delivery quality.

During 2017 and 2018, the Swedish Energy Market Inspectorate ("Ei") reviewed 33 electricity network operators to ascertain whether sufficient measures are taken to minimise downtime, and whether adequate policies and overarching strategies are in place to ensure reliable delivery of electrical energy. The investigation revealed that, during 2016, around 6,300 customers experienced power losses lasting for more than 24 hours. More than 85% of the power losses involved were caused by weather conditions, primarily thunderstorms and falling trees. As a result, the Ei has indicated a need for stricter requirements regarding isolation and installation of ground cables (as opposed to above-ground lines). Furthermore, the Ei has suggested updated functionality demands on electricity meters to enable increased capability (including remote reading) to detect power losses as soon after occurrence as possible.

As indicated above, the energy output is, furthermore, affected by the relatively recent decommissioning of two nuclear reactors, which has led to a general decrease in the electricity supply. This is true despite major wind and solar power installations made during recent years, as these energy sources, in comparison with nuclear power, have lower availability. In this context, it is worth noting that in June this year, the Swedish state-owned TSO for electricity, Svenska Kraftnät, issued a report on the state of the Swedish power balance wherein it concluded that Sweden will have to import more electricity during winter as the country, a net power exporter to the rest of Europe, shifts from nuclear to wind. Svenska Kraftnät stressed that the situation will become worse with the decommissioning of two more of Sweden's nuclear reactors by 2020, and that the margins for the Swedish power balance, and the ability to be self-sufficient with enough electricity under high-load situations, are shrinking. The findings in the report of Svenska Kraftnät are likely to have an impact on future energy policy.

Developments in government policy/strategy/approach and proposals for changes in laws and regulations

Adhering to the framework agreement on Swedish energy policy

An event of significant importance in the political arena in the last few years is the framework agreement on Swedish energy policy. The agreement, which is built on broad political consensus, was executed in June 2016 by five of the eight political parties represented in Parliament. By combining the three pillars of energy cooperation in the EU, *viz.* ecological sustainability, competitiveness and security of supply, the agreement constitutes a strategy for a controlled transition to an entirely renewable electricity system, aiming towards a 100% renewable electricity production by 2040. The framework agreement exercises significant influence on Parliament, which a number of policy trends shed light upon.

Earlier this year (2018), the former Government proposed several changes for ensuring the implementation of the framework agreement. Among other things, the proposals relate to promoting – while simultaneously modernising and climate-adjusting – the use of hydropower. This concentration is a result of the desire to maintain and, henceforth, secure hydropower as the dominant renewable source of electric power. In essence, contemporary environmental demands are to be imposed on hydro-based energy production, however, without disproportionately increasing the administrative and economic burden for the producers. The latter – *viz.* removing unnecessary administrative and financial encumbrances – is a crucial part of the framework agreement's intrinsic ambition to streamline the supervisory landscape in favour of energy market stakeholders. This efficiency-enhancing approach arguably originates from the hydro-energy producers' fierce critique over the past few years towards the lack of regulatory flexibility.

In a further effort to implement the intentions of the framework agreement to label Sweden as a pioneer in striving to decrease carbon dioxide emissions, the so-called "fuel-switch program" came into effect as of July 2018. This legislative program aims to, by no later than 2030, reduce emissions from the domestic transportation sector (however, not counting air traffic) by a minimum of 70%, as compared to 2010. A key part of this program is the introduction of a new "reduction duty", which will be dealt with further below. Moreover, the former Government mandated the Ei to suggest updated reduction levels for the years 2020-2030, to be presented in early 2019. The proposal is expected to include an evaluation as to whether high-grade biofuels should be included under the auspices of the reduction duty. On a more tangible note, the concrete legislative results of the framework agreement, since the execution date, will be assessed further below.

Furthermore, in August 2018, the former Government mandated the Ei to conduct investigations relating to the control function of the electricity certificate system. By way of a brief explanation, the electricity certificate (also known as green certificate) system is a market-based support system designed to promote renewable electricity production in a cost-efficient manner. More specifically, electricity certificates are issued to producers of electricity for each MWh of electricity generated from renewable energy sources. The electricity producers may sell their certificates, thus generating extra revenue, and, in simple terms, electricity buyers are then required to purchase certificates corresponding to a certain proportion of their electricity use, known as their quota obligation.

Pursuant to the mandate referred to above, the Ei will analyse and present proposals with respect to the establishment of a so-called "stop mechanism", aiming to define timeframes during which electricity production facilities have to be up and running, in order to obtain adequate certification. The mandate includes investigating different alternatives to achieve this end, including a volume-based stop mechanism. The Ei is to further provide a detailed analysis of the consequences of the presented solutions as to the electricity certificate market players. Additionally, the Ei will present a suggestion altering the duration of the allocation period, i.e. the limited time period during which an electricity production facility may be granted an electricity certificate. This includes an analysis of whether or not to introduce a time span between the end of one allocation period and the beginning of the next allocation period, in cases where a facility has undergone major reconstruction.

The parliamentary elections

Policy-wise, the majority of Swedish political parties are united in a general aspiration to accelerate the reduction of carbon dioxide emissions. This is evident, not least, by the fact that the framework agreement reaches across existing party blocks. This notwithstanding, there are differences as to the parties' respective execution strategies. While the right-wing and liberal parties tend to advocate market-driven solutions, the left-leaning parties promote higher taxation and legislative restrictions. The Swedish parliamentary elections took place in September 2018 and the outcome will likely have a notable impact on energy policy going forward. We are likely to see a continued inclination for imposing far-reaching legislative measures aiming to decrease profits in the fossil-fuel domain while concurrently seeking to promote renewable energy sources.

Developments in legislation or regulation

The framework agreement's legislative "harvest"

We have looked at the background and motivations behind the importance of the framework agreement to Swedish energy policy. In turn, the agreement has triggered a number of significant regulatory changes. These include tax reliefs within the renewable domain. *As per* a law passed through Parliament stemming from the framework agreement, the property tax for hydropower has been successively reduced during the past 16 months. The reduction will continue by 0.5% of the assessed property value throughout the following two years. Additionally, the law affects the taxation of thermal power in nuclear reactors, i.e. the capability of nuclear reactors to generate heat. The taxation of thermal power is based on how much power the reactors could generate but, as a result of the passed law, the tax is currently being phased out. These reliefs are financed by an equivalent tax increase *vis-à-vis* electric power generated in the residential and service sectors.

The execution of the framework agreement was, furthermore, preceded by extensive discussions and negotiations regarding the need for amplified regulatory measures in the nuclear power sector. This has resulted in laws imposing further restrictions for the purpose of assuring the safety of nuclear energy production by decreasing the risk – and increasing the accountability – for nuclear accidents. More specifically, one provision of the agreement, which became law during 2018, entails an increase of the civil liability for radiological accidents to €1,200 million. Additionally on the nuclear side, the framework agreement has resulted in increased fees to be paid to the Swedish Nuclear Waste Fund (the "NWF") during 2018–2020 by operators of nuclear power plants. The NWF is a governmental agency whose main directive is to administer funds earmarked for the financing of the future management and disposal of spent nuclear fuel and other waste products. The funds are also reserved to enhance research and development within the area of nuclear energy production.

<u>New provisions regarding revenue caps</u>

Ever since 2012, the Ei has regulated the revenues of electricity network companies over a four-year period. Revenue caps limit the amount of revenues that network operators may recover from their operations during one regulatory period. The principal rule is that revenues should cover the reasonable costs of running a network as well as providing a reasonable return on the capital invested. The regulation regarding revenue caps has been the subject of a heated debate, especially in relation to the concurrent issue of security of supply, which constitutes one of the variables for deciding the scope of the revenue caps.

In August 2018, the former Government enacted a new ordinance changing the rules regarding the determination of revenue caps, which will come into force *as per* the next regulatory period starting in 2020. The background of the change was that major network operators in Sweden had been able to raise network tariffs in a manner which the former Government deemed unacceptable, seeing as the rises implemented had not been met with a corresponding increase of investments in the electricity grid.

Additionally, during the first and second regulatory periods, the network operators appealed more than half of the decisions made by the Ei, which – in the eyes of the former Government – indicated a pressing need for more rule clarity. The essence of the provisions of the ordinance pertain to how to set the discount rate for calculating the caps. Moreover, in addition to creating a more tangible regulatory framework, the provisions aim to establish more reasonable distribution charges.

The former Government stated in August that the change may result in a situation where a majority of the customers currently paying fees in accordance with a comparatively high rate will be able to secure up to 21% lower fees (if the new rules were applied based on current market conditions). How future events will unfold – and whether or not this projection holds up – remains to be seen once implementation is in place. However, a general fee reduction appears to be a plausible development. Conversely, we may see a concurrent decrease in the investment willingness of the network operators, and in the prevailing interest among infrastructure funds and institutional investors to continue to make investments within this sector.

Reduction duty for increased usage of biofuel in petrol and diesel

In July 2018, the so-called "reduction duty" came into force on the Swedish energy market. The legislation seeks to promote the use of biofuels by imposing an obligation on sellers of propellants to decrease emissions of greenhouse gases by way of mixing biofuels together with petrol or diesel fuel. Furthermore, the reduction duty constitutes a withdrawal from the previous strategy for increasing biofuel use, which was based on state subsidies. Concurrently, this entails that biofuels are taxed at the same rates as fossil fuels. From a short-term perspective, the reduction duty will likely lead to an overall increase in transportation costs. At the same time, the shift from state subsidies increases foreseeability for bio-fuel producers, which may have a long-term positive effect on the production rate.

New EU regulations

Several new EU regulations have seen the light of day in recent years, all of which form part of the overarching strategy to continue the establishment and maintenance of an intra-European energy market. This aims to serve the purpose of securing energy demand in Europe while simultaneously contributing to sustainable energy production. *As per* its implementation in December 2017, the Commission Regulation (EU) 2017/2195 establishing a guideline on electricity balancing (EB) has had a notable impact on the Swedish energy market. The regulation sets out guidelines to be adhered to by the Transmission System Operators ("TSOs") in order to secure the balance in energy output, by way of, *inter alia*, laying out terms for how "balance services" should be procured and activated. "Balance services" is a common designation of services enhancing a flexible electricity production, which are acquired by the TSO from various suppliers. Previously, offers to the Swedish TSO for electricity, Svenska Kraftnät, regarding balance services were submitted by the supplier through an intermediary agent. The new regulation introduces a new role ("supplier of balance services") which entails that the offers can be conveyed directly to the TSO with no middleman. This aims to lighten the administrative burden while increasing flexibility in the system.

Moreover, we have seen the implementation of the Commission Regulation (EU) 2017-/1485 providing guidelines for system operation (SO). This regulation arose out of large-scale power losses occurring between the year 2000 and 2010. The provisions state minimum requirements for the TSOs pertaining to maintenance and secure operations. From a Swedish viewpoint, the regulation primarily affects the Swedish TSO for electricity, the Ei and electricity network companies, in terms of more extensive requirements for training and educating staff. Moreover, in an effort to comply with the increased demands of an overarching regional strategy for coordinating measures to ensure secure operations, the Nordic TSOs have established the Nordic Regional Security Coordinator (the "RSC"). The RSC now serves as a supporting functions for TSOs in Sweden, Finland, Norway, and Denmark, by providing services aimed towards maintaining operational security of the power systems.

Judicial decisions, court judgments, results of public inquiries

Rulings on revenue caps

During the course of recent years, there have been several court cases relating to revenue caps *vis-à-vis* the electricity network operators. As explained above, revenue caps regulate the amount of revenue that network operators may extract from their operations. A major series of court cases (the so-called "Referral Cases") relating to the second regulatory period was won by the network operators at the end of 2017, after the Administrative Supreme Court declines to try the Ei's appeal.

Since then, the Ei has increased the revenue caps by fixing the discount rate (based on the WACC-method) at 5.85%, which allowed the network operators to, in aggregate, charge fees up to SEK 8 billion more. Recently, the lower administrative courts published a number of additional decisions, however, this time relating to the extent to which a network operator may "roll-over" revenue caps during the course of several regulatory periods. The Ei has interpreted the law in a manner which limits the number of regulatory periods during which a network operator may "save" non-utilised revenue caps.

Around 40 network operators appealed the Ei's decision, arguing that the opportunity to roll over revenue caps extends over at least two regulatory periods. In September 2018, the court ruled in favour of the appealing companies, and decided that operators who had not made use of the revenue caps during the regulatory period between 2016 and 2019 would be able to postpone their utilisation until the end of the next regulatory period, i.e. 2023. The final resolution of this issue, however, remains uncertain, as the Ei will mostly likely appeal the decision to the Administrative Court of Appeal. This notwithstanding, and as described above, the new provisions regarding revenue caps introduced by the former Government aim towards facilitating the calculation of the discount rates, so as to increase rule clarity and foreseeability, while simultaneously reducing the number of appeals going forward.

A similar turn of events has unfolded also on the gas side, i.e. in relation to Sweden's gas network operators. Following a round of appeals against the Ei's decisions on revenue caps for gas distribution for the regulatory period between 2015 and 2018, the lower Administrative Court decided in favour of the Ei in several respects but, nonetheless, accepted the appealing operators' position regarding the length of the applicable depreciation periods.

The ruling of the lower Administrative Court was challenged by the Ei in the Administrative Court of Appeal which, however, ruled in favour of the gas network operators. Thus, the court granted longer depreciation periods for gas transmission lines, *viz.* 90 years, as opposed to 65 which had been applied by the Ei. Furthermore, the court decided on a different method for the calculation of returns. This meant a higher return for the appealing companies compared to the previously decided caps. The Ei filed an appeal of the ruling which, however, was denied in April 2018. Subsequent to the *cert* denial, the Ei changed the revenue caps in accordance with the judgment of the Administrative Court of Appeal.

Major events or developments

Throughout the past few years, we have seen significant changes in the energy markets as well as volatile energy prices. Moreover, rapid digital development has led to historically dominant energy companies facing stiff competition from new players attempting to advance into the energy domain with new, innovative solutions. These factors, among other things, have triggered a need for structural measures among the dominant actors on the energy market and, concurrently, a relatively strong and viable energy-related M&A market.

Most recently (during 2018), a major consolidation encompassing two subsequent acquisitions raised attention within the gas sector. Through the purchase of E.ON Gas Sverige AB, an infrastructure fund managed by First State Investment acquired the gas network operated by E.ON, which constitutes the largest distribution network operator ("DSO") in Sweden. Johan Mörstam, chief of E.ON Energy Distribution and chairman of E.ON Gas, described the divestment as a natural step in the company's development towards a 100% transition to renewable and energy sources. Subsequently, First State

Investment made a second large investment in the Swedish gas market, this time through the acquisition of Swedegas. Swedegas is the Swedish TSO for gas and operates a gas network with a reach extending to around 600 km, and distributes gas to a large number of Swedish municipalities including numerous thermal power plants and industries.

In July this year, another notable transaction took place within the renewables sector. The Chinese power giant China General Nuclear (CGN) agreed to purchase a 75% stake in the so-called North Pole Wind Farm from Macquarie Capital and General Electric (GE). Also known as the Markbygden ETT Wind Farm, the 650MW single-site onshore wind project is being built in northern Sweden. GE and Macquarie's Green Investment Group (GIG) commenced construction of the 179-turbine project in 2017 after reaching financial close in November that year. The wind farm, which will be largest onshore wind farm on European territory so far, is expected to be fully operational by the end of 2019.

Another eye-catching event took place on the Nordic energy market in September 2018. A major Norwegian energy trader, trading on the derivatives markets, failed to make a margin call after market prices rapidly moved against him, triggering the default mechanisms of the Nasdaq Commodities clearing house. Closing out the positions, Nasdaq had to utilise not only the trader's margin collateral, the trader's contributions to the default fund and some of Nasdaq's own capital, but also a portion of the mutual default fund (mandated for derivatives clearing houses under EU law). This in turn triggered a request by Nasdaq to clearing members – a group which includes some of the region's energy giants – to replenish the default fund to the tune of approximately €107 million. The severity of this incident's impact on the default fund seems to have taken clearing members by surprise and has attracted significant attention on the energy market; and perhaps also some indignation among the affected market participants. It is probably a safe prediction that this event will have implications for how the region's energy markets will be organised and managed in the future.

Lastly, an exciting development in the electricity domain is the establishment of the "Northvolt Labs" in Sweden. The labs function as research facilities for developing and testing battery cells prior to larger-scale production. The operations in the labs form part of battery producer Northvolt's plan to build Europe's largest lithium-ion factory in northern Sweden. The factory has a planned capability of generating 32 GWh in battery capacity. In June 2018, Northvolt received necessary environmental permits for the initial stage of the project, and plans to begin production of the first section of the factory in 2020. The company is currently seeking to attract more investors, in addition to companies already involved, such as ABB and Siemens, to secure the continued funding of the project.

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Switzerland

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Overview of the current energy mix, and the place in the market of different energy sources

Switzerland's final energy consumption totalled 854,300 Terajoules (TJ) in 2016. The energy mix consisted of motor fuels (34.2%), stationary fuels (16.1%), electricity (24.5%), gas (13.7%) and other (11.5%). The final sectoral consumption was split between transport (36.0%), households (28.2%), industry (18.2%) and services (16.6%).

While electricity demand in Switzerland can be met by domestic production, Swiss oil and gas demands fully depend on imports. This is due to the fact that Switzerland has no domestic production of crude oil and natural gas. Therefore, energy-related regulations in Switzerland are mainly focused on the electricity sector.

Electricity consumption reached 58.5 billion kWh (or 62.9 billion kWh, taking into account the losses due to transport and pumping for pump storage plants) in 2017. On the supply side, national production amounted to 57.3 billion kWh. The main source for electricity production is hydropower, which represented 59.0% of production in Switzerland. Moreover, electricity production in Switzerland consists of nuclear power (32.8%), non-renewable conventional thermal power (3.1%) and renewable energy other than hydropower (5.1%).

Switzerland aims to phase out nuclear power and to increase its electricity production from renewable energy sources, in particular from solar power. This process is known as the "Energy Strategy 2050". Renewable energy sources therefore benefit from state support. The main instrument for the promotion of electricity production from renewable energy sources is a feed-in tariff system, which has been revised recently as described below. The government's intention to "green" the national electricity production has led to a significant increase of electricity production from solar power since 2012. Today, solar power is the most important renewable energy source other than hydropower. However, solar power accounts for only 2.2% of the total electricity production in Switzerland and therefore still plays a minor role.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

In general, Switzerland has a stable energy mix and the shares of oil, electricity and gas alter only slightly from year to year. With regard to electricity production, however, hydropower is under increasing pressure. There are external and internal reasons for the increasing pressure on hydropower.

Externally, overcapacities due to subsidies for renewable energy sources in several EU Member States (in particular, Germany), as well as faltering demand, have led to low prices in European electricity trading. The low electricity prices in the European electricity market have put Swiss hydropower producers in financial difficulties, as they are no longer able to cover their production costs. Since hydropower is a mainstay of Swiss electricity supply, the financial difficulties of hydropower producers calls for state support, which has been granted as described below.

Internally, the proposal of a temporary reduction of the "water royalty" (i.e. a compensation paid to the communities for the use of water), which accounts for up to 25% of production costs, did not receive majority backing in the consultation phase. Moreover, duties and taxes such as a 'renaturation tax' have been increased or newly introduced through federal legislation, which increases the financial burden for hydropower producers. Lastly, some cantons and communities have refused to renew water concessions and intend to take over electricity production from hydropower from private producers.

These developments in the field of hydropower may have various policy impacts in the future, in particular in the field of trade policy. Internally, it is generally agreed that hydropower shall remain the mainstay of Swiss electricity supply and shall be supported accordingly. However, there is disagreement on which measures suit best, as e.g., the revision of the "water royalty" shows. With regard to the external perspective, it remains open, to what extent Switzerland may keep up with the subsidy race in Europe, as EU Member States have been increasing subsidies for renewable energy sources (in particular, Germany). In order to protect its hydropower producers from low electricity prices in Europe, Switzerland may take trade measures (such as an import tax on electricity produced from fossil energy sources). Moreover, Switzerland may question the consistency of certain EU subsidies for renewable energy sources with international trade agreements by invoking the state aid provision under the Swiss-EU Free Trade Agreement (art. 23), or by submitting a complaint with the World Trade Organization (WTO) against the EU regarding a violation of the Agreement on Subsidies and Countervailing Measures. However, whether Switzerland will use these options depends on political feasibility and opportunity.

Nevertheless, hydropower producers in Switzerland, in particular pumped-storage plants, may also benefit from the increasing electricity production from renewable energy sources in Europe. The restructuring of the electricity supply infrastructure throughout Europe, with increasingly irregular and distributed sources of supply, is leading to a Europe-wide increase of demand for storage. Pumped storage power stations allow spontaneous compensation for over-production or under-production from wind and solar energy sources and, if necessary, permit the temporary storage of electricity for days or weeks. In Switzerland, hydropower producers are able to provide a substantial number of pumped storage power stations. Moreover, a number of pumped storage power stations are under construction as well. Still, the total Swiss storage capacity can only meet a fraction of the Europe-wide demand for storage.

Developments in government policy/strategy/approach

In 2011, the Federal Council and Parliament, triggered by the Fukushima nuclear incident, decided to progressively abandon nuclear electricity production in Switzerland. As nuclear energy provides around 30% of total electricity production, the decision to phase out nuclear electricity production means a complete restructuring of the Swiss energy mix with regard to electricity production. This restructuring process is called the "Energy Strategy 2050". The Energy Strategy 2050 aims at replacing nuclear electricity production with renewable energy sources and will be implemented in phases. An initial package of measures that aim to reduce energy consumption, increase energy efficiency and promote renewable energies such as water, solar, wind and geothermal power, and biomass fuels, has been introduced by the Parliament. In this regard, the Parliament has adopted new legislation, which was endorsed in a referendum on 21 May 2017. The new legislation will be described in more detail below. The further phases have yet to be elaborated, but it is intended to phase out the promotion of renewable energy.

As an essential link between production and consumption, networks are pivotal for electricity supply. Together with the Energy Strategy 2050, the Federal Council developed an "Electricity Grid Strategy". This strategy introduces a new legal framework for grid development. It aims at ensuring that grids are timely developed in order to secure a sufficient energy supply at all times. Measures include e.g. optimisation of approval procedures. The respective legislation was adopted by the Parliament in December 2017 and is expected to enter into force in the second quarter of 2019.

With regard to gas, the Federal Council stated in early 2014 that it will examine the opening of the Swiss gas market. Moreover, the Federal Council intends to present a draft gas supply act within the current legislative period (i.e. 2015–2019) in order to update the existing Federal Act on Pipeline Systems for the Transport of Liquid or Gas Fuel, and to seek compliance with EU standards.

Lastly, Switzerland is interested in participating in the EU energy market, in particular in the electricity market. A mutual free market access would strengthen the position of Swiss electricity producers in the European electricity market and increase the security of supply. The integration of Switzerland into the EU electricity market is also important for a successful implementation of the Energy Strategy 2050. Therefore, Switzerland and the EU started negotiations on an electricity agreement in 2007. In 2010, the negotiations were extended and other energy sources such as gas were included. However, the conclusion of the electricity agreement is uncertain. In order to grant further market access to Switzerland, the EU insists on concluding an institutional agreement, which should establish a general legal framework for Switzerland's participation in the EU common market. However, this agreement is controversial in Switzerland as it requires Switzerland to adopt EU legislation. Therefore, the institutional agreement has not been concluded yet.

Developments in legislation or regulation

In the context of the Energy Strategy 2050, the Federal Energy Act has been completely revised in order to introduce initial measures aimed at implementing the Energy Strategy 2050. The new Energy Act and the required amendments in related legislations were endorsed in a referendum on 21 May 2017. The new Energy Act and the correspondent Ordinances entered into force on 1 January 2018.

The new Energy Act introduces measures to reduce energy consumption, increase energy efficiency and promote renewable energies. Moreover, temporary support is granted to existing large-scale hydropower plants due to their financial pressure.

The new Act sets indicative consumption, production and emissions targets. Compared to 2000, energy consumption *per capita* should diminish by 16% in 2020 and 43% by 2035. With regard to electricity, consumption *per capita* should diminish by 3% in 2020 and by 13% in 2035. On the production side, electricity production from renewable energies other than hydropower should rise from 2,830 GWh in 2015 to 4,400 GWh in 2020, and 11,400 GWh in 2035. Hydropower production should diminish slightly from 39,500 GWh in 2015 to 37,400 GWh in 2035.

The intended increase of electricity production from renewable energies other than hydropower requires state support. In Switzerland, the main instrument for the promotion of electricity production from renewable energy sources is a feed-in tariff (FIT), which was introduced in 2009. The Swiss FIT is available for hydropower with a capacity of up to 10 MW, solar energy, wind energy, geothermal energy as well as energy from biomass and biological waste. It is paid directly to the producers as a fixed remuneration at a cost that covers the difference between the production cost and the market price. This guarantees the producers of electricity from renewable energies a price that covers their production costs. The FIT is financed through a grid surcharge imposed on electricity consumers. The maximum amount of the grid surcharge is defined in the Energy Act. The Federal Council may define the exact amount of the grid surcharge within this maximum amount. In 2018, the grid surcharge amounted to CHF 2.3 cents/kWh, which is the maximum amount as defined in the Energy Act.

The revision of the Energy Act has also led to amendments of the Swiss FIT system. The FIT will be replaced by feed-in premiums. Eligible producers are required to market their electricity themselves. The difference between the market price and the production costs will still be compensated. However, producers are responsible to sell their electricity directly on the market. They should sell their electricity when demand is high, which gives them an incentive to produce electricity when supply is short and prices are high. The feed-in premium system is of limited duration and will only be granted for up to five years after the entry into force of the new Energy Act (i.e. until 2022). The new Energy Act also raises the grid surcharge to CHF 2.3 cent/kWh, which increases the financial resources for the promotion of renewable energies significantly. For electricity consumers, this means an additional financial burden of CHF 40.00 per year based on the consumption of a four-person family household.

For photovoltaic installations, the new Energy Act alternatively provides for an investment aid. The one-time subsidy covers a maximum of 30% of the investment costs of a reference installation. This applies to new hydropower stations with a capacity of more than 10 MW, and significant extensions of existing hydropower stations as well.

Due to the low European wholesale electricity prices and the resulting financial pressure on the existing hydropower plants in Switzerland (as mentioned above), the new Energy Act also provides for support to existing hydropower stations. Existing large-scale hydropower stations (i.e. with a capacity of more than 10 MW) will be able to claim a market premium for electricity, which must be sold for less than the cost of production. The premium is capped to CHF 1.0 cent/kWh and the total available financial resources are limited, as CHF 0.3 cent/kWh of the grid surcharge will be used for this support. This measure is valid for a period of five years.

Judicial decisions, court judgments, results of public enquiries

<u>Costs of system services</u>

In a recent ruling, the Federal Supreme Court stated that power plant operators are not obliged to pay a portion of the costs for the procurement of system services, and declared that the corresponding provision in the Energy Supply Ordinance (SR 734.71) is not applicable. In view of this, in its own ruling dated 4 July 2013, ElCom instructed the Swiss transmission system operator (i.e. Swissgrid) to refund all outstanding payments for system services for 2010 to the involved power plants. In the meantime, all power plants have received a refund of the amounts paid for system services in 2009 and 2010. Some power plant operators also claimed late payment compensation, and ElCom ruled that Swissgrid has to pay them 5% interest with effect from the date of the reminder.

In two other rulings, the Federal Administrative Court stated that the balance groups to which the Gösgen and Leibstadt nuclear power plants are allocated may not be billed for the costs arising in association with the retention of positive tertiary reserve capacity, and it thus repealed the corresponding order issued by ElCom in 2010. As a consequence of this, ElCom reassessed another, similar case. In accordance with another ruling by the Federal Administrative Court, owners of a cross-border connecting line cannot be billed for costs associated with idle energy. The Court did not rule on the question of whether a sufficient legal basis exists for billing individual system services to parties that are not end consumers.

Ownership unbundling

As of January 2015, the majority of the transmission system grid was sold to Swissgrid. Swissgrid has taken over additional transmission system grid facilities per January 2016. Prior to the transmission network transaction, ElCom had specified the method of valuation of the facilities to be transferred. The associated ruling of September 2012 stipulated that the valuation of the various transmission network components was to be based on the regulatory criteria which are applicable for pricing in the electricity supply legislation. This would have amounted to a value of around CHF 2bn. Various companies lodged appeals against this ruling, so at the end of 2013 the Federal Administrative Court upheld these appeals and referred the matter back to ElCom for reconsideration. At the same time, it specified a variety of criteria regarding the valuation method to be applied.

In August 2013, ElCom also ruled that stub lines (with and without supply character) that are operated at the 220/380 kV level belong to the transmission network and have to be transferred to the ownership of Swissgrid. This ruling has become legally binding. This means that uniform criteria are applicable throughout the country with respect to the allocation of stub lines to the transmission network, which now encompasses all lines and installations at the 220/380 kV level.

Right of appeal by end consumers

Tariff audit proceedings may be opened on the basis of a report, or by ElCom in its capacity as regulator. In two rulings, the Federal Administrative Court found that ElCom was not authorised to rule in a specific case upon petition of end consumers regarding tariffs. While an end consumer is entitled to lodge a complaint with ElCom, it is ElCom which has to open proceedings in its capacity as regulator. As complainant, an end consumer does not have the rights of a party in the proceedings. The Federal Administrative Court subsequently qualified this ruling in a decision in which it noted, somewhat vaguely, that this restrictive description of the authority of ElCom was not binding. Thus the authority of ElCom and the status of end consumers in such proceedings will have to be defined more specifically in future rulings.

Water royalty

In May 2018, the Federal Council submitted its dispatch regarding its proposal on the revision of the Federal Act on the use of hydraulic power to the Parliament. The original proposal of the Federal Council to reduce the maximum amount of the water royalty, and to introduce a more flexible model, did not receive majority backing during the consultation phase. Therefore, the Federal Council proposes to maintain the current system including the maximum amount of the water royalty. In order to support the hydropower electricity producers, the Federal Council further proposes to exempt new or substantially modified hydropower plants from the water royalty during 10 years. The draft legislation is now the subject of parliamentary debate. It is intended that the new legislation should enter into force in 2020.

Major events or developments

Currently, only industrial consumers with consumption of over 100,000 kWh a year may choose their electricity provider freely. A full liberalisation of the electricity market was planned for January 2018. However, following a public consultation, on 4 May 2016 the Federal Council decided to suspend indefinitely the full liberalisation of the electricity market. The Federal Council indicated that full liberalisation will depend on the following factors:

- conclusion of negotiations regarding an electricity agreement with the EU;
- progress achieved by the Energy Strategy 2050;
- prevailing market conditions; and
- revision of the Federal Electricity Supply Act.

On 16 August 2017, Switzerland and the EU took a step forward in linking the Swiss and European emissions trading system. Both parties agreed to sign a linking agreement, which has already been technically finalised one year ago and was on hold during the implementation of the "Stop Mass Immigration" in Switzerland. The agreement was signed in November 2017, and has to be ratified by the Swiss and European Parliaments. In this regard, the Federal Council submitted its dispatch on the approval of the agreement and the necessary partial revision of the CO_2 Act, to the Parliament in December 2017. The draft legislation is currently the subject of parliamentary debate. The linkage of both emissions trading systems enables Swiss companies to access a bigger and more liquid market and to benefit from same competition conditions. In compliance with the EU, Switzerland will also include emissions generated by aviation in its system upon entry into force of the agreement.

Proposals for changes in laws or regulations

In February 2014, the Swiss Federal Office of Energy (SFOE) resumed work on revising the Energy Supply Act which was suspended in 2011. The aim of the revision is to coordinate the Energy Supply Act and the Energy Strategy 2050, to close existing gaps in legislation and to examine new regulations for conformity with the changing industry conditions. The revision has no effect on the full liberalisation of the electricity market as a separate schedule has been established for this matter (see above).

Moreover, planning works with regard to legislation for the further implementation phases of the Energy Strategy 2050 are currently in progress.

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Turkey

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Overview of the current energy mix, and the place in the market of different energy sources

The energy sector is one of the most promising and developing sectors in the Turkish economy. Turkey has become one of the fastest-growing energy markets in the world, in parallel with its economic growth recorded over the last 10 years. The Turkish energy market has become a competitive market structure by attracting private sector investments. The energy market is in a rapid growth and liberalisation process with privatisation, licensing deals and strategic alliances in the market. This privatisation programme has given the country's energy sector a highly competitive structure and new horizons for growth.

As per the Ministry of Energy and Natural Resources ("**Ministry**") data, according to energy sources, the number of existing plants in Turkey is as follows:

- 613 hydraulic;
- 40 coal;
- 186 wind;
- 33 geothermal;
- 288 natural gas;
- 1,773 solar; and
- 165 other power plants.

<u>Electricity</u>

Electricity production in Turkey is realised with liquid fuels such as natural gas, hydroelectric, coal and lignite, imported coal, wind, motor and fuel oil, geothermal, biogas and solar energy according to the production share. Turkey produces its electricity mainly from thermal sources (coal, natural gas and other sources). One quarter of the generated electricity of Turkey comes from hydraulic sources and only 8% from renewable sources. According to government reports, electricity consumption is expected to rise by 5.5% to 357.4 TWh by the year 2023. By the end of July 2017, power plants representing a total of 2,049 MW additional capacity were added to the system, and as of the end of February 2018, capacity had risen to around 86,114.9 MW.

In July 2017, 34% of Turkish electricity production was obtained from natural gas; 31% from coal; 24% from hydropower; 6% from wind; 2% from geothermal; and 3% from other sources. In terms of ownership, as at the end of July 2017, EUAS (State Electricity Generating Company) had a share of 25.1% in installed capacity of Turkey; 61.5% was provided by the private sector; 7.6% was of a build-operate model; 1.7% of a build-operate-transfer model; and 2% of power plants were unlicensed.

By the end of July 2017, the distribution of installed power by resources was as follows: 33.6% hydraulic; 28.1% natural gas; 21.5% coal; 7.7% wind; 1.1% geothermal; and 7.4% other sources. According to data from the Turkish Electricity Transmission Corporation (TEİAŞ), as of the end of July 2017, the number of electricity energy production plants in Turkey was 3,098.

As of the end of 2017, figures for licensed and unlicensed installed power, peak demand, licensed and unlicensed electricity generation, consumption, import and export are shown below, together with the values of recent years.

Licensed and Unlicensed Installed Power, Peak Demand, Licensed and Unlicensed Electricity Generation, Consumption, Import and Export Data

	Unit	2014	2015	2016	Change (%) 2015→2016	2017	Change (%) 2016→2017
Licensed Installed Power	MW	69,520	73,146.90	77,563.44	6.04	81,563.32	5.16
Unlicensed Installed Power	MW	29.99	359.04	1,048.21	191.95	3,173.32	202.74
Peak Demand	MW	41,003	43,289.00	44,733.98	3.34	47,659.65	6.54
Licensed Generation	GWh	251,962	261,783.30	272,563.63	4.12	292,574.58	7.34
Unlicensed Generation	GWh	3,92	222,72	1.137,87	410.89	3.031,56	166.42
Consumption	GWh	257,220	265,724.40	277,522.01	4.44	292,003.54	5.22
Import	GWh	7,953	7,411.10	6,400.13	-13.64	2,729.06	-57.36
Export	GWh	2,696	2,964.60	1,442.08	-51.36	3,300.10	128.84

As seen in the table, consumption and licensed production in 2017 increased by 5.24% and 7.34%, respectively compared to 2016, while peak demand and licensed capacity increased by 6.54% and 5.16%, respectively. Unlicensed installed power and production values increased by 202.74% and 166.42%, respectively.

Solar energy

The total established solar collector area within Turkey as of 2017 was calculated as being close to 20,000,000m². As of the end of 2017, there were 3,616 solar power plants with a total installed capacity of 3,421 MW. This is the equivalent of 4% of total potential. In 2017, electricity production based on solar energy realised 2,684 GWh, and 0.91% of our electricity production was obtained from solar energy.

Wind energy

The land surface area of Turkey is nearly 800,000 km². There are many investments both in Turkey and the rest of the world, with increasing scales of wind energy, which is one of the most important renewable energy sources. The installed power of licensed wind power plants in Turkey was 6,353 MW by the end of October 2017. Turkey has 48,000 MW of wind energy potential and the total area corresponding to this potential is equivalent to 1.3% of Turkey's surface. These ratios represent a very advantageous geography for the efficient use of wind energy.

Geothermal energy

Turkey has approximately 1,000 geothermal springs that are located all over the country and have various temperatures. As of the end of 2017, there were 40 geothermal power plants with a total installed capacity of 1,064 MW. In 2017, electricity production based on geothermal energy realised 5,970 GWh and 2.02% of our electricity production was obtained from geothermal energy.

Natural gas

The import ratio of Turkey's natural gas, which is one of its most important sources of electricity production, is 99%. In natural gas, which seriously affects the dependency ratio of energy imports, 80 trillion cubic metres (43%) of total reserves are located in the Middle East; 54 trillion cubic metres (29%) of total reserves are located in the countries of Russia and the Commonwealth of Independent States; and 30 trillion cubic metres (16%) of total reserves are located in Africa/Asia-Pacific countries.

When we analyse the first nine months of 2017 in terms of imports, production, exports and consumption figures, it can be seen that the import ratio has increased by 20.33%. Consumption values increased by 17.67%, while the production rate decreased to 3.8% and export rate to 9.6%.

As per the data of the end of October 2017, installed electricity power provided by natural gas was 23,259 MW and 28.3%. In this context, installed power for electricity generation by natural gas does not show any significant difference compared to last year; due to climate and precipitation conditions, the share of electricity production increased significantly in the last months of the year.

Natural gas generation for the years 2008–2017 (million cm^3)

Years	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Quantity	969	684	682	759	632	537	479	381	367	354

Hydraulic energy

With a share of 34% in electricity generation, hydroelectric power plants are important because it is an environmentally friendly, clean, renewable, high-efficiency, non-fuel-expense, long-lasting, domestic source of energy with low operating costs, which is not outsourced. The hydroelectric potential of our country is 1% of the world's total and 16% of Europe's total. However, the fact that hydroelectric power plants are a production method depending on meteorological conditions may sometimes cause problems. For example, the production of electricity obtained from hydropower plants throughout Turkey in October 2017 amounted to only 2,350 GWh due to low occupancy rates of barrages. By the end of October 2017, the share of total hydroelectric energy from streamed and barraged power plants in electricity production was 33%.

The Turkish government plans to increase the share of renewable sources in Turkey's total installed power to 30% by 2023. Turkey's targets for 2023 include:

- 34,000 MW capacity of hydro power plants;
- 20,000 MW capacity of wind power plants;
- minimum 5,000 MW of solar power plants;
- minimum 1,000 MWe geothermal energy; and
- 1,000 MWe installed capacity for biomass energy.

According to Ministry data, the power capacity of the energy sources of coal, natural gas and hydraulic do not change much over time. Installed power capacities of other thermal energy sources decreased about 5% from 2002 to 2017 in Turkey. Renewable energy sources such as wind, geothermal and solar energy appear in the installed power capacity list of Turkey, their contributions ranging from 0% to about 8%, 1%, and 2%, respectively over the years. Turkey's electricity power facilities are highly dependent on thermal energy, which increases Turkey's imports and environmental hazards. As for renewable energy sources that constitute our main subject, wind energy features rather far ahead of solar and geothermal. The total share of renewable sources is about 11%. The share of solar installed power capacity shows that it has made a great advance in recent years.

Hereby, it can be briefly concluded that renewable energy has been more popular in Turkey since 2005: the share of renewable energy in total electricity generation was 8% then (corresponding to slightly over 21,000 GWh), while it was over 9% (corresponding to about 7,400 MW) for installed power capacity in 2016. Added to that, wind energy from available renewables in Turkey has shown a significant increase. Wind accounted for about 74% of the total renewables-based installed power capacity of Turkey as of July 2017. Solar and geothermal-based installed power capacities account for the remaining 26%, with shares of about 16% and 10%, respectively.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Due to the importance of the energy sector, the Turkish Government continues to study the development of Turkey's energy market very intensively. As per the Government's declaration in the context of recent active energy politics, there will be activities not only in the direction of deep-sea drilling, but also in land exploration. As a step in this process and for the first time in Turkey, the Government has initiated seismic investigation in an area 3.5 kilometres from the Iraq border. Through these detailed onshore studies, it is aimed to take a solid step by investigating energy sources located within the boundaries of Turkey.

As well as this, Turkey's first integrated solar panel production factory is planned to be founded in an Organised Industrial Zone in Ankara. Within this scope, it is aimed to start panel production at the end of 2018. Through this project, Turkey aims to be the production centre for renewable energy technologies.

The Turkish Government has very positive expectations of both deep-sea and onshore projects. To reach a successful result on both will greatly influence Turkey's energy market, and its economy as well.

The national energy and mining policy of the Ministry of Energy and Natural Resources was clearly stated in the context of all energy actions in 2017. The policies put into practice by the Government under the banner of 'Domestic YEKA' comprise six main objectives:

- Through YEKA projects, it will be possible to increase the share of domestic and renewable resources in electricity generation which protect nature. Local staff will specialise in terms of technical staff.
- Domestic production will be accelerated. The share of domestic production in electricity, in both solar energy and wind power plants, will be increased rapidly. Significant increases will be made in the production levels of renewable energy plants.
- With the reduction of external dependency, current production crises can be avoided with domestic production. There is a large share of energy in the current account

deficit. One of the most important goals of domestic and national energy is to reduce the current deficit.

- Serious work is being done on unit costs, which affect the consumer in every case. In the new period, new strategies will be carried out to reduce these costs.
- The state will accelerate its efforts to provide all kinds of support for domestic energy sources. Products to be produced for two years by the solar panel and wind turbine production facilities will be acquired by the YEKA facilities.

In addition to YEKA, the number of power plants under the Renewable Energy Resources Support Mechanism ("**YEKDEM**") continues to increase. Installed electric power within the scope of YEKDEM reached 17,400 MW for the year 2017. This increase is due to the addition of 91 new plants to the list. Within the scope of YEKDEM, the number of power plants that sell electricity at a fixed price based on exchange rates increased to 647 in 2017.

Developments in government policy/strategy/approach

Turkey has become one of the fastest-growing energy markets in the world, paralleling its economic growth over the last 15 years. Turkey's energy sector has become the focus of attention within its geographic zone. In the last 15 years, a lot of radical energy reforms have been made by the Turkish Government.

The energy market of Turkey has been liberalised by the Government within an open, transparent and sustainable regulatory environment. The privatisation of energy generation assets, coupled with a strategy to clear the way for more private investment, has resulted in an increased share of private entities in the electricity generation sector, which have risen from 32% in 2002 to 75% at the end of 2017. A Directorate of Privatisation Administration of Turkey has been assigned in the context of privatisation of the energy market.

The two important developments of the last 12 months in terms of the energy markets in Turkey have been: the decision of the Organization of Petroleum Exporting Countries ("**OPEC**") to extend the term of the Petroleum Production Limit Agreement, speeding up renewable energy investments within the scope of combating climate change by many countries; and Russia's approval of the "TürkAkımı" Natural Gas Pipeline Project.

As is well known, it is necessary to discuss energy efficiency policies sensitively, because of their direct relation with the sustainability of economic growth and social development objectives, and their key role in reducing total greenhouse gas emissions. Through the energy efficiency studies carried out under the leadership of the Ministry of Energy and Natural Resources of Republic of Turkey, the objective is to reduce the energy density of Turkey (energy consumed per national income) by 20% in 2023 *vis-a-vis* 2011.

The following actions are carried out by the General Directorate of Renewable Energy within the scope of Energy Efficiency Law and related Regulations, which aim at increasing the efficiency of energy sources and the use of energy by aiming to contribute to the protection of the environment:

(i) Energy manager trainings, study project trainings and international trainings.

(ii) Studies (industrial facilities, commercial and service buildings, public buildings, dwellings).

(iii) Authorisations (Energy Efficiency Consultancy Companies, Universities and Trade Associations).

(iv) Measurement, Monitoring and Evaluation, Auditing.

(v) Energy Efficiency Support (Productivity Enhancement Project (“**PEP**”) and Voluntary Agreements).

(vi) Promotion and awareness-raising.

(vii) Energy Efficiency Forum and Fair.

(viii) “Development of National and International Projects”.

(ix) Planning and Coordination of Activities related to productivity.

(x) Efficiency and Greenhouse Gas Release and Monitoring Activities and Training Activities.

Within a progressed economy and the increased population of Turkey, privatisations, support and incentives provided in the energy sector, and action on reducing foreign dependency, are extremely important. In this context, the Turkish Government’s approaches work to provide opportunities, and the projects targeted within the 2015–2019 Strategic Plan constitute a positive effect.

Developments in legislation or regulation

Energy Law is a field of law that could be developed within the framework of the search for renewable methods, even if it has some limitations based on international law in terms of exhausted resources, despite increasing daily energy needs.

While in the past, energy production was carried out by the public companies in a monopoly system, now, with new regulations like the Law on the Energy Market Regulatory Authority’s Organisation and Duties No. 4628 and Natural Gas Market Law No. 4646, which entered into force as of the beginning of the 21st century, the Energy Law resources, and electricity and natural gas production, operated more freely. In total, the energy sector in our country has four basic aspects in the form of the electricity market, oil market, natural gas market and LPG market.

Energy Efficiency Law No. 5627, enacted on 2nd May 2007, aims at the efficient use of energy, the prevention of waste, the reduction of energy costs in the economy, the enhancement of the efficiency of energy sources and the use of energy to protect the environment. This law sets the rules for energy management in industry and in big buildings, project support, energy efficiency consultancy companies, voluntary agreements and so on. The last amendment to this Law made on 21st March 2018 includes the regulations regarding the Energy Performance Agreement, which means an agreement based on guaranteeing the energy savings to be provided after the application project and the payment of the expenditures made as a result of the application. As per the Law, public administrations and other public institutions within the scope of general government may sign energy performance agreements to reduce their energy consumption or energy costs, that enter into widespread use for periods not exceeding 15 years.

Also, Law No. 5346 on Utilization of Renewable Energy Resources for the Purpose of Generating Electrical Energy is the main legislation on electricity from renewable energy resources, enacted on 18th May 2005. The aim of the Law is to expand the use of renewable energy sources for generating electrical energy by establishing the necessary legal and regulatory framework while ensuring an increase in the use of renewable energy sources without disturbing free market conditions. According to this Law, companies wishing to become involved in renewable energy projects may obtain a licence from the Energy Market Regulatory Authority (“**EMRA**”) to generate electricity from renewable sources.

In addition to this, Law No. 5686 on Geothermal Resources and Natural Mineral Waters regarding electricity generation was enacted on 3rd June 2007. This Law sets forth the rules and principles for exploring, producing and protecting geothermal and natural mineral water resources.

Moreover, new regulations are being drawn up by the Government regarding nuclear energy; the latest one is the Regulations Regarding Operating Organisation Personnel Qualifications and Training and Operating Personnel Licences No. 30029, published in the Official Gazette on 5th April 2017. In this Regulation, it is aimed to train qualified personnel to work in nuclear energy facilities. As is known, nuclear energy is not only an effective source of electricity, but also a very dangerous energy source. For this reason, the nuclear power plants must pass all safety precautions and be continuously checked. The Regulation on the Construction Supervision of Nuclear Power Plants and Regulation on Radiation Protection in Nuclear Plants have been organised for this purpose. The occurrence of a potential problem in nuclear power plants can have major and dangerous consequences. The necessary arrangements have been made against these possible hazards, and they continue to be done. In order to protect from radiation of nuclear plants and/or to be less exposed to radiation, the Regulation regarding Nuclear Facilities Radiation Protection was enacted to cover aspects such as site evaluation, design, construction, operation, removal from operation and regulatory control of the nuclear facilities, and the protection of employees and people from the harmful effects of ionising radiation in emergency situations.

Electrical energy is widely subject to legal regulation in Turkey. Consumers receive their electrical energy through intermediary companies. The intermediary companies are required to have a distribution licence and are controlled by the Government in all of their activities. In this respect, Law No. 6446 aims to establish a financially strong, stable and transparent electrical energy market operating in accordance with the provisions of private law in a competitive environment, and to provide independent regulation and supervision in this market in order to provide consumers with sufficient, high-quality, continuous, low-cost electricity.

There is also the Regulation on the Electricity Market Capacity Mechanism No. 30307 published in the Official Gazette on 20th January 2018. This Regulation aims to establish rules on the capacity mechanism to be operated by TEİAŞ in order to secure sufficient installed capacity and/or long-term system security, including the reserve capacity required for security of supply in the electricity market.

In addition to this, there is a new Regulation on Electricity Market Consumer Services published in the Official Gazette on 30th May 2018. This Regulation aims to determine minimum standards, procedures and principles on the basis of operations and transactions between consumers, suppliers and/or distribution companies in the supply of electricity and/or capacity sales and related services to consumers within the scope of free, non-free and final source procurement.

Judicial decisions, court judgments, results of public enquiries

Energy law is a legal branch that can be subject to disputes within the context of both private law and public law.

By reason of the fact that energy law is rapidly developing, the field and the energy market are very important in both the manufacturing sector and the business sector; disputes subject to legislation are increasing. The most frequently encountered disputes within the scope of Energy Law are related to thermal power plants, tariffs set for energy resources, and projects for expropriation.

Before making mention of court judgments and judicial decisions concerning Energy Law, it is crucial to state that a new institution called the Energy Law Research Institute Dispute Mediation Center was established to solve energy disputes before the court stage in Turkey. It operates with the aim of resolving disputes in the energy sector faster and with lower costs by the arbitrators who serve the energy sector and Energy Law.

Recently, one of the most important decisions in the context of energy activities within the boundaries of Turkey is the Constitutional Court of Republic of Turkey decision regarding the Ilısu Dam and hydroelectric power plant ("**HEPP**"). According to the decision of the Constitutional Court, it was decided that the Ilısu Dam and the HEPP project planned to be built in the district of Hasankeyf within the boundaries of Batman province, was not contrary to the Constitution, and the claim of contradiction to the Constitution was rejected. According to the justification of the Constitutional Court decision; whether the determined district center (Hasankeyf) and municipal boundaries are in accordance with local requirements, and whether it fulfils the public interest, are in the discretion of the legislator.

One of the recent judicial events reflected in the energy market is the demand made by the Republican People's Party ("**CHP**") regarding the cancellation and suspension of the Akkuyu nuclear power plant project between Russia and Turkey. The Constitutional Court rejected the demand regarding the cancellation and suspension of enforcement of the agreement that Turkey and Russia had signed on the establishment of the plant. The Constitutional Court declared that the justice of international agreements could only be controlled in their form, and that the content of the agreement could not be controlled by the Constitutional Court.

Consequently, it is important to remember that judicial decisions on energy projects are crucial for investors who plan to invest in the future, because of their precedent decision character.

Major events or developments

In Turkey, some activities are carried out in order to supply rising oil and gas demand by domestic sources. In this context, work in the marine areas of the Black Sea and the Mediterranean has gained momentum. In recent years, the structure of hydrocarbons exploration in our seas has been rapidly established along with developments in marine drilling technology, exploration and production opportunities in high (1,000–2,000m) water-depth areas.

In 2018, we have seen a new milestone in Turkey's energy history. Hitherto, the marine drilling programme, which started in the 1970s, has not been realised due to the lack of domestic equipment and human resources. In 2018, for the first time, the ship named "Fatih" came from the port of Hoylandsbygda on the southern coast of Norway to Kocaeli province, and was sent to the Mediterranean after preparations were completed. "Ship Fatih" carried out the first drilling of Antalya openings at 2,600m depth in the summer of 2018, so that a very important step was taken in the oil sector in Turkey.

At the same time, by the investment and leadership of the Azerbaijan Republic State Petroleum Company ("**SOCAR**") and as one of the largest oil and gas operations in Europe, the Middle East and Africa ("**EMEA**"), Turkey's first strategic investment-incentive-certificated private sector project, "**Star Refinery**" is to be commissioned in September 2018, and scheduled to begin formal and actual production in 2018.

Through the Star Refinery Project, which has an annual crude oil processing capacity of 10,000,000 (ten million) tons, it is aimed to produce distillate fuels, which are experiencing a shortage of supply in the domestic market, by the production of petroleum products such as diesel, jet fuel and LPG at Aliaga-İzmir Province within the framework of petrochemical feedstock, where Turkey is dependent on foreign imports.

Star Refinery, which will implement refinery-petrochemical integration as the largest private sector investment in a single location in Turkey, is strategically important not only for the energy sector but also for employment: within the scope of the project, 3,000 (three thousand) engineers from 14 countries; a total of 17,000 people will be employed.

At Turkey's first Energy and Mining Forum held in 2018; it was announced that the largest offshore (sea) project in the world is being prepared in wind energy. The tender of the project is planned to be realised within 2018.

As is widely known, Turkey has rich reserves of boron, and it completed the year of 2017 with export and production at record levels. In this context, it is planned to establish a team consisting of people who have worked in the most competent positions in the world to develop the ground-breaking process at boron facilities with strategic importance in 2018.

One of the most important projects for Turkey – the Trans-Anatolian Natural Gas Pipeline Project ("**TANAP**") – has been 99.9% completed by 2018; the Phase 1 section that will go to Europe, has been realised by 80.7%. A total of 93.5% of the project has been completed. Due to these developments, the first commercial gas flow to Turkey via the pipeline was set to commence in June 2018.

It is important to note that Turkey is substantially increasing investment in the energy sector and as a result, continuing to develop its regional position and the bilateral agreements to which it is a party, by reducing its external affinity and strengthening its commercial and strategic contacts with companies around the world.

Proposals for changes in laws or regulations

Turkey has great potential in terms of both heat generation and electricity production from renewable energy sources such as solar, wind, hydroelectric, geothermal, biomass and wave, although it will be necessary to update the legislation in order for this potential to pass through in full. There is significant demand-management potential in the industry to reduce peak demand in electricity, but also a need to improve legislation and the market structure.

Even if legislation and incentives exist in the field of efficiency, the target effect has not been fully achieved yet. In this respect, legislative development is foreseen by the Government.

The Ministry has developed a strategic plan for 2015–2019 for the energy market. This plan is founded on the themes of the current needs of the energy sector, expectations for the future and the policy development required in the field of natural resources. The Ministry's 2015–2019 Updated Strategic Plan consists in total of eight themes, 16 objects and 61 purposes.

In the field of energy and natural resources:

- good governance and stakeholder interaction;
- regional and international activity;
- technology, R&D and innovation; and
- improving the investment climate,

are discussed.

Additionally, in the energy sector:

- security of supply; and
- energy efficiency and saving;

and in the natural resources sector:

- efficient use of raw materials; and
- security of raw materials supply,

are constituted in the framework of the plan.

The establishment of energy-storage systems, and the establishment of the legislative infrastructure for the integration of energy-storage systems into the network, are in the scope of the Ministry's plan. The other purpose is the completion of nuclear energy legislation infrastructure. Also, a project-supervision structure in mines should be observed and the necessary legislative infrastructure should be established to ensure that the project audit is conducted in the most rational and result-oriented manner.

However, all the developments in the Turkish renewable energy sector may be considered too insufficient to be able to achieve the renewable energy targets in 2023 (30% of total energy production). In the coming years, Turkey will give more importance to the utilisation of its renewable energy resources with the assistance of useful laws and amendments as well as major incentives to remove any outstanding barriers to renewable energy investments.

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In 2011, he worked in the General Directorate of Al Baraka Türk Bank as Legal Counsel and between 2012–2014 he worked as Legal Counsel in the State Oil Company of Azerbaijan Republic in Turkey. He contributed to the legal processes of highly significant major projects in the energy field for today's Turkey, such as Star Refinery, the Trans-Anatolian Natural Gas Pipeline, wind power plant projects and thermal power plant projects.

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Ukraine

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Overview of the current energy mix, and the place in the market of different energy sources

The key factor that has always been critical when it comes to Ukrainian energy matters is the country's goal to achieve energy independence and sustainability. This factor has also been affecting the energy companies, be they state-owned or privately owned companies.

Domestically produced energy

Compared to many other countries in Europe, Ukraine can certainly be considered rich in energy resources. The country is a major producer of electricity, as well as possessing significant deposits of carbons and coal. However, when it comes to the latter, Ukraine's coal resources, and control over them, have been seriously affected by the military conflict in the Eastern part of the country.

Nuclear power accounts for the largest share of Ukraine's electricity generation, even though its share is decreasing compared to past years. As of March 2018, the share of nuclear power generation was 49.4%, versus 55.4% in the same period of 2017.

Despite the fact that all nuclear power consumed in Ukraine is generated at four Ukrainian nuclear power stations (operating a total of 15 nuclear reactors), it should be noted that Ukraine's nuclear power industry is fully dependent on imported nuclear fuel. Presently, approximately 56% of nuclear fuel is supplied by the Russian TVEL company, whereas 44% of nuclear fuel is supplied by Westinghouse. However, in the not-so-distant past, all nuclear fuel was supplied by Russian TVEL. Thus, by involving Westinghouse, the Government of Ukraine is trying to diversify nuclear fuel supplies.

The next-largest producers of electricity are the conventional coal, gas and fuel oil power plants. They generate approximately 39% of electricity. While coal power plants traditionally use mainly Ukrainian-produced coal, due to the difficulties with the sourcing of coal from the territories affected by the military conflict, Ukraine has increased imports of coal from abroad, including from South Africa, United States, Poland and Russia.

Approximately 9% of electricity is generated by hydro power plants. In addition to the hydro power plants that had been constructed and put in operation during the Soviet era (mainly on the Dnipro river), some new hydro power plants are being constructed on smaller rivers, especially on the Dniester river.

Finally, as to renewable sources of energy such as wind, solar and biomass, generation of electricity from these sources has been increasing and is presently approaching 2% of all electricity produced in Ukraine.

As to the other sources of energy, these include mainly natural gas and oil. In 2017, Ukrainian state-owned and privately owned companies produced 20.5 bcm. of natural gas. This is 2% more than in 2016. As to oil, in 2017 Ukraine produced approximately 2.1 million tons of oil, which is 4.2% less than in 2016.

Imported energy

Oil, gas and now coal are the main types of energy resources imported into Ukraine. Although Ukraine used to import no or almost no coal, in 2017 Ukraine imported approximately 20 million tons of coal, spending almost US$ 2.8 billion on this.

As to natural gas, while until 2014 Gazprom was the main supplier of natural gas into Ukraine, since 2016 Ukraine has ceased to purchase natural gas from Gazprom. Presently, gas traders mainly from the EU countries are the suppliers of natural gas to Ukraine. Over 14 bcm of natural gas was imported into Ukraine in 2017.

Ukraine is a major importer of oil: in 2017, over US$ 440 million was spent on importing oil into the country. The main suppliers of oil into Ukraine are Azerbaijan – 85%, Iran – 8.5%, and Kazakhstan – 4% of supplied oil.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Liberalisation of the natural gas supply market

Ukraine's unprecedented liberalisation of the country's natural gas supply market has resulted not only in diversification of the gas supplied to Ukraine (the action critically needed, considering the state of affairs with Russia and Gazprom), but also in high competitiveness of the market.

Major international gas traders, including RWE, Engie, UNIPER, MET, SOCAR, Trafigura, Vitol and CEZ are among the leading suppliers of gas into the Ukrainian market. Ukraine's state-owned company Naftogaz is a major purchaser of imported natural gas.

In addition to international gas traders, Ukrainian gas traders, some of them belonging to Ukrainian industrial groups such as DTEK, have also started importing gas in the Ukrainian market and supplying it to various customers in Ukraine. Such traders include among others ERU Trading, Promenergo-Resource, Naftogaz Trading Europe, and DTEK.

Diversification of the coal supply

Ukrainian power plants and much of the steel industry are still very much dependent on coal. There has been a constant decrease in domestic production of coal in the first six months of 2018. Depending on the type of the coal, the decrease ranges from 8.7% to 10.4%. Due to this, import of coal has increased significantly: by over 50%.

While Russia remains the major supplier of coal and anthracite to Ukraine, with its share of the imported coal reaching up to 64%, Ukraine has started importing coal from the United States. In the first half of 2018, the share of the coal imported from the US reached 28% of imported coal. Not only has this helped to diversify coal supplies to Ukraine, which is considered to be an issue of the national security, but also it has favourably affected overall Ukraine-US trade relations.

It is expected that at least until the conflict in the eastern Ukraine is resolved, Ukraine will continue importing coal, and will be trying to diversify coal supplies, so that dependency on Russian imported coal will decrease.

Increase of renewable energy generation

As both Ukrainian and international energy companies are rushing to implement renewable energy projects so that they may qualify for exceptionally high and Euro-linked tariffs, 2018 has seen a number of large projects launched in this area.

DTEK has raised US$ 90 million debt financing to start developing its 100 MW wind energy project in Zaporizhia region in South-Eastern Ukraine. Norwegian NBT has committed to invest up to US$ 400 million in order to develop an up-to-330 MW wind project in Kherson region in Southern Ukraine.

As to the solar energy, the initiative of the Government of Ukraine to attract solar energy developers into the so-called Chernobyl zone may result in construction of the largest solar park in Europe. Not only the large amount of wasteland, which cannot be used for any other purposes, but also the available grid infrastructure of the Chernobyl nuclear power plant (where operations had been shut down) has attracted interest from over a dozen investors from the EU, Canada and China.

Developments in government policy/strategy/approach

Oil and gas, coal

Unbundling of Ukraine's gas transportation system

It is a requirement of Ukrainian law, as well as an obligation of the country under its commitments under the Energy Community Treaty, that the unbundling of Ukraine's gas transportation system ("GTS") should be conducted. Currently the gas transportation assets and the business are controlled by the Ukrainian state-owned company, Naftogaz. As a result of implementation of the unbundling, these assets and business are to be transferred to an independent company (which will not be part of the Naftogaz group of companies), and this company will then act as the GTS operator ("GTS Operator").

Once the unbundling is implemented, the path for attracting a so-called GTS Partner will be open. GTS operators from the EU or the US may qualify as potential GTS Partners for the Ukrainian GTS. Under the law, the Government may offer up to 49% of shares in the GTS Operator to a GTS Partner. Importantly, the assets of the GTS, despite being transferred into asset management of the GTS Partner, will remain in state ownership, and for the moment cannot become the subject of privatisation.

Successful implementation of the GTS unbundling and attracting of a GTS Partner is important from the point of view of agreeing a new gas transit contract with Gazprom. The currently existing gas transit contract between Naftogaz and Gazprom expires at the end of 2019, and considering the political situation between Ukraine and Russia as well as disputes and arbitrations involving Naftogaz and Gazprom, an independent GTS Operator which will include a GTS Partner from outwith the EU is considered to be better placed to successfully negotiate a new gas transit contract with Gazprom.

On 24 July 2018, Naftogaz and Public Joint Stock Company Mahistralni Gazoprovody Ukrainy (MGU, the future transmission system operator (TSO)) signed a Memorandum of Understanding regarding the GTS unbundling. In the Memorandum, the parties recognise that due to the outcome of the Stockholm arbitration with Gazprom, and Gazprom's unwillingness to amend the existing gas transit contract, substantial risks may arise under the existing Gazprom–Naftogaz transit contract if Naftogaz were to lose control over the gas transportation system without Gazprom's consent. This circumstance may defer complete unbundling to 1 January 2020. Naftogaz and MGU undertook to work collaboratively in order to make the unbundling happen on time.

Oil and gas production licensing streamlined

Complicated licensing procedures and corruption have largely kept foreign companies out of Ukraine's gas fields. But facing a potential cut-off of Russian gas in two years due to the contemplated construction of Nord Stream 2 (the pipeline under the Baltic Sea that will supply Russian gas direct to Germany), Kyiv has moved to cut red tape and adopt transparent rules for auctions on oil-and-gas field licences (special permits for subsoil use).

The procedure for obtaining special permits for subsoil use was streamlined significantly in April 2018, with waiting times halved and the auction procedure itself made more transparent. The State Service on Geology and Subsoils of Ukraine plans to auction off around 40 special permits for subsoil use of oil and gas fields in 2018. Many of these fields are in the Black Sea and Azov Sea shelves. The first auction this year is scheduled to take place on 25 October 2018.

Gas imports

Ukraine has not been importing gas from Russia since November 2015. Gas has been imported from other countries instead (Poland, Slovakia, etc.). Between January and July of 2018, Ukraine reduced gas imports by 31.5%, to 5.578 bcm of gas. The current policy of the government is aimed at reducing gas imports to a minimum, and fostering domestic gas production instead.

The Prime Minister of Ukraine, Mr. Groysman, stated in July 2018 that the country's aim is to cease the importation of natural gas in the near future. Mr. Groysman referred to more than 40 oil and gas fields holding around 150 bcm of gas as the source of future domestic gas supplies. The government plans to auction off special permits for these fields in 2018. Its expectation is that gas supplies from these fields should be enough to cover all domestic needs for natural gas.

Environmental impact

National Plan for Emissions Reduction

On 8 November 2017, the Government of Ukraine approved the National Plan for the Reduction of Emissions from Big Combustion Plants (the "Plan") and provided that the Ministry of Energy shall supervise its implementation. The Plan was adopted to allow Ukraine additional time to modify its big combustion plants (installations) commissioned before 1 July 1992 and with a rated output of at least 50 MW, so that their emissions are in line with the Directive 2001/80/EC (and Directive 2010/75/EU). The Plan also contains the list of more than 220 big combustion plants (installations) that are to be modified. All of those plants are electricity- and/or heat power-generating facilities.

The Plan provides that if Ukraine were to strictly comply with the timelines and emission ceilings provided in the Directive 2001/80/EC (and Directive 2010/75/EU), the majority of Ukraine's big power-generating facilities would have to be put out of operation, which would create significant shortages of electricity and heat energy in the country. Therefore, Ukraine undertook to bring emissions of its big combustion plants (installations) down to the ceilings established in Directive 2010/75/EU until 31 December 2033. The extension of the deadline is in line with the Treaty establishing the Energy Community.

The Plan is the base document for international financing institutions and potential investors that are contemplating investing in the Ukrainian energy sector.

Alternative energy

EBRD program for supporting sustainable energy

In July 2018, the European Bank for Reconstruction and Development (EBRD) approved a new USELF III (Ukraine Sustainable Energy Lending Facility) program to support private projects in renewable energy in Ukraine. The program is worth €250 million.

USELF III is designed to replace the original USELF program, which had been in place since 2009 and ended in June 2018. During the first program, EBRD has been supporting the development of renewable energy in Ukraine and financed projects worth more than €100 million in total with an aggregate capacity of over 150 MW.

The EBRD sees increased interest in renewable projects in Ukraine and their growing number. However, the bank notes that even though the renewable energy sector has been developing rapidly in Ukraine, the share of energy generated by such facilities remains insignificant at 1.5%, which is a far cry from the 11%-by-2020 target enshrined in the National Action Plan for Renewable Energy.

Membership of the International Renewable Energy Agency (IRENA)

On 24 February 2018, Ukraine became a member of IRENA, which was officially founded in Bonn, Germany on 26 January 2009. The organisation has 158 member states and its headquarters are located in Abu Dhabi.

IRENA coordinates and intensifies the work of its members aimed at the development of renewable energy potential by analysing, initiating a dialogue, providing recommendations, and promoting the transfer of knowledge and technology. As a member of the Agency, Ukraine has access to unique knowledge about the development of renewable energy, the world's best experience in renewable energy, and an opportunity to participate in specialised researches that are run by the IRENA Secretariat in order to find effective ways to reduce world dependence on fossil energy sources.

Developments in legislation or regulation

Requirements for wind power plants construction are eased

On 4 September 2018, the Law of Ukraine "On Changes to Certain Laws of Ukraine Regarding Investment Attraction to Construction of Renewable Energy Objects" was enacted. The Law aims to eliminate administrative barriers during the construction of wind power plants and raise the attractiveness of the wind power industry for investment.

In short, it simplified the requirements for expert examination of projects for construction of wind power plants (WPP). The law allows WPP to be referred to the CC1 class of consequences (i.e. minor consequences) where previously, such objects had belonged to not lower than the CC2 class of consequences. As a result, a shorter and more straightforward process of commencing construction works and commissioning of WPP should be achieved.

The Law is expected to come into force once it is signed by the President of Ukraine.

Amended procedure for granting and sale of subsoil use permits

Amendments to regulations on the granting and sale of subsoil use permits by auction were adopted by the Cabinet of Ministers of Ukraine in April 2018 (becoming effective in June 2018, except for certain provisions which become effective on 1 January 2019 and on 8 June 2019).

The changes include:

1. the Cabinet of Ministers of Ukraine has banned the granting of special permits for oil and gas fields, avoiding competitive procedures via the approbation mechanism;
2. a new instrument is introduced: the auction winner and the auction organiser may conclude a permit sale-and-purchase agreement on suspensive condition, so the granting of the subsoil use permit is conditional upon obtaining the environmental impact assessment that allows the planned activity;
3. the payment for the increase of deposits and the fee for extending the oil and gas licence are cancelled;
4. it is allowed to extend the term of special permits for companies that have tax debts, however, their right to dispose of the extracted natural resources will be restricted; and
5. time frames for the issuance of certain approvals were reduced, and a silent consent rule was introduced for certain approvals.

<u>New electricity market rules and codes adopted</u>

In May 2018, the National Energy and Utilities Regulatory Commission of Ukraine adopted a set of important secondary legislative acts necessary for the due implementation of the new electricity market provided by the Electricity Market Law No. 2019-VIII, dated 13 April 2017.

In particular, the following rules and codes were approved:

- Market Rules;
- Day-ahead and Intraday Market Rules;
- Retail Market Rules;
- Code of Transmission System;
- Code of Distribution System; and
- Code of Commercial Measurement.

<u>Simplification of requirements in the oil and gas industry</u>

The Law of Ukraine "On Amendments to Some Legislative Acts of Ukraine on Simplification of Some Aspects of Oil and Gas Industry" was passed on 1 March 2018.

The Law provides for simplification of certain regulatory procedures and is aimed at decreasing corruption risks in the course of granting land for subsoil use, providing more legal protection to investors, and improving relations between land owners and land users.

In particular, the Law provides for cancellation of numerous permits for the holders of oil and gas licences, *inter alia*: mining allotment; certain construction approvals; and approvals for transfer of the company's geological information to third parties.

The Law also simplifies certain procedures in the field of land use. In particular, the Law allows the servitude mechanism for the construction of oil and gas mining and pipe transportation objects to be used without changing the land zoning. The past practice of land allocation has been improved by securing the continuity of deposit development, and in particular, following the completion of exploration of deposits, oil and gas producers are entitled to use land plots based on the agreement with a land owner or upon the land-user's consent in the time period, while the land zoning is changed and the documents for the right to use the relevant land plots are produced (previously the companies had to stop mining operations for the period needed to obtain the documents).

According to Law, the economic evaluation of oil and gas deposits may be performed not just by the State Commission on Deposits of Natural Resources (which had a monopoly for such evaluation), but also by any authorised institution.

Re-estimation of deposits of natural resources no longer required

On 18 December 2017, the Government of Ukraine cancelled the requirement for re-estimation of deposits of natural resources every five years for production companies, which had led to additional financial and bureaucratic burdens on production companies.

The template Power Purchase Agreement amended

In September 2017 and January 2018, amendments to the Power Purchase Agreement (PPA) Template for electricity produced from alternative energy sources were adopted by the National Energy and Utilities Regulatory Commission.

Key amendments include:

- PPA now expressly states that it shall remain in force for the term of the green tariff for the particular renewable energy producer, i.e. until 1 January 2030;
- the "*force majeure*" provision was improved and extended;
- the dispute resolution clause was amended; the new version of PPA sets out different approaches to the dispute resolution procedure, depending on the type of the producer, the possibility of international arbitration is provided;
- the procedure for the termination of PPA was changed. In particular, it is provided that certain legislative amendments, including a change in green tariff, is a ground for the producer to require amendment of PPA or its termination; and
- State Enterprise "Energorynok" has the right to enter into direct agreements with creditors to finance producers' projects. In this case, the producer's consent for the conclusion of such direct contracts is not required.

Judicial decisions, court judgments, results of public enquiries

Commercial arbitration

Naftogaz v. Gazprom

The *Naftogaz v. Gazprom* dispute concerning gas supply and gas transit contracts between the two parties, which is administered by the Stockholm Chamber of Commerce (the "SCC"), was the major (and arguably the largest, in terms of the amount of claims) dispute of last couple of years in the energy sector. SCC passed a number of rulings in the arbitrations.

On 22 December 2017, the SCC handed down a ruling in a dispute over the gas supply contract, ordering Naftogaz to pay to Gazprom just over US$ 2 billion with interest. The tribunal rejected Naftogaz's claim about overpayment for gas supplied between May 2011 and April 2014, but declared certain provisions of the supply contract ("take or pay" provision, destination clause, etc.) onerous for Naftogaz as null and void. The ruling also decreased future contract volume obligations 10-fold. Naftogaz is also not required to pay for volumes of gas supplied to the occupied territories of Donetsk and Luhansk regions.

On 28 February 2018, the SCC delivered a ruling in the dispute between Naftogaz and Gazprom regarding transit of Russian gas via Ukraine. Naftogaz prevailed on its claim that Gazprom had failed to provide the agreed gas volumes for transit as well as to pay for the transit in full. Taking into account Gazprom's counterclaims, based on the ruling Gazprom is liable to Naftogaz in the amount of US$ 2.56 billion. Naftogaz is currently involved in proceedings in courts of various countries aimed at enforcement of the ruling.

Another part of the ruling of 28 February relates to amendments to the gas transit contract currently in place between Naftogaz and Gazprom. Naftogaz asked the tribunal to amend the gas transit contract so that the unbundling of Naftogaz could go ahead as planned. SCC did not satisfy Naftogaz's claims, even though the tribunal did confirm the validity of the transit contract. Accordingly, Gazprom's consent should be sought in order to complete the unbundling and introduce MGU as a TSO, which would require amending the transit contract. Reportedly, such consent of Gazprom would be very hard to obtain and therefore the unbundling process could be delayed until at least 1 January 2020. Gazprom is currently appealing the above ruling in the courts of Sweden.

On 6 July 2018, Naftogaz filed another claim with the SCC against Gazprom, requesting the tribunal to adjust the price paid by Gazprom under the gas transit contract. The possibility of such adjustment is provided for by the gas transit contract between the parties. The claim was filed after negotiations between Gazprom and Naftogaz regarding this issue held earlier in 2018 had brought no results.

Ukrgazvydobuvanya v. Karpatygaz & Misen Enterprises A.B.

In 2016, PJSC Ukrgazvydobuvanya (a 100% subsidiary of Naftogaz and the biggest gas producer in Ukraine) initiated arbitral proceedings at SCC against Misen Enterprises A.B. and its subsidiary LLC Karpatygaz, and requested the tribunal to terminate the joint activity agreement that had been concluded between Ukrgazvydobuvanya and Misen acting with Karpatygaz in 2002. Under the agreement, Karpatygaz (as Misen's subsidiary) was to modernise wells operated by Ukrgazvydobuvanya and also supply certain equipment for such wells, which Karpatygaz failed to do. Reportedly, Misen also failed to contribute US$ 8.8 million to the project or attract funds for the project in the amount of UAH 3 billion.

In July 2018, SCC passed a partial award terminating the joint activity agreement due to Misen's failure to perform its obligations under the agreement. This will allow Ukrgazvydobuvanya to regain full control over its wells.

The story, however, is far from over. A Ukrainian leasing company initiated court proceedings against Ukrgazvydobuvanya as a party to the joint activity agreement, due to certain undertakings of Karpatygaz before the leasing company that Karpatygaz failed to fulfil. Ukrgazvydobuvanya's bank accounts were arrested in late August in connection with the dispute.

<u>Investment arbitration</u>

PJSC Ukrnafta v. the Russian Federation || Stabil LLC and Ten Others v. the Russian Federation

Both of the above arbitrations were commenced by the Claimants against the Russian Federation on 3 June 2015, pursuant to the Ukraine–Russia BIT and in accordance with the UNCITRAL Arbitration Rules 1976. The Claimants submit that, as of April 2014, the Russian Federation breached its obligations under the Ukraine–Russia BIT by interfering with and ultimately expropriating their investments in petrol stations located in Crimea. The ultimate amount of claims has not been disclosed.

The arbitrations are administered by the Permanent Court of Arbitration. The Russian Federation is not participating in the proceedings in any form, and challenged (i) tribunal's jurisdiction as well as (ii) application of BIT to constitution of the tribunal. The first hearing on the merits was held on 5–6 February 2018 in Geneva, Switzerland, where the Tribunal decided to appoint a Tribunal expert to whom it will pose specific questions regarding the quantum of the Claimant's damages.

Naftogaz v. the Russian Federation

Naftogaz and its six subsidiaries (Chornomornaftogaz, Ukrtransgaz, Likvo, Ukrgazvydobuvannya, Ukrtransnafta and Gaz of Ukraine) commenced arbitration against the Russian Federation on 17 October 2016 pursuant to the Ukraine–Russia BIT and in accordance with the UNCITRAL Arbitration Rules 1976. In its claim, Naftogaz requests to refund losses that it and its subsidiaries sustained over the annexation of Crimea by Russia. The amount of losses claimed is ca. US$ 5 billion.

Back in February 2016, Naftogaz initiated a negotiating process regarding the loss of its assets in Crimea by formally notifying Russia of an investment dispute under the bilateral investment protection agreement. The negotiations, however, did not result in any agreement between the parties.

In September 2017, Naftogaz (together with its six subsidiaries) submitted a statement of claim in the proceedings. The Russian Federation refused to appoint any representatives in these proceedings. In its letter of January 2017, the Russian Federation challenged the jurisdiction of the tribunal as well as applicability of the Ukraine–Russia BIT to the process of constitution of the tribunal. No information on hearings or awards in the case is available so far.

Major events or developments

The ongoing process for the unbundling of Ukraine's gas transportation system, which has not yet been completed, and overall developments in relations between Ukraine and its state-owned company Naftogaz on the one side, and Russia and its state-controlled company Gazprom on the other side, have been most closely followed in Ukraine, Russia and in the European Union. The fact that the Government of Ukraine has not crystallised its position on the unbundling process and its results could jeopardise Ukraine's bargaining position when it comes to the transit of Russian gas via Ukraine to the EU.

Some of the events that occur outside of Ukraine but still have an impact on the situation of the country's energy sector should not be disregarded. Such events include the active construction phase of the Turkish Stream, a natural gas pipeline that goes from Russia to Turkey on the bottom of the Black Sea, as well as the beginning of construction of Nord Stream 2 – the additional (to the already existing Nord Steam) pipeline. Although the perspectives of the latter projects are unclear yet, it is considered that both of them may result in serious losses for Ukraine's energy industry and to the country's economy.

Proposals for changes in laws or regulations

<u>Auctions for electricity produced from renewable sources</u>

The Parliament of Ukraine is currently considering a number of draft laws relating to the introduction of auctions for electricity produced from renewable sources. Currently such electricity is sold by producers without auction at prices set in the legislation ("green" tariff).

It is proposed that electricity produced from renewable sources should be sold at auctions to a state enterprise that would resell the electricity to end customers. Auction participants (i.e. electricity producers) would have to make bids at the auctions, offering the lowest prices to win. Producers would also have to compete for the amount of electricity they would be able to sell.

The need to shift from "green" tariff to auction is caused, on the one hand, by the situation when alternative energy producers produce only 1.5% of energy but receive 7.5% of payments for the supplied energy on the market. Moreover, the implementation of auctions is one of the undertakings of Ukraine under the EU Association Agreement.

Electricity from biomass/biogas

The Ukrainian institutional and regulatory environment currently does not foster or encourage electricity generation from biomass and biogas. This is due, first of all, to the low and inflexible “green” tariff for electricity produced from biomass and biogas.

Another obstacle is that state policy does not differentiate between small and large producers: all of them get the same “green” tariff. However, smaller generating installations have higher per-unit costs and therefore need a higher tariff.

Moreover, the “green” tariff will be in force until 2030, which is insufficient for investors investing in biomass/biogas projects to get returns on their investments. If the legislation does not change, the investors will implement new projects only until 1 January 2020, whereupon they will stop investing as there won’t be enough time until 2030 for the projects to become profitable.

Installed capacity of biomass/biogas installations in Ukraine is the lowest compared to other types of installations in the renewable energy sector: 43.8 MWT for biomass; 40.6 MWT for biogas; (for photovoltaic power stations – 841.4 WMT, for wind farms – 512.2 MWT).

Therefore, legislative amendments aimed at encouraging electricity generation from biomass/biogas are being currently contemplated or developed. Such amendments could provide for: the increase of tariffs for electricity produced by biogas/biomass (for smaller installations or overall); other incentives for smaller biogas/biomass installations; and incentives for combined biomass/biogas heat and power plants, which produce heat in addition to electricity. It is unclear whether such amendments will be passed soon.

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Overview of the current energy mix, and the place in the market of different energy sources

In recent years, the biggest change that has occurred in the UK's energy mix has been in relation to the sources of electricity generation. As discussed in more detail below, there has been a marked increase in the proportion of electricity generated from renewable energy sources, and a move away from coal-fired power. Nonetheless, looking at energy consumption as a whole, fossil fuels, in the form of natural gas, oil and coal, are still the dominant source of energy. In 2017, fossil fuels accounted for 80.1% of supply – this was a record low, in contrast to, for example 84.5% in 2014. The balance of energy supply comes from low-carbon sources, including nuclear energy and renewables such as wind, solar, hydro and biofuels. If analysed by fuel type, then based on 2017 figures, petroleum products, such as petrol, top the list at 47.8% of all fuel used by final consumers, followed by natural gas at 28.6%, and electricity at 17.3%.[1] These figures remain, to a large extent, unchanged since 2015.

In terms of electricity generation, the UK continues to have a varied generation mix, although coal-fired generation has continued to decline in line with government policy (as discussed in more detail below). In 2017, generation from coal amounted to just 6.7%, in contrast to 36.4% just four years earlier, in 2013. On the other hand, there has been a steady increase in the proportion of electricity from renewable sources: in 2017, a record 29.3% of electricity was generated from renewables (up from 24.5% in 2016). The proportion of electricity generated from gas and nuclear has remained largely stable – see Figure 1.

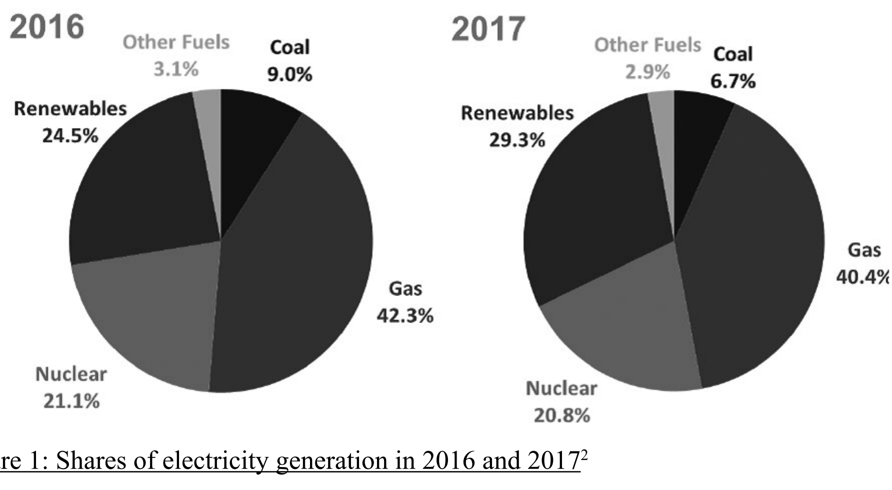

Figure 1: Shares of electricity generation in 2016 and 2017[2]

The move away from coal

As discussed in previous editions of this chapter, there has been a considerable decline in the use of coal for power generation. While EU law and policy has played a significant role in this (most notably the Large Combustion Plant Directive and the Industrial Emissions Directive), the UK Government has also independently taken direct action to phase out coal-fired generation.

A new Emissions Performance Standard, introduced in 2014 as part of the Government's Electricity Market Reform (**EMR**) package of policies, means that no new unabated coal-fired power stations are permitted to be built in the UK, although the Emissions Performance Standard has been set at a level which will allow unabated gas-fired power stations to operate until the end of 2044. The UK's Carbon Price Floor has also played a role in reducing the level of coal-fired generation, by increasing the cost of emitting carbon.

Most significantly, in November 2015 the Government announced its intention to consult on proposals to end unabated coal generation in Great Britain by 2025. The policy on how this would be implemented was finalised in January 2018. The Government has decided that the most appropriate way to ensure the closure of unabated coal-fired power stations by 2025 is to set a new emissions intensity limit to generating units, which will give coal generators the option of investing to reduce emissions to the required standard. The emissions intensity limit is being set at 450g CO_2 per kWh of electricity generated, and it will apply from 1 October 2025. The Government has said that its assessments indicate that the Capacity Market (an auction mechanism to procure capacity, as mentioned in more detail below) will ensure that there is sufficient capacity in place to replace unabated coal units when they close.

In April 2018, a new record was set in the UK, with no electricity from coal being generated for over three days.

A continuing role for the oil and gas industry

While the United Kingdom Continental Shelf (**UKCS**) is considered to be a mature basin, and production figures are down compared to its peak, the UK upstream oil and gas industry continues to play an important role, both in terms of its contribution to the economy and its contribution to meeting the UK's energy needs. Currently gas production from the UKCS would be sufficient to meet nearly 60% of the UK's energy demand.[3] According to the regulator, the Oil and Gas Authority (**OGA**), in 2017 oil and gas production stood at 1.63 million boe/day, a level not seen since 2011.[4] The UK has continued to hold annual offshore licensing rounds, with the 31st offshore licensing round launched by the OGA in July 2018, offering blocks in frontier areas of the UKCS.

Notwithstanding sustained indigenous production levels, the UK is increasingly reliant on oil and gas imports – in particular, the UK imports natural gas by pipeline from Norway, Belgium and the Netherlands, and Liquefied Natural Gas (**LNG**) by ship. In 2017 there was a considerable reduction in LNG imports, with LNG making up just 15% of all gas imports. The reason for this was that higher demand for LNG in Asia increased prices and affected volumes supplied into Europe and the UK. The main source of the UK's crude oil imports has consistently been Norway: in 2017, the proportion of crude oil sourced from Norway was 48%.

Renewable energy: continuing growth but room for improvement

In 2017, 10.2% of total energy consumption came from renewable sources; up from 9.3% in 2016.[5] Moreover, as mentioned above, in 2017 renewable sources provided 29.3% of the electricity generated in the UK, compared to 24.5% in 2016. This was due to increased renewables generation capacity (wind and solar) and more favourable weather conditions for wind generation.

In terms of total renewables capacity in 2017, onshore wind had the highest share of capacity (31.7%), followed by solar PV (31.5%), offshore wind (17.2%), bioenergy (such as plant biomass and landfill gas) (14.9%), and hydro (4.6%).

However, while the figures mentioned above are impressive and mean that so far, the UK has met its national and international greenhouse gas emission reduction targets, there is some concern that Brexit, together with moves by the Government to reduce subsidies for low-carbon energy (see further below) may mean that the current growth in renewables is not sustained. Moreover, so far, 75% of reductions in emissions have been in the power sector, with other sectors, such as transport and industry, lagging behind in their use of renewable sources of energy in place of fossil fuels.[6]

<u>Nuclear energy</u>

The UK Government continues to be committed to increasing the UK's nuclear power capacity, although no new capacity has come online yet. The Government's nuclear power policy is discussed in more detail below.

<u>Gas-fired generation: a scaling back?</u>

Unlike coal-fired generation, gas-fired generation continues to play an important role in the UK's generation mix. In particular, gas-fired generation has been seen as a cleaner alternative (compared to other fossil fuels) and an important source of dispatchable generation to balance out intermittent generation such as solar PV and wind. As discussed in earlier editions of this chapter, the Government's Gas Generation Strategy of 2012 had suggested 26GW of gas-fired generation would be needed by 2030, but the Government has gradually been backing away from this goal. Its most recent projections are that just 6GW of new gas-fired plant will be built by 2035, with most of this coming in the next four years.[7] The key reasons for this change in approach appear to include reductions in the cost of renewables, as well as leaps forward in the commercial deployment of battery storage (see more on this below).

However, exactly how much electricity will come from gas in the future is far from certain: according to modelling undertaken by the system operator, National Grid, depending on the "energy pathway" taken, gas-fired generation could meet anywhere between 7%–40% of annual electricity demand in 2035.[8]

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

As discussed in the sixth edition of this chapter, the Conservative Government's election manifesto of 2017 pledged some specific energy-related initiatives, including continued support for the upstream oil and gas industry; a continued commitment to developing a shale gas industry in the UK; an energy tariff cap for domestic consumers; an independent "cost of energy" review; and controls on foreign investment into the UK. The Government has further developed some of these policies over the last 12 months, as well as taking forward others, as discussed below.

<u>Introduction of energy tariff caps</u>

Calls for energy price caps, as a means to address rising energy prices, have been championed by various stakeholders for the last few years. In October 2017 the Prime Minister, Theresa

May, confirmed that the Government would go ahead with the introduction of a tariff cap, and this measure is being implemented under the Domestic Gas and Electricity (Tariff Cap) Act 2018 (**Tariff Cap Act**). The decision to introduce a tariff cap for domestic consumers is a significant development in UK energy policy, given that the general approach up to now has been that in markets which are open to competition (in contrast to natural monopolies), regulatory intervention should focus on facilitating competition rather than direct price intervention. Indeed, the Competition and Markets Authority (**CMA**), as part of its two-year inquiry into the energy market which concluded in 2016, expressly considered and rejected the idea of a cap that would apply to all domestic customers. The CMA, which did order the introduction of a temporary "safeguard" tariff cap for prepayment meter customers, as part of its suite of remedies to address features of the energy market which have an adverse effect on competition, said that "attempting to control outcomes for the substantial majority of customers [by introducing a price cap] would – even during a transitional period – run excessive risks of undermining the competitive process, likely resulting in worse outcomes for customers in the long run".

Moreover, the move comes at a time when there are more suppliers in the market than ever before: as at March 2017, there were 54 active suppliers in the domestic gas and electricity retail markets. In addition, in the 12 months to March 2016 alone, the combined market shares of small and medium-sized suppliers in the domestic market grew by nearly four percentage points to 14%, while the six large suppliers have continued to lose market share. However, there has been growing political pressure on the Government to "do something" about rising gas and electricity prices.

A key issue is, of course, the level at which the cap will be set. The Tariff Cap Act does not set this out, but requires the regulator, Ofgem, to determine the cap following consultation with industry, which is ongoing at the time of writing. Ofgem has indicated that the cap should rise and fall as suppliers' costs – such as the costs of buying energy, network charges, and government policy costs – change. Ofgem has proposed that it will update the cap every six months. The cap will not apply to prepayment meter customers, because such customers already benefit from the existing prepayment meter cap imposed pursuant to an order made by the CMA. Importantly, the cap will also not apply to the supply of "green energy" – i.e. where, typically, 100% of the electricity being supplied is from renewable energy sources.

It is intended that the cap will be in place by the end of 2018. Importantly, the cap is intended to be a temporary measure, initially in place until 2020. However, the Tariff Cap Act also requires Ofgem to carry out a review in 2020 into whether conditions are in place for effective competition for domestic supply contracts. If, following the review, the Secretary of State considers that such conditions are not in place, then the cap can be extended for another year. This annual review and extension process can be repeated until 2023.

The Cost of Energy Review

As mentioned above, there has been growing political pressure on the UK Government to address the rising costs of energy in the UK, the blame for which, to a large extent, has been put on the various energy policies of successive Governments over the past decade and beyond. Part of the blame has also been directed at the structure of the retail gas and electricity supply market, and that aspect was considered by the CMA in a two-year energy market investigation carried out between June 2014 and June 2016. The CMA investigation has led to a large number of remedies being implemented, primarily aimed at the retail market.

Key among the alleged "culprits" for high energy prices have been the various incentives introduced to drive investment in low-carbon generation. While this is a point many involved in the electricity industry would challenge, what is incontrovertible is that the various policy instruments introduced into the market over time have led to a very complex electricity market structure. What is also significant is that only a few years have passed since the implementation of the EMR package of policies, which were intended to address the UK's energy needs, while keeping costs down. As a response to the growing criticism of the UK energy market structure, the Government decided to commission an independent critique of the policies that have formed the current electricity market.

The "Cost of Energy" Review was officially launched on 6 August 2017, headed by University of Oxford economist, Professor Dieter Helm. The findings of the review were published in October 2017. Helm has recommended quite significant changes to the structure of the electricity industry, and, in particular, the way new capacity is procured. The changes recommended in the review are aimed at addressing Helm's two key findings:

- that the cost of energy is significantly higher than it needs to be to meet the Government's policy objectives; and
- that the regulatory structure and market design is "not fit for the purposes of the emerging low-carbon market".

Helm's recommendations include, but are not limited to, the following:

- replacing current incentives for procuring low-carbon generation with a single carbon price, and a single unified capacity auction on an equivalent firm power basis;
- the creation of a new National System Operator (**NSO**) and Regional System Operator (**RSO**), which new bodies would determine what operations, maintenance and enhancements to the electricity networks are required. Importantly, Helm concludes that rather than being private companies, the NSO and RSOs should be public bodies, accountable to Government, and subject to the National Audit Office and public accounts committee scrutiny and, ultimately, to Parliament; and
- the replacement of separate licences for distribution, supply and decentralised generation with a "general" licence, on the basis that the distinctions between these activities are becoming blurred. Helm acknowledges that current market structures are constrained by the EU's internal energy market rules (specifically, the Gas and Electricity Directives), which may still be relevant post-Brexit implementation. However, he also notes that the breakdown of the distinctions between generation, supply and networks is widespread across Europe.

In November 2017 the Government launched a call for evidence on Helm's report, seeking views from industry and other interested stakeholders. The outcome of that call for evidence, including the government response, has not yet been published. This is perhaps not surprising, given the complexity of the issues raised, at a time when the Government is grappling with Brexit.

<u>Controls on investment in major infrastructure</u>

In July 2018, the Government published a White Paper setting out proposals to strengthen very significantly its powers to scrutinise transactions and projects on national security grounds.

The proposals follow an initial consultation launched in October 2017 on measures to protect national security, which contained "short-term" and "long-term" proposals. The short-term reforms entered into force in June 2018, but these are not directly applicable to the energy sector. The White Paper takes forward the long-term proposals, which will apply to certain "core areas", including upstream oil and gas infrastructure, gas and electricity interconnectors, large-scale power generation plant, and gas storage and LNG facilities. What is being proposed is a voluntary notification regime: where there is a certain "trigger event", such as the acquisition of more than 50% of an asset, the parties will be encouraged to voluntarily notify their transaction. However, the Government will also have powers to "call-in" transactions for review (it suggests for a period of up to six months after the relevant trigger event has occurred).

In order to carry out a full national security assessment (either after notification or following a transaction being "called in"), the White Paper envisages that it will be necessary for the relevant senior Minister to:

- have reasonable grounds for suspecting that a relevant trigger event has taken place or is in progress or contemplation; and
- have a reasonable suspicion that, due to the circumstances of the trigger event (e.g. the nature of the parties or the asset, or the location in the case of land) it may give rise to a risk to national security.

Following the assessment process, trigger events will either be approved, allowed to proceed following the imposition of remedies, or blocked/unwound if the deal has already taken place.

The proposals are expected to be fully implemented in 2019 at the earliest. The Government has sought to present the proposals as a measured response to the increased national security risks the UK faces in a digital world, noting that similar measures have been adopted in many other countries. It is certainly true that other countries, such as the USA, Germany and France, have recently strengthened, or are in the process of strengthening, their national security regimes. However, the new UK regime would involve a sea-change in the UK's approach to national security assessments and, if the Government's predictions are correct, could result in a vast increase both in the number of transactions being assessed for national security concerns and those being the subject of remedies.

<u>Shale gas</u>

Since 2012, the Government has been taking various steps to facilitate the development of a shale gas industry in the UK, in the hope that shale gas can contribute to energy security and the economy. Most recently, in May 2018, the Government announced a number of new initiatives relating to planning consent reform and the establishment of a new shale gas environmental regulator. In July 2018, the Government launched a consultation on the proposed planning reforms, including a proposal to designate exploratory drilling for shale gas resources as a new form of permitted development, meaning that planning consent would not be required. At the same time, the Government also launched a separate consultation on proposals for including shale gas production projects in the Nationally Significant Infrastructure Project (**NSIP**) regime under the Planning Act 2008. Including shale gas production projects within the scope of the NSIP regime would mean that the final decision for granting or refusing development consent for such projects would rest with the Secretary of State for the Department of Business, Energy and Industrial Strategy, rather than the local authority.

<u>The Clean Growth Strategy</u>

The Climate Change Act 2008 commits the Government to meeting a legally binding target to cut greenhouse gas emissions by 2050 by at least 80%, compared with 1990 levels. To fulfil its obligations under the Climate Change Act 2008, the Government is obliged to publish an emissions reduction plan, setting out how the Government intends to meet the fifth carbon budget, which seeks to limit the UK's annual emissions to 57% below 1990 levels by the year 2032. After much delay, the plan, titled the "Clean Growth Strategy", was finally published in October 2017. The Strategy includes the following key policies, which the Government intends to take forward:

- more energy efficiency requirements for commercial buildings;
- more funding for deployment of electric cars;
- more funding for developing heating networks which do not use fossil fuels;
- a renewed focus on carbon capture and storage – now referred to as Carbon Capture Usage and Storage (CCUS);
- continued regulatory reforms to facilitate battery storage; and
- offshore wind is to play a role in meeting the UK's emission reduction targets, and the Government will work with industry to develop a "sector deal for offshore wind", dealing with issues such as employment, training and research in the industry.

Impact of Brexit

Brexit will inevitably have an impact on the UK's energy market and energy policy, but the full extent of that impact is still not completely clear. At the time of writing, it is still not known whether the UK Government can negotiate an agreement on Brexit with the EU, although the Government is preparing the business sector and the public for the possibility of a "no-deal" Brexit.

In comparison to other sectors, such as financial services, Brexit will not have a hugely significant impact on the regulatory regime applying to the energy sector. For instance, the regulatory framework applying to the upstream industry, and in particular, environmental and health and safety regulation, is highly developed independently of EU law. However, a "no deal" Brexit could lead to a period of uncertainty, which could undermine investor confidence. Moreover, depending on the outcome – i.e. "no deal" or the nature of any agreement entered into – there are various issues raised in relation to specific sectors, including the following:

- the impact of Brexit on gas and electricity trading will be determined by whether the UK will still participate in the single European energy market. However, a "no-deal" Brexit would pose immediate barriers to trading across interconnectors, as it is EU rules that govern cross-border trading;
- there is concern from the renewables about the impact that Brexit will have on emission-reduction and renewable energy targets, as currently the UK's targets in this area are a mix of EU law (in particular, the Renewable Energy Directive) and UK law (e.g. the Climate Change Act 2008). Similarly to the oil and gas industry, a "no-deal" Brexit will have repercussions for the renewables industry in terms of trading tariffs and access to labour and markets;
- industry body Oil and Gas UK's Economic Report 2018 warns that a "no-deal" Brexit will potentially have adverse consequences for the upstream oil and gas industry, in terms of trading tariffs and access to markets and labour;
- a "no-deal" Brexit will pose some particular difficulties, such as an inability by oil and companies to meet their "oil stocking obligations" through stocks held in the EU; and
- for the nuclear industry, the Government has taken steps to address the consequences of the UK ceasing to be a member of Euratom, through the enactment of the Nuclear

Safeguards Act 2018. However, a "no-deal" Brexit will have some additional legal implications – for example, nuclear operators may need to obtain licences to import nuclear materials from EU countries, for which an import licence is not currently needed.

Developments in government policy/strategy/approach

Capacity Market

A Capacity Market (**CM**) has been introduced to address concerns about having sufficient flexibility to deal with fluctuations in electricity demand and available supply. Under the CM regime, capacity payments are made to the providers of capacity, including both generation and non-generation forms of capacity such as demand-side response (**DSR**) and storage. This is a significant change to existing electricity market arrangements, which only reward generators for the electricity generated. The starting point under the new regime is that, on an annual basis, the Government estimates the total volume of capacity required 4.5 years ahead of the delivery year (running from 1 October to 30 September), and then the System Operator contracts for the required volume of capacity from providers through a central auction process. Competitive auctions are held four years (T-4 auction) and one year (T-1 auction) before each delivery period.

The most recent CM auctions were the 2017/18 T-4 auction securing capacity for delivery in 2021/22, and the 2017/18 T-1 auction securing capacity for 2018/19, both of which took place in February 2018. The 2017/18 T-4 capacity auction cleared at a price of £8.40/kW: this was much lower than all previous T-4 auctions: £22.50 in 2016, £18.00 in 2015 and £19.40 in 2014. What was also interesting about the auction results was that only 767 MW of new-build generating plant won capacity agreements (just over 1.5% of the total capacity). This is much lower than the 3.4 GW of capacity acquired by new-build generating plant in the 2016 T-4 auction. Moreover, all of the 70 generating units (including battery projects) that make up the 767 MW of new-build capacity are plant that intend to connect to the distribution network, and none of them are new-build CCGT plant. The reason this is noteworthy is because when the CM regime was first implemented, the Government made it clear that one of its objectives was to facilitate investment in new-build, gas-fired generation plant.

This T-4 auction was also the first time that new build interconnectors secured capacity agreements. These interconnectors, which are planned to be operational for delivery in 2021/22 are:

- two, 1GW interconnectors with France: Eleclink (690 MW on a de-rated basis) and IFA 2 (715 MW); and
- a 1GW interconnector with Belgium – NEMO (750 MW).

The first T-1 Capacity Auction cleared at a price of £6.00/kW/year, which was the lowest price ever reached in a GB capacity auction.

The next T-1 and T-4 capacity auctions are scheduled for early 2019, with the amount of capacity to be procured being based on an assessment published by National Grid, the system operator, in May 2018. Relevantly, National Grid's assessment of how much capacity will be required is based on an assumption of continued market harmonisation between the UK and Europe once the UK has left the European Union (Brexit), including continued participation by the UK in the Internal Energy Market or similar future arrangements. This seems by no means certain at the time of writing.

Contracts for Difference

As discussed in earlier editions of this chapter, the new Contracts for Difference (**CfD**) regime has replaced the Renewables Obligation regime (a green certificate system), as the main form of support for renewable energy projects.

Under a CfD, a low-carbon generator is paid a top-up payment above the wholesale price (the reference price), up to a set strike price. The strike price is intended to be an amount equal to that needed to make low-carbon power projects commercially viable. The CfD takes the form of a private law bilateral contract between the CfD counterparty and each low-carbon generator. A Government-owned limited liability company – the Low Carbon Contracts Company (**LCCC**) – has been established to act as the counterparty to CfDs, and to collect from suppliers a levy to fund CfD payments and administer payments under CfDs. A key feature of CfDs is that provision is made for a two-way payment mechanism, so if the wholesale price is higher than the strike price, the generator will be required to make a payment back to the CfD counterparty.

For the vast majority of renewable energy projects, CfDs are being allocated to projects through annual allocation rounds. So far, two allocation rounds have taken place, with a third scheduled for May 2019.

The outcome of the second CfD allocation round was announced on 11 September 2017. The allocation round produced unprecedented low prices for renewable energy projects, that are likely to have implications not just for the renewable energy sector, but the UK's generation mix as a whole.

Since the first CfD allocation round was held in October 2014, there have been some considerable changes to Government policy with regard to support for renewables, which have had an impact on the outcome of the second allocation round. One of the most significant changes was the fact that while a wide range of renewable energy technologies were eligible to take part in the first allocation round, in the second allocation round only less established technologies were eligible to participate: offshore wind; advanced conversion technologies (**ACT**) (with or without CHP); anaerobic digestion (with or without CHP); dedicated biomass with CHP; wave; tidal stream; and geothermal technologies. Moreover, there has been a greater-than-ever focus on reducing the cost of energy to consumers, with a push for renewable energy to be deployed only if it can be cost-competitive.

In total, 11 projects were awarded CfDs in the second allocation round, totalling 3.3 GW in capacity. This is in contrast to the first allocation round, in which 27 projects were awarded CfDs, totalling 2.1 GW. The main difference between the two results is the fact that in terms of capacity, the second allocation round was dominated by large-scale offshore wind farm projects, and the level of support awarded to projects was much lower than in the first allocation round. See Figure 2 for the full results.

Figure 2 – Projects successful in the second CfD allocation round

Project	Developer	Technology	Capacity (MW)	Delivery year	Strike price (£/MWh) (in 2012 prices)
Drakelow Renewable Energy Centre	Future Earth Energy (Drakelow) Limited	ACT	15.00	2021/22	74.75
Station Yard CFD 1	DC2 Engineering Ltd	ACT	0.05	2021/22	74.75

Northacre Renewable Energy Centre	Northacre Renewable Energy Limited	ACT	25.50	2021/22	74.75
IPIF Fort Industrial REC	Legal and General Prop Partners (Ind Fund) Ltd	ACT	10.20	2021/22	74.75
Blackbridge TGS 1 Limited	Think Greenergy TOPCO Limited	ACT	5.56	2021/22	74.75
Redruth EfW	Redruth EFW Limited	ACT	8.00	2022/23	40.00
Grangemouth Renewable Energy Plant	Grangemouth Renewable Energy Limited	Dedicated biomass with CHP	85.00	2021/22	74.75
Rebellion	Rebellion Biomass LLP	Dedicated biomass with CHP	0.64	2021/22	74.75
Triton Knoll Offshore Wind Farm	Triton Knoll Offshore Wind Farm Limited	Offshore wind	860.00	2021/22	74.75
Hornsea Project 2	Breesea Limited	Offshore wind	1,386.00	2022/23	57.50
Moray Offshore Windfarm (East)	Moray Offshore Windfarm (East) Limited	Offshore wind	950.00	2022/23	57.50

Three offshore wind projects were successful in the second allocation round, totalling 3.2 GW out of the total 3.3 GW of CfD capacity awarded. The fact that offshore wind dominated the allocation round, at least in terms of capacity, did not come as a huge surprise, given that in structuring the allocation round the Government imposed a "maxima" of 150 MW in relation to fuelled technology projects to limit the available budget for such projects. Moreover, the fact that all eligible technologies would be competing against each other on price meant that offshore wind was predicted to be in a winning position, based in particular on economies of scale, and the cost savings that have been realised in developing offshore wind technology in the last few years.

What did come as a surprise were the low strike prices awarded to the winning projects. Before the allocation round took place, developers were prepared for the fact that lower levels of support were expected: earlier, the Department for Business, Energy and Industrial Strategy had expressly said that offshore wind farm projects would need to aim to be viable at a strike price support rate of 85/MWh by 2026, and for the second allocation round the administrative strike price (representing a cap on the price) for offshore wind was set at £105/MWh for the 2021/22 delivery year and £100/MWh for the 2022/23 delivery year – see Figure 3. However, the final figures achieved in the auction – £74.75/MWh for one project, and £57.50/MWh for the other two projects – had not been expected.

Given that wholesale power prices are expected to average £53/MWh in the period from 2023 to 2035, offshore wind is approaching a position where it may be viable, or at least be expected to be viable, with no subsidy (although it should be noted that the strike prices quoted are 2012 prices, and will therefore benefit from several years of CPI indexation). This is a position that only recently seemed like a much longer-term proposition. However, in developing future policies for the deployment of renewable energy based on a "zero subsidy" model, the Government will need to be mindful of the fact that the value of a CfD to a project is not simply in the level of the strike price awarded, but also in the change in law protection and price stabilisation mechanism that a CfD provides. The absence of such price stabilisation may make it very difficult for large-scale renewable energy projects to be bankable.

The strike price differential between the three offshore wind projects also raises some interesting questions about the allocation process. While it is unclear what strike price was bid by the Triton Knoll offshore wind project and how much lower such price was below the clearing price of £74.75/MWh, it is very likely that for the 2021/22 delivery year, a fuelled technology project set the clearing price, thereby pushing up the price originally bid by the project. However, a function of the allocation rules meant that while a clearing price of £57.50/MWh was set for the two offshore wind projects for the 2022/23 delivery year, the Redruth ACT project (delivering in the same year) was awarded a lower strike price of £40/MWh which was not pushed up by the offshore wind-clearing price.

Figure 3 – Offshore wind strike prices (with relevant delivery years noted in brackets)

Administrative strike prices set for first allocation round	Strike prices achieved in first allocation round	Administrative strike prices set for second allocation round	Strike prices achieved in first allocation round
£155/MWh (2014/15; 2015/16) £150/MWh (2016/17) £140/MWh (2017/18, 2018/19)	£119.89/MWh (2017/18) £114.39/MWh (2018/19)	£105/MWh (2021/22) £100/MWh (2022/23)	£74.75 (2021/22) £57.50 (2022/23)

Despite concerns that ACT developers would be unable to compete with the competitive strike prices anticipated to be bid by the offshore wind sector, out of the eight remaining winning projects, six were ACT projects and two were dedicated biomass with CHP projects (see Figure 2). As is the case with offshore wind, the strike prices awarded to these projects were much lower than the strike prices achieved in the first allocation round and the administrative prices set for the second allocation round: £74.75/MWh for seven of the projects; and £40/MWh for one ACT project – see Figures 4 and 5.

Despite the fact that this was good news for the ACT sector, the overall CfD capacity that will be delivered by ACT projects is less than 2% of the total capacity awarded, confirming the predicted shift in favour of offshore wind for this allocation round.

Figure 4 – ACT strike prices (with relevant delivery years noted in brackets)

Administrative strike prices set for first allocation round	Strike prices achieved in first allocation round	Administrative strike prices set for second allocation round	Strike prices achieved in first allocation round
£155/MWh (2014/15; 2015/16) £150/MWh (2016/17) £140/MWh (2017/18, 2018/19)	£119.89/MWh (2017/18) £114.39/MWh (2018/19)	£125/MWh (2021/22) £115/MWh (2022/23)	£74.75/MWh (2021/22) £40/MWh (2022/23)

Figure 5 – Dedicated biomass with CHP wind strike prices (with relevant delivery years noted in brackets)

Administrative strike prices set for first allocation round	Strike prices achieved in first allocation round	Administrative strike prices set for second allocation round	Strike prices achieved in first allocation round
£125/MWh (2014/15 – 2018/19)	No CfDs awarded	£115/MWh (2021/22; 2022/23)	£74.75/MWh (2021/22)

No wave, tidal stream or geothermal technologies were awarded a CfD.

From the Government's point of view, the second CfD allocation round has been a success, in procuring new capacity at a low cost to consumers. For developers, the second CfD allocation round sets a precedent in terms of the prices achieved, and therefore developers can expect to see much lower administrative strike prices in the future.

There are also obvious implications for other power generation technologies. In particular, it will add to the already existing pressure on nuclear projects to compete with the low strike prices awarded to other technologies (see discussion of nuclear power below).

What is certain is the fact that the results of the second CfD allocation round are a game-changer, proving that far from being an expensive whim, renewable energy can compete on price with other non-renewable sources of power.

Closure of the small-scale FIT scheme

The small-scale Feed-in Tariff (**FIT**) scheme was introduced in 2010 as a support mechanism for small-scale renewable energy, up to 5MW. It was designed to offer an alternative incentive to the more complex green certificate Renewables Obligation regime. The scheme was instrumental in leading to the growth of solar PV generation in the UK. However, the scheme is expected to close to new entrants after 31 March 2019.

Battery storage

The last 12 months have seen some good and bad news for battery storage projects in the UK. On the upside, there are the various regulatory reforms promised in the Government's July 2017 "smart systems and flexibility plan",[9] designed to facilitate investment in battery storage. Some of these are already being taken forward. In particular, regulator Ofgem has been consulting on the treatment of battery storage as licensed activity within the licensing framework established under the Electricity Act 1989. It is intended that a modified form of a generation licence will be used for licensing battery storage projects, on the basis that generation and storage share similar characteristics and perform similar functions in terms of generating and exporting electricity to the grid. Ofgem has also issued guidance for developers on co-location of battery storage with renewable energy generating plant which benefit from support under the schemes such as the Renewables Obligation green certificate scheme. The guidance confirms that such co-location will not adversely impact the generating plant's eligibility for support, so long as the relevant requirements of the relevant support regime continue to be met. This guidance offers valuable clarity, given the potential benefits of co-locating battery storage projects with intermittent renewable energy technologies such as solar PV and wind.

However, battery storage projects have suffered what some have considered to be a setback in terms of their treatment for the purposes of the Capacity Market mechanism, which is an important source of revenue for prospective battery projects. In December 2017, it was announced that the de-rating methodology for duration-limited battery storage would be changed for the 2017 T-1 and T-4 auctions, to use an Equivalent Firm Capacity metric.

This metric gives shorter duration storage units lower de-rating factors than longer duration storage CMUs, thus reducing payments under the CM for those shorter-duration storage units.

Nuclear policy

As discussed in earlier editions of this chapter, the UK Government decided back in 2008 that new-build nuclear power should form part of the UK's energy mix. It was subsequently decided that the CfD regime should be used to incentivise investment in new-build nuclear power, with the Government negotiating individual CfD contracts with nuclear developers. So far, only one CfD contract has been entered into, in relation to the Hinkley Point C project. To date, the Government has remained committed to new nuclear and there is a pipeline of other projects at different stages of development. However, from a value-for-money perspective, it may be difficult for the Government to justify a repeat of the strike price of £92.50/MWh granted to the developers of the Hinkley Point C nuclear project, particularly in the context of the much lower strike prices achieved in relation to offshore wind. The high price of nuclear was examined by the National Audit Office (**NAO**) in its report in relation to the Hinkley Point C project in 2018. This was followed by a Public Accounts Committee (**PAC**) report, which was also critical of the deal struck by the Government in relation to Hinkley Point C.

While it may be difficult for nuclear power developers to realise the same cost savings that are possible in the offshore wind sector (particularly as nuclear technologies tend to be first of a kind for the purposes of UK deployment), the Government has indicated that, as recommended by the NAO and the PAC, the Government, together with nuclear developers, will consider options to lower the price for nuclear. In particular, the energy Secretary of State issued a statement in June 2018 advising that the Government has commenced negotiations with the developers of the proposed Wylfa Newydd nuclear power plant, which is the next new nuclear project in the pipeline. In that statement the Secretary of State confirmed that the Government will be looking at alternative support structures for this project, including direct Government investment in the project, and that alongside its discussions with the developers of the project, it would be "reviewing the viability of a regulated asset base model as a sustainable funding model based on private finance for future projects beyond Wylfa".

In June 2018, the Government also published details of a new "sector deal" for the nuclear industry, including various commitments, such as funding for research and development.

A transferable tax history regime for upstream oil and gas

The Government has taken further steps to implement a new "transferable tax history" (**TTH**) regime, in an effort to support an upstream oil and gas industry dealing with various economic challenges, including future decommissioning costs. In March 2017, HM Treasury published a formal discussion paper on the case for allowing transfers of tax history between buyers and sellers of late-life assets in the UK offshore oil and gas industry, in an effort to maximise tax relief for decommissioning expenses. The issue being addressed is that under the UK oil and gas fiscal regime, a ring-fence applies to all fields (irrespective of when development consent was obtained) which prevents profits arising within the ring-fence from being sheltered by losses arising from activities carried on outside the ring-fence. In July 2018, the Government published a further policy paper on the proposed regime, together with draft legislation to implement it. TTH will allow a seller of an interest in a UKCS oil licence to transfer some of its tax history to the buyer of the field. The buyer will then be able to set the decommissioning cost of the field against the TTH. TTH will be available for licence transfers that receive OGA approval on or after 1 November 2018.

Endnotes

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Overview of the current energy mix, and the place in the market of different energy sources

Oil and gas

The U.S. mainly relies on petroleum and natural gas fossil fuels for two-thirds of its primary energy needs. The transportation sector accounts for the majority of liquid petroleum consumption, and the electricity, residential and industrial sectors are the major consumers of natural gas. In September 2018, the U.S. reclaimed the title of number one oil producer in the world, last held in 1973.

In 2017, the U.S. produced about 15.4 million barrels of petroleum per day (MMb/d), and consumed about 19.9 MMb/d, resulting in net imports averaging about 3.7 MMb/d from countries such as Canada (40%), Saudi Arabia (9%), Mexico (7%), Venezuela (7%), and Iraq (6%). Imports of petroleum in 2017 represented approximately 19% of total petroleum consumption, which was the lowest%age of imports since 1967. The U.S. Energy Information Administration (EIA) predicts that the U.S. will become a net exporter of petroleum by 2022. According to the International Energy Agency, the U.S. will account for 80% of the increase in global oil supply through 2025, primarily as a result of the onshore oil production boom in the U.S. led by hydraulic fracturing and other tight formation operations.

Power markets

Electricity in the U.S. is generated from three major categories of primary energy sources: fossil fuels (coal, natural gas, and petroleum); nuclear energy; and renewable energy sources. Fossil fuels remain the largest sources of electricity generation (63%), followed by nuclear energy (20%), and renewables (17%). Natural gas has overtaken coal to become the largest single source for electricity generation at about 32%, with coal falling to about 30%. This decline in domestic consumption of coal has occurred despite endorsement of the industry by the Trump administration. Although coal production in 2017 increased by about 6% over the previous year, coal consumption in the U.S. peaked in 2007 and has declined since, primarily due to a move towards natural gas and renewables in electricity generation. The U.S. is a net exporter of coal, with exports increasing slightly in 2017 consistent with the uptick in production and decline in domestic consumption.

Natural gas is serving as a bridge from fossil fuels to a renewable future, by reducing U.S. carbon emissions from older coal-fired plants and filling in the gaps where renewables fall short. In 2017, natural gas production was at its second-highest level on record as a result of more efficient and cost-effective drilling and production techniques used in onshore shale operations. This led to a decline in natural gas prices and increased use by the power sector.

Renewables and energy storage

Wind and solar prices have dropped significantly in the last decade such that these renewables are now undercutting the cost of natural gas in certain regions of the U.S. While the cost of natural gas-generated power is tied to the volatile commodity price of natural gas, the price of renewable energy is tied to its technology costs, which have steadily decreased in recent years. A recent report by Lazard found that the cost of producing one megawatt-hour of electricity from utility-scale photovoltaic solar is around $50, whereas the same megawatt-hour may cost $60 if generated from natural gas, $102 from coal, and $148 from nuclear.

The last few years have seen a strong commitment by many states and the private sector to embrace renewables. Many large U.S. companies have joined the RE100 group pledge to source 100% of their global electricity consumption from renewable sources by a specific deadline. Target, a major U.S. retailer, reported 147 megawatts of solar installed in 300 of its stores and recently announced that it had purchased enough Renewable Energy Credits in 2017 to power 100% of its global operations. Google also reached 100% renewable energy sourcing in 2017, and Apple recently announced that its global facilities are powered with 100% clean energy.

Battery electric storage is a major development on the power side that has accompanied the growth of renewable generation. According to the EIA, as of 2018 the U.S. had 708 megawatts of battery storage capacity, two-thirds of which was installed in the last three years. Much of the current installation is concentrated in California and the region known as "PJM," being all or parts of 13 Mid-Atlantic and Midwestern states plus the District of Columbia. Federal Energy Regulatory Commission (FERC) Order 841 promises to expand adoption in other transmission systems. Following last year's hurricane devastation, Sunnova, Puerto Rico's largest rooftop solar power provider, is now adding a battery system with each new home installation. Storage is increasingly recognised as conferring multiple benefits, including resiliency to grid outages and lower peak power costs.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Tariffs

Following the September 2017 decision by the International Trade Commission (ITC) that imported solar panels are injuring domestic manufacturing, President Trump approved tariffs on imported solar cells and modules. Analysts predicted that the solar tariffs would slow the shift to renewable energy in the U.S., since approximately 80% of solar panel products are imported. Indeed, since the imposition of tariffs, more than $2.5 billion in large solar installation projects have been cancelled or postponed. Many solar companies are presently petitioning for an exemption from the tariffs, arguing that they have unique technology or products.

In addition to the solar tariffs, in March 2018 President Trump announced a 25% tariff on imported steel and a 10% tariff on imported aluminium from select countries, including certain traditional allies of the U.S. such as Canada, Mexico, and the European Union. In August 2018, President Trump singled Turkey out for double tariffs, setting rates on steel and aluminium imported from Turkey at 50% and 20%, respectively. The impacts on the oil and gas industry may be significant, as these industries rely heavily on imported steel for drilling, pipelines, export facilities, refineries, and petrochemical operations. According to recent studies, 77% of steel used in U.S. pipelines is imported. It is not clear whether domestic steel and aluminium production can ramp up production to supply the industry without interruption. Complicating matters is that certain pipelines require a type of steel not manufactured in the U.S. Therefore, the tariffs may result in a delay of pipeline manufacturing and construction, thus hindering transportation. This could have serious implications for high-producing areas that currently have restricted pipeline capacity, like the Permian Basin in Texas and New Mexico.

Steel and aluminium also play a key role in renewable energy production and transmission. The solar and wind industries use a significant amount of steel and aluminium for wiring, transformers, turbines, battery system housing, transmission lines, and towers. Solar and wind assets are usually located in remote locations, and therefore require steel to construct transmission towers and lines to bring the power to consumers.

The global tensions created by the imposition tariffs also threaten U.S. exports. In August 2018, China proposed to counter U.S. solar and steel tariffs by introducing a 25% levy on liquefied natural gas (LNG). With the U.S. set to become the world's largest exporter of LNG as early as 2019, and China being the world's second biggest LNG importer in 2017, the prospect of Chinese LNG tariffs is troubling to the U.S. natural gas sector. Similarly, China announced a 25% duty on U.S. produced coal. China had more than tripled the amount of its U.S. coal imports in 2017 from 2016 levels, and had been looking to increase its purchases in future years. The U.S. coal industry is particularly dependent on foreign exports to remain profitable, so this development is concerning to an already stressed industry.

Permian Basin

The Permian Basin, which lies in the western part of Texas and southeastern part of New Mexico, has been experiencing one of the biggest oil booms in the history of U.S. oil. Over the last two years, the number of drilling rigs in the Permian Basin has more than tripled. In April 2018, an average of 449 rigs served the area, which represented 44% of all rigs drilling that month in the U.S. and 22% of all rigs drilling in the world. According to the EIA, more than half of the emergent growth in crude oil production in the U.S. will come from the Permian Basin.

Recently, the Permian Basin has experienced a surge of investors purchasing or leasing oil and gas assets. In the summer of 2018, the Bureau of Land Management (BLM) auctioned leases in the Permian Basin and grossed nearly $1 billion for 142 parcels, setting a new onshore lease record. Despite transportation bottlenecks due to a lack of sufficient pipelines and other infrastructure, private companies are continuing to pay record prices to secure assets in the region. Some operators have even resorted to transporting the oil via trucks, which has resulted in an inflated cost on producers known as the "basin differential".

Pipeline companies have billion-dollar plans to build new pipelines in the coming years to keep the oil and gas flowing out of the Permian Basin, with some scheduled to come online in late 2019. However, the newly imposed steel tariffs could increase the cost of pipeline projects, and potentially result in significant delays if the type of steel needed is not manufactured domestically.

Clean energy mandates

Despite the solar and steel tariffs and the current administration's strong endorsement of coal, many states across the U.S. continue to pursue clean energy goals. In September 2018, California enacted a law that set a 100% clean electricity goal for the state by 2045. The law sets forth the most ambitious carbon neutrality commitment of any major economic power in the world. California is now the second state in the U.S. to mandate a carbon-free grid, following Hawaii.

In addition to California's ambitious clean energy goal, in May 2018 the California Energy Commission (CEC) adopted new building standards that require builders of new homes in California to include solar photovoltaic systems starting in 2020. California is now the only state in the U.S. that mandates builders of new homes to either make homes available with solar panels or build a shared solar power system serving a group of new homes. The CEC has estimated that the new building standards will save homeowners around $19,000 in energy and maintenance costs over 30 years. Other states such as Hawaii and Arizona are considering enacting their own solar mandates, and New Jersey, Massachusetts and Washington, D.C. are considering legislation to require new buildings to be solar-ready.

Developments in government policy/strategy/approach

Opening federal lands to energy development

Debate has lasted decades on how to balance the use and the protection of federal lands. The administration under President Trump has endeavoured to increase energy exploration and development on federal lands, including an expanded offshore leasing programme, opening the Arctic National Wildlife Refuge (ANWR) to oil development, and shrinking several national monuments to potentially make way for energy development.

In early 2018, the Bureau of Ocean Energy Management (BOEM) released a draft National Outer Continental Shelf Oil and Gas Leasing Program for the years 2019–2024. The draft programme, if finalised, will replace the programme implemented by the prior Obama administration and currently in place for the years 2017–2022. When first announced in January 2018, the proposed 2019–2024 programme aimed to make over 90% of the total Outer Continental Shelf (OCS) acreage available for oil and gas leasing. However, almost immediately after announcing the plan, several state governors, lawmakers and residents objected to the nearly wholesale opening of offshore regions adjacent to their coastal states. In response, the Secretary of Interior made a series of public pronouncements indicating that certain sale areas – such as those lying off the coast of Florida – would be removed from the agency's programme, and other areas – such as the entire West Coast and nearly all the Eastern Seaboard – would be "marked down" from the original plan. In the 60 days after releasing the draft programme to the public, BOEM received over two million comments from interested parties. The comment period closed in early March 2018, and BOEM is expected to release its second draft of the programme in the fall of 2018, with a goal to finalise the programme in early 2019. In anticipation of the final plan, BOEM has moved forward with advance planning of certain lease sales proposed under the 2019–2024 programme, like the Beaufort Sea sale, which is scheduled to go forward in 2019 after finalisation of the leasing programme.

States have also begun to anticipate finalisation of the plan and have moved to block its effectiveness. In late August 2018, California state lawmakers passed a bill intended to prevent any new fossil fuel infrastructure originating from federal offshore leases from passing through the state's jurisdiction, which extends to three miles offshore. This measure follows the lead of New Jersey, whose governor signed a ban in April 2018 prohibiting oil and gas exploration in state waters. The governor of New York has also expressed support for a similar ban in his state.

In addition to offshore leasing, the Trump administration and Congress advanced policies and legislation in late 2017 and 2018 to open the ANWR to oil exploration. The ANWR has long been a point of energy debate in Congress, with proponents of development arguing that the eight-million-hectare (19 million acres) wildlife refuge is a source of potentially significant domestic oil reserves. However, a legislative ban on oil and gas development in the ANWR had been in place since 1980, until Congress lifted the ban in December 2017 as part of its tax-reform package. In April 2018, the Department of Interior (DOI) began the environmental review process necessary for setting up an oil and gas leasing programme in the refuge's 600,000-hectare (1.5 million acres) coastal plain. Although the process is now under way to lease portions of the ANWR for oil and gas development, analysts caution that actual production is likely years away when taking into account the time needed to acquire leases, conduct exploration, and develop necessary infrastructure in the remote region.

The Trump administration has also taken steps to open up onshore federal lands in the lower 48 states that have previously been off limits to energy development due to national monument status granted by previous administrations. In late 2017, President Trump ordered the significant reduction of two national monuments – Bears Ears and Grand Staircase-Escalante – located in Utah, and is reportedly considering shrinking or eliminating at least another 25 monuments around the country. Bears Ears and Grand Staircase-Escalante contain reserves of coal, oil and uranium that could be available for lease now that national monument status has been removed from large portions of the federal lands. At least one company has staked a mining claim on land that was formerly part of the Grand Staircase-Escalante National Monument, although the claim is being called invalid by groups opposing the Trump administration's decision to reduce the monument.

Offshore wind development

Despite a history of fits-and-starts in the U.S., offshore wind is finally gaining a foothold with new projects planned in federal waters off the coasts of New York, North Carolina, and New Jersey. The U.S. Department of Energy (DOE) reports that 28 offshore wind projects are in the planning stages, mainly located off the U.S. Eastern seaboard, but also along the West Coast, near Hawaii, and in the Great Lakes. Analysts anticipate significant growth in the industry over the next decade, and the Trump administration has expressed support for this form of renewable energy. The Interior Secretary endorsed offshore wind in BOEM's proposed budget for 2018, and publicly supported the leasing of federal waters to wind developers off the coast of North Carolina. In addition, DOE created a consortium in late 2017 to support the development of offshore wind technology, with federal funds going towards research and development aimed at decreasing the cost of turbines and improving efficiency. Congress has also been supportive of the wind industry generally by preserving its tax credits in the most recent tax reform bill passed in December 2017.

State governments are likewise getting in on the act with lawmakers in New York, New Jersey, Massachusetts, Delaware, Maryland, Rhode Island, Hawaii, and California all moving to support offshore wind projects in their jurisdictions in various ways. Some of the measures taken include setting aggressive renewable energy targets or mandates that will be partly achieved through anticipated offshore wind development; authorising subsidies for offshore wind projects; and passing laws that require utilities to enter into long-term contracts with offshore wind projects. However, goals to build large wind farms off the coast of California hit a snag in late 2017 and early 2018 when the U.S. Navy released maps objecting to wind projects in large sections of the state's coastline from the central coast down through southern California. State regulators and stakeholders continue to meet with the Navy to determine if there is a way to resolve the apparent conflicts identified by the Department of Defense.

Developments in legislation or regulation

Multiple legislative actions and court and agency challenges are under way that could have a major bearing on efforts by state governments to provide benefits to low-carbon power sources, which potentially conflict with FERC's governance of wholesale power markets.

States continue to expand renewable portfolio standards (RPS) that permit sales of power by wind, solar and other renewable generators at prices higher than those recoverable by gas- and coal-fired sources. As noted above, Hawaii is already on board for 100% renewable power by 2045, and California recently enacted SB100, moving California to 100% renewable and "zero-carbon resources" electricity by that same date.

The legality of zero-emission credit subsidies (ZEC) of nuclear power plants and other generators that receive state subsidies has been in question since the Supreme Court's decision in *Hughes v. Talen Energy Marketing* (U.S. 2016), a case dealing with power plant construction incentives. Illinois and New York federal courts recently sustained ZEC and RPS programs against challenges that such state actions were pre-empted by the Federal Power Act. New Jersey also recently conferred ZEC benefits on nuclear sources, not limited to plants in the state.

The wholesale power market conflict is playing out most notably in connection with FERC's June 2018 decision in *Calpine v. PJM Interconnection*. FERC and independent power producers have argued vehemently that states' "out of market" subsidies for certain types of generating units have created an unlevel playing field in RTO capacity auctions, forcing retirement of generating units that would otherwise be economical to operate. PJM proposed alternative reforms designed to eliminate this defect in its market rules. But FERC rejected both proposals by a 3-2 vote, and PJM's existing rules as "unjust and unreasonable". (Whether this finding affects auctions already held for 2019–2022 or requires refunds for capacity payments collected as a result of previous auction is uncertain.) Moreover, the commissioners in the majority staked out several general requirements for the RTOs to ponder – and for the states, industry and others to challenge.

First, FERC required PJM to impose minimum bid requirements on nearly every generator receiving out-of-market subsidies that bids into the PJM capacity auction. This is a major expansion of PJM's current Minimum Offer Price Rule (MOPR), which applies to only a handful of generating units. In an unexpected reversal of previous FERC policy, the term "subsidy" is defined to include any renewable energy resource that receives state support. Nuclear plants that receive ZEC payments, and coal-fired generators that are subsidised, would also be subject to the Rule.

FERC expects minimum bids to be set high enough so that in most instances, generators subject to the Rule will not clear the auction. This could deprive nuclear generators and other low-carbon resources of a key source of revenues, undercutting ZEC programmes and making it more difficult to finance renewables that previously had been able to receive capacity payments. FERC acknowledges that electricity users in some states will be exposed to double payments, funding state subsidies through state tax payments but still paying a share of PJM's capacity payments passed through to them as ratepayers.

Simultaneously, however, in a major departure from FERC's prior hostility to state subsidies, FERC allowed states to provide any subsidy they choose to generators within their borders as long as both the generator and a corresponding amount of load are excluded from the auction. This option, dubbed the Fixed Resource Requirement Alternative (FRR Alternative) has the potential to significantly alter the landscape in FERC-regulated wholesale markets. Critics fear that, if the FRR Alternative is widely used, the total number of megawatts of capacity procured in the auction will be reduced considerably, turning it into a residual market and giving a significant competitive advantage to generators that receive state subsidies.

Almost no one appears happy with FERC's June decision. The dissenting commissioners complained that FERC has overstepped its role by creating the FRR Alternative, undermining state efforts to subsidise renewable energy resources by preventing wind and solar generators participating in state RPS programmes from obtaining capacity payments in the auction. States made the latter objection as well, stressing that power sources without greenhouse gas emissions do not create externalities that other sources produce. Gas-fired generators also objected to the withdrawal of load from the PJM auction, fearing that it will create a shallow market, with subsidised generators locking in a preferred right-to-sell capacity to an increasing percentage of the state's load.

FERC asked for public comments before a further ruling is made prior to the 2019 capacity auctions. This controversy is sure to continue before the agency, as well as in other forums.

Judicial decisions, court judgments, results of public enquiries

Climate change litigation

Lawsuits filed by various groups and governments regarding climate change and its effects continued to dominate headlines in the U.S. this year. To date, at least 14 local governments and one state have filed lawsuits against major energy producers seeking damages for climate change-related impacts such as rising sea levels and health consequences. In general, the lawsuits make a public nuisance claim against the companies, with some also alleging negligence and civil conspiracy. The governments seek billions of dollars to help pay for infrastructure – such as sea walls – which they say are necessary to protect their jurisdictions, and also to cover health care costs and environmental damages brought on by an increase in greenhouse gases and global warming trends.

A major allegation running through the lawsuits is that companies committed representations by dismissing the consequences of climate change while promoting fossil fuels. This line of attack is behind an ongoing investigation led by the attorneys general from New York and Massachusetts into ExxonMobil's corporate shareholder disclosures, which has resulted in the production of numerous documents on the subject that are then cited in the nuisance cases.

Despite the barrage of lawsuits, energy companies have been successful in having many of these cases dismissed. Many federal judges presiding over the matters have found that the questions at issue relate to policy matters properly decided by the legislative and executive branches of government, rather than by the courts.

Energy companies have not been the only target of climate change lawsuits in the U.S.; the federal government and many state governments have also been sued for failing to prevent and appropriately address the impacts of climate change. These lawsuits, filed by young people across the country and supported by a group called Our Children's Trust, rely on the public trust doctrine, which is the principle that the government holds natural resources in trust for the public. To date, one federal lawsuit and nine similar state cases have been filed from Alaska to Florida. The federal case, pending in federal district court in Oregon, is set to go to trial as soon as October 2018. The plaintiffs in that matter are demanding extensive changes in federal climate policy and government programmes they allege encourage fossil fuel development.

Coal ash

Coal ash, generated in large quantities by coal-fired power plants, is one of the largest industrial waste streams in the U.S. The waste has been classified by the Environmental Protection Agency (EPA) as non-hazardous for purpose of waste disposal rules, although it can contain arsenic, lead and mercury. In August 2018, a federal appeals court threw out EPA regulations that allowed coal-fired power plants to continue using existing unlined and clay-lined coal ash disposal ponds. The court found that the regulations failed to adequately protect the public from the threat of water contamination posed by these types of surface impoundments. If the decision stands, it could impose a significant cost on coal energy producers that may be required to retrofit or else close hundreds of impoundments, which can average 50 acres in size and 20 feet deep. At the very least, the decision creates uncertainty for the industry, which is already under financial pressure due to a changing energy mix brought on by an increase in natural gas and renewables.

Major events or developments

Nuclear

The nuclear industry suffered additional setbacks in 2018, including the announced retirement of three nuclear generating facilities in Ohio and Pennsylvania. After failing to secure a subsidy from the state of Ohio, and following denial of a requested emergency order from the DOE to keep the plants operating, the plants' operator announced in April 2018 that the facilities would close before the end of their operational lives. The closure plan calls for the three plants to shutter by October 2021, although the operator continues to search for a solution with state officials to keep the plants operating.

This development is in line with a trend seen over the last several years whereby coal and nuclear plants have been less able to compete with power generated by natural gas and renewables. Proponents of the industry point to its reliability and carbon-free power generation capabilities. However, such benefits have not succeeded in insulating the industry from market forces that value cost above other factors. The high costs associated with constructing and maintaining nuclear facilities has been detrimental to approvals and financing, and will likely continue to hamper the industry without significant technological advances, modular production, or government intervention.

In addition to high costs, the nuclear industry has also had to contend with a decades-long debate about where to store spent fuel and dispose of nuclear waste generated by power plants and the military. President Trump and the DOE have recently made a push to revive a long-dormant plan to store nuclear waste in Yucca Mountain, located in Nevada. Selected by Congress in 1987 to be the nation's permanent nuclear waste repository, licensing of the Yucca Mountain facility has never been finalised due to opposition by political leaders from Nevada and residents concerned about impacts to groundwater and safety. Approximately 80,000 metric tons of spent nuclear fuel are presently being stored at nuclear power facilities across the country, and finding a permanent disposal solution would represent a key victory for the industry. In June 2018, the House voted to resume the licensing process for Yucca Mountain. Although the bill stalled in the Senate, the administration's attempts to restart the licensing hearings are expected to resume following the midterm elections in November 2018.

Cybersecurity

Cybersecurity continues to be a key concern with respect to resilience and reliability of the energy grid, not least because more than 80% of the U.S.'s energy infrastructure is owned by the private sector. In 2018, several natural gas pipeline operators were the victims of hackers, resulting in service disruptions and breakdowns in electronic communications with customers. In March 2018, the Federal Bureau of Investigation (FBI) and Department of Homeland Security (DHS) issued an alert stating that multiple crucial infrastructures in the U.S., including energy and nuclear facilities, had been targeted by Russian government hackers. Millions in federal funding has been allocated to the newly-established Office of Cybersecurity, Energy Security and Emergency Response (CESER), which will bolster the DOE's efforts in energy security.

Vulnerability of the energy sector will continue to grow as the energy industry becomes more automated and internet dependent. A potential defence against hackers may be the use of blockchain technology with distributed encrypted ledgers. In 2017, DOE began working with other entities to develop blockchain cybersecurity technology to secure distributed energy resources at the grid's edge. Utilities have already begun upgrading their systems to provide for greater grid intelligence and communication with customer devices. Blockchain may revolutionise the energy industry by enabling peer-to-peer energy trading rather than centrally controlled production, transmission and distribution.

Proposals for changes in laws or regulations

Affordable Clean Energy Rule

After much anticipation, the EPA proposed a new rule in August 2018 to curb greenhouse gases (GHG) from power plants called the Affordable Clean Energy (ACE) Rule. The proposed rule replaces the prior Obama administration's controversial Clean Power Plan (CPP), which was a cornerstone regulation of that administration's attempt to address climate change. ACE establishes emission guidelines for states to use to limit GHG emissions from power plants located in their jurisdictions, although unlike the CPP, it provides no numerical targets for states to achieve. ACE aims to reduce GHG emissions from power plants in four main ways: (1) by defining the "best system of emission reduction" for existing power plants as on-site, heat-rate efficiency improvements; (2) by providing states with a list of "candidate technologies" they can use to establish standards of performance and incorporate in their state plans; (3) by updating the New Source Review (NSR) permitting programme to encourage efficiency improvements at existing power plants; and (4) by giving states additional time and flexibility to develop their state plans.

Although EPA estimates that ACE will reduce carbon emissions from current levels, critics of the rule argue that the reductions are not sufficient to stem climate change and are far less than what would have been achieved under the CPP. The CPP had been mired in litigation, which had resulted in a suspension of the rule and uncertain implementation schedule. EPA notes that implementation of ACE, when compared to a no-action baseline, will result in a reduction of carbon dioxide emissions by 14–27 million tons annually.

Just as with the CPP, states are expected to sue to prevent implementation of ACE and will likely argue that EPA's proposal fails to comply with its obligation to regulate carbon emissions. However, market forces and state clean energy mandates continue to push carbon emissions downward, even in the absence of comprehensive federal regulation. If these market forces and actions by states and cities across the country continue, they are predicted to result in a 28% reduction of carbon dioxide emissions by 2030 even without incremental federal regulation.

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Uzbekistan

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Overview of the current energy mix and place in the market of different energy sources

General notes

Along with Kazakhstan and Turkmenistan, Uzbekistan is one of the few countries in Eurasia that is totally energy-independent, self-sustaining and rich enough to subsidise domestic consumption and export energy resources. With abundant gas reserves and a growing gas production rate, Uzbekistan holds the position of the third-largest natural gas producer in Eurasia, behind only Russia and Turkmenistan, and eighth-largest in the world. At the same time, oil production has consistently decreased over the last decade as oil fields are depleted, and this situation puts pressure on the industry to focus primarily on thermal, hydropower and alternative power facilities and capacities.

The entire energy sector is still monopolised by the government, held by the state joint stock power company, Uzbekenergo. Despite efforts, it has never been privatised. Limited export capacities and obsolete energy infrastructure are major concerns for the government, which is now trying to coordinate and implement various programmes to diversify the use of hydrocarbons and their export routes, as well as to encourage alternative energy projects and energy-saving programmes. Uzbekistan has no nuclear power stations yet and, despite previous reluctance to construct a nuclear power station in what is a seismically active area, it now appears that further energy production for Uzbekistan will inevitably hit the nuclear road.

The energy composition of Uzbekistan currently rests upon hydrocarbon consumption, as hydroelectric power is limited by shrinking water resources. Hydrocarbons, mainly gas, comprise nearly 97% of the country's energy balance, with the remaining 3% coming in the form of hydro, coal and charcoal.[1] Renovating the power transmission networks owned and monopolised by the government is one of the energy sector's priorities.

The installed capacity of Uzbekistan power plants exceeds 12.6 GW, which represents more than half of all the generating capacity of the Interconnected Power System of Central Asia, which includes the power systems of Turkmenistan, Tajikistan, Kyrgyzstan and southern Kazakhstan. The annual electricity production volume is 55 billion kWh, which makes Uzbekistan the largest electricity producer in Central Asia and a net exporter.[2]

Natural gas and electricity are two of Uzbekistan's largest export items and represent up to 25% of all exports. The share of annual power consumption across the country is 1,940 kW/h *per capita*.[3]

Overview of the hydrocarbon industry

According to the materials made public during the Oil & Gas Exhibition 2015, Uzbekistan's recoverable proven hydrocarbon reserves exceeded 2.5 billion metric tonnes of oil equivalent as of early 2015, with gas reserves accounting for around 65% of this volume. In 2017, total crude oil production was about 54,000 barrels per day (bbl/d), while its consumption reaches 71,000 bbl/d as per BP *Statistical Review of World Energy* 2018. It is estimated that nearly two-thirds of all known oil and natural gas fields are located in the Bukhara-Khiva region in the south of Uzbekistan.[4]

According to the BP *Statistical Review of World Energy* 2018, Uzbekistan's proven reserves of natural gas were 1.2 trillion cubic metres (tcm) as of the end of 2017, effectively making it the 19th largest proven reserve-holder in the world.[5] According to the BP *Statistical Review of World Energy* 2018, Uzbekistan produces 53.4 billion cubic metres (bcm) of natural gas annually, with a steady growth rate. An Uzbekneftegaz statement suggests that natural gas production stood at 56.5 bcm in 2017, and may reach 66 bcm in 2018.[6] Between January and April of 2018, the production of natural gas reached a new record of 19,51 bcm. The consumption rate of natural gas in Uzbekistan was estimated at 41.6 bcm in 2017, which includes 30 bcm for consumer consumption. At present, Uzbekistan exports approximately 11.8 bcm of its produced natural gas annually, which breaks down into 6.7 bcm for export to Russia, 1.7 for export to Kazakhstan and 3.4 bcm for export to China, according to the BP *Statistical Review of World Energy* 2018. In 2018, Uzbekistan also resumes the export of natural gas to Tajikistan and plans to increase exports to China up to 10 bcm annually.[7]

Uzbekistan serves as a transit country for natural gas flowing from Turkmenistan to China through a strategically important Central Asia-China gas pipeline. This pipeline is also utilised to export natural gas produced in Uzbekistan, and is expected to play a growing role for China. In addition, two new natural gas pipelines, Gazli-Kagan and Gazli-Nukus, were built to connect the Ustyurt and Bukhara-Khiva regions with the existing system.

Overview of the coal industry

Uzbekistan's proven coal reserves were estimated in 2017 at 1,375 million tonnes oil equivalent. The reserves are particularly represented by anthracite and bituminous types of coal, which are widely used in a variety of manufacturing processes, as well as in the production of electricity. The annual production rate, calculated in 2017, is 1.1 million tonnes oil equivalent, and the consumption rate is 1.2 million tonnes oil equivalent, respectively.[8] Four coal enterprises are engaged in open pit mining, underground mining and underground coal gasification.[9] Since the adoption of the Modernization and Retooling Program for the Coal Industry in 2013, coal mining is expected to gradually increase in such a way as to supplement natural gas and oil products for the power industry.

Overview of the nuclear industry

Uzbekistan is a party to the Non-proliferation Treaty and ratified an Additional Protocol Agreement with the IAEA in 1998. It has also ratified the Central Asia Nuclear Weapon Free Zone treaty, and does not plan to build a nuclear power station. In February 2014, the State Committee for Geology and Mineral Resources of Uzbekistan reported uranium resources of 138,800 tonnes of enriched uranium (tU) in sandstone and 47,000 tU in black shale. Navoi Mining & Metallurgy Combinat (NMMC), as part of the State Holding Company Kyzylkumredmetzoloto, undertakes all uranium mining in Uzbekistan. NMMC produces 2,400 tU annually, with exports going mainly to the USA through Nukem Inc.; South Korea through Kepco; Japan through Itochu Corp.; and now to China through CGN. On 27 September 2017, a minister of foreign trade of Uzbekistan communicated that Uzbekistan had agreed to supply uranium concentrate to Nukem Inc. for seven years for the amount of US$300m.[10]

As discussed above, in May 2018 Uzbekistan moved to engage Russian Rosatom to design, build and operate a nuclear power station in Navoi Region.[11] The construction may take more than five years and may cost more than US$ 10bn. On June 19, 2018 Uzbekistan established the Agency for Development of Nuclear Energy under the Cabinet of Ministers, which will oversee the operations of three corporations engaged for: (1) design and construction of a nuclear power station; (2) operation of a nuclear power station; and (3) development of uranium deposits, marketing and utilisation of uranium.[12]

Overview of the power industry

With the gigantic power-generation facilities of the Soviet era and an ample supply of natural gas, Uzbekistan has become the largest electricity producer in Central Asia. Twelve thermal power plants and 31 hydropower plants annually generate up to 58.9 billion kW/h of electrical power and more than 10 million Gcal of thermal power, of which 88.5% is provided by natural gas-powered thermal plants and 11.5% by hydropower plants. Thermal power plants (TPPs) account for a total capacity of 10.6 million kW; the biggest among them being Talimardjan, Syr-darya, Novo-Angren and Tashkent TPPs, generating over 85% of electric power. For power generation at TPPs, the gas share is 90.8%; mazut is 5.3%; and coal is 3.9%.

The electricity is transmitted and distributed through power transmission lines whose voltage ranges between 0.4 kV and 500 kV, and whose total length currently exceeds 243,000 km.

Uzbekistan's electricity capacity is expected to increase thanks to the modernisation of old facilities. Uzbekenergo is currently implementing 28 large-scale investment projects; 14 of them, worth US$ 3.3bn, were terminated by the government due to the failure of sponsors to implement them.[13] The Presidential Decree dated February 3, 2018 approved five investment projects for Uzbekenergo directed at the construction, modernisation and improvement of existing capacities.[14]

The development of the power industry for the period leading up to 2015 was determined by Presidential Decree No. 1442 dated 15 December 2010, which highlighted 48 investment projects, including 15 TPP modernisation plans, with the development of an additional 2,329 MW capacity, and nine hydropower projects with an additional 63.8 MW capacity in small HPPs. However, this did not help Uzbekenergo to stay afloat. In June 2018, the government adopted a new roadmap for Uzbekenergo financial recovery,[15] which included such measures as termination and suspension of certain projects, sale of non-core underutilised assets through public auctions, privatisation of other assets and return of unused land plots and facilities.

During the last decade, hydropower energy production has been steadily increasing. It is expected to grow mainly by virtue of the development of mini-hydropower plants with a capacity of 420–440 MW and the modernisation of existing HPPs, as shrinking water resources are insufficient for a massive hydropower project. In 2017, the consumption of hydroelectricity in Uzbekistan amounted to 2.7 million tonnes of oil equivalent, according to the BP *Statistical Review of World Energy* 2018.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

The government recently adopted a special five-year programme to boost gas production. As announced during the 2017 Global Oil & Gas Uzbekistan Conference, by 2022 Uzbekistan plans to increase gas production by 53.5 bcm; oil production by 1.9 million tonnes; and gas condensate production by 1.1 million tonnes.[16] It is expected that Uzbekistan and foreign investors will direct US$3.9bn towards energy projects during this period.

Falling oil and gas prices around the world have also affected petrochemical projects in Uzbekistan, where some investors have decided to pull out, resulting in uncertainty regarding the future of those projects.

Following the withdrawal of Malaysian Petronas Carigali from all existing petroleum upstream projects in Uzbekistan, it is becoming clear that Russian Gazprom or its affiliates have taken over the Production Sharing Agreement (PSA) in Baisun Area, replacing Delta Oil, another member of the consortium formed for the implementation of the PSA. The area has been renamed "25 Years of Independence", whose crown jewel is the 10 bcm gas-condensate field, Jel. It is expected that Delta, Petronas, and Uzbekneftegaz will somehow sort out the termination of the previous PSA through an ongoing arbitration in London.

The Uzbek Government has been promoting the construction and financing of petrochemical facilities in an effort to diversify the economy and shift the focus of exports from raw materials to added-value products. In 2013, NHC Uzbekneftegaz, KOGAZ and Honam Petrochemical finalised the financing of the construction and operation of a petrochemical joint venture that will: extract US$4.5bn of natural gas from onshore Surgil fields; sell methane gas locally; and process ethane and condensate for petrochemical production, high-density polyethylene and polypropylene, to be sold on local and export markets. The facility was completed and put into commercial operation in 2016. Earlier this year, Uzbekistan and Lukoil commissioned the Gas Processing Facility at Kandym Fields, with a capacity of 8.1 bcm per year, to produce purified natural gas, stable gas condensate and sulphur.[17]

Uzbekistan's plans to gradually reduce its oil imports by converting natural gas into other hydrocarbon products have also been affected by the slump in oil prices. In 2009–2014, Sasol, Petronas and NHC Uzbekneftegaz signed an agreement to establish a joint venture for developing the GTL (gas-to-liquid) project on the basis of the Shurtan Gas chemical facility, which was expected to convert 3.5 bcm of natural gas and condensates into about 1,743,000 t/y of hydrocarbon products. The US$5bn facility was expected to be commissioned by 2017.[18] However, due to the dramatic changes in oil and gas prices, Sasol exited the project.[19] Uzbekneftegaz acquired Sasol's interests in the project and awarded Topsoe the contract for the construction of the plant, with the licence from Sasol.[20] The GTL plant will process 3.5 billion cubic metres of gas and produce 863,000 tonnes of diesel fuel, 304,000 tonnes of aviation kerosene, 395,000 tonnes of naphtha and 11,200 tonnes of liquefied gas.[21]

The government of Uzbekistan is also implementing other projects aimed at developing the production of energy from alternative sources. The "first solar station" in the region, which was planned to be near Samarkand and was expected to produce nearly 100 million MW of electricity per year, has been aborted.[22] This year, however, saw two major solar energy projects. On April 19, 2018 a Presidential Decree approved the power purchase agreement between Uzbekenergo and Canada-based SkyPower Global, which will invest US$1.3bn in a project to build photovoltaic solar energy facilities with total capacity of 1 GW.[23] In August 2018, an agreement was signed between IFC, the State Committee for Investments and Uzbekenergo on financial advisory services by IFC in attracting private investors on a competitive basis for design, financing, construction and operation of solar power facilities worth up to $1bn on the basis of a public-private partnership. A pilot project for construction of a solar power plant with a capacity of up to 100 MW in Navoi region is to be tendered in March 2019.[24] It is estimated that solar energy potential in Uzbekistan, where there are 300 sunny days in a year, can range from 525 to 760 billion kWh, with potential wind generation of more than 1 billion kWh, and biomass energy of up to 6 billion m^3 biomethane per year.[25]

There are plans to build five solar stations by 2020 with a total capacity of 500 MW.[26] In addition to the project near Samarkand, two stations of a similar capacity were due to be located in the Namangan and Surkhandarya regions. The total cost of constructing the stations is estimated to be US$450m.[27]

Uzbekistan also plans to build an oil refinery in Jizzak region with US$2.2bn investments from Russian oil, and to establish an olefin facility in Kashkadarya region with US$2.9bn investments.[28]

Developments in government policy/strategy/approach

The Uzbek government has implemented the following policies in the energy sector:

Renewables: The government of Uzbekistan is aiming to generate approximately 21% of all its energy needs from renewable sources, including solar, by 2031. It is therefore contemplating developing a strategy for the use of alternative sources of energy, along with the very intensive construction of small HPPs in the near future. On 5 December 2017, Uzbek government officials, experts and representatives of business enterprises attended a workshop on renewable energy (RE) policy development jointly organised by the Government of Uzbekistan and the World Bank Group in partnership with the International Renewable Energy Agency (IRENA), to discuss the prospect of using renewable power in Uzbekistan.[29] The decree of the President of Uzbekistan on a programme of measures aimed at reducing energy intensity and implementing energy-saving technologies and systems for the period 2015–2019 dated 5 May 2015, and the Action Program on Renewable Energy Development for 2017–2021 adopted in May 2017 to promote private sector investments in renewable energy development, serve as key indicators in this regard.

Energy efficiency: There are a number of campaigns that are being carried out to install modern meters for consumers of natural gas, hot water and electrical power for households. The efficiency of electricity transmission and distribution is one of the government's priorities, due to significant losses, estimated to represent 20% of net generation, with the cost of excess losses estimated at US$340m.[30] Energy efficiency became a focal point for the National Energy-Saving Company, a newly established authority pursuant to the Presidential Decree dated 23 August 2017.[31]

Added-value: As noted above, the government is also shifting its focus to diversifying the economy by building and operating petrochemical facilities that use natural gas as a raw material to produce petroleum products instead of exporting natural gas.

Substitution: As highlighted, an Uzbekistan GTL facility is expected to convert gas into liquid hydrocarbons and decrease the import of crude oil. Consumer vehicles are also expected to shift from using gasoline to gas-powered engines.

Modernisation: The government undertakes to modernise and retool existing outdated, low-efficiency, gas-fired plants, whose efficiency is 40% lower than that of modern thermal plants, as the country loses approximately US$1.2bn in potential gas export revenues.

Utilisation: Uzbekistan is one of the world's top 20 gas-flaring countries, with 1.8 bcm flared annually. This is being addressed through the programme on the utilisation of the associated gas that was developed by NHC Uzbekneftegaz for its subsidiaries.

Gas exports: To increase and diversify gas exports, the Uzbek government plans to increase gas production by attracting foreign investors for the exploration and development of hard-to-recover fields and committing additional volumes for the Central Asia-China Gas Pipeline.[32] In an effort to increase gas exports, the government also plans to use more coal and alternative energy for TPP and domestic consumption.

Increase of production: The government plans to significantly increase the production of oil and gas condensate to keep the country's economy independent of oil imports that normally come from Kazakhstan. The government is looking to improve the rate of oil recovery, conversion and gas processing efficiency to raise product quality to world standards, and to increase the acreage for the hydrocarbon resource base, primarily liquids, through new discoveries. The Government also approved a special five-year state programme on increasing hydrocarbon production for 2017–2021 in line with the Presidential Decree dated 9 March 2017.[33] Specific privileges and preferences are granted to enterprises and organisations that use energy from renewable sources in their production.[34]

Developments in legislation or regulation

The new Regulation No. 164 adopted by the Cabinet of Ministers of the Republic of Uzbekistan on the use of petroleum products has been in force since June 2014. This regulation sets the general rules of delivery and acceptance of petroleum products, storage conditions, and transportation rules. It also specifies environmental and safety requirements.

Additionally, to monitor reserves of mineral resources, companies engaged in the oil industry must submit annual reports regarding resources reserves used in the past year.

On 14 August 2014, the Uzbek Cabinet of Ministers approved a regulation forming the exploration programme of the NHC Uzbekneftegaz No. 230. The long-term exploration programme determines the main directions of development for the geological sector. The annual exploration programme includes geological exploration to search for oil and gas reserves given the target parameters (direction, stage, types and exploration volume, expected outcomes, the amount of the planned appropriations by indicating the sources of their funding) for each project, as well as the expected timing of their implementation.

On 4 March 2015, a Program of Measures to Secure Structural Reforms, Modernization and Diversification of Production for 2015–2019 was adopted by Presidential Decree No. UP-4707. The new programme covers 846 investment projects worth US$40.8bn. It is expected that the share of the industry in the country's GDP will increase from the current 24% to 27% in 2020.

According to Decree No. UP-4707, the consistent modernisation of existing facilities and the creation of new power-generating facilities is expected on the basis of the introduction of resource-saving and modern combined-cycle plants of solar technologies.[35]

The Government of Uzbekistan is paying special attention to the development of low-carbon sectors of the economy. On 5 May 2015, a Programme of Measures was adopted by Presidential Decree to reduce energy intensity, implement energy-saving technologies and systems, both in different sectors of the economy and in the social sphere during 2015–2019. The programme outlines key directions for the implementation of energy-saving technologies and energy-reduction programmes, whilst also promising tax benefits to entities producing energy from alternative sources.

The New Decree of the President was issued on 9 March 2017 No. PP-2922 that adopted the five-year programme towards increase of hydrocarbon production for years 2017–2021.

The Decree of the President was issued on 28 April 2018 No. PP-3687 that approved the Power Purchase Agreement with SkyPower Global. The Decree also sets a package of incentives which are likely to be expanded to all other successful bidders for solar power projects in Uzbekistan, so as to avoid creating a disadvantageous environment for competitive independent power producers. The Decree, particularly, establishes: (a) that the investor company, its project companies and subcontractors are exempt from customs duties, corporate income tax, VAT and mandatory payments to the Road Fund and Education and Medicine Development Fund, property tax on specific equipment and pertaining land use tax; and (b) that if Uzbekenergo fails to purchase power, the State Budget will take responsibility, and the Ministry of Finance will issue the guarantee for Uzbekenergo.[36]

Judicial decisions, court judgments, results of public inquiries

Judicial practice is not publicly available in Uzbekistan, and we are not aware of cases where the Uzbek courts have interpreted matters relating to the energy sector. However, we should note that electricity tariffs have been escalating over the last decade, raising concerns on the part of investors regarding increases in production costs. Some foreign investors, whose disputes with the government have been brought before different arbitration forums, intend to file claims for damages relating to the unilateral increase in electricity tariffs.

Major events or developments

Key events in the oil and gas sectors in Uzbekistan during the last year include the following:

In June 2017, the Government of Uzbekistan issued the list of strategic state-owned units that are not subject to privatisation. The list includes NMMC, Uzbekneftegaz and its specialised companies (such as UzTransGaz, responsible for gas transportation, and Uzburneftegaz, engaged in upstream operations), and Uzbekenergo.[37] Further, on 30 June 2017 the Decree of the President No PP-3107 was issued to reorganise the integrated chain of companies under Uzbekneftegaz to bring their organisational form into compliance with the requirements of legislation on stock companies.[38] Some privatisation efforts were announced in accordance with the Decrees of the Cabinet of Ministers dated 29 June and 25 August 2018. These documents mandate Uzbekneftegaz to sell off non-core and unused assets to private parties.[39]

Uzbekistan is also witnessing interest in its upstream and downstream assets from large oil and gas corporations and banks from Russia. During the joint forum held on 29 September 2017 in Tashkent, several Russian giants revealed plans to invest US$3bn into the hydrocarbon industry of Uzbekistan through the Russian agency for insurance of export credits and investments. Plans include the involvement of Gazprombank in financing the GTL project.

Lukoil was also reported to be committing additional financing in the amount of US$ 3bn to fund its existing upstream PSA projects in Uzbekistan while renegotiating down the royalty rate, due to the change in the export gas price. On 23 September 2017, Lukoil commenced commercial production at the Gissar Group of Fields in Uzbekistan with the plan to achieve annual production of 5 bcm of natural gas.

In April 2017, Gas Project Development Central Asia (a subsidiary of Gazprom International), Altmax Holding Ltd and Uzbekbeftegaz executed a PSA to conduct appraisal works and further development of the field “25 Years of Uzbekistan Independence”, with a view to constructing a Gas Processing Facility with the US$5.8bn investment plan.[40]

Uzbekneftegaz decided to invest some US$200m in geological prospecting to find heavy oil in the south and east of Uzbekistan. Uzbekneftegaz has already started to look for heavy oil and bitumen in the Korsagly-Dasmamagin area and the Besharcha block in the Surkhandarya district, as well as in the Fergana area in the east of the country. Uzbekneftegaz believes that it will be possible to produce at least 100,000 more tonnes of oil *per annum* in those areas after the works’ completion.

The Russian oil company Lukoil has commenced the implementation of the active phase of the Kandym Early Gas Project for the construction of a gas processing plant (GPP) and the arrangement of the Kandym group of deposits in the Bukhara region worth US$2.66bn. The GPP will be built by 2019, with a projected capacity of 8.1 bcm of gas per year. It is planned that, in the initial stage of the fields' operation, 2.2 bcm of gas will be produced annually and transported to the Mubarek Gas Processing Plant.

Moreover, Lukoil has started testing the operation of two preliminary gas processing terminals (PGPTs) in the area of North Shady, and deposits in Kuvachi-Alat in the Bukhara region of Uzbekistan, as part of the "Early Kandym gas" project. The total capacity of the units is 2.2 bcm of gas per year. The launch of the new facilities will allow Lukoil to significantly increase the volume of gas produced in Uzbekistan.[41]

Lukoil has also reported that it is in talks with South Korean agencies to raise US$2bn in order to finance these projects in Uzbekistan.[42]

Uzbekneftegaz and Chinese CNPC will begin the construction of the fourth line of the Uzbek section of the gas pipeline "Central Asia-China", at a total cost of US$800m. The gas pipeline, with a capacity of 20 bcm of gas, is planned to be put into operation in 2017.

Uzbekenergo has also completed the construction of the external power supply Ustyurt gas and natural gas chemical complex, worth about US$45m. The project has involved the construction of a substation with a capacity of 220 kW. Construction is financed by Uzbekenergo's own funds and Uzbek banks. The capacity of the natural gas chemical complex will allow 4 bcm of natural gas to be processed per year, along with the production of 400,000 tonnes of polyethylene and 100,000 tonnes of polypropylene. The total cost of the project is US$4.2bn.

In the power industry, Uzbekenergo continues to enhance existing power stations, construct new power stations and experiment with renewable energy projects.

For the construction of the new 450 MW Thermal Power Station in Syrdariya Region, the contract for the feasibility study and project documentation was awarded to EDF (France). Mitsubishi Corporation and Mitsubishi Hitachi Power Systems, Ltd commenced two turn-key projects for extension of the Navoi Thermal Power Station with a 450 MW second turbine and construction of a new 900 MW Thermal Power Station in Namangan Region. Hyundai Engineering Co. Ltd and Hyundai Engineering & Construction Company Ltd were awarded a contract for the construction of two turbines of 230–280 MW at Tahiatash Thermal Power Station.[43]

The Russian company 'Power Machines' was chosen for the modernisation works of three hydro-generators at Charvak hydropower plant (HPP), which has a capacity of 155 MW, replacing the stator's winding on the hydro-generators and installing new feed systems on them. Earlier this year, it was reported that Power Machines had completed the modernisation of the Charvak hydropower plant (HPP).[44] Charvak HPP is the largest hydropower plant in the Chirchik-Bozsu cascade of hydropower plants.

In addition, the hydro-mechanical parts of the regulators and oil pressure units were modernised on all four hydraulic units. The capacity of each hydraulic unit is set to increase from 155 MW to 175 MW, which will provide an opportunity to generate an additional 120 million kilowatt hours of electricity annually. The project is believed to have cost US$53.79m.

There are plans to explore and extract hydrocarbon deposits in the Uzbek part of the Aral Sea. The preliminary costs of this project for 2017–2031 amount to US$300m.

In the area of renewable energy, Uzbekenergo announced its plans to deploy five 100 MW solar plants in 2017–2021. The renewable energy plan also envisages the construction of eight hydropower plants and expansion of the capacity of 13 existing hydropower stations by 154 MW. The total investment will reach US$1.8bn.[45]

Proposals for changes in laws or regulations

As proposals for regulatory reforms are not widely discussed in public, we are not aware of any reforms in this sector. We may, however, expect new legislation in the area of renewable energy, particularly solar and wind energy, tariff regulation and green energy laws. It is likely that Uzbekistan will be in a position to develop public-private partnership laws or laws in relation to Independent Power Producers in the short term. There is a proposal to develop the draft of a law on alternative sources of energy for the parliament to adopt in nearest future.

* * *

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Zimbabwe

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Overview of the current energy mix, and the place in the market of different energy sources

Zimbabwe relies for its energy supply on thermal energy, hydroelectric and, to a limited extent, solar energy. Zimbabwe still has huge deposits of coal, which is used in the generation of electricity. The electricity generation company owned by the government recently embarked on an expansion of its coal-fired power plants, which is expected to add an additional 300 MW.

The total electricity supply as of 11th June 2018 of 1,600 MW was met from hydro (38.06%), thermal (27.56%) and imports (34.38%). Zimbabwe is part of the Southern Africa Power Pool (SAPP) which has 12 member counties represented by their respective power utilities organised through the Southern African Development Community. Zimbabwe still relies on members of SAPP for its electricity imports. Because Zimbabwe is centrally located in the SADC block, electricity imports come from members of SAPP.

Solar energy has huge potential but contributes an insignificant amount to the national grid for now. There has been an increase in interest in solar energy generation for both on-grid and off-grid systems. Most of these projects are, however, still in their early stages.

Zimbabwe's population is largely rural and relies mainly on the use of biomass and petroleum products. In 2016, it was estimated that 67.72% of the Zimbabwean population was living in rural areas. Only 9.8% of that proportion had access/or was using electricity.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

There have been significant changes on the political front with the resignation in November 2017 of the former President Mugabe who was in power for over thirty-eight (38) years. This was followed by an election in July 2018 that retained the President who replaced Mugabe. The new administration has been actively encouraging investments in the country across all sectors. This has seen a surge in international interest in energy projects in Zimbabwe and it is most likely that this will result in the licensing of more Independent Power Producers (IPPs).

The work on the expansion of the major hydroelectric plant at Kariba South was also completed, which increased the power generation capacity by a further 300 MW. Work on the construction of two additional units at the main thermal power station at Hwange Power Station also commenced, which will result in an additional 600 MW being added to the national grid on completion.

Developments in government policy/strategy/approach

Zimbabwe enacted in 2007 the Indigenisation and Economic Empowerment Act [Chapter 14:33] which came into force in March 2010. This law requires that the majority shareholding (51%) in any business should be held by indigenous Zimbabweans. This law was regarded as a major impediment to foreign direct investments in major projects such as energy. The indigenous Zimbabweans lacked the resources to fund the majority shareholding in the businesses, and no investor was interested in investing a lot of money in a business in which they had no control. In a major policy shift, the government relaxed this law by removing this requirement in March 2018. The amendment to the Indigenisation and Economic Empowerment Act now enables foreigners to own 100% of a company in Zimbabwe, save in platinum and diamond mining companies. This has created a conducive environment for foreign investment with a lot of investors rushing into the energy sector, as it has a lot of untapped potential due to the energy deficit not only in Zimbabwe but within SAPP.

There has also been a recognition that if the economy is to grow significantly, the energy sector must play an important role to complement that growth. Consequently, there has been increased interest in the licensing of IPPs to participate in power generation, and providing incentives specifically targeted at the energy sector to facilitate its growth.

Developments in legislation or regulation

The major change to legislation that has a direct impact on the energy sector is the change in the Indigenisation and Economic Empowerment Act which removes the restrictions on non-Zimbabweans owning the majority stake in companies in Zimbabwe. In addition to this, direct tax incentives were introduced by an amendment to the Income Tax Act. The income from a licensed power generation entity is exempt from tax for the first five (5) years and thereafter, the tax rate would be at 15%, which is lower than the normal tax rate for companies at 25%.

The Zimbabwe Energy Regulatory Authority (ZERA), which was created in terms of the Energy Regulatory Authority Act [Chapter 13:23], is responsible for the regulation of the energy sector in Zimbabwe. In August 2017, ZERA updated and published the Zimbabwe Grid Code. The Zimbabwe Grid Code is intended to regulate and establish the reciprocal obligations of industry participants around the use of the National Transmission System (NTS) and operation of the Interconnected Power System (IPS).

Work is currently under way on development of the Third-Party Access Code.

Judicial decisions, court judgments, results of public enquiries

The electricity sector in respect of both generation and distribution has largely been controlled by a government-owned entity. There have been no disputes of note that have had to be determined by the courts.

Major events or developments

Major expansion work to the main hydro power station at Kariba Power Station was completed, which has increased capacity by an additional 300 MW. This will go a long way in reducing power imports. Work on the expansion of the Hwange Thermal Power Station has also commenced. This work will see the expansion of the power plant by the addition of two units with a combined output of 600 MW. Presently Hwange Thermal Power Station, the country's largest coal-fired power plant, is operating at an estimated 314 MW with a total installed power output of 920 MW.

The government is also in the process of implementing an ambitious 100 MW solar project in Gwanda. The project has stalled due to the EPC contractor being mired in controversies regarding delays in the implementation of the project. The public outrage at the delays to this project is likely to affect the manner in which future government-controlled projects are awarded to EPC contractors. Increased scrutiny of the bidders for such projects will be implemented.

Proposals for changes in laws or regulations

The proposals for a Renewable Energy Feed In Tariff (REFiT) developed by ZERA may hopefully be implemented now, to promote the use of renewable energy. REFiT is a policy instrument that mandates power utilities operating the national grid to purchase electricity from renewable energy sources at predetermined prices so as to stimulate investment in the renewable energy sector. This is aimed at renewable energy technologies such as Solar PV, small hydro projects, biomass and biogas units of up to 10MW.

ZERA has also made proposals for regulations to deal with various energy sector issues such as the Solar PV Industry regulations, Solar PV integration Code and the Third-Party Access Code. There are no solar PV subsector specific regulations that are in place, and regulation of the sector would be a welcome development, as it is now receiving a lot of attention.

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Nikita joined the firm on 1 July 2000 and became a partner on 1 July 2003. He heads the firm's Energy, Infrastructure and Natural Resources Department and is co-head of the Commercial and Corporate Department. He has a large commercial practice and advises several listed and unlisted companies in relation to acquisitions, mergers, disposals and various types of contracts. He is currently involved in greenfield projects in the energy sector with work covering all aspects including the construction elements involved in such projects. He has handled several completed transactions for companies listed on the Zimbabwe Stock Exchange, including share option schemes, rights issues, mandatory offers to minorities, Zimbabwe Stock Exchange Rules, compliance and related matters. He has acted and continues to act as local counsel for a number of international law firms handling investment transactions into Zimbabwe. He is also involved in advising local, regional and international financial institutions in various loan transactions.

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