



**Asia-Pacific
Economic Cooperation**



APEC ENERGY OVERVIEW 2019



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The views and opinions expressed in this publication belong solely to the authors. For consistency and veracity of the policies and other information contain here, the EGEDA focal points and EWG members of the respective economies were consulted.

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FOREWORD

The APEC Energy Overview (the Overview) is an annual publication that highlights the current energy situation in each of the 21 APEC economies. It has been the pioneer publication of APERC in showcasing the latest energy data in APEC compiled by the Expert Group on Energy Data and Analysis (EGEDA).

The Overview traditionally serves as a point of reference for those wishing to become more informed about recent energy trends in the APEC region. It contains information on energy supply and consumption, energy related policies and notable energy developments in the region, among others. In view of the increasing request from APEC expert groups, the Overview has also become the platform to monitor APEC goals—energy intensity reduction by 45% by 2035 (against the 2005 level) and doubling renewable energy share by 2030 with 2010 as base year.

It is important to note that the analysis on energy intensity improvement and renewable share of final energy consumption included in economy chapters served as indication only and not as each economy's contribution in achieving APEC goals. As they are both collective goals, the progress on APEC energy intensity improvement as well the APEC renewable share of total primary energy supply and final energy consumption are described in the Executive Summary.

You'll be pleased to find in each economy chapter the various efforts and measures that have been put in place in achieving their stated energy goals as they continue to develop and grow.

We hope that this report will help stakeholders deepen their understanding of energy issues in APEC, promote the use of EGEDA (APEC) data and provide useful insights to policy makers in the region.



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EXECUTIVE SUMMARY

The APEC economy continued to outstrip the rest of the world in 2017 with a 4.1% increase in GDP from the 2016 level to reach USD 63 767 billion (PPP, constant 2011 USD). The rest of the world grew by only 3.4% in 2017. The increase pushed APEC's share to the world's GDP one percentage point higher than the 2016 level—55% in 2017. China and South-East Asia (SEA) were the biggest contributors to economic growth in APEC with 6.9% and 5.2%, respectively from 2016 to 2017. Among the South-East Asian member economies, the GDP of Viet Nam; the Philippines and Malaysia grew remarkably in 2017 at 6.8%, 6.7% and 5.9%, respectively.

A similar trend was seen in total primary energy supply (TPES) with APEC accounting for more than 50% of the world's TPES in 2017. TPES in APEC continued to bounce back with 1.7% growth to reach 8 013.63 Mtoe in 2017, after posting negative growth in 2015 (-0.3%) and sluggish growth in 2016 (0.5%). TPES growth in SEA (3.8%), China (3.3%), and Russia (2.5%) contributed significantly to the expansion in 2017. Total final energy consumption (TFEC, excluding non-energy) meanwhile continued to fluctuate. After tapering-off (0.4%) in 2015, it grew 1.3% in 2016 and slowed to 0.3% again to 4 769.84 Mtoe in 2017. The dwindling of TFEC was due in part to the contraction posted in 2017 by two large energy consumers in APEC namely, China and the US at -1.3% and -0.4%, respectively. These declines were offset by the increases from SEA (4.5%), Russia (3.6%) and other Americas (2.1%). If non-energy is included, total final consumption (TFC) reached 5 355.92 Mtoe in 2017, 0.8% more than 2016. Growth rate in TFC was bigger than TFEC as non-energy use (4.6%) drove the increase in TFC.

Except for 2009, which was a recession year, the 2017 growth in final energy consumption (excluding non-energy) was by far below the average of the previous 11 years of 2.0%. Given this, energy intensity consequently improved 3.7% in 2017 from 77.65 toe/USD (PPP, constant 2011 USD) in 2016. This was the biggest improvement since 2005, the base year for APEC energy intensity goal of reducing energy intensity by 45% by 2035. Together with the steady growth of APEC GDP, 4% on average between 2005-2017, energy intensity has declined by 22.1% between those years. This is 49% of the way to the goal in 40% of the time. Using a compound decline rate, which assumes that the current trend continues at a constant rate of decline, final energy consumption intensity exceeds the APEC goal in 2035.

Substantial progress was achieved in the use of modern renewables from 2010 to 2017, because of falling costs and government support, such as feed-in tariffs, auctions, and renewable portfolio standards. Given the current data, it is estimated that the renewable energy (RE) share of TFEC expanded from 6.1% in 2010 to 8.4% in 2017. Assuming this increasing trend continues, the APEC RE share of TFEC will reach 12.6% in 2030—0.4% more than the target of doubling from 2010 to 2030. In terms of TPES, the RE share increased from 4.8% in 2010 to 6.6% in 2017. Assuming this trend continues, the APEC RE share of TPES will reach 10.0% in 2030 and meet the goal. But this does not mean that APEC will stop its efforts to increase the use of RE, as more can be done to identify economy-specific barriers and formulate policy responses as part of a comprehensive roadmap.

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AUSTRALIA

INTRODUCTION

Australia is the sixth-largest economy in the world in terms of land area, covering approximately 7.7 million square kilometres (km²). It lies in the Southern Hemisphere between the Indian and Pacific Oceans and comprises six states and two territories. The population of 25 million people mainly live in cities and regional centres on the east coast and south-eastern corner.

Australia has maintained robust economic growth, with an average annual growth rate (AAGR) of 2.9% from 2000 to 2017 (EGEDA, 2019). Much of this is attributable to population growth of 1.5% AAGR for the same period, combined with a mining and resources boom through the 2000s and into the 2010s. In 2017, gross domestic product (GDP) reached USD 1 104 billion (2011 USD purchasing power parity [PPP]), a 2.3% increase from 2016 (EGEDA, 2019). In the June quarter, 2019, Australia marked 28 years without a technical recession (ABS, 2019a).

Australia has abundant, high-quality energy resources that are likely to last for many decades at the current rates of production. Energy production increased at an AAGR of 3.3% from 2000 to 2017 and 4.2% from 2016 to 2017, reaching 405 154 kilotonne's of oil equivalent (ktoe) (EGEDA, 2019). The proportion of Australian energy production destined for export markets grew from 54% in 2000 to 66% in 2017 (EGEDA, 2019).

In 2017–18, coal constituted 69% of Australia's primary energy production in energy content terms, followed by gas (25%), oil (3.5%) and renewables (2.1%) (Environment, 2019a). Coal was similarly dominant in the energy export mix, constituting 73% of the total energy content, followed by gas (22%) and oil (4.0%). The Australian energy industry accounted for 6.5% (AUD 120 billion) of the economy in 2018–19 (ABS, 2019) and 28% of exports (OCE, 2019; ABS, 2019b).

Australia is the world's largest metallurgical coal and second-largest thermal coal exporter (OCE, 2019). Metallurgical coal exports earned AUD 44 billion in 2018–19, up from AUD 38 billion the year before. Most of this increase was due to an increase in prices. Thermal coal increased to AUD 26 billion in 2018–19 from AUD 23 billion in 2017–18 (OCE, 2019). Again, most of this was a price effect rather than a volume effect.

Natural gas exports ramped up from AUD 31 billion in earnings in 2017–18 to AUD 50 billion in 2018–19. Australia surpassed Qatar as the world's largest liquefied natural gas (LNG) exporter in 2019. Its large energy reserves and proximity to burgeoning markets in the Asia-Pacific region mean that Australia can meet a significant proportion of global energy demand, as well as its own domestic needs, for years to come.

Table 1: Key data and economic profile, 2017

Key data ^a		Energy reserves ^{b, c}	
Area (million km ²)	7.7	Oil (billion barrels)	5.4
Population (million)	24	Gas (petajoules)	279 685
GDP (2011 USD billion PPP)	1 104	Coal (million tonnes)	145 479
GDP (2011 USD PPP per capita)	44 888	Uranium (kilotonnes U ₃ O ₈)	2 669

Sources: ^a EGEDA (2019); World Bank (2020); ^b GA (2019), OECD (2018)

Notes: Oil reserves comprise all identified crude oil, condensate and LPG. Gas reserves comprise all identified resources. Coal reserves are defined as recoverable economically demonstrated resources of black and brown coal. Uranium reserves are considered to be reasonably assured resources at USD 130/kg U.

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

In 2017, Australia's total energy production was 405 154 ktoe and total primary energy supply (TPES, the energy that is used in the economy) was 127 037 ktoe (EGEDA, 2019). Coal remained the primary source of domestic energy supply in Australia at 35% of the primary energy mix, followed by oil (34%), gas (25%) and renewables and others (7%).

Coal's primary role is in the transformation sector, which constitutes 93% of use (Environment, 2019a), almost entirely at coal-fired power stations and coke ovens. Black coal basins in New South Wales and Queensland, and Victoria's enormous brown coal reserves, have fed these power stations and coke ovens. However, coal's share of TPES has been decreasing over the past decade, from 45% in 2005 to 35% in 2017, due to decreased use in the electricity generation sector (which has seen flat consumption and an increased share of gas and renewables) and closures of iron and steel works.

Natural gas has become increasingly important to the Australian economy as a source of export income and as a contributor to domestic energy needs. Almost all of Australia's conventional gas comes from three basins: the offshore Carnarvon Basin and Browse and Bonaparte Basin in Western Australia, the offshore Gippsland Basin in Victoria and the onshore Cooper–Eromanga Basin, which straddles the South Australian and Queensland borders (GA, 2019). Unconventional production, in the form of coal seam gas (CSG), mainly occurs in Queensland and has grown rapidly in recent years (though is not as high as originally forecast).

Gas production in 2018–19 of 145 billion cubic metres represented a 20% increase on the previous year, and is largely due to an increase in production in Western Australia to support the start of LNG exports from new projects around Dampier (OCE, 2019). Northern Territory production also increased. The major LNG projects in Queensland, Western Australia, and the Northern Territory are now complete, and so production volumes are likely to remain steady for the immediate future.

Australia is a net importer of oil products but a net exporter of liquefied petroleum gas (LPG) (Environment, 2019a). Domestic refineries account for approximately half of Australia's liquid fuel consumption, while the other half is imported. The supply of crude oil and LPG increased by 3% in 2017–18 relative to 2016–17 (Environment, 2019a).

Renewable primary energy supply has grown by 4.1% a year since 2010 (to reach 8 823 ktoe in 2017). This is due to significant investments by the electricity sector in utility-scale wind and solar power, and a significant uptake in residential-scale solar photovoltaic (PV) energy (EGEDA, 2019). Decreasing use of biomass in the residential sector and lower-than-average hydro generation in recent years due to drought has tempered renewable energy supply growth.

In 2017, 257 770 gigawatt-hours (GWh) of electricity was generated, with the majority of this coming from coal-powered thermal sources (EGEDA, 2019). Coal is likely to remain the most used fuel for electricity generation for some time, though its share in the generation mix is declining. This trend will continue due to a large and increasing number of committed wind and solar projects. In 2017, renewable energy accounted for 16% of the electricity generation mix, up from 14% in 2016. Hydro was the largest renewable contributor, followed by solar PV (EGEDA, 2019).

FINAL ENERGY CONSUMPTION

Australia's total final consumption increased by 0.55% to 81 845 ktoe in 2017 (EGEDA, 2019). The transport sector accounts for 41% of this final consumption, followed by industry (28%), residential (13%), commercial (10%), and non-energy (5.9%). Oil constituted 51% of final energy consumption in 2017, followed by electricity and others (24%), gas (16%), renewables (5.9%), and coal (3.3%). Oil and gas consumption have been growing in recent years, while coal is in structural decline as an end-use fuel type. Direct-use renewable energy consumption has remained relatively unchanged since 2010 as an

increasing uptake of solar hot water has offset falling biomass use in the residential sector (Environment, 2019a). The 'electricity and others' category has also remained flat since 2010.

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	405 154	Industry sector	22 482	Total power generation	257 770
Net imports and others	-268 762	Transport sector	33 350	Thermal	217 562
Total primary energy supply	127 037	Other sectors	21 183	Hydro	16 037
Coal	43 909	Non-energy	4 830	Nuclear	0.0
Oil	42 901	Final energy consumption*	77 015	Others	24 171
Gas	31 314	Coal	2 523		
Renewables	8 823	Oil	39 542		
Others	90	Gas	12 222		
		Renewables	4 522		
		Electricity and others	18 205		

Source: EGEDA (2019) (data collected in December 2019).

* Final energy consumption and the corresponding breakdown by fuel types do not include non-energy uses. Total final consumption includes non-energy uses. Half of the municipal solid waste used in power plants is assumed to comprise renewables.

ENERGY INTENSITY ANALYSIS

Australia has been contributing to APEC's aspirational goal of a 45% energy intensity reduction from the 2005 level by 2035. Primary energy intensity improved by 3.1% in 2017, though final energy intensity (excluding non-energy) only improved by 1.5% (EGEDA, 2019). Australia's recent energy intensity improvements have been achieved through structural shifts in the economy, away from energy-intensive industries and towards commercial sectors (such as financial services, education and tourism), and efficiency improvements driven by advances in technology (particularly in the transport and building sectors) (OCE, 2015).

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity toe/million USD PPP)		Change (%) 2016 vs 2017
	2016	2017	
Total primary energy supply	119	115	-3.1
Total final consumption	75	74	-1.8
Final energy consumption excl. non-energy	71	70	-1.5

Source: EGEDA (2019).

RENEWABLE ENERGY SHARE ANALYSIS

Modern renewable consumption increased by 3.6% from 2016 to 2017. Increased solar PV and wind in the electricity generation sector is driving this increase. The share of modern renewables to final energy

consumption increased from 7.8% in 2016 to 8.0% in 2017. Traditional biomass continued to shrink as gas and electricity replace wood-fired heating in Australia.

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	76 365	77 015	0.85%
Non-renewables (fossils and others)	69 219	69 666	0.65%
Traditional biomass*	1 183	1 172	-0.93%
Modern renewables*	5 963	6 177	3.5%
Share of modern renewables to final energy consumption (%)	7.8%	8.0%	2.7%

Source: EGEDA (2019).

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on) including biogas and wood pellets are considered modern renewables, although data on wood pellets are limited

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Australia's system of government has three tiers: federal, state and territory, and local. Federal government and state/territory governments own Australian energy resources, rather than private individuals. None of the tiers of government engages in commercial exploration or development. The Australian Federal Government has title and power over energy resources located outside the first three nautical miles of the territorial sea ('offshore'). The state governments and the Northern Territory have jurisdiction over resources on their lands or inside the first three nautical miles of the territorial sea ('onshore').

Each state and territory government has primary responsibility for assessing and approving oil and gas exploration within their jurisdiction. Similarly, each state/territory assesses safety requirements and environmental regulations for the coal industry in its respective jurisdiction. The Australian Government has a role in regulating activities that are likely to affect nationally protected environments in accordance with the *Environment Protection and Biodiversity Conservation Act 1999*. In addition, the National Offshore Petroleum Safety and Environmental Management Authority is responsible for environmental management and structural (and well) integrity for offshore petroleum activities in Commonwealth waters.

At the federal level, the Department of Industry, Science, Energy and Resources oversees energy security, national energy efficiency programs, and issues related to national energy markets. The department is also responsible for resources issues (including some related to onshore gas). All six states and both territories have energy- or mining-related departments (or divisions) responsible for similar matters at the state or territory levels.

Commonwealth, state and territory Energy Ministers actively work together to advance national energy market reform. This was formerly managed through the Council of Australian Governments (COAG) Energy Council. The Prime Minister, the Hon Scott Morrison, MP announced on 29 May 2020 that COAG would be replaced by the National Federation Reform Council. Energy will be one of six initial priority areas of reform under National Cabinet. Further details of the transition are still to be determined.

ENERGY SECURITY

The Australian Government assesses Australia's energy security through National Energy Security Assessments (NESAs) that consider the effectiveness and anticipated resilience of Australia's electricity, natural gas and liquid fuel markets, and changes in energy security drivers. The initial and subsequent NESAs, in 2009 and 2011, found that Australia's energy security was robust. Work is underway on an updated NESA to determine Australia's energy needs, as well as the risks to energy supply, and the costs of supply to consumers (Environment, 2019b). The assessment will be vital in helping shape Australia's energy security policy for the next decade.

A liquid fuel security review is also underway to determine the human and environmental threats to adequate, reliable and affordable energy delivery. The Department of the Environment and Energy released the *Liquid Fuel Security Review Interim Report* for public consultation in April 2019.

Since 2012, Australia has been non-compliant with the International Energy Agency's (IEA's) treaty obligation to hold oil stocks equivalent to 90 days of net daily imports (Environment, 2019c). Non-compliance has been the result of falling domestic crude oil production, and increased demand for liquid fuels. This has meant that Australia's net imports have increased, while stock levels have remained relatively stable.

As part of the Australian Government's plan for returning to compliance with the IEA's 90 day oil stockholding requirement the Australian Government has delivered 5 procurement rounds for oil stock tickets since 2018. The most recent procurement was held in May 2020 for the Australian Government to consistently hold up to 400,000 tonnes of oil stock tickets for quarters between 1 July 2020 and 30 June 2021. By taking advantage of historically low oil prices caused by the impacts of COVID-19, the Australian Government in April 2020 purchased AUD 94 million worth of crude oil stocks for storage in the United States' Strategic Petroleum Reserve. The Australian Government does not place minimum stockholding obligations on industry.

ENERGY MARKETS

ELECTRICITY AND GAS MARKETS

The National Electricity Market (NEM) interconnects five regional markets: New South Wales (including the Australian Capital Territory), Queensland, South Australia, Victoria and Tasmania. The NEM does not extend to Western Australia or the Northern Territory. The NEM comprises competitive wholesale and retail sectors. An electricity spot market aggregates generator output and then delivers the required electricity to meet demand, at five-minute intervals (AEMO, 2019a).

Australia has three separate natural gas markets: the eastern gas market (Australian Capital Territory, New South Wales, Queensland, South Australia, Tasmania and Victoria), the northern gas market (Northern Territory) and the western gas market (Western Australia). Distance and market size have been the limiting factors in linking these separate markets. The Northern Gas Pipeline linked the eastern and northern gas markets in December 2018. But its capacity of 90 terajoules per day will have only a limited impact on price formation in either market.

All three of Australia's gas markets are grappling with structural change associated with the development of significant LNG export capacity. For the eastern gas market in particular, large export commitments have led to the prospect of domestic supply shortfalls. This has prompted government reviews by the Australian Competition and Consumer Commission (ACCC, 2016 and 2019) and the Australian Energy Market Commission (AEMC, 2016) on the supply, demand and competitiveness of the east coast gas market. The impact of these reviews is discussed in the 'Notable Energy Developments' section.

MARKET REFORMS

Energy Ministers are focused on delivering secure, reliable and affordable energy for all Australians. Energy market reforms are delivered through Australia's three energy market institutions:

- the Australian Energy Market Operator (AEMO)
- the AEMC
- the Australian Energy Regulator (AER)

AEMO is responsible for operating the NEM and parts of the retail and wholesale gas markets in eastern and southern Australia. This responsibility expanded to include the equivalent markets in Western Australia in 2015. AEMO oversees system security for the electricity grids and gas transmission networks, and undertakes economy-wide transmission planning (AEMO, 2019a).

AEMO is also responsible for identifying investment opportunities in Australia's energy markets. The National Transmission Network Development Plan provides information to market participants and potential investors with a 20-year horizon. In addition, the AEMO publishes the Electricity Statement of Opportunities and the Gas Statement of Opportunities, both of which forecast long-term supply and demand in the eastern market. It also maintains Australia's gas market bulletin boards (AEMO, 2019a).

AEMO oversees Australia's energy market governance in cooperation with the AEMC, which is the rule-making body, and the AER, which is the regulating body.

From 1 July 2019, a price safety net has been implemented in some electricity markets. Referred to as the Default Market Offer, the safety net sets a price cap on the highest electricity standing offers in regions that were not already subject to price regulation (Industry, 2020).

FISCAL REGIME AND INVESTMENT

FEDERAL CORPORATE INCOME TAX

Corporations that earn income in Australia are subject to corporate income tax imposed at a rate of 30% on profits. Project ring fencing does not apply; losses from one project can offset the profits of another project subject to common ownership criteria.

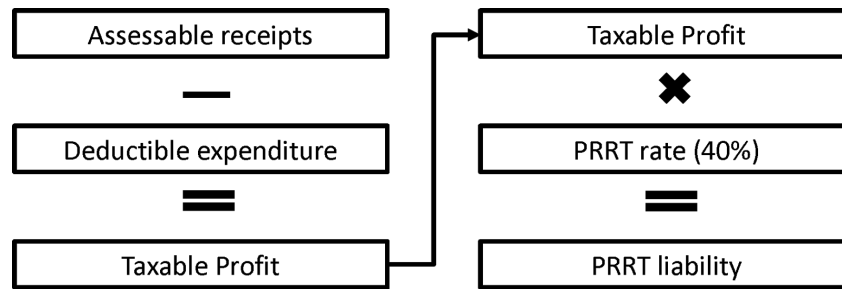
Certain expenditures incurred by energy companies, such as exploration expenditure and royalty payments, are immediately deductible for corporate income tax purposes. Other indirect taxes, such as the payroll tax, fringe benefits tax, fuel excise and land tax may apply.

FEDERAL PETROLEUM RESOURCE RENT TAX

The Petroleum Resource Rent Tax (PRRT) is a tax on profits of petroleum projects undertaken in Australia. The PRRT has applied to offshore petroleum projects since 1987, and from July 1 2012, to onshore projects as well (ATO, 2019a). Since 1 July 2019, onshore projects have again been exempt from the PRRT.

Unlike royalty and excise regimes, the PRRT applies to profits derived from a petroleum project and not the volume or value of the petroleum produced. Deductions are provided for all allowable expenditures (together with indexation of carry-forward losses) to ensure that only the economic rent generated from a petroleum project is captured by the PRRT. When other layers of resource taxes are applicable, such as state and territory royalties and federal crude oil excise, such expenditures are creditable against the liabilities of PRRT projects. This ensures that petroleum projects are not subject to double taxation (ATO, 2019a).

The PRRT is a project-based tax, and so losses cannot offset income from other projects. The exception is exploration expenditure, which is transferable to other petroleum projects, subject to conditions. PRRT payments are deductible for income tax purposes. PRRT liability is calculated as shown in Figure 1 (ATO, 2019a).

Figure 1: Calculating the PRRT liability

Source: ATO (2019a).

The government recently completed a review of the design and operation of the PRRT. The review highlighted possible improvements but did not recommend changes to the crude oil excise or royalty schemes (Treasury, 2017).

ROYALTIES

States and territories apply royalties as an alternative mechanism for charging for resource extraction. Royalty rates vary depending on jurisdiction and commodity. They are either specific, *ad valorem*, profit-based or a hybrid (flat *ad valorem* with a profit component). For petroleum, the state and Northern Territory governments collect royalties for onshore production. The rate is typically 10% to 12% of the net wellhead value of production, depending on whether it is from a primary or secondary production licence or a combination of these (Industry, 2019).

For offshore production, the revenue sharing ratio is 60:40 for royalties between the state or territory government and the Australian Government (The Senate Economics References Committee, 2018).

FEDERAL CRUDE OIL EXCISE

Crude oil or condensate produced onshore, within three nautical miles of the Australian coastline, or offshore in the North West Shelf is subject to a production excise. The excise is a percentage of the weighted average realised selling price. The first 30 million barrels of cumulative production from each field is exempt from crude oil excise (ATO, 2019b).

EXPLORATION DEVELOPMENT INCENTIVE

The Australian Government introduced the Exploration Development Incentive (EDI) in July 2014 to encourage investments in small exploration companies that undertake 'greenfield' mineral exploration in Australia. The scheme is available to junior mineral exploration companies that incur eligible 'greenfield' exploration expenditures in Australia (ATO, 2019c).

When a mining company does not have sufficient income to utilise exploration deductions, the EDI provides a mechanism for Australian resident shareholders to deduct mining exploration expenses from their taxable income. The EDI does not apply to exploration for quarry materials, petroleum exploration (including exploration for natural gas from coal seams and shale oil) or geothermal energy resources.

RESEARCH AND DEVELOPMENT TAX INCENTIVE

The research and development tax incentive (RDTI) has been in effect since 1 July 2011. It replaced the research and development tax concession. The RDTI provides (ATO, 2019d):

- a 43.5% refundable tax offset for companies with a turnover of less than AUD 20 million per year
- a 38.5% non-refundable tax offset for all other firms.

JOINT PETROLEUM DEVELOPMENT AREA

Net revenue earned within the Joint Petroleum Development Area, located in the Timor Sea between Australia and Timor-Leste, is distributed 90% to Timor-Leste and 10% to Australia (ANPM, 2019).

ENERGY EFFICIENCY

In 2015, the former COAG Energy Council released the National Energy Productivity Plan (NEPP), which brings together policy priorities from the Energy Ministers' work program as well as from the Commonwealth and industry. The NEPP sets a national framework and an economy-wide work plan designed to boost industry competitiveness, help manage energy affordability for consumers and reduce Australia's carbon emissions to meet Australia's international commitment and deliver a 40% improvement in Australia's energy productivity from 2015 to 2030. The NEPP incorporates both energy supply and energy demand policies (COAG, 2015).

Australia's energy productivity has improved significantly in the last ten years. Since 2010 energy productivity improvement of 20 per cent has generated almost AUD 50 million more in GDP for every petajoule of energy consumed.

The introduction of policies and programs to support energy efficiency for businesses and households has also been a key driver to improving energy productivity through initiatives such as the Commercial Buildings Disclosure Program, the Equipment Energy Efficiency Program, the Business Energy Advice Program, YourHome, the National Home Energy Ratings Scheme and the National Australian Built Environment Rating System. Other improvements to energy efficiency are funded through the Australian Renewable Energy Agency (ARENA), the Clean Energy Finance Corporation (CEFC) (see Renewable Energy section), and the Emissions Reduction Fund (ERF) (see Climate Change section).

RENEWABLE ENERGY

Australia has abundant and diverse renewable energy resources with significant potential for development. Australia's best wind and wave resources are located along the southern and western coastlines, while outstanding solar resources exist across inland Australia. Large tidal and geothermal resources exist in northern and central Australia, respectively.

Renewable electricity generation increased from 39 000 GWh in 2017 to 49 000 GWh in 2018 (Environment, 2019a). Large-scale solar PV electricity generation increased by an incredible 160%, though this was from a relatively small base. Small-scale PV and wind electricity generation both increased significantly at 22% and 23% respectively. Hydro electricity generation posted an increase of 27% in 2018, but this followed a large fall the previous year due to drought conditions.

Australia's Renewable Energy Target (RET) is a legislated, market-based mechanism that provides a financial incentive for the deployment of renewable energy projects through the creation of renewable energy certificates which can be traded with liable entities (primarily electricity retailers), who surrender the certificates to meet their annual renewable energy Obligations (Environment, 2019c). The RET operates two schemes—the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES).

The LRET sets annual renewable electricity generation targets which peak at 33,000 gigawatt hours in 2020. There are now sufficient projects built or under construction to meet and exceed the 2020 target (Clean Energy Regulator, 2020b). The SRES, which is an uncapped scheme, provides support for small-scale renewable energy technologies, such as residential solar panel and solar hot water systems. Over 3.6 million small-scale systems have been installed under the scheme (Clean Energy Regulator, 2020c).

ARENA is an independent agency established by the Australian Government on 1 July 2012. It has AUD two billion to fund renewable energy projects (for example, solar, bioenergy, marine, geothermal and enabling technologies such as storage) until 2022. It also supports research and development, commercialisation and early deployment activities, energy efficiency and low-emission technology and activities that capture and share knowledge. ARENA's 2019 investment priorities are to integrate renewables into the electricity system, accelerate the development of hydrogen, and help industry to reduce emissions (ARENA, 2019).

In the 2018–19 financial year, ARENA committed AUD 228 million in support of 80 projects (ARENA, 2019). ARENA's decision-making board comprises up to seven members and a CEO appointed by the Minister for Energy and Emissions Reduction on the recommendation of the board.

The Australian Government established the CEFC in 2012 to mobilise investments in renewable energy, low-emissions and energy efficiency projects and technologies in Australia. As of June 2019, the CEFC had committed AUD 7.2 billion in investments (CEFC, 2019). The CEFC acts with commercial rigour and seeks benchmark rates of return.

Most state and territory governments have implemented jurisdictional feed-in tariff arrangements, or other support such as rebates or low interest loans, for small-scale renewable technologies. However, almost all of these schemes are now finished. The SRES still provides an incentive via up-front small-scale technology certificates for systems' expected power generation to 2030.

Growth in renewable energy in Australia over the past decade has been largely due to residential solar PV and utility-scale wind farms. This dynamic is changing as utility-scale solar builds momentum. The largest plants in operation include Coopers Gap Wind Farm in Queensland (453MW), Macarthur Wind Farm in Victoria (420MW), and Sapphire Wind Farm in New South Wales (270MW). There are also very large proposed solar PV plants: Sunshine Energy Solar Farm in Queensland (1 500 MW); Ipswich Regional Energy Hub in Queensland (1 000 MW); Wivenhoe Regional Energy Hub in Queensland (1 000 MW); and New England Solar Farm in NSW (800 MW), among many others that have already been committed to construction (AEMO, 2019a).

A significant number of wind generation projects such as Stockyard Hill (530 MW), Dundonnell (336 MW), Moorabool (312 MW), and Bulgana (205 MW) are also committed or under construction (AEMO, 2019a). The expansion of the Snowy Hydro scheme (dubbed Snowy Hydro 2.0) is also going ahead. The project will provide an additional 2 000 MWs of capacity and 175 hours of full capacity storage (350 000 megawatt-hours) at a construction cost of AUD 4.5 billion (Snowy Hydro, 2019).

ENERGY TECHNOLOGY AND RESEARCH AND DEVELOPMENT

In Australia, the bulk of basic research occurs in the university sector. Funding comes from organisations such as the Australian Research Council, which has established a range of competitive grant schemes. The CSIRO's Energy Flagship Program provides a focus for energy research and development, and ARENA supports research and development into renewable energy through funding and knowledge sharing.

NUCLEAR

The Australian Nuclear Science and Technology Organisation research establishment operates the open-pool Australian light water reactor in Lucas Heights, NSW. Australia has a longstanding moratorium on nuclear energy which prohibits the construction or operation of nuclear power plants.

CLIMATE CHANGE

The Australian Government is committed to a Quantified Economy-wide Emissions Reduction Target 5% below 2000 levels by 2020. Australia has committed to an economy-wide emissions reduction target of 26–28% below 2005 levels by 2030, as per Australia's nationally determined contribution submitted to the United Nations Convention on Climate Change in 2015 as part of the Paris Agreement (Environment, 2019e). The ERF replaced the carbon pricing scheme in 2014, and is now the central program designed to achieve these emissions reductions.

The ERF supports Australian businesses, farmers and Indigenous Australians to take practical actions to reduce emissions. The fund has three main components: crediting emission reductions, purchasing emission reductions and safeguarding emission reductions. The AUD 2.5 billion fund operates as a reverse auction (the government purchases emission reductions on eligible carbon reduction projects) and is administered by the Clean Energy Regulator (CER).

The most recent auction occurred in March 2020, where 1.7 million tonnes of abatement was purchased at an average price of AUD 16.14 per tonne (CER, 2020a). Ten auction rounds have contracted 193 Mt of abatement since 2014, with the average price across all ten auctions AUD 12.06 per tonne. In 2014, the Australian Government committed AUD 2.55 billion to the ERF. The Climate Solutions Fund provides a further AUD 2 billion to continue investment in low-cost abatement.

Other programs supporting action on climate change include 20 Million Trees, the Carbon Neutral Program, and energy efficiency initiatives. Details of these programs and others are available at <http://environment.gov.au/climate-change/government>.

NOTABLE ENERGY DEVELOPMENTS

THE FINKEL REVIEW AND ENERGY SECURITY BOARD

On 16 September 2016, South Australia experienced a rare 'black system' event, where 850 000 customers lost electricity supply. Extreme weather damaged multiple electricity transmission towers, which led to a cascading series of events—the most significant being automatic shutdowns at interconnectors and wind farms—that left the capital Adelaide without power for several hours. The economic and political consequences of these events were widespread and catalysed debate about the role of renewables, energy prices, system operation and stability, and costs and investment.

One of the government's first responses was to establish *The Independent Review into the Future Security of the Electricity Market*, chaired by Australia's chief scientist, Dr Alan Finkel (Environment, 2019f). The review makes recommendations addressing energy security, reliability, affordability and emissions. The review emphasises the importance of agreement across political lines to create certainty for the market so it can make the investments required to build sufficient new capacity. Other recommendations affect frequency response and inertia (required to maintain system stability); generator closures; improved system planning and integration; and better data, forecasting and analysis.

One of the first recommendations implemented by government was the establishment of the Energy Security Board (ESB). The board's role is to coordinate the implementation of the reform blueprint outlined in the Finkel review. This responsibility includes the publication of an annual report that tracks performance, risks and opportunities for the NEM. The most recent Health of the NEM report, released in February 2020, reported that the overall performance of the NEM had improved over the last year (COAG, 2020).

More recently, the ESB designed the Retailer Reliability Obligation (RRO), which came into effect on 1 July 2019. The RRO requires energy retailers and some large energy users to hold contracts, or invest directly, in generation or demand response to support reliability of the NEM. This will go some way to improving the critical status of certain aspects of the NEM.

SYSTEM PLANNING

The AEMO has traditionally been responsible for an annual system planning publication called the National Transmission Network Development Plan (NTNDP). The Finkel review recommended that the AEMO undertake an integrated grid plan to facilitate the development and connection of renewable energy zones. The AEMO responded by rolling the 2017 NTNDP into a new Integrated System Plan (ISP) publication. The first ISP, released in mid-2018, has a greater focus on the role of distributed renewable generation in the grid, including consideration of renewable energy zones and transmission development options (AEMO, 2019c). On 30 July 2020, the AEMO released the 2020 ISP. Similar to the 2018 ISP, it provides a whole-of-system plan that identifies transmission projects and development opportunities to deliver low-cost, secure and reliable energy through a complex and comprehensive range of plausible energy futures. (AEMO, 2020)

GAS MARKETS

Three LNG export facilities in Gladstone, Queensland connect Australia's east coast gas market to international natural gas markets. Long-term contracts with overseas buyers, combined with forecast CSG production from the Bowen and Surat Basins, underpinned the investment decision for each of these export facilities. However, CSG production has been lower than was originally forecast. The CSG-to-LNG exporters have purchased more natural gas than anticipated from the eastern gas market to meet their international supply obligations. This has meant that natural gas prices have increased on the east coast, and long-term contracts for domestic supply have become more difficult to secure. Higher than anticipated demand for natural gas from gas-fired generators (because of coal plant closures), higher production costs, and restrictions on fracking in some states and territories have exacerbated the domestic price rises (ACCC, 2019).

The government introduced the Australian Domestic Gas Security Mechanism in July 2017 as a temporary measure to deal with shortfalls in the domestic market. The mechanism allows the Minister for Resources and Northern Australia, on the recommendation of the AEMO, the ACCC, industry and other stakeholders, to restrict LNG exports by producers that are drawing more gas from the domestic market than they are replacing (Environment, 2019g). The government has also allocated AUD 90 million in the 2017–18 budget and AUD 2.5 million in the 2018–19 budget towards other measures aimed at managing insufficient supply in the domestic gas market. The July 2019 Gas Inquiry Interim Report does not expect there to be a gas supply shortfall in 2020 (ACCC, 2019).

The Gas Market Reform Group, established in August 2016, led the design, development and implementation of a new commercial arbitration framework for pipelines, capacity trading reforms, market transparency reforms and wholesale market reforms aimed at promoting the National Gas Objective¹ (GMRG, 2019).

NEW ENERGY PROJECTS

The huge wave of investment in Australia's LNG sector is now largely complete.

The development of Australia's hydrogen resources has the potential to enhance Australia's energy security, leading to a valuable export industry. The former COAG Energy Council released Australia's National Hydrogen Strategy in November 2019, which sets out a vision for any such development (COAG, 2019c). Some energy projects will be facilitated and supported by new government programs.

UNDERWRITING NEW GENERATION INVESTMENTS (UNGI)

The Underwriting New Generation Investments (UNGI) program will support targeted investment that will lower prices, increase competition and increase reliability in the energy system (Industry, 2020).

UNGI will provide financial support to firm generation capacity as part of the government's commitment to lowering electricity prices and increasing reliability. It will be technology neutral to enable the best and lowest cost generation options.

The program's objectives are to: reduce wholesale electricity prices (increasing competition and supply); assist energy consumers access energy; improve reliability in the system.

GRID RELIABILITY FUND

The AUD 1 billion Grid Reliability Fund will support Australian Government investment in new energy generation, storage and transmission infrastructure, including eligible projects shortlisted under the UNGI program (Industry, 2020). The fund will be administered by the CEFC.

¹ The national gas objective is to promote efficient investment in and efficient operation and use of natural gas services for the long-term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.

The fund will prioritise investments in jurisdictions where state and territory governments are working with the Australian Government towards an agreed reliability goal. Ensuring reliable generation capacity is available to meet periods of high demand in the National Electricity Market is the priority.

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Australian Energy Market Operator—www.aemo.com.au

Australian Energy Regulator—www.aer.gov.au

Australian Government Department of Industry, Innovation and Science—www.industry.gov.au

Australian Government Department of the Environment and Energy—www.environment.gov.au

Clean Energy Regulator—www.cleanenergyregulator.gov.au

COAG Energy Council—<http://www.coagenergycouncil.gov.au/>

COAG Gas Market Reform Group—<http://gmrg.coagenergycouncil.gov.au/>

Energy.gov.au—www.energy.gov.au

Office of the Chief Economist—www.industry.gov.au/industry/Office-of-the-Chief-Economist/Pages/default.aspx

BRUNEI DARUSSALAM

INTRODUCTION

Brunei Darussalam (Brunei) is located to the north of the island of Borneo. It has a land area of 5 765 square kilometres (km²) and a coastline of 168 kilometres along the South China Sea. The non-coastal sides are bounded by the Malaysian state of Sarawak, which divides Brunei Darussalam into two parts. Temburong district is to the east and Brunei Muara, Tutong and Belait districts are to the west (MOD, 2009).

In 2017, the population was 424 473 with GDP of USD 31 billion (2011 USD purchasing power parity [PPP]). GDP growth was 1.3%. Oilfields were first discovered in 1929, and have allowed the population to enjoy many benefits, such as free healthcare, a well-established state education system and even a housing scheme dedicated to providing affordable homes.

Brunei has the second highest per capita income in the APEC region of 72 524 (2011 USD PPP), behind Singapore (EGEDA, 2019). But per capita income has been in a trend of long-term decline, having been at USD 86 139 in 1995. Crude oil, liquefied natural gas (LNG) and methanol made up half of Brunei's GDP and accounted for 95% of export revenue in 2018. Machinery and transport equipment, manufactured goods and food are the main imports (DEPD, 2019).

Brunei's pro-business environment is attracting foreign investors (MOFE, 2019).

Table 1: Key data and economic profile, 2017

Key data ^{a, b}		Energy reserves ^b	
Area (km ²)	5 765	Oil (billion barrels)	1.1
Population (thousands)	424	Gas (billion cubic metres)	269
GDP (2011 USD billion PPP)	31	Coal (million tonnes)	–
GDP (2011 USD PPP per capita)	72 524	Uranium (kilotonnes U)	–

Sources: ^a EGEDA (2019); ^b BP (2019).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Brunei's Seria field is Asia's longest-producing oil field, and has fuelled Brunei's development since 1929. The most prolific offshore field is Champion, which is in 30 metres of water, about 70 kilometres north-east of Seria. It holds 40% of the economy's known reserves and produces around 100 000 barrels a day. Champion has more than 260 wells drilled from 40 platforms (BSP, 2019). In 2017, 86% of the economy's primary energy supply was from natural gas, while oil accounted for 14%. Total primary energy supply was 4 685 kilotonnes of oil equivalent (ktoe) in 2017, a growth of 9.1% from 2016 (EGEDA, 2019).

In 2017, Brunei exported 72% of its gas and oil production. Domestic demand is from power generation and the downstream petrochemical sector. Approximately 4.0% of the crude oil produced is refined to produce petroleum products, and the rest is exported.

Brunei, through Brunei LNG Sdn Bhd (BLNG), has supplied LNG to Japanese and South Korean customers for more than 40 years. Proximity to markets, and its LNG industry experience means Brunei will continue to be an important LNG supplier (Brunei LNG, 2019).

LNG exports were 7 024 ktoe in 2017 (EGEDA, 2019). Japan was the largest buyer (57%), followed by South Korea (22%), and Malaysia (12%). Oil production was much smaller than natural gas production (table 2). The main destination for crude oil exports was Thailand (25%) (DEPD, 2019).

Brunei's total installed generation capacity from public utilities and auto producers was 1 006 megawatts (MW) in 2017. Electricity generation was 4 159 gigawatt-hours (GWh). Natural gas accounted for 99% of generation, while 1.1% of generation was from diesel and 0.07% from photovoltaic (PV) solar (EGEDA, 2019).

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	17 012	Industry sector	151	Total power generation	4 159
Net imports and others	-12 327	Transport sector	448	Thermal	4 156
Total primary energy supply	4 685	Other sectors	319	Hydro	-
Coal	-	Non-energy	448	Nuclear	-
Oil	669	Final energy consumption*	918	Others	3
Gas	4 016	Coal	-		
Renewables	0	Oil	629		
Others	-	Gas	19		
		Renewables	-		
		Electricity and others	270		

Source: EGEDA (2019) (data collected in December 2019).

* Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. Total final consumption includes non-energy uses. Half of the municipal solid waste used in power plants is assumed to comprise renewables.

FINAL ENERGY CONSUMPTION

In 2017, Brunei's final energy consumption (excluding non-energy) increased 7.6% to 918 ktoe. The transport sector accounted for 49% of final energy consumption. There is no rail network in Brunei, and buses are the main means of public transportation. There are some taxis, though they are in very short supply (MTIC, 2014). Low oil prices are a contributing factor to the high consumption in the transport sector. Brunei has the lowest pump prices in the Association of Southeast Asian Nations (ASEAN).

Residential, commercial and agriculture sectors account for 35% of the economy's energy consumption. The remaining 16% is from industry. Oil was 69% of final consumption, followed by electricity and others (29%) and gas (2.1%) (EGEDA, 2019).

ENERGY INTENSITY ANALYSIS

Brunei's primary energy intensity and final energy intensity both worsened by 7.6%, and 6.2%, respectively in 2017. But final energy intensity improved by 4.2% compared to 2016.

Brunei aims to reduce its energy intensity 45% by 2035 from the 2005 level. To achieve this, Brunei needs to reduce energy intensity by at least 5% per year from 2018 to 2035.

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%) 2016 vs 2017
	2016	2017	
Total primary energy supply	141	152	7.6
Total final consumption	46	44	-4.2
Final energy consumption excl. non-energy	28	30	6.2

Source: EGEDA (2019)

RENEWABLE ENERGY SHARE ANALYSIS

The Energy White Paper (EWP), released in 2014, recognises the role of the energy sector in achieving Brunei's sustainable development. The EWP set development targets related to renewable energy technology deployment that make a direct contribution to mitigating greenhouse gas (GHG) emissions from the energy sector. Brunei is setting a target of a 10% share of renewable energy generation in the overall power generation mix by 2035. This target corresponds to 954 000 MWh of renewable electricity generation. A study conducted by the government identifies solar, wind, and waste-to-energy as potential sources for renewable energy power generation (UNFCCC, 2017).

The Ministry of Energy, Manpower and Industry (MEMI) recently announced a 30 MW solar power plant in Kampung Sungai Akar. The move to solar power generation is a significant step in solar energy development in Brunei (MEMI, 2019). Brunei Shell Petroleum (BSP) will also convert its office headquarters in Seria from gas to solar power. The three MW solar-powered headquarters will be an example of the private sector investing in renewable energy to combat climate change.

The government Outreach Program has successfully supplied and installed solar PV systems for houses in Ulu Belait. Solar power street lights have also been installed in remote areas as part of a government commitment to supply electricity regardless of location (DES, 2018).

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption	854	9195	-7.6
Non-renewables (Fossils and others)	854	918	-7.6
Traditional biomass*	–	–	–
Modern renewables*	0.13	0.20	59
Share of modern renewables to final energy consumption (%)	0.01	0.02	48

Source: EGEDA (2019)

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on), including biogas and wood pellets, are considered modern renewables, although data on wood pellets are limited.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Brunei's energy policy is concentrated on the oil and gas industry. Following peak oil production of 254 000 barrels per day (bbl/d) in 1979, the government instituted a limit of 150 000 bbl/d in 1981. In November 1990, the production limit was removed. In 2006, oil production reached another peak of 219 000 bbl/d.

The Brunei Natural Gas Policy (Production and Utilisation) was developed in 2000 to satisfy gas export obligations. The policy aimed to maintain gas production that could sustain obligations, open new areas for exploration, and develop and encourage increased exploration by new and existing operators. The policy prioritised domestic gas use, especially for electricity power generation.

Brunei has set out a long-term vision for the country and energy sector. With ongoing exploration projects both onshore and offshore, the planned target is to grow production of both oil and gas from 400 000 barrels of oil equivalent per day (boe/day) in 2010 to about 430 000 boe/day by 2017 and to more than 650 000 boe/day by 2035.

The Energy Department at the Prime Minister's Office published the EWP in 2013 that presented three strategic goals to drive growth in the energy sector:

- Strengthen and grow oil and gas upstream and downstream activities
- Ensure safe, secure, reliable and efficient supply and use of energy
- Maximise economic spin-off from energy industry — Boost local content and secure high participation of local workforce

Achieving the goals of Wawasan Brunei 2035¹ will require a significant increase in the activity level of all the economic sectors in the economy, including the energy sector (DES, 2014).

ENERGY SECTOR STRUCTURE

The MEMI, formerly known as the Energy Department, Prime Minister's Office, acts as a regulator for the oil and gas industry in Brunei. MEMI has set four strategic goals to accelerate and enhance the economy:

- Strengthen and diversify the economy
- Nurture conducive business environments
- Ensure safe and secure work environments
- Develop an industry-ready local workforce

The above strategic goals relate to the development of the entire economy (not just the oil and gas sector).

The Department of Electrical Services (DES), under the auspices of the MEMI is the government authority mandated to look after, and to be responsible, for the operation and development of the electricity sector. As a utility, DES is responsible for the generation, transmission and distribution of electricity to the end users. As a service provider, DES is responsible for setting standards for the implementation of electricity usage in public buildings as well as for overseeing their electro-mechanical maintenance (DES, 2019).

¹ A plan to reduce Brunei's dependence on oil and gas sectors.

The Electricity Authority Brunei Darussalam (AEBD) was established in June 2017 to enforce and oversee the implementation of Electricity Order 2017, which regulates activities in the economy's electricity industry. The order strengthens the law and safety aspects of the electricity generation, transmission, and distribution to enable the development of a more efficient, competitive and sustainable power industry (AENBD, 2019).

Brunei National Petroleum Company Sendirian Berhad (PetroleumBRUNEI) is Brunei's national oil company. Incorporated as a private limited company on 14 January 2002, PetroleumBRUNEI is wholly owned by the government. The business incorporates upstream, downstream, services, and trading activities (PetroleumBRUNEI, 2019).

Brunei Shell Petroleum Company Sdn Bhd (BSP) is primarily responsible for the exploration and production of crude oil and natural gas from both onshore and offshore fields. It also owns the Brunei Refinery and Seria Crude Oil Terminal (SCOT). The SCOT provides collection, storage and export facilities for crude oil, and has facilities for water separation, dehydration and treatment (BSP, 2019). The Government and the Asiatic Petroleum Company limited are equal shareholders in BSP, and it is the largest oil and gas producer in Brunei.

ENERGY SECURITY

Since gaining independence from the British in 1984, Brunei has become a member of a number of regional and international organisations, such as the ASEAN, APEC, the Organisation of Islamic Conference (OIC), the Commonwealth and the United Nations.

Brunei recognises the need to enhance energy security and sustainability, improve energy efficiency and accelerate the deployment of renewable energy and a clean energy supply. Brunei is working to strengthen the partnership arrangements among all its stakeholders.

Brunei is an active member of the ASEAN, and supports energy security, energy efficiency and conservation strategies among the regions. The economy is actively working with the ASEAN to achieve the ASEAN Plan of Action for Energy Cooperation (APAEC) 2016–2025. This includes flagship projects such as the ASEAN Power Grid and the Trans-ASEAN Gas Pipeline project.

The ASEAN Petroleum Security Agreement (APSA), formulated in 1986, is an agreement among the ASEAN Member States (AMS) that assists in times of emergency. To date, the APSA has not been implemented and is being reviewed by the AMS and Senior Officials Meeting on Energy (SOME) (ASCOPE, 2015).

UPSTREAM ENERGY

Brunei is well known for its reserves of petroleum and gas, which have fuelled its economy for close to a century. Oil and gas have been the core of Brunei's economy since the first commercial well was drilled in 1929. Recent discoveries of mid-size and smaller fields in the shallow offshore shelf contribute significantly to overall oil and gas production. The deepwater shelf is also a priority for development. Oil and gas production activities are handled by government joint venture companies such as BSP, Total E&P Borneo and Shell Deepwater Borneo. To develop the LNG exports, the government has also established several joint venture companies, including Brunei LNG, Brunei Gas Carriers and Brunei Shell Tankers (UNFCCC, 2017).

In March 2019, Brunei earmarked USD 1.2 billion for the development of new oil and gas fields to accelerate petroleum production by 30% over the next five years. These activities include the drilling of five new exploration wells. There are also plans for deepwater exploration.

Brunei has long-term plans to boost upstream production of oil and gas from 370 000 boe/day in 2018 to 485 000 boe/day by 2024 and 650 000 boe/day by 2035. Brunei is committed to maintaining a reserve replacement ratio for oil and gas of more than one to meet its upstream production target. An additional 182 million barrels of oil equivalent reserves are required by

2024 to achieve this. Brunei will undertake several initiatives to stimulate production, such as rejuvenating existing fields, maximising economic recovery from mature and newly discovered fields (including deep water), and reviewing potential solutions for the development of uneconomic, small and unconnected fields.

New offshore discoveries in the South China Sea are expected to extend Brunei's hydrocarbon production. Since 2016, Brunei's oil and gas industry have called for bids valued at more than USD 2.2 billion to assist with the development of these fields.

Brunei aims to achieve around 100 000 boe/day of oil and gas from upstream international venture investments by 2035. On 19 November 2013, PetroleumBRUNEI was awarded Block EP-1, the onshore Kyaukkyi-Mindon area located 250 km north of Yangon, Myanmar. This covers an area of 1 135 km². PetroleumBRUNEI will conduct all petroleum activities in Myanmar under the production sharing agreement. Other upstream projects for PetroleumBRUNEI abroad include an offshore block in Sarawak, Malaysia, and a shale gas project in Canada, (PB, 2013).

DOWNSTREAM ENERGY

BSP operates a local refinery that produces 10 000 bbl/day of petroleum products. Brunei's demand is roughly 15 000 bbl/day. The Brunei Shell Marketing (BSM), also a joint venture company between the government and BSP, is responsible for the distribution and sales of refined petroleum products. To diversify the economy, the government is taking the lead in developing the downstream energy industry. The government has established a joint venture company, the Brunei Methanol Company, to produce and export methanol as a high value alternative to exporting natural gas. The USD 600 million methanol plant has a capacity of 850 000 metric tonnes per year and has operated since 2010 (UNFCCC, 2017).

A plant producing 3 900 metric tonnes of fertiliser (urea) per year began operating in 2019. An integrated refinery and petrochemical complex at Pulau Muara Besar (PMB) also began operating in 2019. The facility will produce refined petroleum products such as gasoline, diesel and jet fuel, as well as downstream petrochemicals such as benzene and paraxylene.

Brunei's current target for downstream economic output is to achieve BDD five billion per year by 2035. Brunei welcomes foreign direct investment (FDI) in the downstream sector, including cross-sectoral opportunities, to achieve this. For example, methanol, ammonia and urea (from Brunei's methanol plant and ammonia-urea plant) can be used as feedstock to manufacture derivatives to then promote opportunities in the manufacturing of wood-based products, tableware, plastics and textiles.

Two industrial sites, Sungai Liang Industrial Park (SPARK) and PMB Industrial Park, will support downstream development. These sites can provide new projects with proximity to existing and future petrochemical plants (BEDB, 2019).

ENERGY MARKETS

The government regulates the energy market in Brunei, and recognises the importance of having a comprehensive framework to support the strategic objectives established for the energy sector. MEMI has identified key policies such as monitoring the local content requirement in the bidding process for operational contracts. A local business development framework is enforced to ensure a fair and level playing field for opportunities from oil and gas activities.

ELECTRICITY MARKET

The DES is responsible for the generation, transmission, and distribution of electricity in Brunei. The DES operates in concert with Berakas Power Company Sdn Bhd (BPC) to supply electricity.

Brunei's power system has three independent electricity networks. The first supplies power to Brunei Muara, Tutong and Belait; the second provides power in Temburong; and the third supplies load centres in Brunei Muara. The DES operates the first two networks, which include five generating plants. Four of the five generators are gas-fired plants with a total installed capacity of approximately 591 MW. The stations are Bukit Panggal, Lumut, Gadong 1A and Gadong 2. The other generation plant, located in Temburong, is diesel-powered.

The Tenaga Suria Brunei (TSB) Project is a 1.2 MW solar PV demonstration project jointly implemented by the Brunei Government and the Mitsubishi Corporation. The plant is in Seria, Belait. One of the core objectives of the project is to identify the most suitable and high performance PV technologies for local meteorological conditions. The project uses six different types of commercially available PV modules (BNERI, 2015).

ENERGY EFFICIENCY

In almost all energy-consuming sectors, space cooling accounts for the largest share of end use electricity consumption. The residential and commercial sectors are the largest electricity end users in Brunei. Energy efficiency of end use technologies represents the major source of potential greenhouse gas abatement on the demand side. A study by MEMI in 2011 found that promoting energy efficiency and conservation measures in the residential sector could lead to a 50% reduction in energy consumption from Business as Usual (BAU) in 2035. The commercial buildings sector could see a 44% reduction in energy consumption from BAU case in 2035 following similar measures. In a recent review of the Wawasan 2035 target, 15% of the total energy consumption could be reduced by legislative measures such as standards and labelling for residential air conditioners. The government is pursuing strategies to improve energy efficiency by promoting energy conservation and achieving energy efficiency targets. Energy efficiency initiatives are (UNFCCC, 2017):

- *Energy management*

Brunei is considering adopting an Energy Management System that is compatible with the ISO 50001. The policy will require each government agency to establish energy management action plans, including an energy audit report, and the appointment of energy managers and energy focal points for facilities.

- *EEC building guidelines for non-residential buildings* The Ministry of Development in collaboration with MEMI launched this initiative in May 2015 to establish energy efficiency and conservation standards, and a regulatory mechanism for buildings in Brunei. The guidelines are mandatory for all government premises and voluntary for commercial buildings. The measures are likely to become mandatory for all buildings in the next phases of the policy.

- *EEC standards and labelling order*

This has the objective of restricting, and potentially halting, the importation of inefficient technologies. The order aims to educate and encourage consumers to purchase and utilise more energy efficient appliances and products. Consultations and roadshows are exploring financial incentives to accelerate its effectiveness.

- *Electricity tariff reform*

A progressive electricity tariff structure for the residential sector was implemented in January 2012, replacing the previous regressive tariff structure. The progressive structure embeds the element of energy savings into the public's consumption habits. The government has also installed prepaid electricity metres in place of the old post-paid metres in residential houses and commercial buildings to improve electricity payment collection.

RENEWABLE ENERGY

The EWP has committed to renewable energy sources providing 10% of power generation by 2035. The target corresponds to 954 000 MWh of renewable electricity generation. Solar, wind and waste-to-energy are identified as the main candidates for renewable power generation. EIDPMO has laid out four main strategies in the EWP to meet this target:

- *Introduction of renewable energy policy and regulatory framework*

Policies and regulatory frameworks will form the backbone of the development of renewable energy in Brunei and will support private sector investments in renewable energy technologies. The rules for renewable energy grid access ensure easier integration of renewable energy into Brunei's national grid system. Policies include feed-in tariffs, net metering, and renewable energy certificates.

- *Boost market deployment of solar PV and promote waste-to-energy technologies*

EIDPMO and BNERI are exploring additional utility scale solar PV projects in Sungai Akar (20-25 MW), Tenaga Suria (20-30 MW), and a hybrid alongside the Temburong diesel power plant (6-12 MW). EIDPMO is also evaluating options for waste-to-energy technologies. A waste-to-energy plant is being proposed at the Sungai Paku Engineered Landfill, Tutong district. In addition to power generation, the plant will also reduce the volume of domestic waste by 80% to 90%.

- *Raise awareness and promote human capacity development*

The TSB solar plant is being used as a training facility to teach the management, operation and maintenance of an on-grid solar PV plant. In addition, EIDPMO is promoting and increasing public awareness of renewable energy among local communities at roadshows and similar events. Higher learning institutions and industry stakeholders are also involved with renewable capacity building and entrepreneurship.

- *Advocate research, development and demonstration (RD&D) and technology transfer*

To strengthen the renewable energy industry in Brunei, EIDPMO is promoting RD&D of renewable energy technologies for domestic commercialisation and exports. This is implemented through collaboration between local and international research institutions.

Waste-to-energy, wind power and micro-hydropower are attracting R&D collaboration among MEMI, BNERI and other agencies (both the government and private sectors). Deployment of these alternative energy sources will depend on technological maturity, and whether the technology has been integrated into the national renewable energy roadmap.

NUCLEAR

Brunei does not have a nuclear energy industry.

CLIMATE CHANGE

The Brunei National Council on Climate Change (BNCCC) was established 28 July 2018 and is co-chaired by the MEMI and the Minister of Development. The council convened its first meeting 16 October 2018, and oversees the challenges, impact and opportunities of climate change.

The Brunei Climate Change Secretariat (BCCS) serves as the secretariat to the BNCCC. The BCCS is also responsible for the Executive Committee on Climate Change; the Mitigation Working Group; the Adaptation and Resilience Working Group; and the Support Framework Working Group. The MEMI, through the BCCS, is formulating the Brunei National Climate Policy (BNCP). Policies will cover fugitive emissions, renewable energy, reforestation and biodiversity conservation, electric vehicles, and climate adaptation and resilience. The BNCP will outline the opportunities of both climate change mitigation and adaptation to ensure Brunei is a climate-resilient economy.

NOTABLE ENERGY DEVELOPMENTS

ENERGY INFRASTRUCTURE PROJECTS

Oil and gas market developments have a large impact on Brunei, given that a large proportion of their government revenue is tied to oil prices. This revenue and FDI are influential in the forward pipeline for infrastructure.

Hengyi Industries Sdn Bhd has recently become operational. Brunei Fertilizer Industries Sdn Bhd is still in the construction phase and is expected to become operational by the second quarter of 2022.

Brunei Darussalam is expecting to sign the Regional Comprehensive Economic Partnership (RCEP) in 2020. This agreement is an economic cooperation involving the ASEAN and Australia, China, Japan, Korea and New Zealand. The RCEP will progressively reduce tariffs on many products. The deal will also allow businesses to sell the same goods with reduced levels of administrative work.

Brunei will supply over 200 metric tonnes of hydrogen to Japan in 2020. In the project, hydrogen produced in Brunei will be transported to the coastal city of Kawasaki, Japan. The hydrogen will be used as a mixture fuel for thermal power generation. The project is led by AHEAD (Advanced Hydrogen Energy Chain Association for Technology Development), established by Chiyoda corporation, Mitsubishi Corporation, Mitsui & Co., Ltd. and Nippon Yusen Kabushiki Kaisha (JASE, 2019).

BRUNEI DARUSSALAM-INDONESIA-MALAYSIA-PHILIPPINES EAST ASEAN GROWTH AREA (BIMP-EAGA)

The history of the Brunei Darussalam-Indonesia-Malaysia-Philippines East ASEAN Growth Area (BIMP-EAGA) began in 1992. The endorsements and confirmations of then Indonesian President Suharto (September 1993), Sultan Haji Hassanal Bolkiah of Brunei Darussalam (November 1993), and Malaysian Prime Minister Mahathir Mohammad (February 1994) paved the way for the BIMP-EAGA Inaugural Senior Officials' Meeting and Ministers' Meeting (SOM/MM) in Davao City, the Philippines from 24 to 26 March 1994 (MINDA, 2019).

BIMP-EAGA covers the entire sultanate of Brunei; the provinces of Kalimantan, Sulawesi, Maluku and West Papua of Indonesia; the states of Sabah and Sarawak and the federal territory of Labuan in Malaysia; and Mindanao and the province of Palawan in the Philippines.

The sub region covers a land area of 1.6 million square kilometres with an estimated population of 70 million (ADB, 2019).

The Trans-Borneo Interconnection Power Grid is one of the flagship projects initiated by BIMP-EAGA under its power and energy infrastructure cluster. Under this initiative, Brunei agreed to purchase 100 MW from Sarawak Energy Berhad (SEB) with an option to buy 50 MW more.

BRUNEI DARUSSALAM – CHINA COOPERATION

In 2013, China and Brunei signed the cooperation agreement between the China National Offshore Oil Corporation and the Brunei National Petroleum Company Sendirian Berhad.

The PBS-COSL Oilfield Service Company was registered in 2014 in Bandar Seri Begawan and began to build six platforms including rigs and gas compression platforms. The two economies agreed to strengthen bilateral trade and investment cooperation, to work closely to implement the Memorandum of Understanding on strengthening infrastructure cooperation, to push forward the cooperation on the Hengyi Industries Sdn Bhd refinery and petrochemical plant, and to promote the "Brunei-Guangxi Economic Corridor".

The first phase of Hengyi's crude oil refinery and petrochemical plant became operational in 2019. The refinery is a joint venture between China's Hengyi Industries and the Brunei Government and is expected to contribute USD 1.3 billion to GDP in 2020. The commissioning will have the crude processing capacity of eight million tonnes per year, producing 1.5 million tonnes per year of paraxylene and 500 000 tonnes per year of benzene as well as gasoline, kerosene, diesel and other products. There are plans for a second phase, in which the refinery will add 14 million tonnes per year of crude processing capacity, bringing overall capacity to 22 million tonnes per year

The first phase of the 276-hectare project involves USD 3.4 billion in investment. Hengyi will commit a further USD 12 billion for development of the second phase, making it the largest FDI project in the sultanate. Crude oil will be transported from Belait for refining at Pulau Muara Besar (additional oil requirements will be met by imports). The second phase will focus on manufacturing downstream products such as aromatics and industrial chemicals that are used to make clothing and plastics, and could generate revenue up to USD 10 billion per year.

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Ministry of Energy, Manpower and Industry— <http://memi.gov.bn>

PetroleumBRUNEI— <http://www.pb.com.bn/>

Electricity Authority Brunei Darussalam - <http://www.aenbd.gov.bn>

CANADA

INTRODUCTION

Canada is the world's second-largest economy after Russia in terms of land mass. The Canada–US border is the world's longest international border and extends from the Pacific Ocean to the west, across to the Atlantic Ocean to the east. There are 10 provinces and three territories in Canada, with a total population of 37 million in 2017 (EGEDA, 2019). In 2017, Canada's gross domestic product (GDP) grew by 3.0% to USD 1603 billion (2011 USD purchasing power parity [PPP]) and GDP per capita grew by 1.8% to USD 43 871 (EGEDA, 2019).

Canada is the fourth-largest energy producer in the APEC region and the sixth largest in the world after China, the US, Russia, Saudi Arabia and India (NRCan, 2019a). The energy sector directly contributed 8.1% to Canada's GDP in 2018 and indirectly contributed (through purchases of goods and services from non-energy industries) an additional 3.0%. In 2018, Canada exported CAD 132 billion worth of energy products and imported CAD 51 billion. Canada is one of the world's top five exporters of crude oil, natural gas, uranium and electricity.

The economy has extensive conventional and unconventional oil, natural gas and coal reserves as well as significant uranium deposits. It has the world's third-largest amount of proven oil reserves after Venezuela and Saudi Arabia. The reserves were estimated at 168 billion barrels, of which oil sands constituted 96% (161 billion barrels) as of December 2017 (BP, 2019) (NRCan, 2019a). The bulk of reserves are in the province of Alberta. Alberta and Saskatchewan have the largest onshore reserves, while Newfoundland and Labrador has the largest offshore reserves (CER, 2019a).

Canada has substantial proven gas reserves, which are estimated at 65 trillion cubic feet (Tcf) and equal to 0.9% of global reserves in 2018. The largest concentrations of gas reserves are in Alberta and British Columbia. Saskatchewan, Newfoundland and Labrador, New Brunswick, Nova Scotia, the Northwest Territories (NWT) and Yukon also have established reserves, although significantly smaller (CER, 2019a).

Canada currently holds 6582 million tonnes of proven resources of coal. More than 90% of Canada's coal deposits are located in the western provinces, namely, Alberta, British Columbia and Saskatchewan, while the rest are located in the eastern province of Nova Scotia (CAC, 2016).

Canada has the third-largest uranium resources in the world after Australia and Kazakhstan. As of 2017, Canada's uranium resources were estimated at 410 kilotonnes (NEA, 2018), most of which are located in the Athabasca Basin of northern Saskatchewan. These resources are equal to 11% of the world's known recoverable resources at a price of US\$130 per kilogram.

Table 1: Key data and economic profile, 2017

Key data ^{a, b}		Energy reserves ^{c, d}	
Area (million km ²)	10	Oil (billion barrels)	168
Population (million)	37	Gas (trillion cubic feet)	65
GDP (2011 USD billion PPP)	1 603	Coal (million tonnes)	6 582
GDP (2010 USD PPP per capita)	43 871	Uranium (kilotonnes U)	410

Sources: ^a EGEDA (2019); ^b StatCan (2016a); ^c BP (2019); ^d NEA (2018).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Canada's domestic energy production reached 509 649 kilotonnes of oil equivalent (ktoe) in 2017. This represented an increase of 6.2% compared with that in 2016 (479 743 ktoe) (EGEDA, 2019). Fossil fuel dominated this production with a share of 85%. Oil, including natural gas liquids (NGLs), constituted the largest share (249 208 ktoe, 49%), followed by gas (153 431 ktoe, 30%) and coal (30 529 ktoe, 6.0%). The share of nuclear energy production was 5.2% (26 346 ktoe), thereby leaving a share of approximately 10% for renewables. Renewables comprised hydro (33 752 ktoe, 6.6%); other renewables (bioenergy), including biomass, wood and waste (13 557 ktoe, 2.7%); and geothermal, solar, wind and ocean (2 826 ktoe, 0.55%) (EGEDA, 2019). Canada is a leading global producer of energy, as evident in its global production ranks for gas (fourth), crude oil (fourth), hydro (second) and uranium (second) as of 2016 (NRCan, 2019a).

Canada is a net exporter of oil, gas, coal, uranium and electricity. The economy's energy exports go mainly to the US. From 2000 to 2017, energy exports grew at 2.5% per year. Exports increased by 5.3% in 2017 to 301 675 ktoe of energy (excluding uranium exports) (EGEDA, 2019). Exports comprised crude oil and NGL (180 618 ktoe), petroleum products (24 129 ktoe), gas (71 045 ktoe), coal and coal products (18 489 ktoe), electricity (6 199 ktoe) and renewables (1186 ktoe). In 2017, energy exports constituted 23% (CAD 132 billion) of domestic merchandise export revenue (NRCan, 2019a). The main export market for Canadian energy continues to be the US.

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	509 649	Industry sector	45 617	Total power generation	658 288
Net imports and others	-217 119	Transport sector	61 306	Thermal	124 710
Total primary energy supply	289 065	Other sectors	67 993	Hydro	392 536
Coal	17 018	Non-energy	21 009	Nuclear	101 112
Oil	99 920	Final energy consumption*	174 916	Others	39 930
Gas	100 864	Coal	2 580		
Renewables	50 058	Oil	71 681		
Others	21 205	Gas	44 523		
		Renewables	11 676		
		Electricity and others	44 456		

Source: EGEDA (2019) (data collected in December 2019).

* Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. Total final consumption includes non-energy uses. Half of the municipal solid waste used in power plants is assumed to comprise renewables.

CRUDE OIL

Canada's oil production has increased over the past two decades. In 2017, it was the world's fourth-largest oil producer. In 2017, Canada produced 249 208 ktoe of crude oil, including NGL. This was an increase of 5.8% from 2016 (EGEDA, 2019). This large increase was the result of production rebounding from extraordinary curtailments that several oil sands producers enacted in 2016 in response to wildfires in the Fort McMurray region (CER, 2016a). Production from oil

sands, which are mainly located in the Athabasca oilfields in Alberta, has consistently grown since it began in 1967, surpassing conventional production levels in 2010. A sustained period of high prices attracted significant investment into incremental capacity gains over the past decade, driving production to 3.0 million barrels per day (Mbbbl/D) in 2018, an increase of 186% over 2005 levels (NEB, 2019a). Conventional oil production continued its second year of annual growth to 1.7 Mbbbl/D in 2018, driven mainly by increases in field condensate in Alberta and heavy oil in offshore fields of Newfoundland and Labrador (NEB, 2019a).

Although Canada's crude oil and equivalent production varies geographically, 94% of production in 2018 came from Western Canada, of which 64% was from the oil sands. The bulk of Canadian crude oil and equivalent production occurred in Alberta (82%), followed by Saskatchewan (10%), British Columbia (2.1%) and Manitoba (0.84%) (NEB, 2019a). Offshore production in the Atlantic Ocean constituted 5.1%. There was also small-scale production in Ontario (0.01%) and the Atlantic provinces (0.03%). Pentanes plus and condensates constituted 9.5% of total crude oil and equivalent production. This has grown at a rapid, annual average rate of 48% since 2010 as producers continue to target the profitable condensate-rich Montney and Alberta Deep Basin. Exports of petroleum products (21 329 ktoe) decreased by 6.0% (EGEDA, 2019).

GAS

Canada holds large proven natural gas reserves. It is the world's fourth-largest producer and fifth-largest exporter of natural gas (NRCan, 2019a). In 2017, Canada's natural gas production reached 153 431 ktoe, an increase of 3.3% from 2016 (EGEDA, 2019). The production increase represents a continuation of growth since 2013, following a seven-year period of decline. Gas exports were exclusively to the United States and totalled 71 045 ktoe, an increase of 3.3% compared with 2016 (EGEDA, 2019). After several years of successive decline, gas export volumes appear to be stabilising around these levels.

Although conventional natural gas reserves are shrinking, technological advances in hydraulic fracturing have renewed the growth potential from the Western Canadian Sedimentary Basin (WCSB). In Canada, these developments have fostered the development of tight gas resources, particularly in the Montney formation and the Alberta Deep Basin. This contrasts with the United States, where hydraulic fracturing mainly targets shale resources. Canada has vast shale resources, but they are either in their infant stages of development (the Duvernay), lack the NGLs needed to make drilling economic at today's prices (Horn River Basin), or are located in areas where hydraulic fracturing is under a moratorium (the shale formations in Quebec and New Brunswick).

Western Canada provinces Alberta (65%), British Columbia (32%) and Saskatchewan (2.5%) accounted for over 99% of Canada's marketable gas production in 2018 (NEB, 2019a). Alberta and British Columbia (from the Montney, Deep Basin and Duvernay plays) drove production growth, more than offsetting declines from conventional plays and the rest of the economy. Eastern Canada's marketable gas production is in decline, with Nova Scotia and New Brunswick shutting in production in 2019 and small amounts of onshore production in Ontario making up less than 0.06% of Canadian gas production (NEB, 2019a). Solution gas—gas produced in association with oil production—is still prominent, making up 13% of production in 2018. Offshore oil producers of Newfoundland and Labrador also produce associated gas but consume all of it on site via electricity generation or flaring.

COAL

Annual coal production has declined since 2014, driven by Ontario's phase-out of coal-fired electric generation, lower global metallurgical prices, and, most recently, coal-to-gas switching in Alberta. Albertan utilities have been aggressively scheduling coal-to-gas conversions on their coal generators to take advantage of low natural gas prices, reduce emission compliance costs, and align with investor sentiment to phase out coal generation (TransAlta, 2019a). According to Statistics Canada, production declined by 10% in 2018 and by another 3.7% in 2019 (StatCan,

2019). Almost all of Canada's coal production is taking place in Western Canada; however, Nova Scotia restarted production at its Donkin mine in 2017 to supply domestic power needs and for export to global thermal and metallurgical markets (Morien, 2018).

Canada ranks 13th in global coal production (NRCan, 2019a). Approximately 49% of its annual production of 56 million tonnes (Mt) is metallurgical (coking coal, which is used in steel manufacturing and is largely exported). The other 51% is thermal coal for use in electricity generation and some heating requirements in both domestic and export markets (CAC, 2017). Canada exported 60% (18 470 ktoe) of its coal production in 2017, of which coking coal constituted 93% (EGEDA, 2019). The value of these exports was CAD 7.5 billion, and most went to Asia.

URANIUM

Canada's uranium production declined 6.6% in 2017. Even so, Canada maintained its position as the world's second-largest producer, producing 15 kilotonnes of uranium metal (tU) in 2017 (NRCan, 2019a). Uranium production has continued to decline because low prices forced the suspension of operations at McArthur River, one of the world's largest mines (Cameco, 2019). Cigar Lake remains the world's largest uranium mine, producing 13% of global mining uranium output in 2018 (WNA, 2019).

RENEWABLES

Canada is a world leader in the production and use of renewable energy. In 2017, the economy's total renewable production was 49 928 ktoe, consisting of hydro (33 752 ktoe); bioenergy and waste (13 350 ktoe); and solar, geothermal, wind and ocean (2825 ktoe) (EGEDA, 2019). Renewables accounted for 10% of total indigenous energy production in 2017.

Hydro is the most important source of renewable energy in Canada, supplying 61% of Canada's electricity generation in 2018 from an installed hydraulic capacity of 81 474 MW (NEB, 2019a). Hydro is also the key fuel source for Canada's electricity exports, making up 73% of the generation in the six provinces that export electricity to the United States. The completion of several large-scale projects across the economy will bring an additional 2.3 GW of hydroelectric capacity online by 2023 to service both domestic demand growth and exports markets. These projects include Site C in British Columbia, Keeyask in Manitoba, Romaine-4 in Quebec and the Lower Churchill Project in Newfoundland & Labrador (Site C, 2017) (Manitoba Hydro, 2019) (HQ, 2019) (Nalcor, 2019).

Canada has access to large and diversified biomass resources for energy production owing to its large land mass and active forests that are utilised by the agricultural, forest and paper industries. In 2017, biomass represented 3.7% of Canada's total primary energy supply (EGEDA, 2019). It is estimated that 6.3% of gasoline demand in Canada is met with blended ethanol and 2.2% of diesel is met with blended biodiesel (CEEDC, 2018).

Wind is also an important renewable energy source. Provincial generating leaders are Ontario, Quebec and Alberta (NEB, 2019a). While Prince Edward Island (PEI) only makes up 1.7% of Canada's wind generation, wind's share of its provincial generation leads Canada at almost 99%. Other provinces with wind potential are increasing the share of wind energy in their power mix. Canada has vast areas to facilitate the expansion of economic wind-generated power, particularly in Alberta and Saskatchewan. Installed wind power capacity has rapidly expanded in recent years. Low prices demonstrated at recent capacity auctions indicate that strong growth will continue (AESO, 2018). Canada has close to 300 wind farms in operation, with a total installed capacity of 12 998 MW in 2018 (CanWEA, 2019) (NEB, 2019a).

Solar is also growing, both in thermal and photovoltaic (PV) power. Cumulative PV power capacity increased to 2926 MW in 2018 (NEB, 2019a). Ontario is the leading province in terms of solar capacity (88% of total installed capacity). Canadian off-grid solar capacity is not currently tracked (IEA, 2019). Alberta, Manitoba, British Columbia and NWT also expanded solar capacity in 2018 (CER, 2019a).

Canada has access to a significant energy source in the form of waves and tides from both the Atlantic Ocean and the Pacific Ocean. The province of Nova Scotia has one of the world's few tidal power plants, with 20 MW of generation capacity, and has several prospective projects looking to install capacity in the Bay of Fundy, Nova Scotia in the coming years.

Despite ample potential, geothermal power has not experienced the momentum of solar, wind and biomass. Alberta, British Columbia, Saskatchewan, the NWT and Yukon are where the highest temperature geothermal resources are located. Several demonstration projects are underway in Western Canada. Examples include, DEEP Earth Energy's pursuit of a five MW geothermal-electric project in Saskatchewan (JWN, 2019a); Terrapin Geothermics exploring a five MW geothermal-electric facility in Greenview, Alberta (Terrapin, 2019); and the federal government's partnership with the Saulteau First Nation to assess the potential of geothermal electricity for reducing fossil fuel reliance in indigenous communities (NRCan, 2019b). However, DEEP is the only project of these that has listed a tentative commission date, which is between 2021 and 2022.

FINAL ENERGY CONSUMPTION

Canada's final energy consumption in 2017 reached 174 916 ktoe, a decrease of 1.4% from that in 2016. This makes Canada the fifth-largest energy consumer in APEC after China, the US, Russia, and Japan (EGEDA, 2019).

The transport sector accounted for the largest share of final energy consumption (61 306 ktoe, 35%), followed by the industrial sector (45 617 ktoe, 26%) (EGEDA, 2019). Residential, commercial and public services, together with agriculture and non-specified others, made up the remainder (67 993 ktoe, 39%). Non-energy (fuels used as raw materials and not consumed as fuel or transformed into another fuel), which is excluded from final energy consumption, was 21 009 ktoe in 2017.

Fossil fuels accounted for 68% of final energy consumption in 2017, comprising petroleum products (71 681 ktoe, 41%), gas (44 523 ktoe, 25%) and coal and coal products (2 580 ktoe, 1.5%) (EGEDA, 2019). The remainder was the share of renewables (11 676 ktoe, 6.7%) and electricity and others (44 456 ktoe, 25%), of which the share of renewable electricity and others was 28 815 ktoe (65%).

POWER GENERATION

Canada generated 658 288 gigawatt-hours (GWh) of electricity in 2017, a decrease of 1.2% from the previous year (EGEDA, 2019). Renewables constituted the largest share of this generation (66%), with hydro as the major contributor (60%) and solar, wind, geothermal and tidal at 6.0% combined. The share of nuclear was 15%, which increased the combined share of non-emitting power generation to 81%. The share of coal, oil, and natural gas-fuelled thermal generators was 19%. Coal constituted the largest share (9.1%), followed by gas (8.7%), and a combination of biomass (wood and spent pulping liquor) and other fossil fuels, such as diesel, light fuel oil and heavy fuel (1.1%).

Canada has been increasing the share of renewables, including hydroelectricity, for electricity generation since 2000. Low natural gas prices, the rapidly decreasing cost of renewable energy, the introduction of emission pricing on electricity, and new regulations that limit the use of coal have all decreased the greenhouse gas (GHG) intensity of Canada's electricity sector. Canada is the APEC region's and the world's second-largest hydroelectricity producer after China (NRCan, 2019a). Canada's water resources enable many parts of the economy to rely on hydropower.

Several provinces have introduced policies and programs to promote renewable energy while discouraging the continued use of coal-fired power plants. In 2016, the federal government announced its plan to accelerate the phase-out of coal-fired electricity generation in Canada by 2029. The negotiation of equivalency agreements with the provinces allows some flexibility in

achieving this (GOC, 2018a). For example, the federal government reached an in-principle agreement with Nova Scotia to burn coal after 2029 during periods of high demand, in exchange for deeper sectoral reductions elsewhere in the economy.

Coal-fired generation ceased in Ontario in 2013 (CER, 2015). Competitive bidding processes have led to large increases in solar and wind capacity. Ontario's renewable capacity is set to continue to grow for the next few years, even though a good portion of the contracts have been cancelled (CER, 2019a). As part of the 2017 Long-Term Energy Plan, Ontario intends for nuclear to continue to be a major source for the province's electricity supply (GOO, 2017). To this end, the province plans to continue with the refurbishment of 10 nuclear reactors, albeit on an altered, more cost-effective schedule. These refurbishments will add approximately 25–30 years to the operational life of each unit.

In November 2015, Alberta announced a new policy to accelerate the 2012 federal plan to phase out coal-fired power generation. Alberta's plan will result in the retirement of six coal-fired electricity plants or their conversion to natural gas by 2030 (Alberta Energy, 2015). However, in 2018, the combination of low natural gas prices, higher carbon prices, and an output-based emission pricing system (that uses a natural gas-based benchmark) increased the operating cost of coal-fired generation. Several utilities began to co-fire natural gas at existing coal units to reduce their carbon compliance costs¹. This reduced coal-fired generation by 22% in 2018 while increasing gas-fired generation by 26% (AESO, 2019). Utilities are planning to convert several coal units to run exclusively on natural gas ahead of the scheduled 2029 federal phase-out (TransAlta, 2019b).

On the renewable side, Alberta has had several successful government-driven bidding processes to increase wind capacity over the next several years (AESO, 2018). A fourth phase of bids has been cancelled, but private investment is still expected to drive growth in wind and solar. For example, BHE Canada intends to build a 118 MW wind project without the guaranteed producer price that was characteristic of the government-driven initiatives (RES, 2019).

The electricity networks of Canada and the US are highly integrated. In 2017, Canada exported 6199 ktoe of electricity to the US while importing 851 ktoe (EGEDA, 2019). The bulk of the electricity trade with the US occurs between Quebec, Ontario, Manitoba and British Columbia and their neighbouring American states (CER, 2019b). New international power lines (IPLs), the ITC Lake Erie and Manitoba-Minnesota Transmission Line, have been approved by the federal government and certificates issued by the National Energy Board (NEB) (CER, 2016b). Three additional IPLs are under consideration in Quebec. In 2018, Hydro Québec announced it had been successful in its bid to deliver 1900 MW of hydropower to the New England electric grid via the proposed Northern Pass Transmission Line (HQ, 2018).

ENERGY INTENSITY ANALYSIS

The vast geography, cold climate and a high proportion of energy-intensive industries all contribute to make Canada a highly energy-intensive economy. The relatively low cost of the economy's abundant fossil energy reserves and renewable capacity (particularly hydro) also plays a role.

Canada has gradually reduced its energy intensity over the past four decades (EGEDA, 2019). Primary energy intensity continued this trend in 2017 and fell by 0.18%. In contrast, final energy consumption intensity increased by 0.92% in 2017. The residential sector and freight transport

¹ According to the financial statements and investor presentations of the utilities that operate the remaining coal fleet in Alberta. Coal-unit operators who embraced natural gas co-firing in 2018 include Capital Power and ATCO (Capital Power, 2019) (ATCO, 2019).

are responsible for much of the improvement in energy intensity, with both registering the largest reductions in energy use in 2016 (NRCAN, 2019c). Increasing energy efficiency and reducing energy intensity have been pursued by the Canadian Government as means to mitigate climate change and conserve energy.

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%)
	2016	2017	2015 vs 2016
Total primary energy supply	181	180	-0.18
Total final consumption	123	122	-0.96
Final energy consumption excl. non-energy	108	109	0.92

Source: EGEDA (2019).

RENEWABLE ENERGY SHARE ANALYSIS

The share of modern renewables was 21% of final energy consumption in 2017 (an increase of 13%). Traditional biomass remained flat, while modern biomass increased 33% (EGEDA, 2019).

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	168 313	174 916	3.9
Non-renewables (fossils and others)	135 185	137 427	1.7
Traditional biomass*	3 002	3 002	0.0
Modern renewables*	33 128	37 489	13
Share of modern renewables to final energy consumption (%)	20	21	8.9

Source: EGEDA (2019).

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on) including biogas and wood pellets are considered modern renewables, although data on wood pellets are limited.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Canada's federal, provincial and territorial governments all have a role in shaping the economy's energy policy. The Constitution Act of 1867 outlines jurisdictional power. Energy market interventions achieve policy objectives (for example, pipeline regulation) through regulation and other means (GOC, 1867).

The Canadian provinces are the owners of ground resources and mineral rights within provincial boundaries, excluding the resources located in aboriginal lands and frontier lands

(that is, national parks and international waters) in accordance with sections 91 and 92 of the Canadian Constitution (GOC, 1985). The provincial governments have the primary responsibility for shaping policies in their jurisdictions; energy policy varies from jurisdiction to jurisdiction. Unlike the provinces, the three territories do not own the ground resources but share partial management responsibility. In addition to frontier lands, the federal government is responsible for regulating uranium mining and nuclear energy, interprovincial/international trade and commerce, trans-boundary environmental impacts and interprovincial work (for example, pipelines), as well as developing policies in the national interest (economic development, health and safety and energy security) (CER, 2019c).

Energy policy at the federal level involves multiple government agencies. Natural Resources Canada (NRCan) is the federal department mandated to 'ensure that Canada's resource sector remains a source of jobs, prosperity, and opportunity within the context of a world that increasingly values sustainable practices and low-carbon process' (PMO, 2015). The CER is an independent federal regulator responsible for pipelines and transmission lines that cross international borders or provincial boundaries; for energy development; and for trade issues in the Canadian public interest. The Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) is the independent joint agency of the governments of Canada and Nova Scotia and regulates petroleum activities in the Nova Scotia Offshore Area (CNSOPB, 2018). The Canadian Nuclear Safety Commission (CNSC) regulates the use of nuclear energy and materials to protect health, safety, security and the environment and implements Canada's international commitments on the peaceful use of nuclear energy. Other important government organisations are Environment and Climate Change Canada (ECCC), Fisheries and Oceans Canada, Indigenous and Northern Affairs Canada and Global Affairs Canada.

ELECTRICITY MARKETS

Federal and non-federal actors have distinct roles in the Canadian electricity market. The federal government is responsible for electricity exports, international and designated interprovincial power lines, and nuclear policy. The provinces and territories have jurisdiction over the generation, transmission and distribution of electricity within their boundaries, a power which also encompasses restructuring initiatives and electricity prices.

The electricity industry in most provinces is highly integrated. A small number of dominant utility providers deliver the bulk of generation, transmission and distribution services. Provincial governments own most of these utility providers through Crown corporations. Alberta is an exception, with full wholesale and retail competition. Ontario too, has established a hybrid system with competitive and regulated elements.

The election of a new Conservative government in 2019 has brought several changes to Alberta's electricity markets. In July 2019, Alberta announced that it would not transition to a capacity market and would continue with the current energy-only market. The Alberta Electric System Operator (AESO) recommended the implementation of a capacity market to provide greater revenue certainty for generators, thereby encouraging investment in new generation capacity and maintaining the competitive market structure used to set wholesale prices (ERQ, 2017).

Electricity prices vary across the provinces in terms of their levels and the mechanisms by which they are set. Provinces with an abundant supply of hydroelectricity generally have the lowest prices. In most provinces, the regulator sets the prices according to a formula that determines the cost of service (COS) plus a reasonable rate of return. There are two exceptions: in Alberta, retail electricity prices are derived from a competitive wholesale market; and in Ontario, retail prices are derived from a combination of market spot prices and a dynamic price component (global adjustment) set to cover the costs of guaranteed rates to generators (IESO, 2019). Transmission and distribution rates generally follow the COS operating model across provinces and are passed on to customers based on fixed and variable components. Alberta removed a cap on retail electricity prices that subsidised the portion of

residential rates that exceeded the threshold of 6.8 cents per kWh. In December 2019, the first month after the elimination of the cap, residential prices increased by between 7.6% and 19% throughout the province (AUC, 2019).

ENERGY MARKET

OIL AND NATURAL GAS

Canada's Western Accord and the Agreement on Natural Gas Markets and Prices fully deregulated Canada's wellhead oil and natural gas prices in 1985. The agreement opened up the oil and gas markets to greater competition by permitting more exports, allowing users to buy directly from producers and unbundling production and marketing from transportation services (NEB, 1996). Natural monopolies of oil and gas pipeline networks are still subject to regulation.

Arctic and offshore energy exploration by the oil and gas industry and the Geological Survey of Canada have indicated a strong potential for petroleum discoveries in Canada's north, particularly in the Arctic. However, the costs of developing these fields and transporting oil and gas to markets are high. Low oil prices in the previous decades and transportation bottlenecks have made discoveries uneconomical to develop, limiting production growth in the region.

The CER regulates Canada's oil and gas industry in the north, including offshore drilling in the Arctic, as set out in the Canada Oil and Gas Operations Act, Canada Petroleum Resources Act and National Energy Board Act. The exception is most onshore lands in the NWT, which the Government of NWT assumed responsibility for in 2014. The CNSOPB and the Canada-Newfoundland and Labrador Offshore Petroleum Board regulate Canada's Atlantic offshore oil and gas industry.

A 1972 federal moratorium restricts offshore field development off the Pacific coast of Canada (NRCan, 2018a). The fiscal regime applied to the Canadian oil and gas industry comprises a combination of corporate income taxes and royalty payments. Corporate income tax rates applied to the key oil and gas regions are set out in Table 5.

Table 5: Corporate income tax rates, 2017

CIT rates	British Columbia	Alberta	Saskatchewan	Newfoundland and Labrador	Nova Scotia
Federal	15%	15%	15%	15%	15%
Provincial	12%	12%	10%	15%	16%
Total	27%	27%	27%	30%	31%

Sources: BDO (2019).

Canada does not allow corporations to file consolidated tax returns; each corporation must compute and pay taxes on a separate legal entity basis. Non-capital losses (business losses) can be carried back three years and carried forward 20 years. Capital gains are subject to tax at one-half the capital gain (taxable capital gain) at regular income tax rates. Capital losses are exclusively deductible against capital gains and can be carried back three years and forward indefinitely or until the company is acquired. Non-capital losses can be deducted against taxable capital gains (EY, 2019).

The owner of a resource, which is typically the applicable province, applies royalty regimes (or rent-based taxes). But a small proportion of surface owners (freehold land) or First Nations own the petroleum rights. Resource owners lease the land to potential developers in exchange for a fee (land sale) and royalty agreement. Interests (drilling or production) in crown land are also sold or auctioned. Royalty regimes vary both by province and by commodity and are typically paid based on a combination of well productivity and wellhead price (EY, 2019). Royalties paid are deductible for tax purposes.

Table 6 describes the basic structure of royalty regimes across Canada, as published by the Fraser Institute in a report by Bazel & Mintz (2019).

Table 6: Summary of regional royalty regimes, 2018

Province	Royalty	Rent-based tax
British Columbia	For conventional oil and gas, the royalty is based on gross revenue. The royalty rate differs first by product category, such as density of oil or type of gas (that is, conservation vs. non-conservation gas) and by well age (except for heavy oil and conservation gas). Formulation of the royalty rate for a given product category differs between oil, gas and natural gas by-products. For oil, the royalty rate is sensitive mainly to productivity; for gas, it is sensitive only to price; natural gas by-products have set royalty rates. For certain high-cost gas projects, there is a pre-payout of 2% royalty on gross revenue (refer to next column).	For certain high-cost gas projects, a newly introduced net profit royalty program with four tiers of royalty rates applies: a pre-payout of 2% royalty on gross revenue and three post-payout tiers associated with a royalty that is the greater of 5% of gross revenue and a higher rate of net revenue (that is, 15%, 20% or 35%, depending on the tier order). To reach each of the three tiers of net royalty, a progressive return allowance applies.
Alberta <i>(Updated)</i>	For conventional oil and gas, the royalty rate is based on gross revenue or production and is sensitive to both the market price and well productivity. Since 2017, the royalty has ranged from zero to 40%, and for natural gas 5% to 36%. There is also an initial 5% royalty that applies in the first 12 months with a volume cap. As for oil sands, a progressive gross royalty ranging from 1% to 9% applies before payout. It is creditable against the net royalty (unused credits are carried forward at the investment allowance rate).	For oil sands only, in addition to a pre-payout gross royalty, there is a net royalty of 25–40% after payout, depending on the price level of the oil.
Saskatchewan	The crown royalty and the freehold production tax (FPT) on oil and gas are determined using formulas containing parameters adjusted monthly by the government. Both royalty and FPT are sensitive to price and well productivity and differ by product in terms of their vintage and characteristics (for example, type of product, well and location). The FPT is lower than the crown royalty by a production tax factor (PTF) which varies by the type of product and ranges from 6.9–12.5%.	None.

Province	Royalty	Rent-based tax
Newfoundland and Labrador (Updated)	Under the generic offshore oil royalty structure: a basic royalty is charged on adjusted gross revenues at rates rising from one to 7.5% as cumulative production rises to the point the R factor is greater than 1.25. The basic royalty is payable over the entire production period. However, after payout it is creditable against the net royalty. The R factor is calculated as: $R = (\text{cumulative gross sales revenue and incidental revenue less cumulative transportation costs less cumulative basic and net royalty paid to prior month}) \div (\text{cumulative pre-development, capital \& operating costs})$.	Net royalty set to one tier with a sliding scale of rates ranging from 10% (for $1 \leq R \leq 3$) to 50% ($R > 3$). Rates are based on the same R factor as that defined for the revenue-based royalty.
Nova Scotia	The revenue-based or gross royalty is two-tiered—2% before payout and 5% after payout—and deductible for calculating the base for the net revenue royalty (ie: the rent-based tax). Note that regardless of the revenue and profit level reached, the 2% gross royalty applies for a minimum of 24 months, and the 5% gross royalty applies for a minimum of 36 months. This implies that there is no net royalty or rent tax payable for the first five years after the commencement of production.	The two-tier net royalty rates are 20% and 30%, depending on the net revenue tier reached. Even after the net royalties become payable, only the greater rate of 5% of gross revenue and 20% or 35% of the net revenue is payable. To reach each of the two tiers of the net royalty scheme, a progressive return allowance applies; 20% above the long-term bond rate (LTBR) for Tier 1 and 45% above LTBR for Tier 2.

Sources: Bazel & Mintz (2019)

Canada has three expenditure pools that are relevant to the oil and gas sector.

- Oil and gas rights expenditures accumulate in a pool called the Canadian Oil and Gas Property Expense (COGPE), and are deductible at up to 10% on a declining balance basis.
- Drilling and completion expenditures accumulate in a pool called the Canadian Development Expense (CDE), and are deductible at up to 30% per year on a declining balance basis.
- Exploration expenditures accumulate in a pool called the Canadian Exploration Expense (CEE). They are immediately deductible in the year incurred.

Indirectly, the energy sector is subject to general, provincial and harmonised sales taxes as well as climate-related policies such as carbon taxes or cap-and-trade systems. However, businesses paying GST/HST are eligible to receive input tax credits (ITCs) on necessary inputs for their commercial activities. The 'Climate Change' section discusses climate policies in more detail.

COAL

Canada is rich in coal resources. The largest known reserves are located in the Western provinces, which are also Canada's principal producers. Nova Scotia restarted production at its Donkin mine in 2017. Together with provincial-level law and regulations, there are 35 federal acts and regulations related to the mining industry (CAC, 2016).

Among the many existing guidelines, Canada finalised regulations to phase out conventional coal generation by 2029 (GOC, 2018b). The regulations add to a performance standard on new

coal-fired electricity established in 2012. Generation that incorporates carbon capture and storage (CCS) technology is exempt from the performance standard. Nova Scotia has also negotiated terms to burn coal past the 2029 deadline (subject to achieving emissions reductions in other sectors).

ENERGY EFFICIENCY

The federal and provincial governments have joint responsibility for energy efficiency, but their roles and responsibilities vary. Each province has ministries responsible for administering energy and environmental policies and programs, including energy efficiency programs. Examples of energy efficiency programs include energy-efficient building codes, equipment standards and consumer rebates. The foundation of all provincial policies rests upon the federal Energy Efficiency Act 1992, which was amended in 2009 to expand its scope and effectiveness (GOC, 1992). This act provides for the creation and enforcement of regulations on the energy efficiency of products, and supports the replacement of the least efficient products with high-efficiency, cost-effective ones.

NRCan, through its Office of Energy Efficiency administers the Energy Efficiency Act 1992 and deals with related efficiency issues at the federal level. The aim is to improve the utilisation of energy through energy efficiency (NRCan, 2019d).

The Government of Canada is investing more than CAD 300 million to foster greater electrification and use of lower-carbon fuels in the transportation sector (GOC, 2019a). These investments support the development of a coast-to-coast network of fast-chargers for electric vehicles (EVs), a network of EV chargers where Canadians live, work, and play, natural gas refuelling stations along key freight corridors, and hydrogen stations in metropolitan areas. These investments are also supporting the demonstration of next-generation charging technologies, and the development of enabling codes and standards.

Additionally, NRCan's Greening Government Services initiative assists federal departments and agencies to reduce the energy consumption and GHG emissions of their facilities (NRCan, 2018b). The voluntary program aids the self-finance of energy efficiency retrofit projects. Reducing building and transport fleet emissions to 40% below 2005 levels by 2030 is the goal of the initiative.

The federal government is collaborating with partners across the economy to reduce energy costs and increase energy efficiency. In the budget of 2019, the federal government committed CAD 950 million to the Green Municipal Fund to support municipalities in improving the energy efficiency of residential and commercial buildings (FSDS, 2019). The federal government is also promoting energy management and energy efficiency through the Canadian Industry Partnership for Energy Conservation, and is working with Efficiency Canada to foster evidence-based analysis for the promotion of energy efficiency in Canada.

CLEAN ENERGY RESEARCH AND DEVELOPMENT

The federal government is taking a comprehensive approach to clean energy research, development, and demonstration (RD&D). The budget of 2017 funded several program streams, focusing in whole or in part on clean technology innovation. Actions on clean energy innovation support the Pan-Canadian Framework on Clean Growth and Climate Change. In 2017, Canada launched Generation Energy with the goal of helping identify actions to reduce emissions and support a competitive energy industry. Through public consultation, the initiative identified four low-carbon pathways for Canada: wasting less energy, using clean power, supporting renewable fuels, and producing cleaner oil and gas (NRCan, 2018c).

As the federal lead on clean energy innovation, Natural Resources Canada (NRCan) funds and performs clean energy RD&D. CanmetENERGY and CanmetMATERIALS federal laboratories lead public research into, and development of, clean energy technologies. The laboratories are

located across Canada and undertake RD&D that reflects Canada's geographic and industrial strengths.

NRCan also funds industry-led RD&D to advance emerging technologies across the energy sector. Programs such as the Energy Innovation Program and the Green Infrastructure programs support innovations in clean electricity, low-carbon transportation, energy-efficient buildings, and industry. NRCan's Clean Growth Program supports clean technology RD&D in natural resource operations. These innovation programs target innovations that can reduce environmental impacts while enhancing competitiveness and creating jobs. Other federal organisations, including the Natural Sciences and Engineering Research Council and Sustainable Development Technology Canada also contribute to advancing clean energy innovation in Canada.

NRCan collaborates with the National Research Council (NRC) and the Canadian Commission on Building and Fire Codes to establish national energy codes—energy-efficient design and construction frameworks—for new buildings. NRC published a revised building code in 2017 that improves the overall energy performance of new buildings. The code is a step towards achieving the Pan-Canadian Framework's goal of achieving Net-Zero Energy Ready buildings by 2030.

The federal government is also enhancing Canada's clean energy innovation ecosystem. The Clean Growth Hub, an interdepartmental effort to streamline client services, improves program coordination, and tracks outcomes. NRCan is implementing the clean technology stream of the Impact Canada Initiative to pilot new, outcome-focused programs, such as prize-based challenges. The program leverages experimentation and rigorous evaluation to pilot innovative approaches and to broadly implement 'what works'.

Provincial, territorial and international stakeholders complement federal programs. For example, the Government of Canada is forming 'Trusted Partnerships' with provincial and territorial funding bodies to pool resources, share risks, and streamline delivery through the Clean Growth Program. Mission Innovation and the Powering Past Coal Alliance are also accelerating clean energy innovation.

NUCLEAR POWER

Nuclear energy is an important component of Canada's energy mix. In 2017, nuclear energy accounted for 15% of its electricity generation (EGEDA, 2019). Canadian nuclear power generation is concentrated in the provinces of Ontario (18 reactors) and New Brunswick (one reactor). Hydro Québec is currently decommissioning Gentilly, its only nuclear plant, which was permanently shut down due to prohibitive costs in 2012 (CNA, 2014).

Unlike other energy sources, nuclear energy falls within federal jurisdiction. The federal government is responsible for all regulation of nuclear materials and activities along with supporting R&D. Concerned with the impact of nuclear activities on health, safety, security and the environment, the federal government has put in place a comprehensive nuclear legislation framework. The latter comprises the Nuclear Safety and Control Act 1997, the Nuclear Energy Act 1985, the Nuclear Fuel Waste Act 2002 and the Nuclear Liability Act 1985² (NRCan, 2017). They provide the framework for developing nuclear energy in Canada.

However, the decision to invest in nuclear power plants for electricity generation rests with the provinces (in concert with relevant provincial energy utilities) (NRCan, 2017). There are

² The Nuclear Liability and Compensation Act (NLCA), which came into force on 1 January 2017, repealed and replaced the previous Nuclear Liability Act of 1985. The NLCA provides stronger legislation in order to deal more effectively with liability for a nuclear accident within Canada and allows Canada to join the International Atomic Energy Agency (IAEA) Convention on Supplementary Compensation for Nuclear Damage. The NLCA increases the operator's liability limit from CAD 75 million under the previous Nuclear Liability Act to CAD 1 billion, an amount to be phased in, from CAD 650 million in 2017 to CAD one billion in 2020.

currently no plans to build new nuclear power plants. They remain under consideration, due to Canada's commitment to phase out coal-fired power plants. Small modular reactors (SMRs) are particularly appealing to multiple provinces.

Ontario plans to refurbish 10 nuclear reactors in Ontario before 2035: four at the Darlington Nuclear Generating Station and six at the Bruce Nuclear Generating Station (GOO, 2017). Refurbishment at Darlington began in 2016. A commitment on subsequent reactors will consider the cost and timing of preceding refurbishments, with appropriate contractual off-ramps. The refurbishment of Bruce will begin in 2020. The development of SMRs also progressed in 2019. Atomic Energy Canada Limited announced plans to pilot a demonstration SMR unit in Chalk River, Ontario by 2026 (AECL, 2019), the CNSC received Canada's first Phase 1 pre-licensing vendor design review for an SMR (CNSC, 2019), and several provinces announced a non-binding MOU to collaborate towards the development and deployment of SMRs (GOO, 2019).

CLIMATE CHANGE

Canada's approach to climate change is multifaceted and layered at the provincial, federal and international levels. International commitments support and drive action at the federal and provincial levels. Canada is a signatory to the United Nations Framework Convention on Climate Change (UNFCCC) and has committed to the GHG reduction target developed at the Twenty-First Conference of the Parties (COP21) in December 2015 (the Paris Agreement). Canadian elected officials declared a climate emergency in Canada in June 2019, as did hundreds of municipal governments and the Assembly of First Nations, emphasising Canada's need to make deeper reductions than were committed to in the Paris Agreement (HOC, 2019) (RAOG, 2019).

Section 91 of the Constitution Act, 1867 gives the federal government the authority to make laws on a broad range of issues. Section 92 sets out the issues for which the provinces may make laws. Neither section explicitly mentions the environment. This leads to overlap and uncertainty in terms of which level of government is responsible for different aspects of the environment. Protection of the environment is a matter of shared jurisdiction between the Parliament and provincial legislatures, according to multiple decisions by the Supreme Court of Canada.

Canada has seen significant changes to its climate policy since 2015. Most notable is the Pan-Canadian Framework on Clean Growth and Climate Change (the Pan-Canadian Framework), which was collaboratively developed by federal, provincial and territorial governments with input from Canadians, including businesses, non-governmental organisations and Indigenous peoples.

PAN-CANADIAN FRAMEWORK ON CLEAN GROWTH AND CLIMATE CHANGE

Canada adopted the Pan-Canadian Framework 9 December 2016. It is a comprehensive plan to reduce emissions across all sectors of the economy, accelerate clean economic growth and build resilience to the impacts of climate change (GOC, 2016). The actions outlined in the Pan-Canadian Framework will contribute to Canada's goal of reducing emissions to at least 30% below the 2005 levels by 2030.

The Pan-Canadian Framework builds on the leadership of provinces and territories and the diverse array of policies and measures already in place across Canada to reduce GHG emissions in all sectors of the economy. Pricing carbon pollution is central to Canada's climate plan. The Government of Canada has outlined a benchmark for pricing carbon pollution that will build on existing provincial systems and expand carbon pricing across Canada in 2019. Provinces and territories may choose to implement a price-based system or a cap-and-trade system. Jurisdictions with a price-based system should have a minimum price of CAD 10 per tonne in 2018, rising to CAD 50 per tonne by 2022. Provinces with cap-and-trade systems must

have (i) a 2030 emission reduction target greater than or equal to Canada's 30% reduction target and (ii) declining (more stringent) annual caps to at least 2022 that correspond, at a minimum, to the projected emission reductions resulting from the carbon price that year in price-based systems.

Revenue generated by carbon pricing will remain in the jurisdiction of origin. The federal government introduced legislation and regulations to implement a carbon pollution pricing system—the backstop—for those provinces that do not have carbon pricing systems that align with the benchmark (GOC, 2018c). The backstop includes an output-based pollution pricing system plan to mitigate the competitiveness impacts for trade-exposed, carbon-intensive industrial emitters while still providing them with the incentive to reduce emissions (GOC, 2018d). The Pan-Canadian Framework includes a commitment for a review of the approach to price carbon by early 2022.

In addition to carbon pricing, complementary mitigation measures are included in the framework. Expanding the use of clean electricity and low-carbon fuels, as well as increasing energy efficiency, are fundamental actions that will reduce emissions across the economy.

To increase the use of low-carbon fuels, the federal government, working with provincial and territorial governments, industry and other stakeholders, will develop a clean fuel standard that sets emission intensity requirements for liquid, gaseous and solid fossil fuels. ECCC detailed the regulatory approach for liquid fuels in a paper in 2019 (ECCC, 2019a). The approach aims to reduce the carbon intensity of liquid fuels to 10 to 12% below 2016 levels by 2030. The crafting of regulations for the gaseous and solid streams is ongoing. ECCC is targeting 2022 for the enforcement of the liquid fuel stream standards and 2023 for the gaseous and solid stream standards.

Using a mix of regulations and investments, Canada will continue to reduce emissions from electricity. New regulations will accelerate the phase-out of traditional coal units by 2030; increase performance standards for natural gas-fired electricity; and institute an output-based pollution pricing system for electricity generation that varies depending on the carbon intensity of the fuel type (GOC, 2018d). Investments will reduce diesel use in rural and remote communities; support emerging renewable energy sources; modernise Canada's electricity systems (including smart grid and energy storage technologies); and build new and enhanced transmission lines to connect new sources of clean power with places that need it (GOC, 2016). In 2019, the federal government, along with Indigenous Clean Energy Social Enterprise and the Pembina Institute, announced the Generating New Opportunities: Indigenous Off-diesel Initiative to help indigenous communities transition away from diesel through the development and implementation of community-led energy projects (Impact Canada, 2019).

Canada will also take action to reduce energy use by improving energy efficiency and fuel switching, and by supporting innovative alternatives. 'Net-zero energy ready' building codes are in development to transform the built environment. Existing buildings will be retrofitted based on new retrofit codes, and businesses and consumers will be provided with information on the energy performance and energy efficiency of appliances and equipment. Canada is engaging in a public review of updates to its building codes, with the expectation of making significant progress towards the state adoption of 'net-zero energy ready' codes by 2030 (Efficiency Canada, 2019).

Actions in the transportation sector include continuing to set increasingly stringent standards for light- and heavy-duty vehicles (LDVs and HDVs), in addition to taking action to improve efficiency and support fuel switching in the rail, aviation, marine and off-road sectors. In 2018, Canada released new HDV standards covering the 2021-2027 model period (ECCC, 2018a) and began the process of reviewing its LDV standards (ECCC, 2018b). In addition to developing the Clean Fuel Standard, Canada is running two competitions to encourage the adoption of alternative jet fuel in the aviation sector (Impact Canada, 2018). Canada is also developing a zero-emission vehicle (ZEV) strategy, investing in infrastructure to support lower

carbon and zero-emission vehicles, and investing in public transit and other infrastructure to support shifts from higher- to lower-emitting modes of transportation (GOC, 2016).

To reduce emissions from industrial sectors, energy efficiency, targeted regulations and strategic investments in clean energy technology are priorities. Canada developed regulations to achieve a reduction in methane emissions from the oil and gas sector, including offshore activities, by 40–45% below 2012 levels by 2025 (ECCC, 2018c). Federal, provincial, and territorial governments will work together to assist businesses to improve their energy efficiency and invest in new technologies to reduce emissions. For example, the Canada and Quebec governments are partnering with private investors to commercialise the world's first carbon-free aluminium smelting process in Quebec (PMO, 2018), and the Canada and B.C. governments are both funding the commercialisation of technologies to capture carbon from the air and use it to produce synthetic fuels (GOC, 2019b). Canada has also committed to finalising regulations to phase down the use of hydrofluorocarbons (HFCs) in line with the Kigali Amendment to the Montreal Protocol (ECCC, 2018d).

Other actions in the Pan-Canadian Framework involve protecting and enhancing carbon sinks, including those in forests, wetlands and agricultural lands; identifying opportunities to generate renewable fuel from waste; and demonstrating leadership by reducing emissions from government operations and scaling up the procurement of clean energy and technologies. The framework also includes support for clean technology and innovation that promote clean growth, including early-stage technology development; establishing international partnerships; and encouraging 'mission-oriented' research to help generate innovative new ideas and create economic opportunities. Other complementary actions include support for RD&D or clean technology in Canada's natural resource sectors, and a Smart Cities Challenge (GOC, 2016).

The Pan-Canadian Framework recognises the importance of building climate resilience and sets out measures to help Canadians understand, plan for, and take action to adapt to unavoidable impacts of climate change. With Indigenous peoples and coastal and northern regions particularly vulnerable to climate impacts, helping these communities is a priority (GOC, 2016). The Pan-Canadian Framework also encourages federal-provincial-territorial collaboration to reduce GHG emissions, implement carbon pricing, and accelerate clean growth.

PROVINCIAL

Each province develops and implements policies, regulations and initiatives to mitigate climate change. Example regulations and programs include those highlighted in the Pan-Canadian Framework as well as new initiatives.

- British Columbia: introduced a carbon tax in 2008, which applies to the purchase or use of fossil fuels. The current rate of CAD 40 per tonne of carbon dioxide (CO₂) equivalent (tCO₂) in 2019 is planned to increase by CAD 5 per tCO₂ annually until it reaches CAD 50 per tonne in 2021 (GBC, 2018a). In 2018, British Columbia released the first phase of its CleanBC climate plan, which includes measures to meet 75% of its 2030 GHG reduction goal and plans to release further measures to meet the rest of its reduction goal (GBC, 2018b). The strategy includes: ZEV standards; increasing the 2030 carbon intensity improvement requirement of the Low Carbon Fuel Standard to 20%; increasing building efficiency with improved building codes and the encouragement of heat pump adoption; mandating a 15% renewable standard for natural gas use; and electrifying natural gas producers and large industrial operations with clean electricity.
- Alberta: upon removing its CAD 20 per tCO₂ carbon levy in May 2019, the federal government announced a federal backstop price of CAD 30 per tCO₂ on the province on 1 January 2020 (ECCC, 2019b). However, the federal government accepted Alberta's Technology Innovation and Emissions Reduction (TIER) pricing system, as compliant with the federal standard. TIER replaces the Carbon Competitiveness Incentive Regulation (CCIR), which had been in place since 2018 (Osler, 2019). Benchmarks in TIER are historical facility-level emission intensity, as opposed to

industry-wide benchmarks of CCIR. The output-based pricing schedule for electricity generators in the TIER does not vary by fuel type and uses a “good-as-best-gas” benchmark. This provides a higher incentive for reducing electricity emissions. Alberta also announced a cap on GHG emissions from oil sands production (excluding those related to primary production, net new upgrading facilities and cogeneration) of 100 Mt per year and a commitment to phase out coal-generated electricity by 2030. The province procured over 1300 MW of wind capacity at a weighted price of CAD 38 per MWh in three rounds of bidding over the past two years (AESO, 2018).

- Saskatchewan: the provincial power utility, SaskPower, has made the world’s largest per capita investment in CCS technology at its electricity generating facility at Boundary Dam. The plant has captured over 2.9 Mt of CO₂ since October 2014 (SaskPower, 2019). Saskatchewan uranium fuels nuclear power plants in Ontario, New Brunswick and other plants internationally, displacing between 230 and 550 Mt of the world’s GHG emissions each year. In 2015, Saskatchewan announced a goal to double the percentage of renewable capacity to 50% by 2030. The province also plans to procure 60 MW of solar capacity in 2018 and has a target of 30% wind capacity by 2030 (SaskChamber, 2018). Saskatchewan will apply sector-specific output-based performance standards to industrial facilities emitting 25 Mt of CO₂-e or more per year (CEC, 2017). Expected emission intensity reductions were released in 2018 (GOS, 2018). The federal government imposed its backstop carbon price schedule on the province in 2018 (ECCC, 2018e).
- Manitoba: in October 2017, Manitoba announced its provincial Climate and Green Plan with a carbon price of CAD 25 per tonne with output-based allowances for large industrial emitters (GOM, 2017). However, in October 2018, the province announced that it would no longer be implementing its own carbon pricing system. The federal backstop carbon price schedule will apply to Manitoba starting in 2019, instead. Manitoba has implemented a carbon savings account to track its progress in meeting its goal to reduce cumulative emissions one Mt below counterfactual levels in the 2018 to 2022 period and plans to set additional goals for the 2023 to 2027 period in late 2022 (GOM, 2019).
- Ontario: joined the Western Climate Initiative (WCI) cap-and-trade market operating in Quebec and California on 1 January 2018. It then passed legislation to withdraw from the WCI on 3 July 2018 (GOO, 2018a). Ontario also cancelled its electric and hydrogen vehicle and charging incentive programs (MTO, 2018) in the same month, and released an updated climate plan in November 2018. The climate plan includes an industry-performance standard for large emitters and the intention to increase the ethanol content of gasoline to 15% by 2025 (GOO, 2018b). Without a plan to price carbon, the federal government applied the backstop price schedule to Ontario in 2019.
- Quebec: has an economy-wide cap-and-trade system linked with California through the WCI. In 2015, Quebec adopted two emission reduction objectives: 1) to reduce emissions to 20% below 1990 levels by 2020; and 2) to reduce emissions to 38% below the 1990 levels by 2030 (GOQ, 2018a). Through the implementation of its 2018-2023 Master Plan, Quebec is targeting energy efficiency increases of 1% a year and petroleum demand reductions of at least 5% below 2013 levels (GOQ, 2019). Quebec is the first province to introduce a ZEV standard. The standard came into effect in 2018 and utilises a credit system to encourage automakers to increase the number of low-carbon vehicles and the number of low-carbon vehicle models (GOQ, 2018b). Quebec announced several transport-related 2030 targets in 2018, including a 20% reduction in solo car trips, a 40% reduction in petroleum fuel demand and a reduction in transport GHGs of 38% below 1990 levels (Whitmore and Pineau, 2018).
- New Brunswick: has GHG emission reduction targets that reflect a total output of 11 Mt by 2030 and five Mt by 2050. New Brunswick also plans to phase out coal-fired power

generation (GNB, 2016). The federal government approved New Brunswick's proposed carbon pricing system to replace the federal backstop pricing system in December 2019 (ECCC, 2019c). The carbon price will be in effect on 1 April 2020. Large industrial emitters now face the federal government's standards as of 2018 (GNB, 2017).

- Nova Scotia: the Greenhouse Gas Emissions Regulations 2009 places a cap on electricity sector emissions from all facilities, with targets that have been set until 2030. In November 2016, Nova Scotia and the Government of Canada agreed to negotiate a new equivalency agreement regarding federal coal-fired electricity regulations. Nova Scotia committed to establishing a cap-and-trade program at the beginning of 2019 for large industrial facilities, the electricity sector, petroleum product suppliers and natural gas distributors, to comply with the Pan-Canadian approach to pricing carbon pollution (GNS, 2018). The federal government approved the stringency of Nova Scotia's system in 2018. Nova Scotia is targeting emission reductions of 45% to 50% below 2005 levels by 2030 (GNS, 2019).
- PEI: released its Climate Change Action Plan in 2018 (PEI, 2018a). PEI agreed to adopt the federal benchmark for pricing emissions from large emitters but opted for a slightly different approach to carbon pricing that includes exemptions for some industries, fuels and end-uses (PEI, 2018b).
- Newfoundland and Labrador: released a carbon pricing plan in October 2018. The plan incorporates a broad-based carbon price, with some exemptions. There is also a mechanism to ensure that overall gasoline taxation compares to other Atlantic provinces (GNL, 2018). The plan includes a modified output-based performance standard to address competitive concerns with trade-exposed, carbon-intensive industries, including a separate standard to govern offshore petroleum resource production. In 2016, the province created a new fund for clean technology, financed through carbon pricing on large industry (GNL, 2016). The Management of Greenhouse Gas Act was passed in June 2016 and aims to reduce GHG emissions from large emitters.
- The Territories: NWT implemented the federal benchmark in 2019 with exemptions for aviation fuels, heating fuels, and diesel-fired generation. There is also a 75% carbon compliance rebate for the combustion of non-motive diesel and heating oil by large industrial emitters (GNWT, 2019a). NWT announced its commitment to reduce emissions in the territory to 30% below 2005 levels by 2030 (GNWT, 2019b). Yukon and Nunavut also imposed an altered version of the federal carbon pricing backstop in 2019, which includes the federal output-based pricing system for large emitters, exempts the combustion of aviation fuels and provides relief for diesel-fired generation in remote communities.

INTERNATIONAL

Canada is active on the international climate change stage. Prior to the Paris Agreement., Canada signed the Copenhagen Accord (2009) and committed to reducing GHG emissions to 17% below the 2005 levels by 2020 (EC, 2011). Since the end of the Doha round of negotiations under the UNFCCC in December 2012, Canada has continued its engagement in the negotiations to support the establishment of a fair and comprehensive global climate change regime, leading up to the signing of the Paris Agreement in 2015, where it pledged to reduce its 2030 emissions to 30% below 2005 levels.

In 2015, Canada announced it would contribute CAD 2.7 billion over five years to help developing economies tackle climate change, and in 2017, announced a partnership with the World Bank Group to support climate action in developing economies and small island developing states (World Bank, 2017). Canada helped to secure an agreement among

signatories to the Kigali Agreement, an amendment to the Montreal Protocol, to reduce the use of factory-made HFC gases. In 2015, Canada, along with 20 other economies, launches *Mission Innovation*, which encourages the acceleration of global clean energy investment with the goal of making “clean energy more affordable” (Mission Innovation, 2015). At COP23, Canada co-founded the Powering Past Coal Alliance with the United Kingdom.

In September 2017, Canada hosted the 46th session of the Intergovernmental Panel on Climate Change (IPCC) in Montreal. Hundreds of scientists and representatives from 195 economies gathered to advance the science of climate change and decide the scope of the sixth IPCC assessment report. The IPCC reports provide the most up-to-date international scientific knowledge on climate change and play an important part in supporting the implementation of the Paris Agreement and the Pan-Canadian Framework on Clean Growth and Climate Change (IPCC, 2017).

Canada has been a member of the IPCC since its inception in 1988. Canadian scientists hold leadership positions on the IPCC’s scientific advisory body, the Task Force on National Greenhouse Gas Inventories, and serve as authors for IPCC reports.

Canada, China and the European Union launched the Ministerial for Climate Action (MOCA) in 2017. The MOCA is a forum for over 30 ministers from major economies, and key players on climate change, to discuss implementation and build common ground on ongoing multilateral negotiations. The first MOCA took place in September 2017 in Montreal, Canada.

NOTABLE ENERGY DEVELOPMENTS

REGULATORY DEVELOPMENTS

On 8 February 2018, the Government of Canada introduced an integrated bill, Bill C-69, with the aims of instilling public trust, improving investor confidence, advancing Canada’s reconciliation with Indigenous peoples, streamlining the review process, and replacing the NEB with a new agency, the Canadian Energy Regulator (CER). The transformation took place on August 2019 after the senate passed Bill C-69 in June.

On 12 May 2017, the Government of Canada introduced Bill C-48 to implement the Oil Tanker Moratorium Act (GOC, 2017b). The act prohibits the shipment of various petroleum products along B.C.’s north coast if the oil component of the shipment exceeds 12 500 metric tonnes. It effectively prohibits shipments from most oil tankers. In the long-term, the act will discourage the development of an oil export pipeline on B.C.’s north coast, as the tonnage limit will prohibit seaborne crude oil shipments via the very large and ultra-large crude carriers (EIA, 2014). The Senate passed Bill C-48 in June 2019.

OIL INFRASTRUCTURE DEVELOPMENTS

Oil exports through pipelines are a major means for the landlocked portion of Canada’s oil industry (mainly located in WCSB) to access markets. Some domestic refinery demand exists in Western Canada, but most production travels via pipeline to the major refining hubs in the US Midwest and US Gulf Coast. Canada is looking to increase its WCSB export capacity to both the US Gulf Coast, the world’s largest heavy oil refining market, and to its own coasts to access an expanding overseas market. This is on the back of expected growth in heavy oil production from the oil sands.

Pipeline capacity out of the WCSB grew over two Mbb/D from 2010 to 2016 to about four Mbb/D but has since stalled at 2016 levels. Production from the oil sands and new light oil prospects has been growing steadily. In 2018, crude available for export from the WCSB exceeded pipeline capacity for the first time; exceedance reached 202 Mbb/d in the fall of 2018 (CER, 2018a). Surplus supply led to several market anomalies in 2018. Alberta inventories

reached their highest levels on record, ranging from 15 to 30% above the five-year average. Canadian benchmark price discounts increased to abnormal levels. These constraints and record discounts led to record levels of Canadian crude-by-rail exports, as producers turned to more expensive transport methods to move surplus crude oil production to market.

Benchmark prices suggested that many producers were selling oil at levels below production costs. This prompted government intervention in December 2018. The Albertan government mandated an 8.7% crude oil production decrease, and announced that it would procure railcars, with the aim of clearing inventory and lowering the price discount facing Albertan producers. Price discounts returned to their historically normal levels in 2019, and the government has maintained production limits, with some exceptions for conventional oil producers (GOA, 2019). A federal decision ordering Enbridge to cease open season nominations for its Mainline volumes, a key conduit for oil exports into the United States, removed pressure to offer price discounts (CER, 2019d). Enbridge is currently pursuing the approval of an augmented open season.

Canadian governments and industry are working together to find options to increase pipeline capacity. The federal government approved two pipeline projects in 2016: the expansion of the Trans Mountain Pipeline (TMX), flowing from Edmonton, Alberta to Vancouver, British Columbia, and the expansion of Enbridge's Line 3 Pipeline from Edmonton to Superior, Wisconsin. The Canadian portion of Line 3 was commissioned in 2019 and the American portion should follow in 2020. TMX is progressing after having its original approval quashed by the federal court of appeal (FCA) and its ownership transferred to the federal government in 2018. The federal government has attempted to address the shortcoming identified by the FCA and approved the project for a second time. Construction on the Albertan leg of the pipeline has started and, barring any setbacks, the construction of the British Columbia portion of the pipeline will begin in the first half of 2020.

There is significant opposition to the TMX from several municipal governments and first nations along the pipeline route. TransCanada's Keystone XL Pipeline project has been in political limbo for about a decade and is currently awaiting its final permits to begin construction. However, Canada could increase its pipeline capacity as much as a large-scale export project by optimising existing pipelines (CBC, 2019). Examples of optimisation include the installation of extra compressors to increase the pressure and flow on the pipeline and adding laterals to relieve key chokepoints. Enbridge is already employing these strategies on its Mainline. The prospects of long-term oil production growth are dependent on the success of these pipeline developments.

Industry is also pursuing new methods to move incremental bitumen to market. Bitumen requires upgrading into synthetic crude oil, or dilution to reduce its viscosity enough for pipeline shipment. These upgrades are not as necessary for rail shipments. Several oil sand producers are pursuing the construction of diluent recovery units to remove excess diluent from diluted bitumen at oil-loading rail terminals. This decreases the volume of the physical product in the railcar and effectively increases bitumen export capacity by 20%. Pipelines could then ship the diluent back to producing fields for another round of bitumen dilution. Several projects are targeting operation in the 2021-2023 timeframe (Cenovus, 2019) (JWN, 2019b).

NATURAL GAS INFRASTRUCTURE DEVELOPMENTS

In recent years, Canadian natural gas supply growth has been occurring in new areas of the WCSB. This is creating bottlenecks, as infrastructure development has been unable to keep pace with resource development. With the combination of declining demand from traditional markets, Canadian natural gas prices have been trading at a heavy discount to Henry Hub prices (CER, 2018b). These discounts are exacerbated by periods of maintenance on the NOVA Gas Transmission system (NGTL), which reduces storage services. Low prices and low storage levels led the CER to order NGTL to prioritise storage injections over receipt services in

maintenance and outage periods. This increased Canadian prices so that their differential to Henry Hub is now in line with historical levels. Even so, several producers are still curtailing spending plans and production guidances, limiting short-term growth prospects for Canadian natural gas production. Long-term production growth prospects are dependent on the successful reconfiguration of WCSB upstream infrastructure and the diversification of Canada's export markets.

LNG export facilities are the sole means of growing Canada's natural gas export market. American production growth from shale and tight gas plays has displaced Canadian gas from its traditional eastern Canadian and eastern American markets. After years of declining prospects for LNG export development, 2018 saw two positive final investment decisions for LNG export facilities off the west coast of British Columbia: Woodfibre LNG and LNG Canada (LNG Canada, 2018). Both expect to be exporting LNG by the early 2020s, but there is potential for delays. Coastal Gaslink, the connector pipeline for the LNG Canada project, faces significant opposition from the Wet'suwet'en First Nation, whose unceded territory the pipeline partially traverses. The Wet'suwet'en First Nation opposes the current route because its current heading poses environmental risks to the natural resources that they live on and could even restrict access to parts of their own territory. Court injunctions to remove opposition and to expedite the construction of the pipeline have drawn support for the Wet'suwet'en across Canada. Supporting protests blockading key infrastructure, such as railroads, highways and transit links, and government buildings are taking place throughout the economy).

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USEFUL LINKS

Atomic Energy of Canada Ltd—www.aecl.ca

Canada Gazette—www.gazette.gc.ca

Canada-Nova Scotia Offshore Petroleum Board—<http://www.cnsopb.ns.ca/>

Canadian Energy Regulator—<https://www.cer-rec.gc.ca/index-eng.html>

Canadian Nuclear Laboratories—www.cnl.ca

Canadian Nuclear Safety Association—<http://nuclearsafety.gc.ca>

Canada Newfoundland and Labrador Offshore Petroleum Board <http://www.cnlopb.ca/>

Environment and Climate Change Canada—www.ec.gc.ca

Natural Resources Canada—www.nrcan-rncan.gc.ca

Statistics Canada—www.statcan.ca

Transport Canada—www.tc.gc.ca

CHILE

INTRODUCTION

Chile is one of the longest and narrowest economies on the planet, occupying a stretch of land in the southwest of Latin America. It extends from the Antarctic in the extreme south to the Atacama Desert in the north. Chile spans three continents. Chile's sovereign territory is mainly on the South American continent, while its westernmost border is on Easter Island in Oceania, and its southernmost territory is in Antarctica. Peru is to the north, Bolivia and Argentina to the east, the Antarctic to the south, and the Pacific Ocean is to the west, along its 6 435 km coastline. Chile has a land area of 756 102 square kilometres (km²), with an average width of 175 km.

Chile is the fifth-largest energy consumer of the Americas, but unlike most other large economies in the region, it is only a small fossil fuel producer. Chile is dependent on energy imports, despite vast solar and wind energy resources and the rapid shift towards cleaner energy over the past decade. Recent exploratory drilling in the Magallanes Basin, a shale formation, may increase Chile's domestic oil supply. There are an estimated 2.4 billion barrels of shale oil in the Magallanes Basin (EIA, 2019).

Chile is one of the fastest-growing economies in South America, with an average annual growth rate of 2.7% between 2000 and 2018. In 2018, Chile's gross domestic product (GDP) reached USD 428 billion (2011 USD PPP), an increase of 4% from 2017, and GDP per capita grew by 2.6% to USD 22 873 (WorldBank, 2019).

Chile has 16 regions headed by president-appointed regional governors. In 2017, the population reached 18.7 million, with 40% residing in the Santiago metropolitan region (INE, 2018).

Table 1: Key data and economic profile, 2018

Key data ^{a, b}		Energy reserves ^{b, c, d}	
Area (km ²)	756 092	Oil (million barrels) ^b	150
Population (million)	18.7	Natural gas (billion cubic metres) ^c	98
GDP (2011 USD billion PPP) ^b	428.4	Coal (million tonnes) ^c	171
GDP (2011 USD PPP per capita) ^b	22 873	Uranium (kilotonnes U) ^d	1.45

Sources: ^a. IEA (2019), BP (2019), ^b. WorldBank (2019), ^c. EIA, (2019) ^d. NEA (2019)

Chile's primary fuel mix has historically been dominated by oil, most of which is consumed in the industry and transport sectors. Industry oil use has risen in the past decade in response to the severe energy crisis that occurred when natural gas imports from Argentina suddenly dropped in 2004 (Chávez-Rodríguez et al., 2017). Transport remains the largest oil consumer and has the second-highest overall energy consumption after the industry sector. The number of private vehicles has increased as GDP and living standards have risen.

Chile's economy has benefited from exports of copper, wood pulp, fish, and wine in recent decades. Chile has begun to capitalise on domestic energy resources, namely gusty coastal winds, intense desert sun, and plate tectonics for geothermal power generation.

In 2018, China increased investments in electricity, renewable energy, agribusiness, and mining in Chile substantially. The most significant foreign investment in 2018 was from the China-based

Tianqi Lithium Corp., which acquired a 24% stake in the Chilean lithium mining company SQM for USD 4 billion

The flows of foreign direct investment (FDI) in Chile increased in 2018 after three consecutive declining years. FDI inflows reached USD 7.2 billion (an increase of 4.4% from 2017) according to the World Investment Report 2019. The increase was mainly due to higher copper prices and record levels of mergers and acquisitions in the mining, health services, and electricity industries, as well as the stronger interest shown by Chinese companies in investing in Chile. FDI stocks decreased by 1.7%, reaching USD 269 billion (90.3% of GDP). The US, Canada, the Netherlands and Spain represented more than half of the FDI stock in 2017. Investment is mainly directed towards mining, finance and insurance, transportation, energy and manufacturing (UNCTAD, 2019).

Chile has one primary electricity grid and two smaller electricity grids:

- National Electricity System (SEN)
 - The Chilean power system has two major distinct power grids, running 4 300 km from the north to the south. In December 2017, Chile established the National Electricity System which interconnected the previously independent systems. The previous Northern Interconnected System, SING, covers an area equivalent to 25% of Chile's continental territory in the desert mining regions to the north (6% of Chile's population). The previous Central Interconnected System, SIC, covers the central and south parts of the economy and reaches about 92% of Chileans
 - The total installed capacity of SEN was 22 964 MW in 2019: 53% thermal (21% coal, 19% natural gas and 13% diesel), 29% hydro, 9% solar photovoltaic 7% onshore wind, 2% biomass and one geothermal plant of 48 MW (CNE, 2020a)
- The Aysén and Magallanes systems serve small areas in the extreme southern part of the economy
 - The total installed capacity of the Aysén power system was 63 MW in 2019: 58% diesel, 36% hydro and 6% onshore wind (CNE, 2020a)
 - The Magallanes power system has total installed capacity of 104 MW in 2019: 82% natural gas, 15% oil and 3% onshore wind (CNE, 2020a)

Hydropower has long been an essential component of Chile's electricity generation mix. When the supply of gas from Argentina was curtailed in 2008, hydropower's importance increased significantly. Chile's energy transformation over the past 20 years has involved power generators switching from natural gas to diesel, then to coal, and most recently to renewable energy. At the beginning of 2010, only 3% of power generation capacity used modern renewable energy resources: 183 MW in onshore wind farms and small amounts of solar PV, small hydro, biomass and biogas plants.

As of 31 December 2019, 5 331 MW of modern renewable energy capacity has been installed in Chile, which represents 22% of total installed power capacity. The renewables breakdown is 30.4% for onshore wind farms, 49.6% for solar PV, 9.6% for small hydro, with the rest in biomass, geothermal and biogas plants (CNEc 2019). A 20% target for renewables by 2025, combined with declining capital costs and outstanding renewable resources, is transforming the market.

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

In 2018, Chile's total primary energy supply (TPES) was 39.4 million tonnes of oil equivalent (Mtoe) and increased by 4.2% compared with the 2017 level of 37.8 Mtoe. By fuel type, oil contributed the largest share (41.7%), followed by renewables (27.8%) and coal (19.1%). In 2018, Chile's net imports of energy sources constituted 69.3% of the TPES, growing by 2.6% a year from 2010 (to reach 27 366 ktoe in 2018).

Chile is dependent on imported fossil fuels (oil, gas and coal). Fossil fuel imports represented 67% of the total primary energy supply in 2018 (IEA, 2019).

In 2018, the two largest source economies for Chile's imported crude oil were Brazil (51.1%) and Ecuador (34.4%). Natural gas mainly came from Trinidad and Tobago (54.4%) and the US (29.4%). Coal was mostly from Colombia (59.5%), the US (28.1%) and Australia (9.1%) (CNE, 2019). Crude oil constituted 29% of Chile's primary energy supply, followed by biomass (25%), coal (24%), natural gas (15%), and modern renewables (5% hydro, 1% wind, and 1% solar) (BNE, 2018). Coal's primary role is in the transformation sector, where it is used almost entirely in coal-fired power stations and coke ovens.

In 2018, Chile produced 82 300 gigawatt-hours (GWh) of electricity, 50.2% of which came from fossil fuel plants, 28.3% from hydro, 8.6% from solid biofuels, and 6.4% from solar PV (MEN, 2020).

Total renewable energy production in Chile in 2018 was 10 867 ktoe or 27.5% of the total primary energy supply. Production increased by 1.8% from the previous year's level, with growth in wind, solid biofuels, hydro and photovoltaics (IEA, 2019a). The most significant forms of renewable energy production were biomass (71.7%) and hydro (18.4%).

Table 2: Energy supply and consumption, 2018

2018 Total primary energy supply (ktoe)		2018 Total final consumption (ktoe)		2018 Power generation (GWh)	
Indigenous production	13 522	<i>Mining & industry sector</i>	11 519	Electricity generation	82 300
Net imports and others	27 366	<i>Transport sector</i>	10 815	<i>Coal</i>	29 306
Total primary energy supply	39 445	<i>Other sectors</i>	6 628	<i>Hydro</i>	23 367
<i>Coal</i>	7 197	<i>Non-energy</i>	167	<i>Gas</i>	12 029
<i>Oil</i>	16 385	Final energy consumption	30 117	<i>Solar PV</i>	5 218
<i>Gas</i>	5 065	<i>Coal</i>	169	<i>Wind</i>	3 588
<i>Renewables</i>	10 867	<i>Oil</i>	17 367	<i>Solid Biofuels</i>	7 077
<i>Others</i>	0	<i>Gas</i>	2 012	<i>Geothermal</i>	214
		<i>Biomass</i>	3 906		
		<i>Electricity and others</i>	6 662		

Source: IEA (2019), MEN (2019)

* Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. Please note that the total final consumption includes non-energy uses.

Studies by the National Oil Company (Empresa Nacional de Petróleo [ENAP]), endorsed by the United States Geological Survey (USGS), estimate non-conventional shale gas potential in Magallanes at 8.3 trillion cubic feet (tcf). This is twice the volume of gas that has been extracted by ENAP from the Magallanes Basin over the last 70 years (4.2 tcf).

Chile's conventional uranium resources are estimated at 1.45 kilotonnes (NEA, 2018). These resources are recoverable at a price of US 260 per kilogram using a recovery factor of 75%. No new uranium resources have been identified since 2011 (NEA, 2012).

FINAL ENERGY CONSUMPTION

In 2018, Chile's final energy consumption was 30 117 ktoe, representing an increase of 4.2% from the previous year's level (MEN, 2020). By sector, total final consumption in the industry sector accounted for 38%; followed by transport (36%); residential (15%), and commercial (5%). Energy own consumption accounted for 3% of this final consumption. The remaining 2% represented non-energy use, including agriculture and others. Strong annual growth in energy consumption was from aviation (6%) and domestic transport (3%).

Chile's net installed electricity capacity was 25.3 gigawatts (GW) as at December 2019. Thermal power plants provided 53% of total installed capacity. The remainder was provided by hydropower (29%), solar photovoltaic (PV) (10%), onshore wind (6.1%), biomass (1.4%) and geothermal (0.11%) (CNE, 2018b).

Oil supplied 56.8% of Chile's final energy consumption, primarily consumed by the transport and industrial sectors. Electricity and other sources (23%), natural gas (5.6%) and coal (1.1%) consumed the remainder. Oil consumption increased by 2.7% from 2016, and electricity and other use decreased by -0.5% (EGEDA, 2019).

ENERGY INTENSITY ANALYSIS

Energy intensity has been declining since 2000, indicating a more efficient use of energy sources. Chile's energy intensity in terms of primary energy supply in 2018 was 92.1 tonnes of oil equivalent per million USD (toe/million USD), continued this declining trend in 2018 and fell by 1.1%. In contrast, final consumption energy intensity increased by 10.7% in 2018 to 70 toe/million USD in 2018.

Table 3: Energy intensity analysis, 2018

Energy	Energy intensity (toe/million USD PPP)			Change (%) 2017 vs 2018
	2016	2017	2018	
Total primary energy supply	93	93	92	-1.1
Total final consumption	65	65	70	8.4
Final energy consumption excl. non-energy	64	64	70	10.7

Source: IEA (2019), EGEDA (2019)

RENEWABLE ENERGY SHARE ANALYSIS

Chile has vast untapped potential for solar power as well as for onshore wind, geothermal and hydro energy. The share of modern renewable energy in final energy consumption was 16.6% in 2017, a decrease of 1.1 percentage points from the previous year (5.5% decline). Production of energy from wind, biofuel, hydro and photovoltaic (PV) sources increased, while production from biogas decreased. The use of modern biomass decreased, mainly in the power sector, while use of traditional biomass increased, primarily in the residential and commercial areas.

Table 4: Renewable energy share analysis, 2017

	2015	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	24 795	25 925	26 158	0.9%
Non-renewables (Fossil fuels and others)	18 572	19 556	20 010	2.3%
Traditional biomass*	1 706	1 768	1 799	1.8%
Modern renewables*	4 506	4 600	4 349	-5.5%
Share of modern renewables to final energy consumption	18.2%	17.7%	16.6%	-6.3%

Source: EGEDA (2018)

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass. Solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies, which often have adverse effects on human health. This definition applies to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal, and so on), including biogas and wood pellets, are considered modern renewables, although data on wood pellets are limited.

POLICY OVERVIEW

Chile's economic policies are founded on the principle of capital transparency. Non-discrimination against foreign investors is one of the economy's strengths. Investors feel attracted by the richness of Chile's natural resources and economic stability. Juridical security, high quality infrastructure, and an independent central bank with an explicit inflation target and a floating exchange rate system are additional strengths. The economy ranks 56th out of 190 economies in the 2019 Doing Business report issued by the World Bank.

The Chilean legal framework for the energy and mining sectors has similarities with most APEC economies; the state is the owner of all hydrocarbon reservoirs. The Chilean Parliament established this framework through the Political Constitution (Art. 19 numeral 24). The private sector remains important for the exploration and exploitation of energy resources in Chile.

Chile's energy policies have evolved dynamically in recent years, especially in the electricity sector. In 2015, the National Energy Policy 2050 was enacted following an inclusive public consultation (IEA 2018). Chile's energy policies are based on the development of a free-market economy, oriented towards enhancing economic efficiency and energy security by reducing vulnerability to supply disruptions and reducing high dependence on imports.

ENERGY POLICY FRAMEWORK

Chile's economy has been based on the free market and international trade since the 1980s. From the 1980s to 2018, Chile more than doubled its income per capita and was one of the fastest-growing economies in Latin America. Streamlined administrative processes and simplified tax payments help to facilitate foreign investment in Chile.

The Ministry of Energy is responsible for formulating the policies, programs and standards aimed at promoting proper functioning and development of the energy sector. The ministry must also ensure compliance with industry standards, and advises the government on energy matters. These matters include energy research, hydrocarbon exploration and exploitation, electricity generation and transmission, energy transportation, storage systems, distribution, energy consumption, energy efficiency, energy import and export, and anything else that relates to electricity, hydrocarbons, nuclear energy, renewable energy, and other energy sources. The

Chilean Parliament approved the creation of a Ministry of Energy in November 2009, and the new Ministry of Energy started operations in February 2010.

In the 1970s, Chile's national oil company, ENAP, was entitled to exploit oil reservoirs by itself or through private companies. An administrative concession or exclusive operation contract (CEOP), granted by the Ministry of Mining, was required for the latter arrangement.

At the end of the 1970s, and following worldwide trends, the production and distribution segments of the oil and gas market were liberalised. The new framework encouraged investors to engage with the oil and gas market in both the upstream and downstream sectors.

The National Energy Commission (CNE using the Spanish acronym) is a decentralised public institution that communicates with the President of the Republic through the Ministry of Energy. The CNE is responsible for analysing prices, tariffs and technical standards that energy companies must adhere to concerning energy production, generation, transport and distribution. The CNE ensures energy system security and economic efficient outcomes. It was created by Decree-Law No 2.244/1978 and modified by Law N° 20.402 of 2009.

The CNE must issue a report suggesting whether to approve or reject investor applications for a CEOP. Chile does not have a separate legal framework for onshore and offshore oil and gas exploration and production.

The Chilean 1982 electricity law provided framework conditions for generators to compete to provide electrical energy to large consumers, while sharing a user-pay transmission system. These market conditions had been in operation since 1978; the electricity law merely formalised what was already occurring. Chile's electricity market preceded similar formulations in the US and the UK by several years (Rudnick, 1994).

The electricity generation, transmission, and distribution systems operate as separate businesses, and have been developed mainly by the private sector. The government acts primarily as a regulator. Electricity companies are free to decide about their investments and the commercialisation of their services. However, they must also adhere to regulations and technical standards established by law.

The transmission system in Chile is open access. Transmission companies impose tolls for their available transmission capacity. The distribution companies operate under a 'distribution public concession regime' with service obligations and regulated tariffs for the regulated customers. Chilean regulations define regulated customers as those with a connected capacity of below 500 kW. Those who have an installed capacity of over 5 000 kW can negotiate the energy price directly with generation companies. Those who fall in between (500 to 5 000 kW) can choose either regulated or unregulated tariffs for periods of no less than four years.

The state support for deprived areas of the population is provided through direct subsidies. The state also performs entrepreneurial activities where private sector incentives are lacking, or where conflicts of interest may arise. For instance, the operation of generation and transmission facilities is coordinated by the Economic Load Dispatch Centre (Coordinador Eléctrico Nacional). This state-owned institution values electricity transfers among all the generation companies at the hourly marginal rate.

Legislation has established that electricity tariffs accurately represent electricity generation, transmission and distribution costs. Representative tariffs transmit efficient price signals to both companies and consumers, which deliver optimal investment levels.

Large customers with a demand over 5 MW can engage in the wholesale market. Electricity distribution companies that supply customers that demand less than 2 MW are subject to regulated prices. These prices are periodically revised by CNE.

The New Electricity Act on Energy Auctions (Law 20 805, 2015) establishes the process of open energy auctions, encouraging the entrance of new players and electricity generation

technologies. The primary purpose of the act was to improve competitiveness and promote better price mechanisms in favour of end-users in the electricity market for regulated users.

Regulated tariffs are set every four years by the CNE and consider two components:

- **The long-term node price:** the price that the distribution companies pay to generators for the electricity to supply regulated clients, which is calculated based on open energy supply auctions (tender process)
- **The distribution value added:** the amount that distribution companies charge for providing the electricity distribution service. This value is calculated based on a yardstick competition scheme, where an efficient theoretical company is used as a reference to set the tariff for the real distribution companies

For large consumption users, the regulation stipulates a non-regulated price regime. Generators usually supply energy for non-regulated clients directly.

Generation companies commercialise their energy and power by:

- Supplying large consumers in the market at non-regulated prices
- Establishing long-term supply contracts with distribution companies through competitive auction processes
- Selling their energy in the spot market at marginal cost on an hourly basis

Nuclear energy is not a short- or mid-term option under the energy policy and the current Energy Roadmap 2018-2022. The International Atomic Energy Agency (IAEA) has recommended new requirements regarding energy security and independence for the nuclear regulator. The Ministry of Energy recently released an update of the energy policy assumptions. Nuclear power is not an option for the next 30 years.

Chile has emerged as an excellent destination for solar and wind energy developers. New legislation encourages investment in generating capacity across the electricity sector. The expanded role of the state in energy planning has helped to boost project development, especially in electricity transmission.

DECARBONISATION AND CARBON NEUTRALITY

The Chilean Government and the Ministry of Energy have developed policy to advance decarbonisation of the electricity system. Developing voluntary and binding agreements to retire coal generation facilities is a prominent initiative taking place via a working group (Inodu 2019).

A volunteer agreement was signed between the Chilean Government and power generators that own coal-fired power plants in early 2018. The Ministry of Energy and the Chilean Association of Power Generators facilitated the agreement signing process.

The agreement stated:

1. No new coal-fired projects are to be developed unless they have carbon capture and storage technologies, or equivalent
2. The Ministry of Energy will establish a working group to evaluate the social, economic, environmental, health, employment and technical trade-offs associated with the decarbonisation plan for the electricity system

Chile's government announced in June 2019 its aim to reach carbon neutrality by 2050. As part of this, 1.73 GW of coal-fired power plants will shut down by 2024, equivalent to 26% of its total coal electricity capacity in 2024. Thermal coal plants will cease operations by 2040, at the latest.

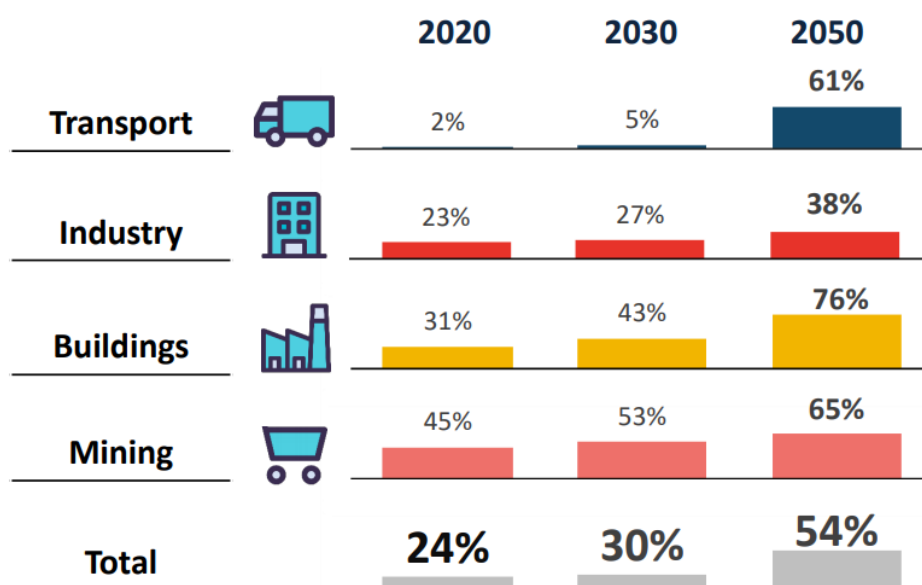
In December 2019, Chile's Energy Minister, Juan Carlos Jobet, announced a speeding up the shutdown of four coal plants (700 MW). AES Gener will close Ventanas 1 (114 MW) in 2020, and Ventanas 2 (208 MW) in 2022.

To make these closures viable, Chile is accelerating regulatory changes and transmission investments. Meanwhile, Engie agreed to shut-down its plants CTM 1 and CTM 2 by the end 2024. These plants were originally scheduled to shut down in 2028 and 2030, respectively.

Also, On May 28, 2020, Enel Chile SA has agreed to accelerate the closure of the group's last coal-fired plant in Chile. The company has requested authorizations to cease operations at the Bocamina coal-fired power plant in Coronel at units Bocamina I (128 MW) and Bocamina II (350 MW commissioning in 2012) by Dec. 31, 2020, and May 31, 2022, respectively. The first unit was previously scheduled to close by the end of 2023, with the second due to cease operations no later than 2040.

The renewables share of electricity generation reached 45% in 2018. According to technical studies and projections by power companies and the government, solar can provide 30% of electricity by 2030 to become Chile's leading power source. Near 85% of electricity could be renewable in 2030.

Figure 1: Electricity share by sector between 2020 and 2050.



Source: Trajectories of the Energy Sector to Carbon Neutrality (Chilean Association of Power Generators, 2019)

Chile is currently formulating a new Climate Change Framework Law. The main objectives are a transition to low emissions development (achieving carbon neutrality in 2050), increasing resilience against climate change effects, and complying with international climate change commitments. The draft bill provides details on governance, management instruments, financing measures and economic instruments.

Carbon neutrality will require more than double the current electrification rate. Electric mobility and buildings with heat pumps will drive the increase in electrification (Chilean Association of Power Generators, 2019).

ELECTRICITY REGULATORY FRAMEWORK

The General Electricity Services Law (DFL N° 1 of 1982 – LGSE) outlines the basic principles that are the basis for current energy regulation. The law privatised the electricity industry, introduced competition into the generation sector, and separated the industry's generation, transmission and distribution segments. Operational rules and regulatory details are also detailed in the Electricity Regulation DS N° 327 of 1998.

Privatisation of the state-owned utilities began in 1986 and was completed in 1998. Chile was the first economy in the world to embrace competition and free markets and to deregulate its power industry (CNE, 2018a).

Private companies wholly serve the electricity market. The government plays the role of a regulator and policymaker, and offers technical support in identifying requirements to meet projected demand growth.

The LGSE has been amended multiple times. Some prominent changes are:

- Short Law I, Law 19 940 (Ley Corta I) – March 2004: amendments to regulate the decision-making and the development of the expansion of electricity transmission. The Law establishes a new tariff regime for medium-sized systems and for the first time, promotes the use of non-conventional renewable energies in the Chilean power market
- In May 2005 the electricity law (Law N° 20 018 – also known as Short Law II) was modified to define the auction process of long-term supply contracts of the distribution companies. The objective was to promote additional investments in power generation based on long-term power purchase agreements with regulated utilities. The law also defines the legal framework for the development of non-conventional renewable energy (NCRE)
- Enacted in September 2007, Law N° 20 220 modified the LGSE concerning safeguarding the security of supply to regulated customers and the adequacy of electricity systems. It considers court action for the termination of contracts due to the bankruptcy of electricity companies. In April 2008, Law N° 20 257 set long-term targets to be met by non-conventional renewable energy sources. In 2010, 5% of the total energy supplied was generated through NCRE sources, gradually going up to 10% in 2024. The obligation for NCRE falls on the generators, with penalties equivalent to USD 26 up to USD 40 per MWh (2020 USD Exchanges rates). Law N° 20 698 increased the renewable share to 20% by 2025. NCRE sources include biomass, hydropower with a capacity less than 20 MW, geothermal, solar, wind, marine energy and other means of electricity generation determined by the CNE
- On July 2016, Law N° 20 936 established New Power Transmission Systems and created an independent coordinating body for the National Power System. The objective was to ensure that transmission did not become an obstacle to power generation. The law introduced significant changes to the LGSE and is known as the new transmission law

The law enhanced the role of the state in energy planning and the expansion of the transmission system. The Chilean Government now assumes certain functions that were previously in the hands of the private sector. The law introduced the National Electric Coordinator (CEN), a unified, independent system operator. It also supported grid expansion and cross-border connections as well as a long-term energy planning (LTEP) process for at least 30 years. An approach to remunerating ancillary services was devised as well.

- In 2016, Law N° 20 928, also known as Residential Tariff Equity Law, introduced mechanisms for equity in electricity tariffs and sought to reduce the differences in the electricity bills of final customers in different areas of the economy

- A modification to Law N° 20 571 was enacted in November 2018 to promote residential/distributed generation by extending the maximum limit for private installations from 100 kW to 300 kW (MEN, 2018)
- In the context of the New Social Agenda implemented by the Chilean Government on November 2, 2019, Law 21 185 was enacted, creating a transitional mechanism for stabilising electricity prices to customers under the regulated price system

The mechanism cancels the 9.2% price rise that should have been applied to regulated customers under Decree No 7T and postpones the price increase for the sale of electricity contracts between generation and distribution companies that start supplying before 2021. This procedure works by creating a stabilisation fund implemented by the CNE and funded by the companies in the generation industry (not including any small distributed generation suppliers).

GENERATION

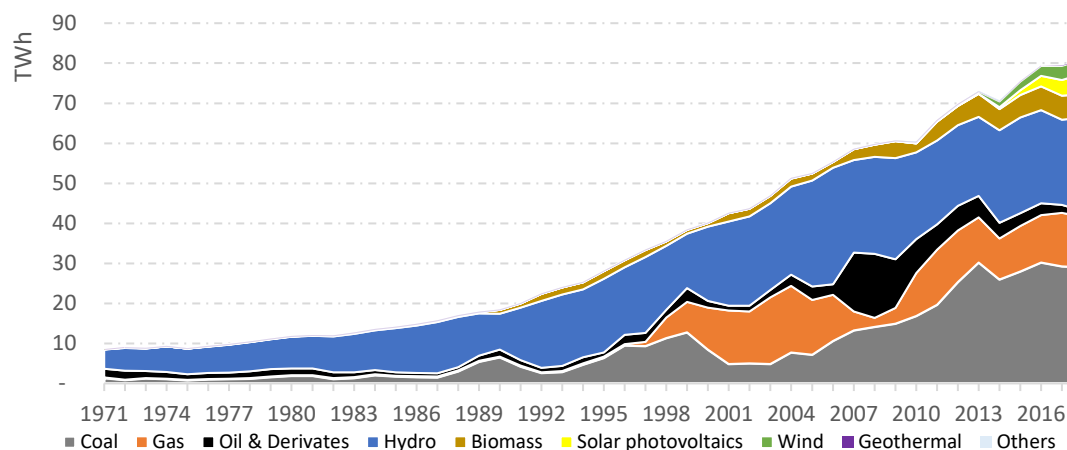
Generation represents the production phase of the electricity supply chain. In Chile, this segment is a competitive market where generator companies offer energy at their marginal cost of production. The system operator (CEN) must balance the market, aiming to meet the electric demand at minimum cost, preserving system security levels.

Electricity demand has grown at an average annual growth rate of 4.0% between 2000 and 2018, reaching 81.2 TWh of electricity generation in 2018. Chile remains an electricity island, with only one intermittent cross-border connection with Argentina.

Over the past two decades, the energy mix of Chile's power generation has changed remarkably with the introduction of low-carbon technologies, mostly renewables. Between 2004 and 2007, Argentina, which was then the sole natural gas supplier to Chile, faced an energy crisis and restricted its gas exports. Consequently, the natural gas supply in Chile decreased significantly in 2007 and its contribution to electricity generation dropped by 60% (IEA, 2018).

Oil was replaced by a combination of coal-fired generation and, after the commissioning of the two liquefied natural gas regasification plants, natural gas from other economies. Since 2010, the increased use of renewables has started to shape a new energy matrix. Nevertheless, the share of coal is still large, around 36% in 2018. Also, Chile has faced ten consecutive drought years in the central-south region, which reduced hydropower supply from 44% in 2008 to 29% in 2018.

Figure 2: Electricity generation in Chile by source 1971 -2018 [TWh]



Source: 2019 IEA World Energy Balance and Statistics (IEA, 2019a)

Regulatory framework and market structure

Generation companies are defined as companies that own generation plants and whose energy is transmitted and distributed to final consumers.

The wholesale electricity market in the Chilean system has two components:

- The spot market: where generators buy and sell electricity on a real-time basis
- The bilateral contract market: where large consumers and distributors buy electricity from the generators.

The spot market (or market for short-term transactions) allows the purchase/sale of electricity at marginal cost and is operated by the CEN. Only generators may sell or buy electricity on the spot market. Power plants are dispatched in a merit order using regulated estimates of their marginal costs (audited variable costs). This rule is mainly to avoid the negative impacts of high levels of market concentration. The marginal cost of the system is calculated on an hourly basis for each node of the network.

The financial contract market has two components: one for large customers and another for distributors. Generators can sell their electricity to large consumers at prices freely agreed between the parties. In contrast, electricity sales to distribution companies with regulated customers are organised through tenders for long-term supply.

Wholesale competition in Chile occurs in the 'contract market,' where generators sell electricity freely to large (non-regulated) customers, and through tenders to distributors that supply small (regulated) customers. Around half of the electricity demand in Chile is provided under these tenders.

Generators can operate in a spot market and in a contract market at the same time. The spot market works as a short-term market where demand and supply meet instantaneously. The contract market operates as a long-term market where generators and customers contract to supply and demand in advance.

The spot price mechanism in the Chilean system follows a peak-load pricing scheme, which includes an energy price and a capacity charge. The marginal cost of generation is the energy price, and it is equal to the most expensive generation unit (variable cost) in use to balance demand and supply, considering transmission constraints and energy losses.

In case of any shortage, the spot price is equal to an outage cost calculated by the CEN. The outage cost is based on consumer willingness to accept compensation for a planned outage of a specific range or magnitude. The capacity charge, instead, is given by the lowest unitary capital cost of a generation unit to supply the peak of demand (calculated by CNE). The energy price covers the variable costs of the marginal supply unit, while the capacity charge is an annual payment that it is allocated proportionally to the actual capacity of each plant to cover the peak demand (Bustos and Fuentes 2017).

CUSTOMERS

Customers connected to the grid through a local distribution company, with a power connection between 0.5 and 5 MW, can choose between being a regulated or non-regulated customer.

- Regulated customers: the regulated price takes account of the distribution fee, node price (based on respective tender processes), capacity charge, transmission charge and distribution fees. Both the transmission charge and the distribution charge are volumetric (CLP/kWh)
- Unregulated customers: these customers are free to negotiate with the power generation companies directly (bilateral PPAs) but will have to stay in this contracting market for at

least four years and inform the distributor at least a year in advance to begin supply with a new generator/utility.

TRANSMISSION

The transmission system in Chile is defined as the group of lines, substations, and equipment of nominal voltages over 23 kV, used to transport electricity from generation plants to distribution facilities, or directly to large customers.

The transmission segment is a natural monopoly. Transmission companies are subject to regulation that ensures open access to all clients.

The transmission systems are classified as follows:

- **The national transmission system**, which refers to the bulk transportation network that connects the generation plants with main consumption centres or other transmission systems (zonal or dedicated)
- **Zonal transmission systems**, which allow energy transmission from the trunk system to distribution companies or groups of non-regulated final customers
- **Dedicated transmission systems**, which allow generation companies to inject their production into the national or zonal system(s)

A major reform (Law N° 20 936 mostly known as the transmission law) to promote and develop renewables projects and enhance the performance of this sector was enacted in 2016. The law enhances the role of the state in energy planning and the expansion of the transmission system—the state now assumes certain functions that were previously in the hands of the private sector.

The new law introduced **Generation Development Hubs/Poles** (the “Development Poles”). The concept allows for the construction of transmission corridors to transport electricity from geographical areas with a high concentration of solar and wind energy resources as part of the long-term expansion plan.

For that purpose, the Ministry of Energy must identify areas for so-called development hubs, i.e. areas of high economic potential for power generation from renewable. The use of these renewable energy resources, which use a single transmission system, is in the public interest as it is economically efficient for electricity supply.

These areas are identified in the long-term energy planning process and will be included in future transmission-grid expansion plans. This will enable renewable generation at these hubs to reach demand, which will open the market to several renewable energy projects in the same area and will optimise the costs of connecting to the grid (Rudnick, 2016).

The Ministry of Energy oversees the development of long-term energy planning processes for time spans of at least 30 years. One result of this process is the generation expansion planning scenarios which are used by CNE for transmission expansion planning. The CNE analyses which transmission lines are necessary and the CEN issues tenders for companies to build and operate these lines. Currently, eight companies own national transmission networks in Chile.

Law N° 20 936 transfers national, zonal, and dedicated transmission costs to final consumers (both unregulated and regulated). One of the largest amendments introduced by this law is the full guarantee of open access to transmission facilities. Other changes are related to the introduction of single-access charges and the transfer of transmission system costs to the final customers. Access charges are calculated using “postage stamp methodology”.

The new transmission law establishes the transmission system's collection, payment and remuneration, which will be valid until December 31, 2034. The price of electricity transportation

for current supply contracts remains unaltered. Payments made by final clients (mostly large unregulated clients) shall be compensated, if applicable, under those contracts.

The procedure to permit transmission projects was simplified and shortened in 2013. The procedure now also allows requests for transmission concessions to be divided into segments. It also proves a clearer process for valuing land and resolving conflicts between concessionaries (IEA, 2018).

DISTRIBUTION

Distribution systems in Chile comprise transmission lines, transformation equipment and substations in rated voltages less than or equal to 23 kV. They provide the electricity distribution services for residential, commercial and large final customers.

Electricity distribution is a natural monopoly. Distribution companies operate using a concession model of public service distribution. This means that the state grants the distribution company the rights to operate in a specific geographic zone (the “concession zone”). This concession allows the distributor to use public spaces, but at the same time, sets the following obligations:

- To provide electric services inside the concession zone to every consumer that requires it
- To ensure open access: allow free network access for PMGD—a Spanish acronym for small scale distributed generation
- Electricity sales and associated services to regulated customers must comply with a regulated tariff (sales of energy, power and associated services).

This sector is organised through concessions, and there are 32 distribution companies. Energy charges are fixed, and are determined by the CNE every four years.

The energy services provided by the distribution company can be separated into three activities: energy and power retailing; electricity distribution; and associated services. Associated services involve installation; renting and maintenance of connections and meters; public lighting; and the physical support of telecommunication cables. Prices of associated services are regulated.

Distribution energy charges are calculated using a model company to determine a reasonable return, accounting for capital, operation, maintenance and administration costs. A similar rule applies to energy tariffs. Distribution charges are subject to an equalisation mechanism to ensure distribution charges are consistent.

In December 2019, the Chilean Government added a short modification to the current distribution law as part of the process of modernisation of the distribution sector. The objectives are to encourage the development of a more efficient and intelligent distribution grid, to introduce new technologies and new companies, and to expand business opportunities in the sector. The main changes delivered by this law are:

- Determination of a new capital cost rate of the distribution companies which will have a floor of 6% and will be applied after taxes
- Introduction of a new procedure to determine tariffs. Objections with tariff determinations can be disputed at a special court to resolve disagreements in the energy sector (Panel of Experts)
- An improvement to the concept of the “common areas”, leading to a better estimation of the distribution charges in each concession area

TENDERS FOR LONG-TERM ELECTRICITY SUPPLY

The New Electricity Act on Energy Auctions (Law 20 805, 2015) establishes the process of open energy auctions, encouraging the entrance of new players and electricity generation

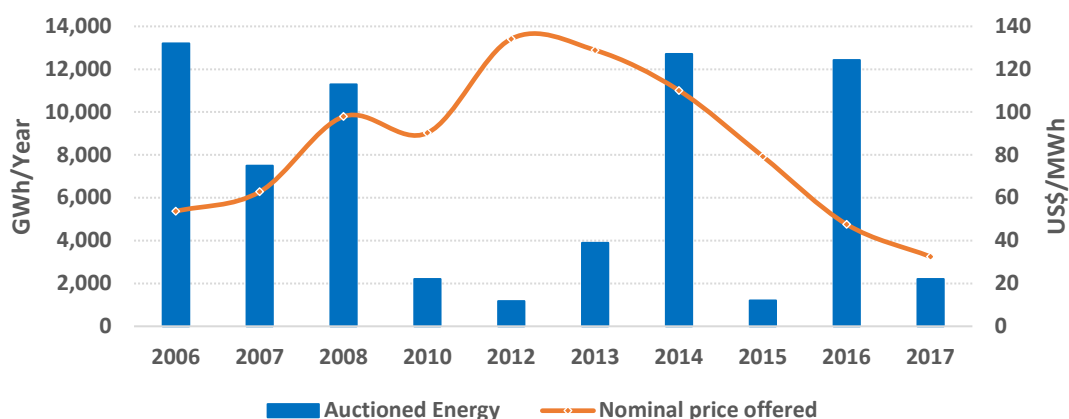
technologies. The new procedure improves competitiveness and promotes better price mechanisms in favour of end-users in the electricity market for regulated users (CNE, 2018a).

The main features of these tenders are:

- The energy tenders provide the opportunity to acquire 15-year power purchase agreement and to invest in new generation projects.
- The coming long-term auction process will lead to supply starting five years after the supply contract, giving enough time for the construction and commissioning of new projects
- The maximum limit for regulated customers changes from 2 MW to 5 MW, allowing access to a regulated market for some mid-size customers, and improving their negotiation conditions with generators
- Different generation projects and efficient technologies will be able to participate due to different energy supply blocks (i.e. intraday blocks)
- Prices may be revised if taxes or laws change.

The auction winners in 2017 will start delivering energy to the grid from 2022 to 2041. In 2017, the average price was USD 32.5 per MWh, the lowest since 2006. The average electricity price since 2012 has decreased from USD 134.2 per MWh to USD 32.5 per MWh.

Figure 3: Energy Auctions 2006–2017.



Source: Empresas Electricas (2019)

RENEWABLES

Chile has vast untapped potential for solar power as well as for onshore wind, geothermal and hydro energy. The Atacama Desert in the north boasts a direct normal irradiance of more than 9 kilowatt hours (kWh) per square metre (m²) per day, the highest in the world. In its extreme south, together with Argentina, Chile has the best onshore wind resources in the world.

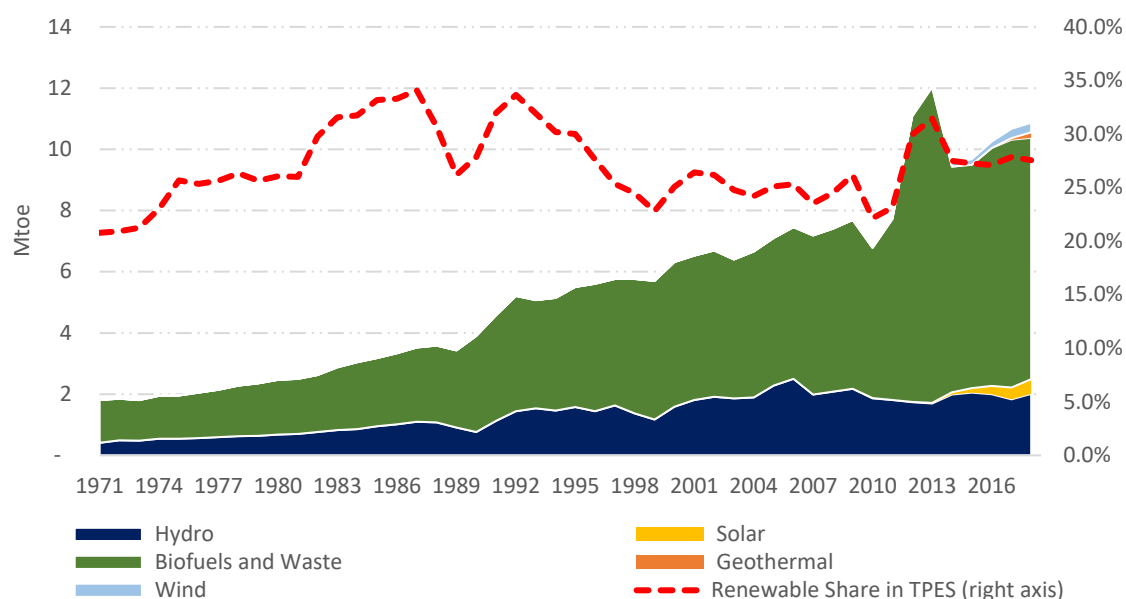
According to the Ministry of Energy data, solar potential is 829 GW for PV technologies and 510 GW for Concentrated Solar Power systems (CSPs). Onshore wind power potential is 37 GW, geothermal energy is 2 GW and hydropower is 6 GW (Santana et al., 2014).

The development of renewable energy resources is expected to bring economic and social benefits to the economy. According to IRENA, supplying 20% of electricity from NCRE by 2020

would contribute an additional USD 2.3 billion to the GDP (+0.6%) and generate 7 800 jobs (IRENA, 2016; NRDC & ACERA, 2013a, 2013b).

Renewable energy was the second-largest source of TPES in 2018, with a total of 10 867 ktoe (27%). Solid biomass accounted for 13% of total final consumption (excluding non-energy). Chile's primary supply of renewable energy in 2018 mainly consisted of biomass, solar, wind and hydropower.

Figure 2: Renewable energy in TPES, sources in Chile



Source: 2019 IEA World Energy Balance and Statistics (IEA, 2019a)

In December 2017, the Ministry of Energy published the LTEP process, which detailed the vast untapped potential for solar (PV and CSP), onshore wind, geothermal and hydro. PV potential was estimated at 829 GW, CSP at 510 GW, onshore wind power at 37 GW, geothermal at 2 GW and hydropower at 6 GW (Ministerio de Energia, 2018d). Figure 2 below shows the vast untapped potential for solar (PV and CSP), onshore wind, geothermal and hydro.

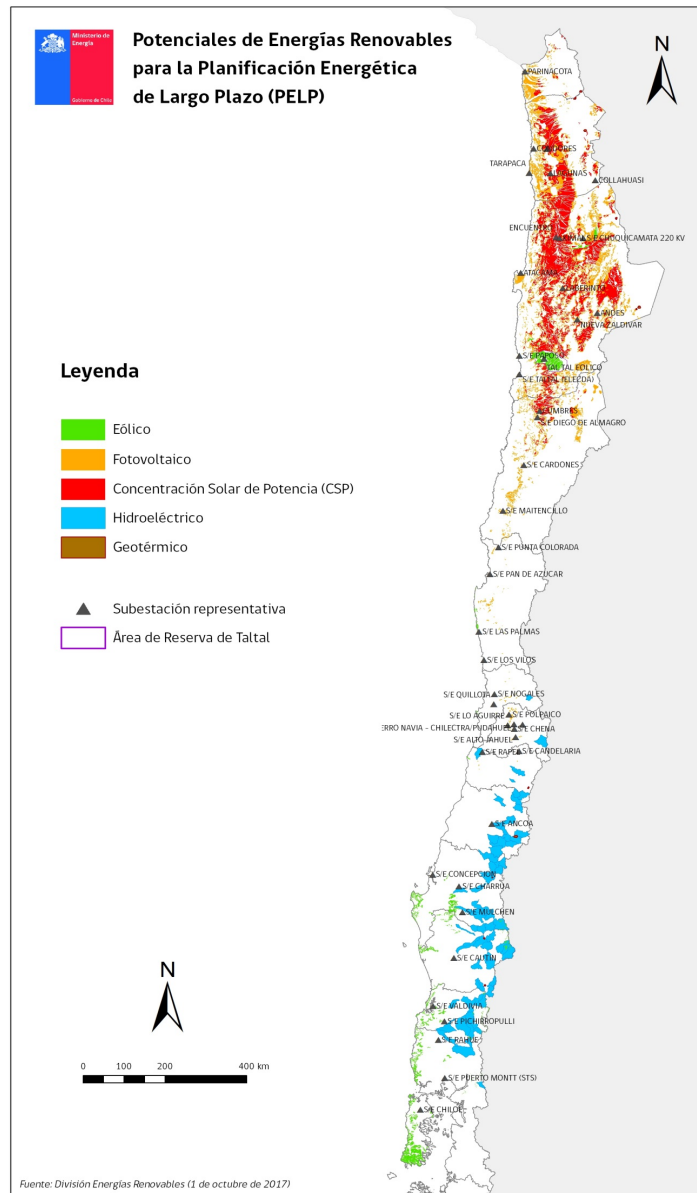
At the end of January 2020, Chile had an installed capacity of 5 331 MW of NCRE. Solar and wind account for 9% and 7%, respectively. An additional 3 654 MW of NCRE is under construction. NCRE installed capacity is 20% of the total installed capacity and 15% of whole system generation (CNE, 2020b).

Table 6: NCRE units in operation and under construction

Energy Source	Operation (MW)	Construction (MW)
Biomass	502	180
CSP		110
Geothermal	48	33
Hydro (<= 20 MW)	512	36
Solar PV	2 648	1 648
Wind	1 621	1 557
Total	5 331	3 564

Source: CNE (2020b)

Figure 3: Potential renewable resources in Chile



Source: Ministerio de Energia (2018d)

ENVIRONMENTAL POLICY

According to Law No 19 300 (Environmental Law) and the procedures of the Environmental Impact Assessment System (SEIA – Spanish acronym), every project or activity likely to have an impact on the environment must be assessed before its execution or modification.

Article 10(I) of the Environmental Law stipulates that mining activities must be assessed by the SEIA. Pipelines with a capacity of more than two litres per second (or 0.5 litres per second in urban areas) are also subject to the SEIA.

Supreme Decree No 40 (SEIA Decree) was enacted 30 October 2012, and published on 12 August 2013, regulating the Environmental General Basis Law. The SEIA Decree sets out the procedure for conducting:

- Environmental impact studies (EISs): for large-scale projects or amendments that could significantly impact the environment. Once an EIS is filed, the environmental authority has 120 business days to assess the project and issue an environmental qualification (RCA), which approves or disapproves the project. The assessment period can be extended for an additional 60 business days (a total of 180 business days)
- Environmental impact declarations (EIDs): for more straightforward and lower-scale projects. The government authorities have 60 business days to assess the project, which can be extended by 30 business days (a total of 90 business days)

Under normal circumstances, an EIS takes approximately one year to complete, while an EID takes six to eight months. The duration depends on the number of questions received and the information requested during the assessment procedure.

The decision to submit a project for an environmental assessment through an EIS or EID is made by the project's titleholder. Before commissioning a project that may have an ecological impact, the titleholder must analyse whether the project (or modification) needs to be assessed.

According to Article 11, a default submission is an EID. An EIS is needed instead if the project generates or presents any of the following effects, characteristics, or circumstances:

- Risks for human health due to the quantity and quality of effluents, emissions, or wastes generated or produced
- Potential adverse effects on the quantity and quality of renewable natural resources, including land, water, and air
- Potential alteration of traditions and life structure environments for communities
- Potential impact on any location in, or adjacent to, protected populations, resources, and areas (priority conservation sites, protected wetlands and glaciers), that are likely to be impacted
- Under any scenario where tourist value of the area is compromised
- The possibility of impacting monuments or culturally/historically significant sites
- If citizen participation is required

An EIS can also involve a citizen and communities participation procedure (CPP). Article 29 of the Environmental Law provides that "any person or legal entity can submit observations to the EIS before the competent agency, for which they will have a period of 60 days from the publication of the respective abstract".

If the EIS is subject to clarifications, amendments or additions that would substantially affect the project, the authority can open a new term of citizen participation, for a period of 30 business days, during which assessment will be suspended.

Unlike an EIS (in which a CPP will always take place), for EIDs specific requirements must be met before a PAC can occur. Under Article 30bis of the Environmental Law, the environmental authority can allow 20 days of citizen participation for EIDs if the project has the potential to burden nearby communities.

OIL AND GAS

Oil is the most dominant fuel in Chile, accounting for 42% of TPES and 58% of total final consumption (excluding non-energy). In 2018, domestic production accounted for less than 2% of supply (790 000 barrels of crude oil and 1.1 million standard cubic metres of gas). The current mandatory minimum oil inventory is the equivalent of 25 days of average sales (or average imports)(IEA, 2019a; MEN, 2020).

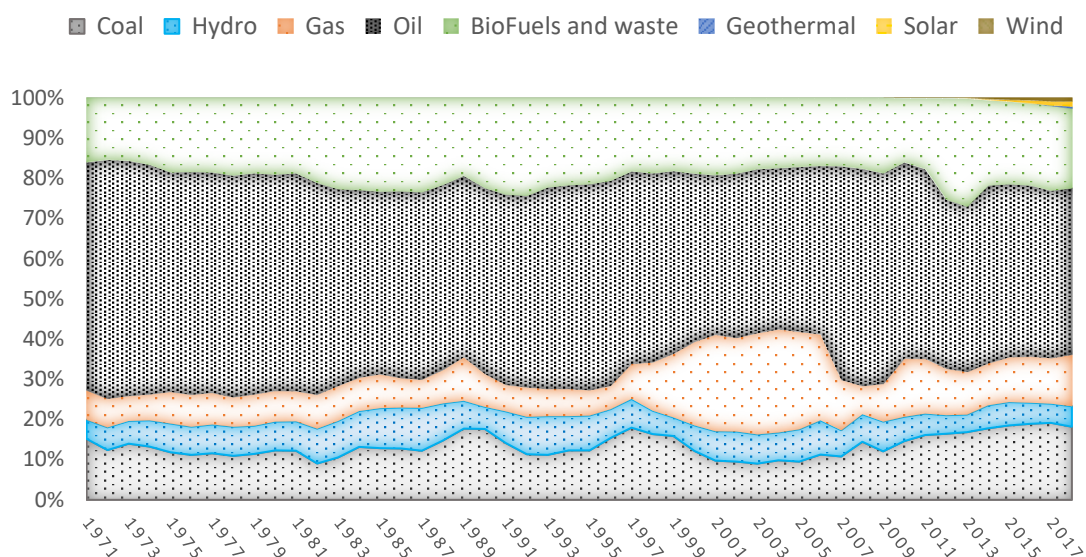
Considering the low domestic production, nearly all of Chile's crude oil supply (13 485 ktoe) in 2018 came from imports. These imports included by-products such as diesel, gasoline and

liquefied petroleum gas (LPG). Imported crude oil came from Brazil (62% of imported crude) and Ecuador (38%).

Liquefied Natural Gas (LNG) has a more active role within the Chilean market. The uncertain natural gas supply from Argentina after 2004 led Chile to develop two LNG regasification facilities. One was Terminal GNL Quintero, located in the Valparaiso region (15 million cubic metre average daily production) and the second was Terminal GNL Mejillones, built in the Antofagasta region (5.5 million cubic metres average daily production).

From 2007 to 2008, oil consumption saw an abrupt increase of 32%, driven by the need to compensate for the curtailment of natural gas imported from Argentina. The share of oil in TPES increased from 42% in 2006 to 53% in 2007. The oil share in TPES started to decrease at the beginning of this decade reaching 41% in 2018 due to increases in electricity supply from renewable energy and new coal and gas-fired power plants.

Figure 3: Share of primary energy supply by fuel 1971 – 2018



Source: 2019 IEA World Energy Balance and Statistics (IEA, 2019a)

The transport sector is the largest oil consumer, accounting for 56% of consumption in 2017 (IEA 2019). Road transport consumes nearly 90% of all oil products, followed by air transportation at 5%.

The industry sector is the second-largest oil consumer, accounting for 26% in 2017. Industry oil consumption has increased by 87% over the past decade. Mining is the largest oil-consuming industrial sector.

PETROLEUM-BASED FUELS REGULATORY FRAMEWORK

The state is the owner of hydrocarbons and minerals. The constitution stipulates that “*the state has absolute, exclusive, inalienable and imprescriptible domain over hydrocarbon deposits*”.

The owner of the real estate does not hold any rights over these two assets. ENAP can explore or exploit hydrocarbons directly or can do this along with a (local or foreign) private investor. The third party plays the role of a contractor, bearing both the risk and the expenses of the venture. This kind of structure is generally aligned with UN Resolution No 1803 on Permanent Sovereignty over Natural Resources.

Decree with Force Law No 2 of the Mining Ministry of Chile, sets out the restated, coordinated and system text of Decree-Law No 1 089 of 1975 (DFL 2). DFL 2 regulates the granting of administrative concessions or exclusive operation contracts (CEOPs). CEOPs are licences granted by the Chilean state that authorise third parties to explore and exploit its oil and gas reservoirs. Most licences are for the Magallanes region. CEOPs are awarded through an open auction process. The CNE must issue a report recommending whether to approve or reject applications for a CEOP

Chile does not have a separate legal framework for onshore and offshore oil and gas exploration and production.

The CEOP structure has similarities with a Share Production Agreement, a type of oil contract developed in Indonesia in the 1960s, which is now one of the most common oil agreements in developing economies.

Law Decree No 340/60 regulates the procedure for granting and holding maritime concessions. This authorisation is relevant for LNG industry development in Chile. Another important framework law is Decree No 160, which sets out safety regulations for production, refining, transportation, distribution, storage and distribution of liquid fuel.

CEOP policy considers two stages or phases: exploration and exploitation. If a discovery is made during the exploration term, and development of the reservoir is commercially feasible, the exploitation field must set a Commercial Operation Date (COD) within the schedule set out in the CEOP. The exploitation and exploration phases combined can last for 35 years. In the case of force majeure, the term may be extended (although the contractor or CEOP titleholder bears the burden of proving the force majeure). Areas of a field where no further development is required are relinquished back to the state in accordance with the CEOP schedule.

Finally, the concession holder must issue a performance bond during the exploration phase. The amount of the surety will depend on the budget of the project and the tender rules (if any).

CEOPs can be granted to concessionaires in two ways:

- Direct negotiation between the state and the interested party (which can be either local or foreign). The applicant must file its request with the Ministry of Mining, where creditworthiness, applicable tax regimes, etc. are assessed
- Awarded through a public tender process. The licence is based on pre-defined selection criteria and issued by a decree which must be approved by the CNE

The most relevant criteria are prior exploration and exploitation experience. If the application is approved, the CEOP is granted to the applicant, with a decree by the Ministry of Mining enacted on behalf of the State of Chile.

The CEOP can establish that the concession holder is bound to satisfy local demand for oil and gas before exploiting export opportunities. The CEOP may also provide that any surplus to domestic requirements can be traded in the market through a public tender process.

In Chile, there is open access to the pipeline network for the oil and gas sectors. This policy is intended to avoid abuse of market power by pipeline owners. Gas cylinders are also used as an alternative to pipeline transportation, adhering to Decree No 194/1989, issued by the Chilean Ministry of Economy. Households are the largest consumers of gas cylinders in Chile.

OIL PRICES AND TAXES

As a general rule, Chile does not regulate retail fuel prices. Prices are freely set at all stages of the distribution system (i.e. refiners, distributors, retailers, etc.). A specific excise tax (IEC – impuesto específico a los combustibles]) is levied on transport fuels, although the rates vary by fuel type. Gasoline is taxed at a fixed rate of monthly tax unit (UTM – unidad tributaria mensual)¹ of 6 UTM per m³ (UTM/m³) diesel at 1.5 UTM/m³, automotive LPG at 1.4 UTM/m³ and

automotive compressed natural gas (CNG) at 1.9 UTM/1 000 m³. All fuels are subject to the normal value-added tax rate of 19%.

Owing to its high levels of imports, Chile is exposed to the volatility in international crude oil and product markets. To compensate, it has a history of using price stabilisation mechanisms to mitigate the impact of this volatility on end consumers

MEPCO works by applying weekly changes to the variable component of the IEC to limit weekly variations in prices to 0.12 UTM/m³. The IEC consists of both a base component (which remains constant) and a variable component (i.e. total IEC = base IEC + variable IEC).

OIL PIPELINES

Chile's oil pipeline network is 825 km in total length (excluding the Magallanes region), which is not very large considering the economy is over 4 000 km in length. For areas with no pipelines, ships or trucks transport oil or LNG.

Two companies dominate Chile's pipeline logistics: ENAP and Sonacol. Sonacol is a state-owned entity that was established in 1957. It transports over 98% of oil by-products to the metropolitan region (the broader metropolitan area of Chile). The shareholders of Sonacol are COPEC, Shell, ESSO Chile and ENAP. The fee regimes are less regulated than in the gas sector.

Sonacol operates a 465 km product pipeline network, primarily serving the central regions. Copec owns the largest share of the company (40.8%), followed by Petrobras (22.2%), ENEX (14.9%), Abastible (12%) and ENAP (10.1%). ENAP operates a pipeline network in the central and southern regions, and it is also the network's sole user (IEA, 2018).

The key components of Chile's pipeline network are (APEREC, 2019):

- *Quintero to Concon*: Carries liquid fuels, including LPG, from the marine terminals and fuel storage plants in Quintero to ENAP's Aconcagua refinery. ENAP and Sonacol both own different portions of this section, and certain sections of ENAP's pipelines are bidirectional
- *Concon to Quillota*: Supplies diesel to the Nehuenco and San Isidro power plants located near Quillota. The pipelines are owned by Electrogas.
- *Concon to Maipu*: Two pipelines that transport LPG and liquid fuels from the Aconcagua refinery to storage facilities in Maipu, near Santiago in the Metropolitan Region. This system is owned by Sonacol
- *Maipu to Santiago Airport*: Transports liquid fuels that are used at the airport. It is owned by Sonacol
- *Maipu to San Fernando*: Supplies fuel (but not LPG) to storage facilities and is bidirectional. This section of the pipeline is owned by Sonacol
- *Linares to San Fernando*: Carries fuels (but not LPG) to ENAP storage facilities. The pipeline is also owned by ENAP
- *Biobio to Linares*: Connects marine terminals and fuel storage plants near Bio Bio with the storage plants located in the city of Linares. It carries liquid fuels, which include LPG. This section of the pipeline is owned by ENAP

Chile also has two international crude pipelines: Sica-Sica, owned by Bolivia's Yacimientos Petrolíferos Fiscales Bolivianos YPF, and Estensoro-Pedrales, owned by Argentina's YPF. The Estensoro to Pedrales crude pipeline, which was designed to supply the Concepción refinery with Argentine crude, no longer operates as the refinery now processes crude sourced from other economies.

GAS PIPELINES

The Transport Safety and Distribution of Gas Regulation sets the minimum requirements for gas pipelines concerning their design, construction, operation, maintenance, amendment and decommissioning. The Transport Safety and Distribution of Gas Regulation follows the construction and design standards of the American National Standards Institute, the American Petroleum Institute and the American Society of Mechanical Engineers.

Decree No 263/1995 regulates the concessions for distribution and transportation of gas. Concessions for distribution are necessary for private entities to be distributors of gas. Concessions are awarded on a temporary or permanent basis. One of the critical elements of a distribution concession is to provide the necessary easement or right of way to the concession area.

Decree No 323/1931 (as amended by Law No 20 999) regulates the fees or tariffs for concession titleholders. Generally, Articles 30 to 36 of the Decree provide that gas companies can determine, without any limitation, the cost of transporting the gas. However, in 2017, the fees charged were capped. If the revenues of a company exceed the maximum profitability in the same concession area for three years in a row, the CNE can fix the maximum transportation fee.

The Gas Services Law (DFL N° 323 of 1931), amended by Law 20 999 of 2017, establishes that companies that own concessionary gas distribution networks are free to set gas prices, subject to a maximum profitability check administered by the CNE. The three-year average profitability in a concession zone (typically the same as Chile's administrative regions) for a utility cannot exceed the three-year average of the cost of capital. These rates are company-and-zone-specific. The current floor is 6% (capital cost recovery rate) plus an additional margin of 3%.

When distribution companies exceed their profitability ceiling, CNE initiates a new rate-setting process. A distribution utility can request a special non-regulated gas rates regime by asking for a review by the national competition tribunal. If other energy sources are sufficient to avoid price abuse by the distribution company in that zone, the tribunal can order the Ministry of Energy to end the regulated rate regime.

Chilean regulation provides special treatment for Magallanes and the Chilean Antarctica Region. Current hydrocarbon regulation establishes a permanent regulated gas rates regime for these regions. CNE calculates gas rates every four years.

The CNE also determines parity and reference prices of fuels for the application of the Fuel Price Stabilisation Mechanism every week. Parity prices are determined for gasoline fuels of 93 and 97 octanes, diesel oil and liquefied gas (Law 20 765) and domestic kerosene (Law 19 030).

Reference prices reflect the cost of the respective fuels without considering short-term volatility. These reference prices are determined based on the past and future average values of crude oil, past values of refining differentials, transportation costs, insurance, customs duties and other expenses, as appropriate.

The Gas Service Act (Gas Act) (Law No 20 999 amendment to Decree No 323/1931) sets out the new legal framework of gas distribution, and established:

- An original method to calculate the setting of tariffs
- A user option to change energy supplier using a new streamlined procedure
- Ways to promote competition within the energy distribution sector.

The Gas Act establishes caps on the profits that gas distributors can make on a "maximum profitability allowed" basis (Capital cost recovery rate + margin). This threshold is 9%. This system has a similar structure to the feed-in tariff mechanism that regulates the energy generation sector in Spain, which also sets a limited profit mechanism on generators.

There is still a high level of vertical integration in the natural gas distribution sector in Chile. Companies frequently control multiple aspects of the supply chain, which means the risk of monopoly is high.

NATURAL GAS

Chile has the third-largest shale gas reservoirs in South America. Most of these reserves are in the Magallanes region, in the south of Chile. Chile's legal framework does not have any special regulations to encourage the exploration and production of this type of hydrocarbon. In 2018, 5.3 billion cubic metres of gas natural were supplied in Chile.

Natural gas accounted for 12% (5 065 ktoe) of TPES and 6.7% (2 012 ktoe) of total final consumption (excluding non-energy) in 2018. Domestic gas production in 2018 was 1 278 ktoe or 25.2% of the primary energy gas supply. Production increased by 1.7% from the previous year's levels.

Domestic gas production supplies an isolated network in the Magallanes region in the far south. The largest sources for imported natural gas are Trinidad and Tobago (54.4%) and the US (29.4%).

In 1997, Chile imported gas exclusively from Argentina. By 2004, gas supply hit a peak of 7 013 ktoe, then fell to a low of 2 108 ktoe in 2008. The gas networks of Chile and Argentina are connected by seven pipelines, which run from Mendoza in western Argentina to Santiago in central Chile. The so-called 'gas crisis' began with a restriction on the supply of natural gas from Argentina. A group of private and public investors worked together to build LNG terminals to avoid dependence on only one supplier.

Quintero LNG was constructed in the Valparaíso region, and Mejillones LNG was built in the Antofagasta region. Mejillones LNG has a storage capacity of 175 000 cubic metres (one tank) with a regasification capacity of 5.5 million cubic metres (mcm) per day, and Quintero LNG has a storage capacity of 334 000 cubic metres (two tanks) with a regasification capacity of 15 mcm/d.

Industry is the largest gas consumer, accounting for 45% of TFEC in 2018 (MEN, 2020), followed by the service and residential sectors, which consumed 37%.

From 2016, Chile began exporting (part of the imported) natural gas to meet Argentina's demand during the peak winter months of the southern hemisphere. Between May 2016 and August 2017, Chile supplied natural gas to Argentina, with a total flow of 360 (mcm). Between May and June, 2018, 86 mcm was provided through the Norandino gas pipeline and another 274 mcm between June and August through the GasAndes gas pipeline

In October 2018, Argentina restarted pipeline exports as a significant step towards regional energy integration.

Gas distribution is not separated from gas supply, and six gas distribution companies in Chile own a distribution grid and supply the commodity. In theory, more than one distribution company can have a distribution network in a city, which could result in direct competition. In practice, this rarely happens, as it is inefficient to duplicate networks.

Gas prices for consumers are indirectly regulated through capping the return on assets of the distribution companies to 9% (capital cost rate + three percentage points of margin). The retail gas price contains the distribution tariff and the price for the commodity. The costs of making a connection to a residential dwelling are considered an operational expenditure of the distribution companies and can be amortised as part of the asset base of the distribution company for ten years.

COAL

Coal accounted for 18% of the TPES, 36% of the electricity generation, and 0.56% of the total final consumption (excluding non-energy) in 2018. Domestic coal production accounted for 2.4% of the primary energy supply. The share of coal in TPES increased from 14% in 2008 to 18% in

2018. Despite a rapid growth in indigenous coal production with the operation of a new coal mine in the Magallanes region, imported coal still accounts for 82% of total coal supply (IEA, 2018, 2019a).

Most of Chile's coal supply of 7 128 ktoe in 2018 came from imports. The largest source economies for imported coal were Colombia (42%), the US (33%) and Australia (21%).

Use of coal increased in the power generation sector following the curtailment of natural gas from Argentina from 2004. Increased coal reliance maintained the security of electricity supply and reduced the use of expensive diesel fuel. Coal supply has increased by 98% over the last 10 years (3 658 ktoe).

The power sector is the largest coal consumer, accounting for 95% of the total coal consumption in 2018; the rest was mainly consumed by iron and steel production. In contrast to coal power generation, coal consumption in other sectors has been declining since 2000. (IEA 2019, IEA 2018).

In 2018, Chile produced 2.3 million of tonnes of hard coal, accounting for 18% of its total coal supply. Coal production fell by 8% compared to 2017.

The opening of the Mina Invierno mine in the Magallanes region in 2013 increased domestic coal production more than fourfold. However, coal demand continues to be met mostly through imports (11.4 Mt). Chilean coal is typically sub-bituminous and mixed with imported coal of higher calorific value (SERNAGEOMIN, 2019).

Chile has around 1.2 billion tonnes (bt) of coal reserves, mostly in the south, and around 4.1 bt of coal resources (BGR, 2016). The largest reserves are on the island of Isla Riesco which also hosts the Mina Invierno. Several mines are being planned on the island.

Chile has 29 coal-fired power plants units, located mainly along the coast, which provide baseload power to the economy. They are fitted with subcritical technology with a relatively low average thermal efficiency of less than 36%. The exceptions are Colbún's Santa María (350 MW) and Engie's IEM (375 MW). Both are pulverised coal combustion plants with a maximum thermal efficiency of 41%.

To ensure that coal use is compatible with the renewable energy and climate targets, the government needs to consider introducing higher CO₂ taxes or CO₂-intensity limits for power generation. A first step in that direction was the September 2014 green-tax regulation to limit emissions of CO₂, sulphur dioxide, nitrogen oxide and particulate matter from thermal power generation (from 2017 onward).

NUCLEAR ENERGY

In 1964, the Chilean Government created the Chilean Nuclear Energy Commission (CCHEN) to address nuclear energy issues.

CCHEN operates the research reactor RECH-1 located in the Santiago metropolitan region. Chile does not have any commercial nuclear reactors. CCHEN's primary duties are:

- To provide technical and legal advice to the government on nuclear issues related to energy and radiation
- To conduct research and development on peaceful uses of nuclear power
- To regulate, control and supervise nuclear facilities
- To undertake technology transfer and its applications.

The use of nuclear energy has been subject to concerted debate. In 2007, the Nuclear Energy Working Group was formed to study the feasibility of Nuclear Power in Chile. Nuclear power was

deemed to be a viable option despite risks of earthquakes, and waste management concerns (MINREL, 2007).

In January 2015, the Government of Chile created the Nuclear Power Energy Committee, and delivered 'Nuclear Power Generation in Chile: Towards a Rational Decision' (CCHEN, 2015). The report found that nuclear power should not be discarded without a 'rational and comprehensive analysis'. The report also found that social approval is crucial before nuclear development takes place.

Despite the exclusion of nuclear energy from the final Energy Roadmap 2018-2022, Chile has not ruled out using nuclear power. Energy 2050 notes that nuclear power is not currently a short-term option for Chile, and that its uptake depends on further research regarding security and economic rationality, as well as community acceptance.

CCHEN has been appointed to consider nuclear power in the next review of energy policy, which will take place in 2020. It is unlikely that the technology will be considered as a viable option in the current power market. The latest revision of the long-term energy policy will be released at the end of 2020.

ENERGY EFFICIENCY

Energy efficiency (EE) is a priority for Chile, and it will help to enhance energy security. EE also stabilises energy demand growth.

The Ministry of Energy entrusts the Chilean Energy Sustainability Agency to implement and manage EE policies and programs. The government has set a goal of achieving 20% savings by 2025.

The energy policy defines long-term EE goals to 2035 and 2050 aligned with the UN Sustainable Development Objectives (Ministry of Energy, 2016). These are:

- To build a robust regulatory framework for energy efficiency
- To progressively implement energy management tools that have been validated by international competent bodies
- To use locally available resources and exploit potential energy in the production process
- To build efficiently by incorporating energy efficiency standards into the design, construction and refurbishment of buildings, in order to minimise energy requirements and environmental externalities, while attaining adequate comfort levels
- To promote control, intelligent energy management and self-generation systems to enable progress to be made towards buildings that use efficient solutions to meet their energy needs
- To strengthen the market for efficient buildings and progress towards more productive and efficient local markets
- To improve the energy efficiency of urban public transportation
- To promote a fundamental shift towards more efficient modes of transport, adopting the highest international standards of energy efficiency for road, air, rail and maritime transport
- To ensure consumer data availability, including alternative energies and methods
- To design, implement and track energy education initiatives
- To develop new professionals and technical human capital for production

The agenda states short-term concrete activities to encourage EE, which consider measures to extend the development of EE projects, including the continuity of the Action Plan on Energy Efficiency 2020, published initially in 2012. These measures are applicable to industry and mining, transport, buildings, end-use devices and heating.

Table 8: Chile's action plan on energy efficiency, 2020

Industry and Mining	<ul style="list-style-type: none"> - Promote energy management systems - Promote energy cogeneration - Encourage efficient technologies - Technical assistance in industry and mining projects
Transport	<ul style="list-style-type: none"> - Improve EE standards for light- and heavy-duty vehicles - Use new transport technologies in heavy-duty vehicles - Promote public transportation - Promote electric vehicles - Technical assistance in transport projects
Buildings	<ul style="list-style-type: none"> - Encourage efficient technologies - Improve thermal insulation in buildings without EE standards - Promote energy management in buildings - Give training to relevant actors in the construction chain - Promote building labelling - Promote EE in street lighting
End-use devices	<ul style="list-style-type: none"> - Extend appliance labelling - Establish a minimum energy performance standard (MEPS) - Promote minimum lighting efficiency standards through programs focused on low-income households
Heating	<ul style="list-style-type: none"> - Encourage new technologies in the use of firewood - Improve firewood quality - Improve knowledge regarding the correct use of wood biomass and its process

Source: Ministerio de Energia (2012)

Since 2012, the government has been implementing the 2020 Energy Efficiency Action Plan. Besides this policy, the Superintendence of Electricity and Fuels certifies security, emission levels, and EE standards on firewood home appliances. These are part of the institutional framework for EE policies owing to the importance of firewood in residential consumption in Chile.

In 2014, the Chilean Government approved the Minimum Energy Efficiency Standards Act, which applied to refrigerators and lamps. Three-phase induction electric motors up to 10 horsepower, and air conditioning systems were incorporated in 2017. In late 2015, the government also banned the commercialisation of incandescent bulbs.

EE programs include subsidies for thermal insulation in housing, the promotion of energy efficiency of public buildings (e.g. hospitals), the replacement of inefficient public lighting, and campaigns to improve EE awareness.

The Energy Efficiency Bill was recently approved both by the Senate (October 24, 2019) and the House (March 17, 2020) and its final discussion and procedures are underway in Congress (Bulletin 12058-08).

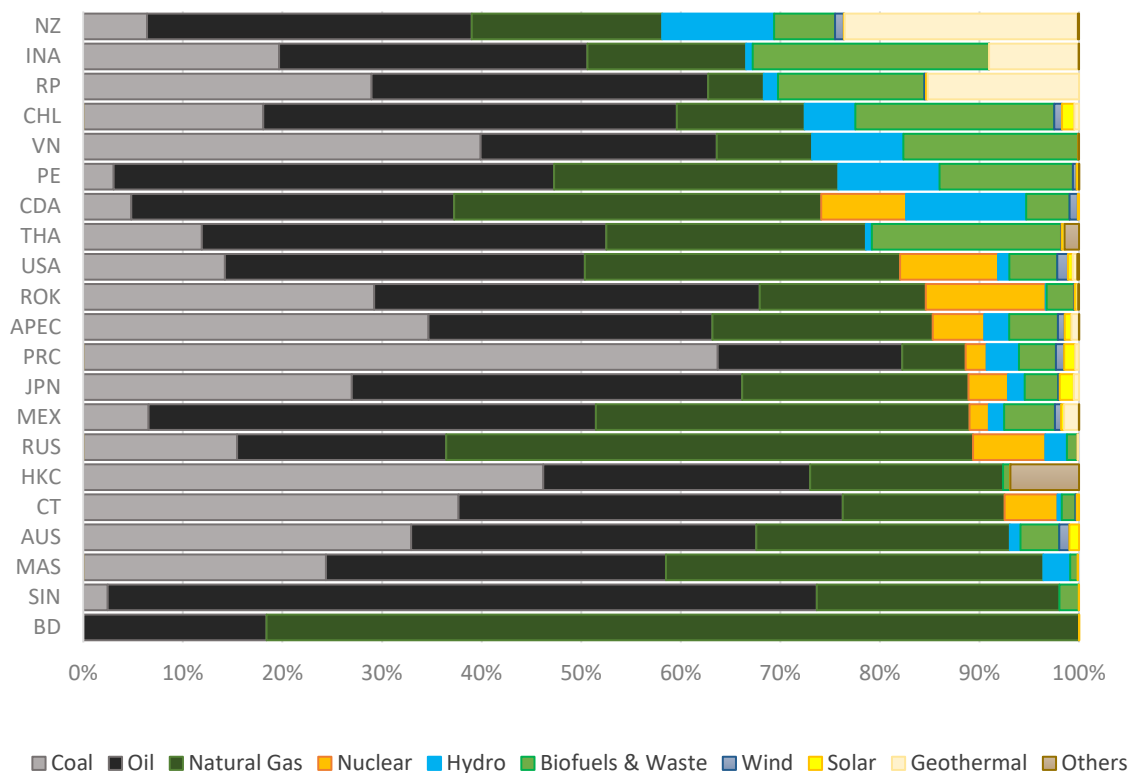
The Energy Efficiency Bill proposes changes to the current regulations across six dimensions (The Energy Efficiency Bill - Chilean Government, 2018):

1. Institutionalise energy efficiency within the framework of the Council of Ministers for Sustainability
2. Promote the management of energy by large consumers
3. Deliver information to home buyers regarding housing energy requirements
4. Promote energy management in the public sector
5. Facilitate the installation and operation of charging stations for electric vehicles
6. Improve the renewal of the vehicle fleet, with more efficient cars.

CLIMATE CHANGE

In 2018, Chile had the fourth-lowest fossil fuel dependence out of the 21 APEC member economies, behind New Zealand, Indonesia and the Philippines (IEA, 2019a).

Figure 4: TPES by fuels in Chile and APEC economies



Source: 2019 IEA World Energy Balance and Statistics (IEA, 2019a)

Chile became a signatory to the United Nations Framework Convention on Climate Change (UNFCCC) in 1992 and ratified the Kyoto Protocol in 2002. In December 2008, Chile published

the National Action Plan on Climate Change 2008–12, which assigns institutional responsibilities for adapting, mitigating and strengthening Chile's response to climate change (MMA, 2008).

According to the results of vulnerability studies conducted by the Ministry of the Environment (MMA in Spanish), some of the most relevant effects of climate change are:

- A decrease of up to 75% in the average rain precipitation in some regions. A sea level average temperature increase of up to 1.5%, and a reduction to 77% of the rainwater flow rate in some areas
- There has been a marked reduction in the recorded population of a vast majority of species
- Regions that are predominately small in area and have low levels of technological access show the greatest vulnerability to climate change

While Chile's contribution to global carbon emissions is low, at around 0.24% of the total CO₂ emitted globally in 2017 (IEA, 2019b), its territory is highly vulnerable to the effects of climate change. Glacial melting, shifts in rainfall patterns, expanding deserts and higher frequency of El Niño weather patterns will have an impact on the economy's water supply, food production, tourism industry and migration, as well as on its socioeconomic development and energy security.

Chile's action plan identified hydroelectric resources, food production, urban and coastal infrastructure and energy supply as the four areas most vulnerable to climate change, where adaptation will be required.

Ten sectoral Climate Change Adaptation Plans have been approved, the last one in December 2019, corresponding to the Tourist sector¹ (MMA, 2019).

At the 21st Conference of the Parties (COP) to the UNFCCC in 2015 (COP21 Paris Agreement), Chile submitted a Nationally Determined Contribution (NDC) reflecting policy action to support the agreement.

The NDC includes a target for carbon intensity, expressed in GHG emissions per unit of GDP, and another for tonnes of carbon dioxide equivalent (tCO₂) from Land Use Change and Forestry (LULUCF) activities. Chile contributes only 0.24% of global emissions (Banco Central, 2018), with most of its emissions coming from the energy sector (78% in 2016) (SNiChile & Ministry of the Environment, 2018). To reduce emissions under the COP21 Paris Agreement, Chile's NDC commits to (Ministry of the Environment, 2019):

- Unconditional reduction of the intensity of emissions per unit of GDP to 30% below the 2007 level by 2030, not including LULUCF activities
- Conditional on international funding, reducing CO₂ emissions per unit of GDP to 35% to 45% below the 2007 level by 2030, not including LULUCF activities
- Making specific LULUCF contributions of:
 - Sustainably developing and recovering 100 000 hectares (ha) of forest land, mainly native, for GHG sequestrations and reductions equivalent to around 600 000 tCO₂ annually by 2030
 - Reforesting 100 000 ha, mostly with native species, to sequester the equivalent of 900 000 to 1 200 000 tCO₂ annually by 2030. This commitment is conditional on the extension of Decree-Law 701 and approval of a new forestry promotion law

¹ This plan is currently being revised and edited.

To reach the targets outlined in the NDC and to ensure the sustainability of Chile's energy future, the government prepared its second *National Action Plan for Climate Change 2017-22* (MMA, 2017). This plan contains the following action lines and objectives.

Table 9: National Action Plan for Climate Change 2017–2022.

	OBJECTIVES
ADAPTATION	To strengthen the capacity to adapt to climate change. Improving knowledge on its impacts and the vulnerability of the economy, and generating actions to minimise adverse effects and take advantage of positive results, promoting economic and social development and ensuring environmental sustainability.
MITIGATION	To create the enabling conditions for the implementation, compliance and follow-up of Chile's GHG emission reduction commitments to the UNFCCC, and to contribute consistently to the economy's sustainable development and low growth in carbon emissions.
IMPLEMENTATION	To create the enabling conditions to implement the climate change mitigation and adaptation actions at a national and subnational level in the transversal elements related to institutional and legal areas, technology transfers, capacity-building and technical assistance, financing and international negotiation.
CLIMATE CHANGE (INSTITUTIONS)	To develop the necessary institutional and operative elements and capacity-building to advance the management of climate change in the territory, through local and municipal governments and by incorporating all social actors.

Source: MMA (2017)

In 2016, the balance of Chile's GHG and removals accounted for 46 MtCO₂-eq, while total GHG emissions were 112 MtCO₂-eq, increasing by around 115% from 1990 levels and 7.1% since 2013 (SC-COP25 & M&EWG, 2020). The main GHG emitted was CO₂ (79%), followed by CH₄ (13%). The energy sector is the leading emitter (78%), primarily due to the utilisation of coal and natural gas in power plants and diesel in the transport sector (Ministry of the Environment, 2018). Preliminary data of 2018 showed 86 million of tonnes of CO₂ from fuel combustion in the energy sector. (IEA, 2019b).

Fuel combustion activities in 2016 accounted for 99% of the sectoral emissions, while the remaining 1% was associated with fugitive emissions from fuels. Within the fuel combustion activities classification, the electricity generation subclass is the most important with 32%, followed by 21% for land transportation, 14% for manufacturing industries and construction and finally, 7% for residential activities.

The National Energy Policy 2050 includes goals to adopt the necessary mitigation and adaptation actions to achieve a sustainable and clean energy sector and to help to achieve the emission reduction targets set in Chile's NDC.

The policy is explicit in terms of setting medium- and long-term goals. For instance, it states it will contribute to the COP 21 commitment of reducing the intensity of GHG emissions in Chile by 30% in 2030 compared with the 2007 levels. There is also a plan to commit to the implementation of a GHG Emissions Mitigation Plan for the energy sector and a plan to adapt the energy sector to the impacts of climate change. To 2050, the National Energy Policy states 'GHG emissions of the energy sector are consistent with international thresholds and national NDCs'.

The Energy Sector Mitigation Action Plan (committed to under the Energy Policy 2050), by the Ministry of Energy (in collaboration with other ministries), and with the support of the Partnership of Market Readiness Policy Analysis Work Program, was approved in October 2017 by the Sustainability Ministries Council. The primary goal is to address the energy sector's share of responsibility in achieving the economy's first NDC. Measures are proposed for all sectors of the economy.

Carbon market mechanisms are important to provide necessary incentives for clean technology investments. In 2017, the Chilean Government applied a carbon tax of USD 5 per tonne of CO₂ emitted for thermal plants with installed capacity greater than 50 MW. This policy is under revision and a new proposal to address this carbon tax is under discussion by the parliament as part of Chilean tax reform.

On March 2020, the Chilean Ministry of the Environment released Chile's NDC update with a series of unconditional 2030 targets. Relevant changes to the unconditional NDC pledges are:

- A new absolute emission target: A maximum emission level in 2030 of 95 MtCO₂ (excluding LULUCF)
- A GHG emission budget of 1 110 and 1 175 MtCO₂ between 2020 and 2030, and GHG emissions peaking in 2025. The new target is 26% lower than the 2016 NDC agreement
- Reduce total black carbon emissions by at least 25% by 2030, with respect to 2016 levels. This commitment will be implemented primarily through national policies focused on air quality. In addition, it will be monitored through permanent and periodic work to improve information available in the black carbon inventory

NOTABLE ENERGY DEVELOPMENTS

As outlined in the Energy Roadmap 2018-2022, Chile announced an aim to reach carbon neutrality by 2050, increasing resilience against climate change effects, and complying with international climate change commitments, alongside ceasing coal power plant operations by 2040, at the latest. Decarbonizing the electricity sector is one of the most significant measures to reduce CO₂ emissions.

In September 2017, Enel and ENAP started operating South America's first and only geothermal power plant, the 48 MW Cerro Pabellón Project. The plant sits at an elevation of 4 500 metres above sea level in Chile's harsh and remote Atacama Desert. It will produce around 340 GWh per year, equivalent to the annual consumption needs of more than 165 000 Chilean households. This is equivalent to avoiding 166 000 tonnes of CO₂ emissions per year (ENAP, 2018).

ARGENTINEAN GAS SUPPLY AND NEW STAKEHOLDERS OF PEAK UNITS

During the second quarter of 2018, ENAP signed an agreement on the exportation of natural gas with Argentina for a three-year term. The gas is supplied through the gas pipeline running between Santiago, Chile and Mendoza, Argentina, which is 450 km long. The maximum daily volume is 3 mcm.

On 22 November 2018, imports of natural gas from Argentina (the Vaca Muerta deposit) to Chile began to supply the central-southern zone of Chile once more. The gas is being supplied through Gas Supply Agreements made with INNERGY and two Argentinian providers. The first is an agreement between YPF and INNERGY for a minimum of 1.5 mcm per day. The second is between ExxonMobil Argentina and INNERGY for 0.4 mcm per day.

THE MECHANISM FOR STABILISING ELECTRICITY PRICES

In the context of the New Social Agenda presented by the Chilean Government on November 2, 2019, a transitional mechanism for stabilising electricity prices was enacted by Law No 21 185.

The mechanism cancels the 9.2% price rise that would have been applied to regulated customers under Decree 7T. The new law also postpones price increases for the sale of electricity contracts between generation and distribution companies that start supplying before 2021. The CNE will deliver these changes through a stabilisation fund, which is funded by large generation companies.

The final tariff to be paid by regulated clients consists of the sum of the transmission price, the added distribution value and the average node price, which is set every six months by the CNE Decree.

The price stabilisation mechanism will take effect in two stages:

- Between July 1, 2019 and December 31, 2020: the previously enacted Law Decree 7T that increased the price of electricity will no longer affect the final tariff. The tariff determined in Decree 20T remains in force (the Stabilised Regulated Customer Price)
- Between January 1, 2021 and the end of the stabilisation mechanism (January 31, 2027 at the latest): distribution companies will charge the average node price as set by the CNE. This price cannot exceed the tariff established by Decree 20T, adjusted for inflation (the Adjusted Stabilised Regulated Customer Price)

The final tariff that the distribution concession holders pay to their suppliers (in every node of the distribution system defined by the nodal Decrees reports) must include an adjustment factor. The adjustment factor ensures that charges are consistent with their expected revenues with reference to the Stabilised Regulated Customer Price or adjusted Stabilised Regulated Customer Price of the relevant distributor.

If the average node price is higher than the (adjusted) Stabilised Regulated Customer Price, suppliers will receive a credit balance. Otherwise, the (adjusted) Stabilised Regulated Customer Price will be modified to the extent needed to cover the outstanding payment balances.

The CNE will review the outstanding supplier balances every six months until July 2023 or until a total balance of USD 1 350 million has been accumulated. These balances will not be increased. This mechanism will remain in force until all outstanding balances have been discharged, which cannot take place after December 31, 2027.

ELECTROMOBILITY

In December 2017, Chile announced a National Electromobility strategy that outlines actions to be taken in the short- and medium-term to meet the government's goal of having 40% of the private vehicle fleet and 100% of the public transport fleet powered by electricity in 2040.

By the end of 2050, 58% of privately-owned vehicles will be powered by electricity. The new strategy's objectives are to establish regulations and requirements to standardise components and promote the efficient development and penetration of electric vehicles (EVs). The strategy will support R&D to enhance human capital and knowledge transfer.

The summary of the electromobility aspirational goals includes:

- 100% of the taxi fleet to become fully electric by 2050
- 100% urban public transportation will be fully electric in Santiago by 2040
- 100% urban public transportation will be fully electric in other regions by 2050
- Electrification of 58% of private and commercial vehicles by 2050
- Replacement of private motor transportation for buses and bicycles (no metrics)

The National Energy Policy sets the improvement of energy efficiency in vehicles and their operation and sets a goal for 2050 of Chile having adopted the highest international standards

on energy efficiency in the various transportation means. In this context, the Electromobility Strategy for Chile was created in order to systematise efforts and coordinate relevant actors to promote the introduction of technologies with greater energy efficiency in the economy's vehicles market.

In May 2018, the Ministry of Energy presented the Energy Roadmap to serve as a guideline for government action in promoting socially responsible energy policies for the next four years (2018–2022). As of January 2020, Chile owns the largest fleet of electric buses in Latin America and the Caribbean.

More than 200 electric buses hit the road in 2019 in Santiago, as part of a plan to cut emissions and reduce air pollution. As part of its National Energy Roadmap, Chile also pledged to increase by 40% the share of private EVs by 2022. At the end of 2019, around 500 private electric cars were on the roads.

In January 2020, an Enel X press release announced the first Chilean Electric route (called ElectroRuta Enel X in Spanish) connecting Chile from Arica to Punta Arenas. The route will incorporate 1 200 charging stations and over 1 800 connections for EVs to allow drivers to cover over 5 000 km from north to south, guaranteeing the autonomy and continued circulation of electric cars. This first national electric route will require an initial investment of USD 15 million (Enel, 2020).

The project will be complete by 2024 and will provide over 50% of necessary charging infrastructure for the more than 81 000 EVs projected to be on the road by that date. There will be a charging station every 60 km along interstate road and several alternatives in cities thanks to an alliance signed with automotive, retail, real estate, hotel and industrial companies, as well as public offices and academic institutions.

DECARBONISATION AND CARBON NEUTRALITY POLICIES

The Chilean Government and the Ministry of Energy have relied on carbon policy instruments to advance decarbonisation of the electricity system. Establishing a working group to develop voluntary and binding agreements to retire coal generation facilities is one initiative (Inodu 2019).

As of December 2018, the renewables share of electricity generation had reached 45%. According to technical studies and projections made by generators, utilities and government, 30% of electricity could come from solar by 2030, making solar Chile's leading power source. Almost 85% of electricity could be renewable by 2030.

Chile's government announced in June 2019 its aim to reach carbon neutrality by 2050. Almost 1.73 GW of coal-fired power plants will shut down before 2024, equivalent to 26% of total coal electricity capacity by 2024. Operation of coal power plants will cease by 2040, at the latest.

Chile is currently formulating a new Climate Change Framework Law. The main objectives are to achieve GHG neutrality by 2050, increase resilience against climate change effects, and comply with international climate change commitments. The current draft bill, which is open to public input, includes governance (rules, mechanisms and instruments), management strategies, financing measures and economic instruments.

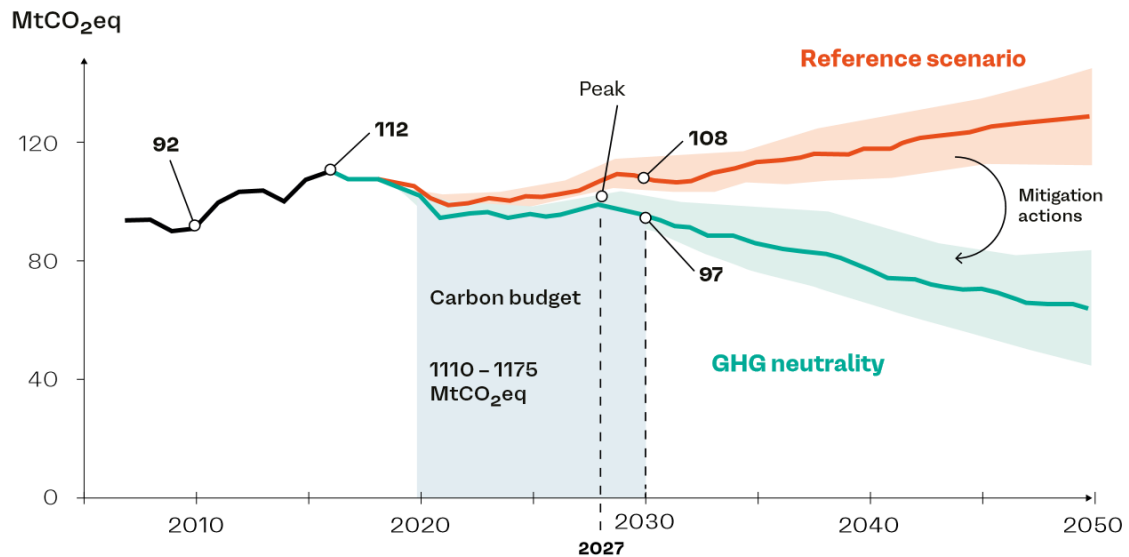
Carbon neutrality will require more than double the electrification rate. Electric mobility and buildings with heat pumps will push the electrification increase (Chilean Association of Power Generators, 2019).

PROPOSED AND UPDATED CHILEAN NDC

Before the official submission, Chile released an NDC draft for public consultation (ME, 2019), which refers to economy-wide emissions excluding the Land Use, LULUCF sectors. The final update report was submitted to UNFCCC on April 9th, 2020.

It provides targets in terms of absolute emissions (95 MtCO₂eq in 2030), which includes a carbon budget for the period 2020 to 2030 of 1 110 MtCO₂eq. The proposal predicts a peak in emissions by 2025. The new NDC proposal also includes a potential reduction of total black carbon emissions by at least 25% by 2030, with respect to 2016 levels. This commitment will be implemented primarily through national policies focused on air quality.

Figure 5: Paths GHG emissions in the period 2005 – 2050

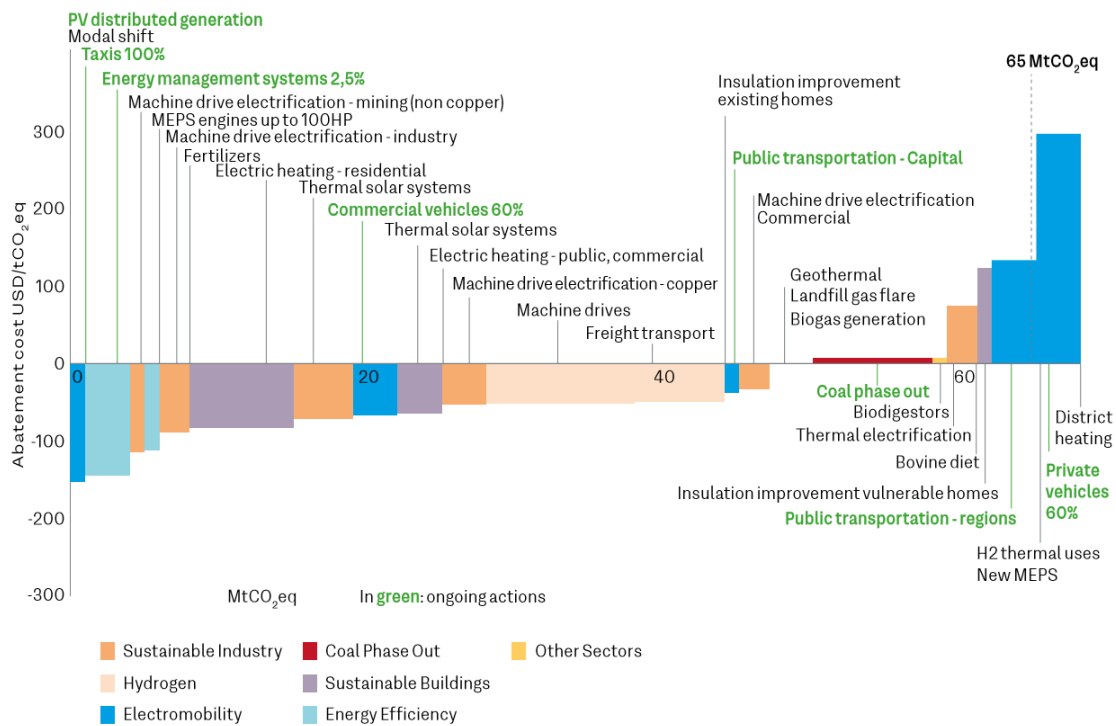


Source: *Chilean NDC mitigation proposal (SC-COP25 & M&EWG, 2020)*

In this new NDC draft update, Chile also acknowledges its 2030 target as a medium-term goal towards achieving its long-term goal of GHG neutrality by 2050. Additionally, this draft proposal also mentions planning processes involving governance rules, strategies and management instruments, as well as existing and future strategies including the “Long-term Climate Strategy 2050” (SC-COP25 & M&EWG, 2020).

Marginal abatement cost curves (MACC) are used to analyse emission abatement potential and associated abatement costs for different mitigation actions. A study made by the Ministry of the Environment released the latest version of the MACC considering the necessary measures and policies to achieve GHG neutrality by 2050.

Figure 6: MACC to achieve GHG neutrality by 2050 in Chile



Source: *Environment and Climate Change Division, Ministry of Energy (2019)*

Decommissioning of all coal-fired power plants by 2040 would create a reduction of 7.5 MtCO₂eq by 2050, and although it represents a positive abatement cost of 8 USD/tCO₂eq, it may be the most relevant measure in the analysis, since the coal phase-out would clean the energy grid, giving space to other macro and cost-efficient measures. The more relevant measures in the sustainable industry are related to electrification of machine drives (by replacing traditional mechanical and hydraulic drives with electric), electromobility (electric public transportation and commercial vehicles), hydrogen (heavy-duty vehicles and machine drives), and sustainable buildings (electric space heating).

Other measures with positive abatement costs are thermal refurbishment of housing, electrification of boilers and furnaces in the industrial sector, promotion of public transportation and use of district heating.

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USEFUL LINKS

Government Institutions

Chilean Commission of Energy (CNE)—www.cne.cl

Chilean Energy Sustainability Agency (ASE)—www.agenciaSE.org

National Electric Coordinator—www.coordinador.cl

Government of Chile—www.gobiernodechile.cl

Ministry of Economy, Development and Reconstruction—www.economia.cl

Ministry of Energy—www.energia.gob.cl

Ministry of the Environment—www.mma.gob.cl

Nuclear Energy Chilean Commission (CCHEN)—www.cchen.cl

National Energy Commission (CNE)—www.cne.cl

National Institute of Statistics (INE)—www.ine.cl

National Oil Company (ENAP)—www.enap.cl

Superintendence of Electricity and Fuel (SEC)—www.sec.cl

Energy Associations

Chilean Association of Power Generators —www.generadoras.cl

Chilean Association for Renewable Energies and Storage ACERA A.G—www.acara.cl

Chilean Association of power utilities —www.electricas.cl

Chilean Association of Solar Energy —www.acesol.cl

Chilean Association for small and mid-hydro power plants (APEMEC) —www.apemec.cl

CHINA

INTRODUCTION

China is located in Northeast Asia and is bordered by the East China Sea, the Yellow Sea and the South China Sea. Its population of 1.4 billion is approximately one-fifth of the world's population. China has a land area of approximately 9.6 million square kilometres (km²) with diverse landscapes, which comprise mountains, plateaus, plains, deserts and river basins. Its total maritime area is 4.7 million km², and the length of its coastline is 32 400 km (NBS, 2020).

After reforming its economy in 1978, China entered a period of high-speed growth. Its entry into the World Trade Organization (WTO) in 2001 further contributed to its prosperity in the first decade of the 21st century. In 2004, China overtook Japan as Asia's leading exporter. In 2009, China surpassed Germany to become the world's leading exporter. By 2017, China's merchandise exports constituted 13% of global merchandise exports (WTO, 2018). In 2017, China's GDP was USD 21 224 billion (2011 prices and 2011 purchasing power parity [PPP]), with the primary, secondary and tertiary industries constituting 7.9%, 41% and 52%, respectively (EGEDA, 2019; NBS, 2020).

With its huge population and booming economy, China plays an important role in world energy markets. China is the largest contributor to the growth of oil, gas, coal, and renewable energy. The economy also accounted for around half of the increase in global liquefied natural gas (LNG) imports (21 bcm) in 2018 (BP, 2020).

China is relatively rich in energy resources, particularly coal. According to BP statistics published in 2020, China had total proven coal reserves of over 141 billion tonnes, total proven oil reserves of 26 billion barrels and proven natural gas reserves of 8.4 trillion cubic metres (tcm) (BP, 2020). In addition, China has 400 gigawatts (GW) of economic hydropower potential, more than any other economy. Coal and oil resources have been utilised more extensively than natural gas and hydro for power generation and industrial development.

From 2000 to 2017, the compound annual growth rate (CAGR) of final energy consumption (excluding non-energy use of energy products) was 6.9% and the CAGR of GDP was 9.3% (EGEDA, 2019; World Bank, 2020).

Table 1: Key data and economic profile, 2017

Key data ^{a, b}		Energy reserves ^c	
Area (million km ²)	9.6	Oil (billion barrels)	26
Population (million)	1 379	Gas (trillion cubic metres)	8.4
GDP (2011 USD billion PPP)	21 224	Coal (million tonnes)	141 595
GDP (2011 USD PPP per capita)	15 309	Uranium (kilotonnes U)	370.9 ^d

Sources: ^a World Bank (2019); ^b NBS (2017); ^c BP (2020); ^d recoverable at USD 130 per tonne, OECD (2018).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

China's primary energy supply has expanded massively since 2001. The expansion was driven by rapid economic growth, especially by heavy industry. In 2017, total primary energy supply

(TPES) increased by 3.3% compared with 2016, reaching 2 954 million tonnes of oil equivalent (Mtoe). Natural gas supply increased by 16%. Renewable energy posted strong growth in 2017, increasing 8.9%. Indigenous production increased by 3.7% compared with 2016, while net imports grew by a very large 12%. Coal was the dominant source of TPES, constituting 65%, followed by oil (19%), gas (7.3%), renewables (6.5%) and others (2.4%) (EGEDA, 2019).

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	2 364 795	Industry sector	970 053	Total power generation	6 495 143
Net imports and others	607 444	Transport sector	287 109	Thermal	4 662 739
Total primary energy supply	2 954 084	Other sectors	451 026	Hydro	1 189 840
Coal	1 903 908	Non-energy	178 753	Nuclear	248 070
Oil	574 028	Final energy consumption*	1 708 188	Others	394 493
Gas	215 775	Coal	548 726		
Renewables	190 819	Oil	418 097		
Others	69 554	Gas	138 430		
		Renewables	42 252		
		Electricity and others	560 683		

Source: EGEDA (2019) (data collected in December 2019).

* Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. Total final consumption includes non-energy uses. Half of the municipal solid waste used in power plants is assumed to comprise renewables.

China has been the world's second-largest economy in terms of electric power generation capacity since 1996. Its electric power industry experienced a serious overcapacity problem in the late 1990s, largely due to lower consumption after the closure of inefficient state-owned industrial units that were major consumers of electricity. A power supply shortage developed because of rapid economic expansion after 2001. During 2010–17, electricity generation output rapidly increased from 4 207 terawatt-hours (TWh) to 6 495 TWh, of which thermal power generation constituted 72% of the total power generation. In 2017, installed generation capacity reached 1 777 GW (NBS, 2020).

The power supply structure has diversified, with wind power and nuclear energy generation increasing rapidly. In 2017, the total power generation in China was 6 495 TWh. Thermal power constituted 72% (4 663 TWh of the total generation); hydropower constituted 18% (1 190 TWh); nuclear energy constituted 3.8% (248 TWh); wind power constituted 4.5% (295 TWh); and photovoltaic (PV) constituted 1.5% (97 TWh) (NBS, 2020).

FINAL ENERGY CONSUMPTION

Total final consumption in China reached 1 887 Mtoe in 2017, 1.2% lower than 2016. The industrial sector was the largest consumer, constituting 51% of total final energy consumption, followed by other sectors (including residential, commercial and agricultural) at 24% and the transport sector at 15%. The remaining 9.5% was due to non-energy use (EGEDA, 2019). By energy source, coal use declined by 5% compared with the previous year while use of gas and electricity increased by 2%, showing fuel switching is taking place from coal to gas and power.

In the Thirteenth Five-Year Plan for Energy Development, China set its annual energy consumption growth target at an average of 2.5% during 2016–20, 1.1 percentage points lower

than the 3.6% during 2011–15. As a result, total energy consumption will be within 5.0 billion tonnes of coal equivalent by 2020.

ENERGY INTENSITY ANALYSIS

China has reduced its energy intensity in the last two decades. Compared with the 2010 levels, the intensities of primary energy supply and total final consumption in 2017 reduced by 26% and 23%, respectively (EGEDA, 2019).

In 2015, China eliminated more than 5.3 GW of outdated thermal power plants, 50 million tonnes (Mt) of outdated cement production capacity and 102 Mt of outdated coal mining production capacity (MIIT, 2017). With these efforts, the intensity of total final consumption improved by 7.6% from 2016 to 2017. The government also introduced policies on energy structural optimisation and overall energy efficiency improvement in the industrial sector, contributing to a lower energy intensity from the industrial sector. However, because of the booming economy and transportation needs, vehicle purchases remain high, which has resulted in increased energy intensity in the transportation sector.

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%) 2016 vs 2017
	2016	2017	
Total primary energy supply	144	139	-3.3
Total final consumption	96	89	-7.6
Final energy consumption excl. non-energy	87	80	-7.7

Source: EGEDA (2019).

RENEWABLE ENERGY SHARE ANALYSIS

As a result of China's policy support to promote clean energy and a more diversified energy structure, China's final energy consumption of modern renewables increased by 6.8% from 2016 to 2017. China's traditional biomass consumption increased by 6.8% due to economic development and an increasing per capita energy consumption. To mitigate this increase, China has been working on shutting thermal power capacity and heavily polluted fossil fuel consumption terminals, such as outdated steel and cement production lines. China's non-renewable energy consumption declined by 2.1%. This was mainly due to declining coal consumption despite the rapid increase in the consumption of oil and natural gas between 2016 and 2017.

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	1 731 446	1 708 188	-1.3
Non-renewables (fossil fuels and others)	1 585 888	1 552 719	-2.1
Traditional biomass*	21 494	22 952	6.8
Modern renewables*	124 063	132 516	6.8
Share of modern renewables to final energy consumption (%)	7.2	7.8	8.3

Source: EGEDA (2019).

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal, and so on), including biogas and wood pellets, are considered to be modern renewables, although data on wood pellets are limited.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

China's energy consumption is growing rapidly in line with robust economic development and accelerated industrialisation. Energy has become an important strategic issue for China's economic growth, social stability and security. China aims to be a low-carbon economy. The structural transformation of energy is the key to economic restructuring, which is also an important indicator of social progress. Achieving the goal of a low-carbon and orderly energy structure is the basis of China's energy strategy.

During the Twelfth Five-Year Plan for National Economic and Social Development (2011–15), China achieved an annual GDP growth rate of 7.8% and an annual energy consumption rate of 3.6%. Furthermore, the installation scale of hydropower, nuclear power, wind power and solar power has increased by factors of 1.4, 2.6, 4.0 and 168 fold, respectively. The Thirteenth Five-Year Plan for National Economic and Social Development (2016–20) was approved by the National People's Congress in March 2016 (NDRC, 2017a). It has four major energy-related objectives:

- To enhance energy supply capability
- To make a breakthrough with key technology
- To greatly increase the share of non-fossil fuel consumption
- To make a breakthrough in the clean use of fossil fuels.

The Thirteenth Five-Year Plan for Energy is a specification of the Master Plan for the energy sector, with more detailed targets that will provide a better guide for policymaking, government spending and project planning in the sector. The State Council approved it in December 2016, and the National Energy Administration (NEA) unveiled it in January 2017 (NDRC, 2017b). Clean and low-carbon energy will account for most of the newly added energy supplies during 2016–20. By 2020, China expects an annual energy consumption of less than 5 billion tonnes of coal equivalent (tce) from 4.3 billion tce in 2015. This will ensure that the average annual growth rate remains below 3.0% over the next five years.

ORGANISATION

The National Energy Committee is a high-level body that coordinates overall energy policies. The committee, chaired by the premier, is in charge of formulating China's energy strategy and deliberating on major issues in energy security. In March 2013, the State Electricity Regulatory Commission (SERC) merged into the NEA under the administration of the National Development and Reform Commission (NDRC). The NEA is currently composed of 12 departments and has an authorised staffing complement of 248 civil servants. It is responsible for developing and implementing energy industry planning as well as industrial policies and standards. In addition, it is in charge of administering the energy sector, which includes coal, oil, natural gas and other forms of power such as nuclear energy and new and renewable sources of energy. The NEA has also assumed responsibility for the Office of the National Energy Committee. The NEA has six regional regulatory bureaus and 12 provincial-level regulatory offices overall. Formerly under the SERC, this administration has the responsibilities of regulating local and state-owned energy enterprises. Some departments within the NDRC also contribute to energy conservation and climate change issues.

In 2009, China established the National Energy Conservation Centre under the NDRC to provide technical support to the government for the implementation of energy efficiency and conservation management initiatives. Its main duties include energy efficiency and conservation policy research; the assessment of fixed asset investment projects; information dissemination; the promotion of technologies, products and new mechanisms; label management; and international cooperation in the field of energy conservation.

In 2018, to push forward reforms to streamline administration and improve services, China launched a massive cabinet reshuffle. After merging, restructuring and dissolving, 26 ministries and commissions remained, reducing the number of ministerial-level entities by eight and vice-ministerial-level entities by seven. The responsibility for addressing climate change and emission reduction was switched from the NDRC to the newly established Ministry of Ecology and Environment (MEE).

LAW

The laws relating to energy in China include the Coal Law (issued in 1996 and revised in 2013), the Mining Law (issued in 1986 and revised in 1996 and 2009), the Electricity Law (issued in 1995 and revised in 2015 and 2018), the Renewable Energy Law (issued in 2005 and revised in 2009), the Energy Conservation Law (issued in 1997 and revised in 2007) and the Environmental Protection Law (issued in 1989 and revised in 2014). The Energy Law is a comprehensive legal basis for the energy sector and is currently under consideration. The Standing Committee of the National People's Congress endorsed the amended version of the Renewable Energy Law on 26 December 2009, which originally took effect on 1 April 2010. It more clearly defines the responsibilities of the power grid and power generation enterprises. It also emphasises the completely secure purchase of power from renewable energy sources and the establishment of a development fund for renewable energy. The amendment provides that power grid companies receive all of the revenue generated from the surcharge on retail power tariffs. In addition, it sets a minimum target for the amount of renewable electricity that grid companies must buy from renewable energy projects (Xin Qiu and Honglin Li, 2012).

The Oil and Natural Gas Pipeline Protection Law, endorsed on 25 June 2010, went into effect on 1 October 2010. This requires that oil and pipeline companies take safety measures while constructing pipelines. These measures include ensuring the quality of construction materials, conducting regular patrols of pipelines and promptly eliminating any hazards.

The State Council approved the Regulation on Electricity on 15 February 2005. It became effective on 1 May 2005. This regulation clarifies the content and responsibilities of electricity regulation.

The State Council approved the Regulation on the Administration of Urban Gas on 19 November 2010. It went into effect on 1 March 2011. This regulation clarifies the responsibilities and duties of gas operators, unifies gas market management into a regular channel and sets the basis for local government activities.

ENERGY SECURITY

China has been endeavouring to guarantee itself and its industries long-term access to sufficient energy and raw materials. Currently, China's energy portfolio mainly comprises domestic coal, oil and gas from domestic and foreign sources and small quantities of uranium. China has also created a strategic petroleum reserve to secure emergency supplies of oil for during price and supply disruptions. Chinese policy focuses on diversification to reduce oil imports, which almost exclusively rely on producers in the Middle East.

On 13 June 2014, Chinese President Xi Jinping presided over the sixth meeting of the Leading Group for Central Financial Work, stressing that energy security is a global and strategic issue related to economic and social development. To enhance China's energy security, Xi Jinping proposed the promotion of a revolution in energy production and consumption. This revolution is a long-term strategy and contains the following five major requirements:

- The promotion of an energy consumption revolution, which curbs irrational energy consumption. This involves the firm control of total energy consumption; the effective implementation of an energy saving priority principle; energy saving throughout the whole process of economic and social development and the adjustment of the industrial structure; significant emphasis on urban energy saving; the establishment of the concept of thrifty consumption; and the acceleration of the formation of an energy saving society
- The promotion of an energy revolution and the establishment of a multi-supply system. This system is based on domestic supply, with the goals of ensuring safety; vigorously promoting the efficient use of clean coal; focusing on the development of non-coal energy; forming a multifaceted coal, oil, gas, nuclear, new energy and renewable energy supply system; and strengthening the energy transmission and distribution network and storage facilities
- The promotion of an energy technology revolution and industrial upgrading. The goals are guided by the principles of green, low-carbon energy; promotion of technological, industrial and business model innovation; vigorous promotion of high-tech fields; and cultivation of technology and related industries to upgrade the status of energy as domestic industry's new growth point
- The promotion of an energy system revolution, which is achieved through fast-track energy development. The goals are not to stagnate or retreat but to develop the revolution, thereby reducing energy commodity attributes, constructing a market structure and system that have effective competition, ensuring that the formation of the market structure and system is mainly determined by the market mechanism of energy price, transforming government energy regulation and establishing and improving the Energy Law system
- All-round strengthening of international cooperation to achieve energy security in accordance with the foregoing requirements. On the precondition that energy production is mainly domestic, the guideline sets out the need to strengthen international cooperation in all aspects of the energy production and consumption revolution and make effective use of international resources

In the Thirteenth Five-Year Plan for Energy Development, energy security is set as a clear target. The plan targets to keep China's energy self-sufficiency rate above 80% by the end of 2020, which was 84% in 2015. Since China's crude oil supply and natural gas supply heavily depend on imports through pipelines or marine transportation, the government expects to control China's level of dependence on foreign oil and natural gas through energy structure adjustment and efficiency improvements. The Asia Pacific Energy Research Centre (APEREC) projects that

China's oil and natural gas imports will continue to increase due to the rapid increase in domestic consumption and population growth. To achieve such goals during the Thirteenth Five-Year Plan, energy supply-side reform and advanced fossil fuel geological exploration are considered as effective solutions. On the other hand, domestic shale gas, coal-bed methane, combustible ice utilisation and production developments are also potential possibilities for decreasing China's level of dependence on foreign resources.

ENERGY MARKET

Energy market reform is a key driving force behind the acceleration of China's move towards a market-based economy. Therefore, the Chinese Government has promoted such reform in the past few years. The Chinese Government has announced that the entire range of projects included in the National Energy Plan is open to private investment, except where prohibited by laws and regulations. In 2010, the State Council issued a report entitled *Several Opinions of the State Council on Encouraging and Guiding the Healthy Development of Private Investment*. This report encourages private capital to participate in the exploration and development of energy resources, oil and gas pipeline network construction, power plant construction, coal processing, energy conversion, the refining industry and a comprehensive, new renewable energy industry.

COAL MARKET

Owing to the abundant domestic reserves and low cost, coal has always been the primary energy fuel in China. However, due to seriously deteriorating air quality in recent years, China has been stepping up its efforts to reduce coal consumption to cope with air pollution issues and climate change.

In October 2013, several organisations, including government think tanks, research institutes and industry associations, jointly launched the China Coal Consumption Cap Project. This project aims to develop a comprehensive roadmap and policy package to cap coal consumption.

In November 2014, China's State Council launched the Energy Development Strategy Action Plan (2014–20). This sets the target for capping coal consumption at no more than 4.2 billion tce, with the share of coal in primary energy consumption kept below 62%.

In November 2015, the China Coal Cap Project issued a report entitled the China Coal Consumption Cap Plan and Research Report: Recommendations for the Thirteenth Five-Year Plan. This report presents recommendations for controlling and reducing China's coal use to below 3.8 billion tonnes and 3.4 billion tonnes by 2020 and 2030, respectively. In addition, the report recommends that the economy's total energy consumption should be at or lower than 4.7 billion tonnes of standard coal equivalent by 2020 and that the share of coal within primary energy consumption during this period should be reduced to less than 57%.

China also began its 'supply-side reform' in recent years to cut unnecessary and outdated production capacity. One of this reform's targets is to avoid overcapacity of supply in the coal mining industry. From 2015 to 2017, China shut down many small and inefficient coal mines and merged several private mines into state-owned enterprises (SOEs) to improve efficiency and control overall production.

Furthermore, in December 2015, the Chinese State Council pledged to upgrade coal-fired power plants to cut pollutant discharge by 60% before 2020, thereby saving approximately 100 Mt of raw coal and reducing carbon dioxide (CO₂) emissions by 180 Mt annually. In addition, China aims to cut the total coal consumption to below 65% of the total primary energy consumption by 2017 as part of an energy supply structural transformation (SCC, 2015). According to a statement by the NDRC, the NDRC targeted a capacity cut of 250 Mt for 2016, a reduction that was met 'ahead of schedule' in late November.

In October 2016, the NEA issued the Thirteenth Five-Year Plan for Energy Development, in which China set the target for capping energy consumption at no more than 5 billion tonnes of coal

equivalent and coal consumption at no more than 4.1 billion tonnes, with the share of coal in primary energy consumption reduced to below 58% and the share of coal used for generating electric power in coal consumption increased to 55% by 2020.

OIL MARKET

China surpassed the United States as the world's largest oil importer in April 2015. According to Chinese customs data, crude oil purchases from overseas reached a new record of 7.4 million barrels per day (Mbbbl/D) in April. This is approximately 7.7% of the world's oil consumption per day and exceeds United States' imports of 7.2 Mbbbl/D. Larger shipments from Iran, Oman and UAE (Abu Dhabi) partly contributed to the soaring increase in oil imports in China.

Although China faces slowing economic growth, oil consumption is still rapidly increasing. Hence, its state-owned oil traders, such as Unipecc and China Oil, have been gaining increased visibility in the global crude oil market.

However, with China's high dependence on overseas oil imports of more than 60%, it must establish strategic oil reserves to secure its energy supply. As of the middle of December 2015, China's strategic crude oil reserves had reached 26 Mt or approximately 191 million barrels. This occurred at a time of low oil prices. Consequently, China has taken advantage of the lower prices to stockpile crude oil.

According to the Statistics Bureau, the reserves are stored in seven above-ground facilities in Zhoushan, Zhenhai, Dalian, Huangdao, Dushanzi, Lanzhou and Tianjin and one underground facility in Huangdao, with a total capacity of 29 million cubic metres (mcm) (or approximately 180 million barrels) (FT, 2015; Reuters, 2015).

China stopped the United States oil imports in October and November 2018 influenced by the tit-for-tat tariffs imposed on both sides of China-US trade war. China resumed some imports in December, but purchased only 1 million barrels, a minute portion of the more than 300 million barrels of total imports after the two economies entered into a truce of three months, agreeing to impose no new tariffs on each other that would take effect from 1 January 2019. (Reuters, 2018)

NATURAL GAS MARKET

Natural gas has not been a major component of China's primary energy supply. However, its share in the economy's energy mix has been increasing rapidly. Securing a stable gas supply is one of China's energy strategies. Thus, China has been encouraging the transportation of gas from areas with significant resources (such as Western China, Russia and Central Asia) to East China, where gas consumption is high and an energy shortage is apparent.

China's first west-east gas pipeline was built by the China National Petroleum Corporation (CNPC) and completed in October 2004. At 4 200 km, this is China's longest natural gas pipeline, with one trunk line and three branch lines. The pipeline has an annual capacity of 600 billion cubic feet per year (Bcf/y).

In August 2007, the CNPC announced proposals for a second west-east gas pipeline with a capacity of 1.1 trillion cubic feet per year (Tcf/y) and a length of more than 5 480 km, including the trunk line and eight main branch lines. This natural gas pipeline now transports gas from Central Asia and Western China's Xinjiang Province to the south-eastern provinces. The western section of the line runs parallel to the first west-east gas pipeline to Zhongwei in North-Central China. The eastern section transports natural gas from Zhongwei to southern Guangdong Province and Shanghai in the east.

To meet rising gas demand in China, the CNPC began constructing the third west-east gas pipeline with a capacity of 1.1 Tcf/y. The western section of the pipeline was launched in 2014. The eastern section was in operation by the end of 2015. This pipeline runs parallel to the second pipeline for most of its length and ends in the south-eastern province of Fujian (EIA, 2015; Primeline, 2015).

In addition, the NDRC announced a reduction in the wholesale price of natural gas for non-residential users in November 2015. This lowers the gas price by an average of USD 0.1 (or approximately 28%) per cubic metre. This reduction was prompted by the decrease in gas procurement costs following the fall in oil and gas prices. It is also intended to make natural gas an alternative to coal for electricity generation. The NDRC predicts total operational cost savings of CNY 43 billion for industrial users, power generation companies, concentrated heating suppliers, taxi drivers, commercial entities, service providers and others in the downstream market.

The 'shifting from coal to gas' policy is significantly impacting China's natural gas market. Between 2015 and 2017, NDRC and the Ministry of Environmental Protection jointly issued a series of policies to encourage residential users and commercial enterprises to replace their coal-fired boilers and facilities with natural gas-fired facilities to solve the serious air pollution during winter months in the northern area of China. This caused a large spike in demand for natural gas, and the LNG prices tripled from October 2017 to December 2017, leading to a large-scale natural gas shortage across the whole economy.

To meet the rapidly rising demand for natural gas, China has increased its LNG imports and became the second-largest LNG importing economy after Japan in 2017. China invested in LNG facilities, such as regasification stations, large-scale LNG marine carriers and LNG terminals to expand its LNG import ability. These facilities are mainly concentrated along the eastern coastal areas.

In addition, the NDRC has also announced that the gas pricing mechanism will be reformed by introducing 'benchmark city station gate prices' for non-residential gas. These will replace the rigid 'ceiling city station gate prices'. The benchmark prices could either increase by up to 20% or decrease to the level decided by suppliers and purchasers. On 1 Sept 2017, NDRC further lowered the city benchmark city station gate prices of non-residential natural gas by 100 RMB/1 000 cubic metres (NDRC, 2017c).

In 2018, China drew lessons from the severe gas shortages and record-high gas prices during the 2017–18 winter, and also took measures to avoid a repeat during the 2018–2019 winter. These measures included increasing domestic natural gas production, boosting gas pipeline infrastructure and connectivity, improving gas storage capacity and making pre-arrangements for peak demand. China has also set targets for all gas supply companies to ensure that they have sufficient gas storage capacity by 2020. The implementation of a coal to gas switching policy is more measured and moderate, taking expectations of gas demand into consideration. The NDRC has also pledged to strengthen monitoring to ensure stable gas prices and supply throughout the winter heating season (Guangming Online, 2018).

ELECTRICITY MARKET

The main objectives for electricity market development in the Thirteenth Five-Year Plan are to accelerate structural reformation and innovation, transform to green energy, and relax the regulations regarding electricity supplies. To achieve these objectives, there are five major strategies (CNSTOCK, 2015).

- The innovation of the electricity market structure. In 2015, the Chinese Government finalised the 'Deepening Reform of the Power Sector', a policy document co-signed by the Central Committee of the Communist Party and the State Council to accelerate innovation in the electricity market structure. Furthermore, an investment regime must be established by opening public bidding in a specific and orderly manner, thereby developing innovation for the electricity market and its business model
- Coherent development. The development of the electricity market and economics in upstream and downstream industries must be coordinated in a way that emphasises electricity consumption rather than supply. The planning of the electricity market, regional

strategy, transmission lines and energy fuel allocation for peak hours must be strengthened

- Continuation of green development. The objectives are to continue increasing the share of non-fossil fuels in power generation, optimise the energy mix for power generation with hydropower and nuclear energy as the prioritised choices in the energy mix, promote green transformation in the power generation structure, and develop a low-carbon approach to securing a stable and economic supply of electricity in the long-term
- Continuation of the open market. Domestic and international resources and markets must be combined to implement a 'One Belt, One Road' strategy, especially to export nuclear energy, hydropower and thermal power to overseas markets
- Allocation concerning development. Trading in the electricity market must begin by establishing an electricity market trade platform, enhancing the service level of the electricity industry and accelerating the upgrading of the power distribution network

Furthermore, on 30 November 2015, China announced reforms of its electricity sector to improve competition in the marketplace. These reforms will end the monopoly of electricity distribution by SOEs. The government will expand pilot programs related to the cost of building transmission lines, thereby allowing electricity consumers to directly negotiate with electricity generators (OilPrice, 2015). In November 2015, the NEA issued a draft document called 'Basic Rules for Electricity Market Operations', which calls for expansion of longer-term markets based on contracting between generators on one side and large end-users or retail companies on the other.

In summary, electricity market reform has mainly taken the form of expanded direct trading. This is partly in reaction to pressure from large users for lower electricity prices. Given their interest in finding a use for excess capacity, the operators of coal-fired generators have also been supportive of the emphasis on direct trading. Policymakers have proceeded cautiously so far, limiting the access of relatively inefficient end-users, in line with China's longstanding policies on differential pricing.

In recent years, China has achieved various electricity market reforms. Power trading centres have been set up. Power transmission and distribution price reform has realised a full coverage of provincial-level power grids. Power generation and consumption schedules have been deregulated in an orderly manner. The market-oriented power trading mechanism has improved gradually. The number of electricity retailers has also increased due to market liberalisation.

In August 2017, NDRC and NEA jointly issued the Notice on Pilot Work of Electricity Spot Market Construction. Eight regions, including Guangdong, Inner Mongolia, Zhejiang, Shanxi, Shandong, Fujian, Sichuan and Gansu, were the first pilot areas to make use of an electricity spot market (NDRC, 2017d).

In December 2018, the State Grid Corporation launched its first trial operation of the spot electricity market in Gansu and Shanxi. This marked a great step forward in the pilot construction of spot electricity markets in China and a new stage in the reform of the national electricity market. China will further promote the reform of electricity and continue to move to a full competition wholesale and retail market.

ENERGY EFFICIENCY

In June 2015, the Chinese Government announced its intention to develop an energy revolution that focuses on reducing energy consumption, increasing energy supply and improving energy efficiency. With regard to the energy efficiency improvement policy, there are two major strategies (USCBC, 2017).

- Eliminate inefficient facilities. In May 2014, the NEA issued a notice called the '2014 Elimination of Outdated Production Capacity for the Power Industry'. Shortly after this

notice was issued, provincial-level NDRCs launched implementation plans. Meanwhile, the central government has made plans to develop large-scale power plants and combine heat and power stations to replace small power stations. At the State Council executive meeting in June 2014, Prime Minister Li Keqiang stated that new coal power plants would be prohibited in the Beijing, Tianjin and Hebei regions. Instead, large-scale coal power plants in Central and Western China will play a more significant role in power production and transmission

- Establish a market-oriented energy pricing mechanism. Energy inefficiency in China is mainly caused by governmental control of energy pricing and the monopoly of SOEs. To encourage competition and weaken the power of SOEs, the Chinese Government will invite more private companies into the sector through a bidding process for power transmission, distribution and sales as part of the policy reform

On 23 April 2015, the State Council introduced 80 pilot projects to attract private investment in infrastructure projects. These projects include hydropower, wind power, PV power, oil and gas pipelines, energy storage facilities, the modern coal chemical industry and the petrochemical industry. The State Council indicated that these projects would be put out to public tender to attract private capital through joint ventures, sole proprietorship or franchise arrangements. With regard to the next step, the government will release more projects from other sectors. These will include oil and gas exploration and water conservancy.

Carbon trading schemes are also being used by the central government to promote market-based energy pricing structures. Since October 2011, China has launched pilot carbon markets in two provinces (Hubei and Guangdong) and five cities (Beijing, Tianjin, Shanghai, Chongqing and Shenzhen). Under the Draft National Regulation, the Chinese carbon market will be a two-tier system where the applicable central government department will be responsible for regulating and supervising the Chinese carbon market at the economy level.

The central government will determine greenhouse gas (GHG) categories, the scope of industries and the criteria of the companies or entities that the Chinese carbon market will cover. It will also approve, supervise and regulate the carbon exchanges. The local governments will have primary responsibility for implementation and monitoring in their jurisdictions. On 19 December 2017, China formally launched the national carbon market., with the first phase covering power stations. The second stage incorporated market trading in the power sector. In the third phase, spot trading was launched. After stable operation, this will expand to seven other sectors such as petrochemical, chemical, building materials, etc. (NDRC, 2017e).

RENEWABLE ENERGY

China's renewable energy sector is growing faster than its fossil fuels and nuclear energy sector. In 2015, China became the world's largest producer of PV power at 43 GW installed capacity. China also led the world in the production and use of wind power and smart grid technologies, generating almost as much water, wind and solar energy as all of France and Germany's power plants combined.

China will spend CNY 2.5 trillion (USD 361 billion) on renewable power development by 2020, according to the latest strategy for the Thirteenth Five-Year Plan (2016–20). China's goal of generating 20% of its energy from non-fossil fuel sources by 2030 will require the installation of an additional 800–1 000 GW of renewable energy, an amount which is equal to the current size of the entire US electricity grid.

To better utilise renewable resources and reduce waste, the NDRC and NEA jointly issued the Clean Energy Consumption Action Plan (2018–2020) on 30 October 2018. As part of the new quota system, minimum targets for renewable power consumption will be set for each region in China. The goal for 2020 is to solve the problem of renewable energy integration into power grid, where average utilisation rates for wind power, PV power and hydro power should reach about

95% while the curtailment is controlled at a reasonable level at around 5%; nuclear power economy-wide should be safely and securely integrated into the power grid (NDRC, 2018a)

WIND

Wind offers one of the greatest opportunities for renewable energy growth in China. During 2007–14, China's wind energy capacity increased nearly 25 times, growing from 6.0 GW to 149 GW, and it is expected to continue to grow. Since 2010, China has been the largest wind power producer in the world. In 2016, the electricity generation output of wind reached 241 TWh, making it the third-most popular energy source in the economy after coal (3 906 TWh) and hydro (1 150 TWh) (EGEDA, 2017).

In 2016, China added 19 GW of wind power generation capacity and generated 241 TWh of electricity, representing 4% of the economy's total electricity consumption. Both China's installed capacity and new capacity in 2017 are the largest in the world by a wide margin, with the next largest market, the United States, adding 8.2 GW in 2016 and having an installed capacity of 82 GW. By the end of 2016, China's large-scale wind power capacity had reached 142 540 MW, which is 26% more than the previous year's level. It is estimated China will have 250 GW of wind capacity by 2020 as part of the government's pledge to produce 15% of all electricity from renewable resources by that time.

However, the wind power industry faces the challenge of wind power curtailment because of the limitations of wind farm grid connections and grid capacity. Wind power curtailment has gradually increased since 2010 and reached a peak in 2012 of with 21 billion kWh. This constituted just 17% of wind power electricity generated in that year, leading to a direct economic loss of CNY 100 billion. In 2013, the situation improved because the wind power curtailment rate fell to 11% and decreased further to 8.5% in 2014. In 2016, the average utilisation of wind power in China was 1 742 hours, 14 hours more compared with that in 2015; the abandoned wind power represented 50 billion kWh, with the average wind abandonment rate being 17% (NEA, 2017).

SOLAR

The solar PV industry in China has long depended on subsidies and is expected to experience a crucial period of transformation in 2016–20. Under the economy's energy transformation policy, China's solar PV industry is changing towards intelligent manufacturing for stronger competitive advantages. This is because China is endeavouring to accelerate energy technology innovation to construct a clean, low-carbon and high efficiency energy system.

In 2015, China's installed solar PV capacity surpassed Germany, and the economy had the largest capacity in the world at 43 GW (PV Magazine, 2016). Indeed, China has been the world's largest market for solar PV since 2013, when it had 17.5 GW.

In 2016, China added 34 GW of solar PV generation capacity, and China's accumulated installed capacity reached 77 GW, including 67 GW of centralised PV power plant capacity and 10 GW of distributed PV. The total generation in 2016 was 66 TWh, constituting 1% of the economy's power generation.

In December 2016, the NEA issued the Thirteenth Five-Year Plan for Solar Energy Development, setting a target for installed solar power generation capacity of 110 GW by 2020, including 105 GW of solar PV capacity. The basis of this target is that the economy will continue to expand solar PV generation during the 13th Five-Year Plan (FYP) period. In addition, NDRC solicits opinions on reducing the benchmark on-grid price of electricity generated by wind and solar PV power periodically. The opinions requested are those of local governments and power companies. A lower price will help the industry to expand (Xinhua Finance Agency, 2015).

In 2017, China surpassed its 2020 solar PV target with installed capacity reaching 130 GW, accounting for 32% of the global total (CEC, 2018). To promote a healthy and sustainable development of the PV industry and speed up the withdrawal of subsidies, China released the Circular Regarding Matters Related to Photovoltaic Power Generation on 31 May 2018. It stopped

approving any new subsidised utility-scale PV power stations in 2018 and set a cap of 10 GW on the distributed PV projects connected to the grid before 31 May. It also reduced feed-in tariffs for newly distributed PV projects (NDRC, 2018b).

According to the NDRC, solar construction costs in China decreased by 45% from 2012 to 2017. In January 2019, the NDRC and NEA jointly issued the Circular on Actively Promoting Subsidy-Free Wind and Solar Power Projects. Under the new policy, China will set up several pilot wind and solar power projects without subsidies, optimise the investment environment, support the construction of pilot projects involved in cross-regional deliveries, encourage pilot projects, obtain reasonable compensation from Green Certificates trading, and encourage the power grid to support the development of the pilot projects by guaranteeing the integration and the priority electricity purchase of pilot projects and reducing transmission fees. Some regions with good natural resources and reliable demand have achieved subsidy-free or grid price parity conditions (NDRC, 2018c).

HYDRO

Hydropower is a significant part of China's renewable energy mix. However, it cannot be scaled up indefinitely. China is the world leader in terms of hydropower capacity. The installed capacity at the end of 2016 was 332 GW, including 27 GW of pumped storage, making it the economy's single largest renewable power source by far. Although China has set a goal to increase capacity to 350 GW by 2020, the potential for new large-scale hydropower capacity is limited. Thus, the proportion of hydropower in China's renewable energy mix is likely to decrease in the near future (EGEDA, 2017).

The pumped storage hydroelectricity industry has significantly developed in recent decades due to rapid development in the modern renewable energy industry. Pumped storage stations are also being deployed in more diverse locations, and new pumped storage stations are constructed near energy basements or supply centres rather than demand centres to smooth the output of solar farms and wind farms or to store energy during the off-peak time. By May 2017, China's installed capacity and under construction capacity reached 28 GW and 31 GW, respectively, which are both the largest in the world. According to the Hydro Power Development Plan for the 13th Five-Year Plan, China's target is to have 40 GW of pumped storage capacity by the end of 2020.

NUCLEAR

Following Japan's Fukushima Daiichi crisis in early 2011, China reviewed its nuclear plant safety requirements. On 25 October 2012, the State Council approved new safety rules and a nuclear power development plan, which prioritises safety and quality in Chinese regulations and sets a target of 58 GW of nuclear capacity by 2020 (WNA, 2018). The Chinese Government has said that it will approve a small number of plants along the coast in accordance with new and stricter safety rules, and no plants were approved for inland areas during the Twelfth Five-Year Plan (2011–15) (NNSA, 2013). According to the Energy Development Strategy Action Plan 2014–20, all new nuclear plants must meet the strictest world safety standards (SCC, 2014).

Because China is striving to reduce air pollution from coal-fired power plants, it is aiming to construct more nuclear power plants. By the end of 2016, 38 nuclear power reactors were in operation with 19 under construction and more to be constructed. In 2016, the electricity generation output of nuclear was 213 TWh, which was approximately 3.6% of the total power generation. The installed capacity was 26 GW, which was approximately 1.8% of the total capacity. The year 2015 also saw the beginning of the greatest number of nuclear power projects in a single year in China since the 2011 crisis, with eight new units being approved for construction.

No new nuclear projects were approved for construction in 2016. However, some projects were in the process of evaluation and their construction would possibly begin soon. These included the CAP1400 demonstrative project in Rongcheng City, Shandong Province and the second phase

of AP1000 nuclear reactors in Lufeng City, Guangdong Province; Sanmen City, Zhejiang Province; and Xu Dapu, Liaoning Province.

China is also significantly focusing on the next generation of nuclear power. In China's nuclear development plan, pressurised water reactors (PWRs) are to be the main type of nuclear reactor by 2030. Fourth-generation reactors (high-temperature, molten-salt, gas-cooled fast, sodium-cooled fast and lead-cooled fast reactors) with improved operating safety features will be available for commercial construction by approximately 2030. Then, the fourth-generation reactors will gradually replace the current PWRs. By 2040, it is projected that new technology will play an important role in China's energy supply (World Nuclear, 2016).

In December 2012, the Shidaowan nuclear power plant in Shandong Province, China's first demonstration-scale 4th generation nuclear power plant, restarted construction as the original plan had been cancelled after the Fukushima Daiichi crisis in 2011. This high-temperature gas-cooled technology nuclear power plant was projected to be completed and begin generating electricity at the end of 2018.

By the end of 2018, China had approximately 45 nuclear power reactors in operation, 15 under construction and more about to start construction. Taishan 1, the world's first European/Evolutionary Pressurised Water Reactor (EPR), and Sanmen 1, the world's first AP1000, were put into operation consecutively, which marked an important milestone in the Chinese nuclear development program. China has a strong desire to let domestic nuclear technology go global as part of the 'Belt and Road' initiative. Hualong One technology, China's independent Gen-III nuclear technology, was first applied with the Fuqing-5 nuclear reactor. Pakistan became the first market to use the Hualong One reactor when it installed it in its Karachi nuclear power plant. It has already been used in the Bradwell project in the United Kingdom. Some other economies have also expressed interest in the technology, including Argentina, Thailand, and Indonesia. Even though there is a trade war between China and the United States and this has already influenced nuclear power development, it has had no practical effects on China's own independent Gen-III nuclear technology, Hualong One technology (WNA, 2019).

CLIMATE CHANGE

In June 2015, China submitted a climate action plan called the Intended Nationally Determined Contribution to the Secretariat of the United Nations Framework Convention on Climate Change (UNFCCC). In the action plan, China reaffirmed the bilateral climate deal agreement with the United States in November 2014. It also pledged to reach a total emission peak by approximately 2030 and try its best to peak earlier. Furthermore, China committed to increasing the share of non-fossil fuels in its energy mix to 20% by 2030.

China also announced two goals in addition to the November deal with the United States. These are to reduce carbon intensity by 60% to 65% based on the 2005 level, and restore approximately 4.5 bcm of forested land beyond the 2005 level. This is an important change because the economy is increasingly decoupling its economic growth from greater growth in carbon emissions.

The cooperation between China and the United States on addressing climate change has injected momentum into UNFCCC negotiations. In 2013, the United States and China also came to a joint bilateral agreement to work through the existing Montréal Protocol and UNFCCC mechanisms to reduce the use of HFCs, which are potent GHGs emitted through a variety of industrial processes.

In November 2016, China's GHG Control Work Plan and Power Sector Development Thirteenth Five-Year Plan were issued, while its Ecological and Environmental Protection Thirteenth Five-Year Plan was released later. Covering a comprehensive set of policies, these documents lay out benchmark goals for 2020 that will put China on track to surpass its 2030 Paris goals, strengthen its enforcement of environmental laws and standards, and continue its transition to low-carbon energy.

In July 2018, China released a Three-year Action Plan to Win the Battle for a Blue Sky (2018–2020). The old Air Pollution Action Plan released in September 2013 expired at the end of 2017, which set the PM 2.5 (atmospheric particulate matter that has a diameter of less than 2.5 micrometres) reduction targets of 25%, 20% and 15% in the Beijing-Tianjin-Hebei Area, Yangtze River Delta and Pearl River Delta, respectively. The new plan has given the timetable and roadmap for improving air quality within a larger area. By 2020, total emissions of sulphur dioxide and nitrogen oxides should decrease by more than 15% from 2015 levels, while PM 2.5 density should fall at least 18% from the 2015 levels. The percentage of days with good air quality should reach 80% annually, and the percentage of heavily polluted days should drop by 25% or more from the 2015 levels in cities at prefecture level and above. To achieve the goals, the new action plan puts forward six measures, including adjusting and optimising the industrial structure to promote its green development; accelerating the restructuring of the energy mix to build a clean, low-carbon and efficient energy system; actively restructuring the transport framework to develop a green transportation system; optimising land-use systems to enhance pollution management; implementing special actions to reduce pollutant emissions, and strengthening regional joint control to deal with heavily polluted weather effectively (SCC, 2018).

By the end of 2017, China had cut carbon dioxide emissions per unit of GDP by 46% from the 2005 level, meeting its 2020 carbon emission target, which is to reduce carbon emissions by 40–45% by 2020 from the 2005 level. It achieved this three years ahead of schedule with the help of the economy's carbon trading system. China raised the forest stock volume by 2.1 billion cubic metres from the 2005 level, meeting the goal of a 1.3 billion-cubic-metre increase by 2020 (UNCC, 2018).

NOTABLE ENERGY DEVELOPMENTS

CLEAN ENERGY CONSUMPTION ACTION PLAN

In October 2018, the NDRC and the NEA issued *the Clean Energy Consumption Action Plan (2018-2020)*, which proposes to solve:

- by 2018, the average wind power utilisation rate to be higher than 88% (aiming at more than 90%) and wind curtailment rate lower than 12% (aiming at below 10%)
- by 2019, the average wind power utilisation rate to be above 90% (aiming at 92%) and wind curtailment rate below 10% (striving to hold it at around 8%)
- by 2020, the average utilisation rate of wind power to reach the international advanced level (95% or higher) and the curtailment rate to be controlled at a reasonable level (5% or less)

NOTICE ON ACTIVELY PROMOTING WIND AND SOLAR PV GENERATION AND SUBSIDY-FREE GRID CONNECTION

In January 2019, the NDRC and the NEA issued the Notice on Actively Promoting Wind Power and Photovoltaic Power Generation and Subsidy-Free Grid Connection. Based on the 2019 Notice, NEA published the 2020 Notice to further promote the transition of wind and solar PV to the universal grid price. Subsidised wind power projects will be scaled down in 2020, with projects that received approval before the end of 2018 encouraged to transit to the grid price. Projects that do not participate in the pilot of distributed market-based transactions will still receive subsidies. For solar PV, only new solar PV projects in 2020 can bid for subsidies. The subsidy budget for new solar PV projects in 2020 is 1.5 billion RMB, with 0.5 billion RMB to go to household PV.

COAL POWER

By the end of 2018, 810 GW of China's coal-fired power plants had completed ultra-low-emission technology retrofits. The emissions of these retrofit power stations were not higher than those specified for gas-fired power plants. The technology of high efficiency pulverised coal industrial boilers with independent intellectual property rights in China has increased the thermal efficiency of bulk coal combustion to over 90%. China now possesses the largest clean coal-fired power generation capacity in the world. China is determined to reduce coal's share in the economy's energy mix, lowering its 2020 percentage in primary energy consumption from 62% to 58%. China is also aiming to develop more renewables: the installed capacity of wind energy and solar energy should reach 'more than 210 GW' and 'more than 110 GW' by 2020, respectively. By 2020, the proportion of non-fossil fuels should rise above 15% from 12% in 2015. Natural gas should constitute at least 10% of the energy consumption.

NATURAL GAS

China's gas storage capacity increased by more than 3 bcm. In terms of gas supply capacity, China's natural gas consumption in 2018 was 280 bcm, an increase of 18% over the year before. Consumption in the winter season was 109 bcm, an increase of 17% over the year before; daily maximum gas consumption was 1.037 bcm, an increase of 20%.

RENEWABLE ENERGY

Following the strategies of clean energy and low-carbon development, China has gradually increased renewable energy utilisation, with great emphasis on technology development and innovation. By the end of 2018, the cumulative installed capacity of renewable power generation exceeded 700 GW, accounting for 30% of the world's total. Non-fossil fuel power generation accounted for about 40% of total installed capacity and nearly 30% of total electricity generation.

By the end of 2018, China's total installed hydropower capacity was about 350 GW, and its annual generating capacity was about 1.2 TWh, the highest in the world. About 640 large and medium-sized hydropower stations (with a capacity of 50MW or above) have been built with a total installed capacity of about 270 GW. China has invested more than 200 billion yuan in hydropower projects overseas, and Chinese enterprises have participated in about 320 overseas hydropower projects with a total installed capacity of 81 GW.

For solar PV, the cumulative installed capacity exceeds 170 GW, of which the centralised capacity is about 23 GW. The distributed capacity is about 20 GW. It is expected that the increased capacity will be between 35 GW and 45 GW in 2019.

NUCLEAR POWER

By April 2019, China's nuclear power units had been operating safely and steadily for more than 300 reactor-years. During the 13th Five-Year Plan period, nuclear power plants producing 30GW will begin operation and plants producing 30 GW will begin construction. By 2020, the installed capacity will reach 58 GW. Unit 1 of the Taishan Nuclear Power Plant completed its final regulatory test of continuous operation and full capacity operation for a full week, becoming the world's first EPR third-generation nuclear power plant in commercial operation.

DRAFT ENERGY LAW

In April 2020, China announced a draft Energy Law which outlines the strategic direction of Chinese energy policy. The to-be-announced Energy Law gives all energy policies a clear legal basis to ensure the direction of energy development and the stability of energy regimes. The draft Energy Law consists of ten chapters: overview, energy strategy and planning, energy exploration and transformation for fossil and non-fossil fuels, energy application and use, energy market, energy security, technology advancement, international cooperation, supervision and management and legal responsibility.

The draft law emphasises the development of renewable energy, market competition, further opening of the energy sector, and greater international cooperation. According to the draft, market mechanisms are expected to play an essential role in resource allocation, encouraging market competition and allowing the market to decide energy prices. China has been encouraging the private sector and foreign companies to participate in China's energy sector. These companies will have legal protection after the Energy Law is passed. The government has released the draft and has sought public comments.

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USEFUL LINKS

Central People's Government of PRC—www.gov.cn

China Electricity Council (CEC)—www.cec.org.cn

Energy Research Institute of National Development and Reform Commission (ERI)—www.eri.org.cn

Ministry of Ecology and Environment (MEE)—<http://www.mee.gov.cn/>

Ministry of Industry and Information Technology (MIIT) — www.miit.gov.cn

Ministry of Housing and Urban-Rural Development—www.mohurd.gov.cn

Ministry of Science and Technology—www.most.gov.cn

National Bureau of Statistics (NBS)—www.stats.gov.cn

National Development and Reform Commission (NDRC)—www.ndrc.gov.cn

National Energy Administration (NEA)—www.nea.gov.cn

National Nuclear Safety Administration (NNSA)—nnsa.mep.gov.cn

Standardisation Administration—www.sac.gov.cn

World Nuclear Association (WNA) —<http://www.world-nuclear.org>

HONG KONG, CHINA

INTRODUCTION

Hong Kong, China is a special administrative region of the People's Republic of China. It is a world-class financial, trading and business centre with a population of 7.4 million people and is located at the south-eastern tip of China. Hong Kong, China has no natural resources and completely relies on imports to meet its energy requirements. The energy sector comprises investor-owned electricity and gas utility services.

In 2017, the per capita gross domestic product (GDP) of Hong Kong, China was USD 56 088 (2011 USD purchasing power parity [PPP]), the third-highest among the APEC economies. The GDP increased by 22% in real terms to USD 415 billion after 2010 (2011 USD PPP) (EGEDA, 2019). The service sector remained the dominant driving force of overall economic growth, constituting 92% of GDP in 2017 (Hong Kong Yearbook, 2018).

Hong Kong, China is driven by its financial, high value-added and knowledge-based services. To stay competitive and attain sustainable growth, Hong Kong, China needs to restructure and reposition itself due to challenges posed by globalisation and its closer integration with mainland China. The mainland and Hong Kong Closer Economic Partnership Arrangement (CEPA) is a manifestation of the advantages of the 'one country, two systems' principle. As part of the liberalisation of trade in goods under CEPA, all products imported from Hong Kong, China to mainland China enjoy tariff-free treatment.

With the support of mainland China under the CEPA and the Framework Agreement on Hong Kong/Guangdong Cooperation, Hong Kong, China is poised to reinforce and enhance its status as an international centre for financial services, trade and shipping, advanced manufacturing, and modern services. The central government has announced that it will promote the restructuring and upgrading of traditional industries, strengthen emerging industries, and widen and deepen external economic and trade relations under the principle of 'one country, two systems'.

Hong Kong, China will also foster the diversification of its financial services, provide planning assistance and advice to Guangdong province, and continue to negotiate with Macao on the establishment of a closer economic partnership arrangement. Hong Kong, China will also expand and enhance the functions of its offices in mainland China and will establish six more liaison units (Policy Address, 2016).

Table 1: Key data and economic profile, 2017

Key data		Energy reserves	
Area (km ²)	1 106	Oil (million barrels)	–
Population (million)	7.4	Gas (billion cubic metres)	–
GDP (2011 USD billion PPP)	415	Coal (million tonnes)	–
GDP (2011 USD PPP per capita)	56 088	Uranium (kilotonnes U)	–

Source: EGEDA (2019).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Hong Kong, China has no domestic energy reserves or petroleum refineries, importing the fuels required to meet all its primary energy needs. A substantial share of imported energy is converted into secondary energy, such as electricity and gas, for final consumption. The total primary energy supply in Hong Kong, China was 14 million tonnes of oil equivalent (Mtoe) in 2017, 0.10 Mtoe lower than the previous year. Coal maintained the highest share in the total primary energy supply (44%), followed by oil (28%), gas (21%), renewables (0.5%) and other sources (7.0%) (EGEDA, 2019).

In 2017, total installed electricity generating capacity in Hong Kong, China was 12 492 MW (Hong Kong Energy Statistics, 2017). All locally generated electricity is thermal-fired. Electricity is supplied by CLP Power Hong Kong Limited (CLP Power) and Hong Kong Electric Company Limited (HKE). CLP Power supplies electricity from its Black Point (2 500 MW), Castle Peak (4 108 MW) and Penny's Bay (300 MW) power stations. Natural gas and coal are the main fuels used for electricity generation at the Black Point and Castle Peak power stations.

CLP Power has arrangements with China National Offshore Oil Corporation and PetroChina International Company to procure gas supplies from the mainland. CLP Power has commenced constructing a 550 MW gas-fired generation unit at Black Point Power Station. It is proposing to construct an offshore LNG terminal in Hong Kong, China waters to enable direct access to a range of gas sources from around the world and strengthen the reliability of its fuel supplies. HKE's electricity is supplied by Lamma Power Station, which has a total installed capacity of 3 237 MW. Natural gas used at HKE's power station is mainly imported through a submarine pipeline from the Dapeng LNG terminal in Guangdong, mainland China. HKE has also operated wind turbines (capacity 800 kW) since 2006 and a photovoltaic (PV) system (1 MW) since 2010 (CLP, 2015a; HKEI, 2015a, 2015b, 2015c).

While natural gas and liquefied petroleum gas (LPG) are the main types of gaseous fuels used in Hong Kong, China, town gas serves as another fuel product. Town gas is locally manufactured from naphtha and natural gas and is distributed by the Hong Kong and China Gas Company Limited (Towngas, 2017).

FINAL ENERGY CONSUMPTION

In 2017, final energy consumption in Hong Kong, China was 6 715 kilotonnes of oil equivalent (ktoe), a decrease of 0.69% from the previous year. The residential and commercial sectors consumed the largest share of energy (65%), followed by the transport sector (31%) and the industry sector (4.5%). By energy source, electricity and 'others' constituted 56% of end-use consumption, followed by petroleum products (33%) (EGEDA, 2019).

Town gas and LPG are the main types of fuel gas used in the domestic, commercial and industrial sectors. LPG is also used as fuel for taxis and light buses, while natural gas is used for electricity generation and town gas production.

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	111	Industry sector	300	Total power generation	37 010
Net imports and others	31 773	Transport sector	2 078	Thermal	36 911
Total primary energy supply	14 339	Other sectors	4 337	Hydro	2.8
Coal	6 272	Non-energy	0	Nuclear	–
Oil	3 971	Final energy consumption*	6 715	Others	96
Gas	3 017	Coal	0		
Renewables	114	Oil	2 278		
Others	966	Gas	615		
		Renewables	50		
		Electricity and others	3 773		

Source: EGEDA (2019) (data collected in December 2019).

**Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. Total final consumption includes non-energy uses. Half of the municipal solid waste used in power plants is assumed to comprise renewables.*

'Total power generation' does not include electricity generated by hydro and nuclear energy facilities located in the mainland.

ENERGY INTENSITY ANALYSIS

In terms of primary energy or final energy consumption, the energy intensity of Hong Kong, China is the lowest among the APEC economies. The primary energy intensity in 2017 was only 34 tonnes of oil equivalent per million USD (toe/million USD), while the final energy consumption was only 16 toe/million USD (EGEDA, 2019).

Hong Kong, China endeavours to achieve sustainable development and fully supports APEC's Honolulu Declaration of 2011, seeking to reduce its energy intensity by 45% by 2035. Energy efficiency and conservation policies have been implemented to achieve this, including the Mandatory Energy Efficiency Labelling Scheme, Energy Efficiency Registration Scheme for Buildings, Building Energy Efficiency Ordinance, the Scheme on Fresh Water Cooling Towers, and the Charter on External Lighting (GHK, 2017).

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%) 2016 vs 2017
	2016	2017	
Total primary energy supply	43	35	–18.9
Total final consumption	20	16	– 18.9
Final energy consumption excl. non-energy	20	16	–18.9

Source: EGEDA (2019).

RENEWABLE ENERGY SHARE ANALYSIS

Despite geographical constraints in developing renewable energy (RE), the government has been implementing various plans to develop its potential. Actions such as developing wind energy, building floating PV farms and turning various types of waste into RE have already been taken to address the issue. In 2017, the share of modern renewable energy in the total final energy consumption was approximately 0.70%. The situation is expected to improve with the materialisation of various RE projects.

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	6 762	6 715	-0.69
Non-renewables (Fossil fuels and others)	6 717	666	-0.78
Traditional biomass*	2.4	2.3	-5.4
Modern renewables*	43	47	9.7
Share of modern renewables to final energy consumption (%)	0.64	0.70	10

Source: EGEDA (2019).

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal, and so on), including biogas and wood pellets, are considered to be modern renewables, although data on wood pellets are limited.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Hong Kong, China's energy policy objectives are to ensure that the energy needs of the community are met safely, efficiently, and affordably, while minimising the environmental impact on the production and use of energy (ENB, 2017a). The government also promotes the efficient use and conservation of energy. In combating climate change, reducing greenhouse gas (GHG) emissions and developing a low-carbon economy, Hong Kong, China's emission reduction strategy emphasises the wider use of cleaner and low-carbon energies and fuels in power generation.

In keeping with the free market economic policy of Hong Kong, China, the government intervenes only when necessary to safeguard the interests of consumers, ensure public safety and protect the environment. The government works with the oil companies to maintain strategic reserves of gas, oil and naphtha. It monitors the performance of the power companies through the Scheme of Control Agreements (SCAs). New SCAs were signed in April 2017 to promote quality services, cleaner energy sources, energy efficiency and conservation. The new SCAs support further development of RE to supplement conventional power generation, as well as public awareness and public participation (ENB 2017b, 2017c).

Hong Kong, China proposes to optimise the fuel mix for power generation. In 2014, the government conducted a public consultation on the future fuel mix for electricity generation in Hong Kong, China to solicit the public's views on the subject. Two fuel mix options were proposed

for public consultation. They were (i) to import more electricity through purchasing from the mainland power grid, and (ii) to use more natural gas for local generation.

Having considered the public's views, the government plans to increase natural gas generation to approximately 50% by 2020 and maintain the current interim measure of importing 80% of nuclear output from the Daya Bay Nuclear Power Station so that nuclear imports would constitute approximately 25% of the total fuel mix. The government is preparing to develop more RE and to enhance efforts to promote energy saving, subject to public views on tariff implications. The remaining energy demand will be met by coal-fired generation.

This energy mix will help Hong Kong, China achieve its environmental targets for 2020, including the target to reduce carbon intensity by 50–60% in 2020 compared with the 2005 level. Hong Kong, China is endeavouring to enhance energy efficiency, promote green buildings, advocate electricity savings, facilitate low-carbon transport, reduce waste, and develop facilities to turn waste into energy (ENB, 2017d, CLP, 2015c).

The Energy Saving Plan for Hong Kong, China's Built Environment 2015–2025+ has a target of reducing its energy intensity by 40% by 2025 based on the 2005 level. The planned actions are as follows:

- Promoting energy saving and green building development by enhancing the green performance of government buildings, public housing and public sector developments
- Conducting periodic reviews to expand and/or tighten relevant energy-related standards, including the statutory requirements under the Buildings Energy Efficiency Ordinance, Building (Energy Efficiency) Regulation and Energy Efficiency (Labelling of Products) Ordinance
- Updating schools and public education programs and strengthening government energy saving efforts by appointing green managers and energy wardens, and encouraging public sector institutions to save energy
- Supporting community campaigns through government funding schemes and collaborating with key energy consumers in the commercial sector to develop sector-specific campaigns to promote energy saving. The Secretary for the Environment is engaging environment leaders to accelerate green building adoption in the private sector

ENERGY MARKETS

A memorandum of understanding (MOU) was signed by the Hong Kong, China Government and the National Energy Administration of the People's Republic of China on 28 August 2008. To ensure the prosperity and stability of Hong Kong, China, the central government of China will continue to support energy cooperation between the mainland and Hong Kong, China over the long-term. This will include efforts to provide a stable supply of nuclear electricity and natural gas to the economy. The intergovernmental MOU contemplates the delivery of natural gas to Hong Kong, China from three sources (CLP, 2008a):

- Existing and new gas fields planned for development in the South China Sea
- A second west-to-east gas pipeline, transporting gas from Central Asia
- An LNG terminal in Shenzhen, mainland China

The MOU also contemplates the ongoing supply of nuclear-generated electricity to Hong Kong, China. An extension of the Guangdong Daya Bay Nuclear Power Station joint venture and supply contracts was approved by the Hong Kong, China Government in September 2009. These contracts will enable the continued supply of non-carbon-emitting electricity to Hong Kong, China for an additional term of 20 years from 2014. CLP Power has successfully negotiated an increase in the proportion of electricity supplied from the Guangdong Daya Bay Nuclear Power Station to Hong Kong, China, increasing the plant's generation from 70% to approximately 80% from late 2014 to 2018 (CLP, 2015b, 2015c).

ENERGY EFFICIENCY

Buildings consume approximately 90% of the electricity used in Hong Kong, China. Therefore, one of the government's first priorities is to conserve the energy used by buildings. Efforts are being made to improve public awareness regarding energy efficiency to drive behavioural changes.

ENERGY DATA

To help monitor the energy situation, Hong Kong, China has developed an energy end-use database. The database provides useful insights into the energy consumption situation, including the energy consumption patterns, trends and usage characteristics of each sector and segment. A basic dataset is publicly available on the Internet. The government can analyse the current system based on the data and develop policy and strategy revisions for future implementation. The private sector can use the data to benchmark its own energy efficiency when seeking improvements in its energy consumption systems (EMSD, 2017a, 2018b).

BUILDINGS

To strengthen its efforts towards improving energy conservation, the government has enhanced the regulatory system for building energy efficiency. The Buildings Energy Efficiency Ordinance was fully implemented on 21 September 2012. The three key requirements of the ordinance are as follows (EMSD, 2012a):

- The developers or building owners of newly constructed prescribed buildings should ensure that the building service installations (air conditioning, lighting, electrical, lift and escalator installations) comply with the design standards of the Building Energy Code (BEC)
- When carrying out 'major retrofitting works', responsible persons of prescribed buildings (for example, owners, tenants or occupants) should ensure that the building service installations comply with the design standards of the BEC
- The owners of commercial buildings, including the commercial sections of composite buildings, should conduct an energy audit for the central building service installations in accordance with the Energy Audit Code (EAC) every 10 years. The first energy audit should be conducted within four years of the commencement of the ordinance in accordance with the timetable set out in Schedule 5 for that ordinance. The EAC 2018 Edition was issued on 16 November 2018, and it will take effect on 16 August 2019

The BEC is reviewed once every three years in accordance with public opinion, international trends and the latest technological developments. The first comprehensive review was completed in 2015, and the new standards required a further 10% improvement in energy efficiency. The BEC 2018 Edition was issued on 16 November 2018, and took effect on 16 May 2019, resulting in a more than 18% improvement compared with the 2012 edition. By the end of 2028, the implementation of the BEEO is expected to bring about an energy saving of some 27 billion kWh from both new buildings and existing buildings in Hong Kong, China, equivalent to the total annual electricity consumption of about 5.8 million households and a reduction in carbon dioxide emissions of about 19 million tonnes.

The government continues to utilise government buildings to demonstrate state-of-the-art energy-efficient designs and improve energy conservation technologies. These are based on an environmental performance framework that covers energy efficiency, GHG emissions reduction, RE application, waste reduction, water management and indoor air quality. All newly built government buildings over 10 000 square metres should aim to obtain not lower than the second-highest grade under the Hong Kong Building Environmental Assessment Method Plus (HK-BEAM+).

Retro-commissioning (RCx) helps to identify the improvement potential for existing buildings to reduce energy consumption by fine-tuning their building systems and equipment so that they can

operate at optimal efficiency, thus reducing operating costs and contributing to energy conservation. In 2017, the Electrical and Mechanical Services Department has published the first edition of technical guidelines of RCx (TG-RCx). Feedback and comments were received from various professional bodies and stakeholders, a TG-RCx 2018 were launched in December 2018.

Six government buildings with different sizes, uses, ages and energy consumption were selected to carry out the RCx energy improvement as pilot projects. About 5% of the overall energy saving could be achieved through the RCx process. Major government buildings would be identified to carry out RCx phase by phase in coming years.

EMSD signed a Memorandum of Co-operation (MOC) with various RCx organizations in Hong Kong, Macau and Mainland at EMSD Symposium in 2018 to promote application of RCx of buildings in the Guangdong-Hong Kong-Macao Greater Bay Area.

In April 2009, the government promoted a comprehensive target-based green performance framework for new and existing government buildings and set targets for aspects of environmental performance. It achieved the target of 5.0% savings on the total electricity used in government buildings from 2009–10 to 2013–14 after discounting activity changes, using electricity consumption in 2007–08 as the baseline. Building on this success, the government has set a new target of 5.0% savings in the electricity consumption of government buildings in the next five years from 2015–16 to 2019–20 under comparable operating conditions. This target uses electricity consumption from 2013–14 as the baseline.

In April 2009, the government introduced the Buildings Energy Efficiency Funding Schemes totalling HKD 450 million to subsidise environmental performance reviews and upgrades for communal areas in residential, commercial and industrial buildings. These schemes also cover energy/carbon audits and upgrading of the energy efficiency performance of building service installations. The subsidy can cover up to 50% of the expenditures. These funding schemes were closed in April 2012.

Since 1998, the government has launched the voluntary Energy Efficiency Registration Scheme for Buildings (EERSB) to encourage building owners to outperform the statutory requirements by conferring upon them recognition and commendation through the scheme. The EERSB 2018 Edition was effective from 1 January 2018, all types of new and existing buildings/ premises achieved energy performance outperform the minimum statutory requirements under the BEEO, with obtaining certificates of good building energy performance through an internationally recognized building environmental assessment system, can apply for joining the EERSB. Capital expenditure incurred on the construction of energy-efficient building installations (include lighting, air conditioning, electrical, and lift and escalator installations) registered under EERSB may be eligible for accelerated tax deduction (EMSD, 2015d).

WATER-COOLED AIR CONDITIONING SYSTEMS

Water-cooled air conditioning systems (WACS) using fresh water cooling towers are generally more energy-efficient than air-cooled systems. Examples of adoption of energy-efficient WACS in Hong Kong, China include the WACS using fresh water cooling towers for individual buildings, WACS using seawater cooling for individual buildings, and the large-scale district cooling system (DCS) (EMSD, 2015a).

The government has implemented a DCS in the Kai Tak Development to supply chilled water for centralised air conditioning to buildings in the new development. The DCS is the first project of its kind implemented by the government. It is an energy-efficient air conditioning system as it consumes 35% and 20% less electricity compared with traditional air-cooled air conditioning systems and individual WACS using fresh water cooling towers, respectively. The project is scheduled to be implemented in three phases: Phases I and II were completed in 2013 and 2014, and Phase III commenced in 2013 and is expected to be completed by the end of 2025 (EMSD, 2015c).

ENERGY CONSUMPTION INDICATORS

Since 2001, the government has commissioned the development of energy utilisation indexes and benchmarking tools for the residential, commercial and transport sectors. There are a total of 95 energy-consuming groups covered in the 3 sectors, i.e. 5 groups in the residential sector, 58 groups in the commercial sector and 32 groups in the transport sector. The tools help stakeholders to compare the energy consumption performances of the different sectors and provide applicable advice regarding energy conservation (EMSD, 2017a).

ENERGY EFFICIENCY LABELLING

Hong Kong, China has a voluntary Energy Efficiency Labelling Scheme that covers 22 types of household and office appliances, including 13 types of electrical appliances (refrigerating appliances, washing machines, non-integrated type compact fluorescent lamps (CFLs), dehumidifiers, electric clothes dryers, room air conditioners, household electric storage water heaters, televisions, electric rice cookers, electronic ballasts, LED lamps, induction cookers and microwave ovens). The scheme also includes seven types of office equipment (photocopiers, fax machines, multifunction devices, printers, LCD monitors, computers and hot/cold bottled water dispensers) and two types of gas appliances (domestic gas instantaneous water heaters and gas cookers). The scheme also covers petrol passenger cars (EMSD, 2015b).

To further assist the public in choosing energy-efficient appliances and to raise public awareness regarding energy saving, the government has introduced a Mandatory Energy Efficiency Labelling Scheme (MEELS) through the Energy Efficiency (Labelling of Products) Ordinance, Cap. 598. The MEELS covers eight types of products such as room air conditioners, refrigerating appliances, CFLs, washing machines, dehumidifiers, televisions, storage type electric water heaters and induction cookers. Under the MEELS, energy labels must be displayed on the products supplied in Hong Kong, China to inform consumers regarding their energy efficiency performance (EMSD, 2018a).

TRANSPORT

Transport constitutes approximately 18% of the total GHG emissions in the economy and is the second most significant contributor of emissions. To reduce carbon emissions from the transport sector, Hong Kong, China has implemented the following initiatives (EPD, 2018).

EXTENSION OF THE PUBLIC TRANSPORT SYSTEM

An extensive and energy-efficient public transport system in Hong Kong, China is instrumental in helping maintain low levels of GHG emissions. Approximately 90% of commuter trips are made each day via the public transport system. The government is committed to further expanding and upgrading its public transport infrastructure, with an emphasis on the railways (ENB, 2017d).

PROMOTION OF CLEANER VEHICLES

The government actively promotes the wider use of electric vehicles. The Government has been waiving in full the FRT for electric commercial vehicles. On the other hand, electric private cars (E-PCs) currently enjoy a first registration tax (FRT) concession and is also eligible for the 'One-for-One Replacement' Scheme, which offering a higher FRT concession. The government liaised with electric vehicle (EV) manufacturers and dealers to encourage them to introduce EVs to Hong Kong, China. As a result, the economy is one of the leading APEC economies in terms of EV use. The government is encouraging the private sector and expanding the public charging infrastructure for EVs in Hong Kong, China. There are approximately 3 000 different types of public EV chargers, including over 1 100 medium chargers and around 590 quick chargers.

The government's ultimate policy objective is to have zero-emission buses running throughout the territory. As such, the government has allocated approximately HKD 180 million to fully subsidise the franchised bus companies to purchase 36 single-deck electric buses and six double-decker hybrid buses for trial usage. If the trial results are satisfactory, the government will

encourage the franchised bus companies to use these green buses on a larger scale, considering affordability for the bus companies and passengers (EPD, 2018d).

CREATION OF THE PILOT GREEN TRANSPORT FUND

To encourage the public transport sector and non-profit organisations to test green and innovative transport technologies, the government set up an HKD 300 million Pilot Green Transport Fund in March 2011 (GHK, 2015b). The government has been encouraging vehicle suppliers and technology companies to introduce more means of transport and related technologies. Furthermore, it encourages the transport sector to carry out trials by allocating subsidies from the fund. At the end of February 2016, 87 trials had been approved under the fund, including 67 electric commercial vehicles (taxis, light buses, buses and goods vehicles), 63 hybrid commercial vehicles (goods vehicles and light buses), one solar air conditioning system and four electric inverter air conditioning systems. Additionally, a ferry was retrofitted with a diesel-electric propulsion system and a seawater scrubber (ENB, 2017e).

PROMOTION OF BIODIESEL AS A MOTOR VEHICLE FUEL

Since 2007, the government has adopted a duty-free policy for biodiesel to facilitate the use of biodiesel in motor vehicles (Policy Address, 2007-08). In 2010, it introduced regulatory controls for motor vehicle biodiesel to help safeguard its quality and encourage drivers to use it (EPD, 2010).

RENEWABLE ENERGY

Despite the geographical and natural constraints on developing wind energy, both power companies (CLP Power and HKE) have started to explore the feasibility of offshore wind farm projects.

CLP Power is currently conducting a feasibility study for an offshore wind farm. An offshore meteorological wind mast was installed to collect site environmental data. CLP Power completed the installation of an RE power system of approximately 200 kW on Town Island in late 2012. The system now comprises 672 solar panels and two wind turbines supplying RE to the island.

The RE assets of HKE also performed well, with Lamma Winds generating an average of 800 to 1 000 megawatt-hours (MWh) of electricity since being commissioned in 2006. A thin-film photovoltaic (TFPV) solar power system of 1 MW was installed at Lamma Power Station, generating 1 100 MWh annually, offsetting an average of 1 715 tonnes of CO₂ emissions per annum together with the wind turbines (HKEI 2015b, 2015c).

To increase its RE portfolio, HKE plans to install up to 33 offshore wind turbines, each of 3.0 to 3.6 MW with a total generation capacity of around 100 MW, producing 175 gigawatt-hours (GWh) of electricity per year for the consumption of 50 000 four-person households. In 2012, HKE set up a wind monitoring station at its offshore wind farm site to collect meteorological and oceanographic data for detailed design purposes. Data collected indicate that the site is feasible for development of an offshore wind farm. Additional data are being collected for optimising the offshore wind farm design (HKEI, 2015d).

Landfill gas, a waste gas produced at landfill sites, has been used as a waste-to-energy source for onsite electricity generation and leachate treatment as well as for use by the town gas production plant (EPD, 2017a).

In 2007, landfill gas generated at the North-East New Territories (NENT) Landfill was treated and transferred to the town gas production plant to replace some of the naphtha used as a heating fuel. In 2016, the South-East New Territories (SENT) Landfill Gas Treatment Plant was completed. Landfill gas is treated with impurities, removed and converted to synthetic natural gas before being injected into the Town gas supply network. It can offset 56 000 tonnes of CO₂ emissions per year, equivalent to planting 2.4 million trees (Towngas, 2017).

CLP Power is planning to develop Hong Kong, China's largest landfill gas power generation project that would produce 10 MW of renewable power close to one of its power plants (CLP, 2016b).

The government has taken the lead in using RE by installing PV systems at various government premises. Notable installations are a 1 100 kW system at the Siu Ho Wan Sewage Treatment Works, capable of generating 1.1 million kWh annually, a 468 kW system at a swimming pool complex and a 350 kW system on the roof of the Electrical and Mechanical Services Department Headquarters (DSD, 2016) (EMSD, 2017b).

The government has also installed large-scale solar water heating devices on government buildings, including those with swimming pools, to save power in heating water.

The government is studying the practicality of installing floating photovoltaic (FPV) systems on reservoirs. Two pilot projects were commissioned in 2017, each having a capacity of 100 kW and capable of generating 120 GWh of electricity annually to power the equivalent of 36 households, with a reduction of 84 tonnes of CO₂ emissions. Data gathered will be used as a reference for the future implementation of large-scale FPV farms on reservoirs in Hong Kong, China (WSD, 2017). In its effort to convert waste to energy and reduce GHG emissions, the government has been planning and constructing several waste management facilities.

- Phase 1 of the Organic Resources Recovery Centre (ORRC) was commissioned in early 2018. It will treat 200 tonnes of organic waste per day to produce biogas and compost. The biogas will be used to generate electricity, with approximately 14 million kWh of surplus electricity supplied to the power grid per year, which is enough to meet the needs of 3 000 households. This will contribute to a reduction of 25 000 tonnes per year of GHG emissions via reduction in the use of fossil fuels for electricity generation. Study on the second phase of the ORRC has already commenced (EPD 2017b)
- The government is planning to construct an integrated waste management facility (IWMF). IWMF. Phase 1 will be able to incinerate 3 000 tonnes of mixed municipal solid waste per day and will be capable of exporting approximately 480 million kWh of electricity (approximately 1% of the total electricity consumption in Hong Kong, China). This project will satisfy the electricity use of more than 100 000 households and will help reduce GHG emissions by approximately 440 000 tonnes per year (EPD 2017c)
- Phase 1 of the Sludge Treatment Facility (STF) was commissioned in April 2015 and Phase 2 in April 2016. The STF incinerates 1 200 tonnes of sewage sludge per day (2 000 tonnes by 2030). The heat of the steam is converted to electricity by two 14-MW steam turbine generators to fully meet the energy needs of the entire STF. When running at full capacity, approximately 2 MW of surplus electricity is expected to be exported to the public power grid, enough to supply 4 000 households (EPD, 2017d)

NUCLEAR ENERGY

Hong Kong, China imports electricity of nuclear origin from mainland China.

CLP Power is contracted to purchase around 70% of the electricity generated by the two 984 MW pressurised water reactors at the Guangdong Daya Bay Nuclear Power Station in mainland China to help meet the long-term demand for electricity in its service area. This arrangement meets 27% of electricity demand in Hong Kong, China. In September 2009, the government approved the extension of CLP Power's contract for the supply of nuclear-generated electricity from the Guangdong Daya Bay Nuclear Power Station for another 20 years, starting 7 May 2014. The extension of the contract ensures a continued supply of cleaner electricity to Hong Kong, China, which will help alleviate air pollution and GHG emissions locally.

CLIMATE CHANGE

Responding to the Paris Agreement, which came into force on 4 November 2016, Hong Kong, China has developed the 4Ts as its operational framework. The 4Ts are setting Targets with

Timelines, ensuring that there are Transparent metrics to track results, and for everyone to work Together (ENB, 2017f). Hong Kong's Climate Action Plan 2030+ report (ENB, 2017a) released in January 2017 sets out Hong Kong, China's new carbon emission reduction target for 2030 and action plans to meet it. The ambitious target is to reduce carbon intensity by 65% to 70% from the 2005 level by 2030, which is equivalent to a 26% to 36% absolute reduction and a reduction to 3.3–3.8 tonnes on a per capita basis. The carbon reduction actions are:

- Continuing to phase down coal for electricity generation and replacing it with more natural gas and non-fossil fuel sources
- Optimising the introduction of renewable energy in a more systematic manner, with the government taking the lead, based on currently mature and commercially available technologies
- Continuing to improve energy saving for new buildings, mainly focusing on existing buildings and public infrastructure. Changing behaviour in energy use and management through partnership
- Extending rail services, facilitating walking and enhancing the quality of all public transport services. Providing a safe, efficient, reliable and environment-friendly transport system with multi-modal choices that meet the community's needs
- Continuing to work to adapt to climate change. Improving city infrastructure planning and management, strengthening the urban fabric and slope safety, enhancing drainage management and flood control with the 'Blue-Green Infrastructure' concept, ensuring water security, and considering how best to meet the challenge of sea level rise
- Protecting and enhancing ecosystems and appropriate landscaping in urban areas. Expanding country and marine parks and promoting urban forestry and ecology
- Raising social awareness of climate-related risks and emergencies. Creating an appropriate decision-making structure to implement the Paris Agreement within the government, and facilitating and encouraging dialogue among stakeholders

NOTABLE ENERGY DEVELOPMENTS

PUBLIC CONSULTATION ON THE FUTURE DEVELOPMENT OF THE ELECTRICITY MARKET

The current SCAs were signed in April 2017 (ENB, 2017b, 2017c). To plan beyond 2020, the government conducted public consultations in 2015 to solicit public views on the future development of the electricity market. These consultations included public views on (a) the introduction of competition, (b) the future regulatory framework and possible areas for improvement, and (c) the development of RE and demand-side management (DSM). The government has collated the views from the public and will develop specific proposals on future contractual arrangements before commencing negotiations with the power companies. Solicited public views are summarised as follows (ENB 2015b):

- Introduction of competition: the public held different views with regard to competition. Most respondents considered that the current power supply in Hong Kong, China was reliable, safe and affordable and that there was no need to introduce competition to expand the choices available to the public. Some respondents considered that while choice had merits, the requisite conditions for introducing competition did not exist at this stage
- Development of the future regulatory framework and demarcation of possible areas for improvement: regarding the regulatory arrangement, almost all respondents considered that the current contractual arrangement by SCAs had mostly worked well and allowed the economy to achieve the energy policy objectives. It was generally agreed that

improvements should be made to the current SCAs with respect to areas such as the level of permitted rates of return and mechanisms to promote energy saving and RE

- Development of RE: the community's views on the development of RE were generally positive. Around half of the respondents supported the further development of RE despite its higher tariff implications. Some respondents suggested that specific measures should be introduced to promote RE, such as improving the grid access arrangements for distributed RE generators and encouraging their connection to the power grids

FEED-IN TARIFF SCHEME AND RE CERTIFICATION SCHEME

FEED-IN-TARIFF SCHEME

As an important new initiative to promote the development of RE, the Feed-in-Tariff (FiT) Scheme has been introduced by the Hong Kong, China Government under the post-2018 SCAs. The power generated can be sold to the power companies at a rate higher than the normal electricity tariff rate to help recover the costs of investment in the RE systems and generation of the FiT Scheme, thereby encouraging investment in RE. Individuals who successfully apply to the FiT Scheme may receive FiT payments from CLP Power and HKE from 1 October 2018 and 1 January 2019, respectively. FiT will be offered throughout the project life of the RE systems until the end of 2033. The electricity generated by the RE systems after 2033 will belong to the RE system owner. Hong Kong, China will provide support and facilitation to the private sector, including by suitably relaxing the restrictions on installation of solar PV systems on the rooftops of New Territories Exempted Houses (also known as 'village houses') and making appropriate relaxation of restrictions for other private buildings, in particular low-rise. Hong Kong, China will introduce a new program to help schools and NGOs to install small-scale renewable energy systems (EMSD, 2018c) (Policy Address, 2018).

RE CERTIFICATES

Hong Kong, China has introduced renewable energy certificates (REC), which will be sold by the two power utilities (CLP & HKE) for units of electricity generated by renewable energies. The revenue from selling the RECs will help balance the cost of paying FiT and will alleviate the tariff impact brought about by the introduction of the FiT Scheme. Purchasing RECs shows support for RE that is demonstrable via corporate reports (EMSD, 2018c) (Policy Address, 2018).

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USEFUL LINKS

Electrical and Mechanical Services Department—www.emsd.gov.hk

Environment Bureau—www.enb.gov.hk

Environmental Protection Department—www.epd.gov.hk

The Hong Kong Government—www.gov.hk/en

EMSD— https://re.emsd.gov.hk/english/fit/int/fit_int.html

INDONESIA

INTRODUCTION

Indonesia is the world's largest archipelagic state and is located south-east of mainland South-East Asia between the Pacific Ocean and the Indian Ocean. Indonesia's territory encompasses 17 504 large and small islands and large bodies of water at the equator over an area of 7.9 million square kilometres (km²). This constitutes Indonesia's exclusive economic zone. The economy's total land area (25% of its territory) is approximately 1.9 million km². The population was 265 million in 2018 (Indonesia Statistics Bureau, 2019).

Indonesia had a gross domestic product (GDP) of USD 2 954 billion and per capita GDP of USD 11 161 in 2017 (2011 USD purchasing power parity [PPP]). Indonesia is the largest economy in South-East Asia. Indonesia's sovereign credit is classified as investment grade by credit rating agencies such as Standard & Poor's, Fitch Ratings and Moody's Investors Service.

The Indonesian Government has intensified infrastructure development over the last five years (2014-2019). Government spending for infrastructure projects has doubled from IDR 207 trillion in 2014 to IDR 415 trillion in 2019. Notable infrastructure developments are 3 793 km of highway, 980 km of toll roads, subway and monorail, 18 ports, and 65 hydro dams. Energy demand is expected to rise due to economic growth and improved infrastructure connectives.

Indonesia has substantial and diverse energy resources of oil, natural gas, coal and renewable sources. In 2018, Indonesia's proven fossil energy reserves consisted of 7.5 billion barrels of oil, 135 trillion cubic metres of natural gas and 40 billion tonnes of coal (MEMR, 2019c). Indonesia is one of the largest thermal coal producers in the world. Coal production reached 558 million tonnes in 2018, with 64% of the production exported (MEMR, 20189c). Indonesia exported 21 489 ktoe of liquefied natural gas (LNG) and 6 567 ktoe of natural gas through pipelines (MEMR, 2019c). Renewable energy resources include 25 gigawatts (GW) energy equivalent of geothermal, 75 GW of hydro power, 208 GW of solar, 33 GW of biofuels and 61 GW of wind power.

Table 1: Key data and economic profile, 2017

Key data ^a		Energy reserves ^{b, c, d}	
Area (million km ²)	1.9	Oil (billion barrels)	7.5
Population (million)	265	Gas (trillion cubic metres)	135
GDP (2011 USD billion PPP)	2 954	Coal (billion tonnes)	40
GDP (2011 USD PPP per capita)	11 161	Uranium (kilotonnes U)	6.3

Sources: ^a EGEDA (2019); ^b MEMR (2018a); ^c NEA (2014) (MEMR (2019c))

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

In 2017, Indonesia's total primary energy supply was 241 302 ktoe of commercial energy, consisting of oil (36%), coal (24%), natural gas (13%) and other energy (mainly hydropower, geothermal and biomass) (27%). Indonesia is a net exporter of energy; energy exports of crude oil, condensates, natural gas, LNG, petroleum products and coal totalled 170 543 ktoe in 2017. Total energy exports in 2017 decreased by 16% from 2016 (204 018 ktoe), driven by reduced coal imports from China, India and Japan.

OIL

Indonesia produced 50 886 ktoe of crude oil in 2017, a 3.9% decrease from 2016. In the same year, oil exports were 15 249 ktoe (30%). Oil production has significantly declined over the past decade (in 1997, Indonesia produced 80 775 ktoe of crude oil and condensates), and so imports have grown commensurately to meet domestic demand. In 2017, Indonesia imported 21 032 ktoe of crude oil and 28 299 ktoe of petroleum products (EGEDA, 2019).

Most crude oil is produced onshore from three of Indonesia's largest oilfields: the Minas and Duri oilfields in the province of Riau on the eastern coast of Central Sumatra, and the Banyu Urip oilfields in East Central Java. All three fields are mature. The Duri oilfield has been subject to one of the world's largest enhanced oil recovery efforts to increase oil production. In 2018, Indonesia produced 772 million barrels of oil per day (MBOPD) (MEMR, 2019a).

NATURAL GAS

Indonesia produced 62 326 ktoe of natural gas in 2017, a decrease of 0.9% from 2016 (EGEDA, 2019). Of this production, 37% was converted to LNG for export (23 262 ktoe), which represented a 3.4% contraction in volume compared to 2016. Indonesia also exported 6.8 billion cubic metres of natural gas through pipelines to Singapore and Malaysia in 2017. Almost half (48%) of Indonesia's natural gas production was exported in 2017 (EGEDA, 2019). A greater share of natural gas and LNG will be allocated for domestic use as domestic demand increases. Indonesia's gas consumption increased by 7.8% yearly on average between 2003 and 2017 and will continue to rise to meet domestic gas demand, from the power, petrochemical, and building sectors.

Indonesia's large natural gas reserves are located in Badak in East Kalimantan, Corridor in South Sumatra, the Natuna Sea, the Makassar Strait, the Masela Block in Maluku and Bintuni Bay in Papua. Smaller offshore gas reserves are in West and East Java. LNG exports from Tangguh, Bintuni Bay, Papua began in 2009 with gas from the onshore and offshore Wiriagar and Berau gas blocks, which have 23 trillion cubic feet of estimated reserves (SKKMIGAS, 2014). On 19 February 2019, the Repsol-Mitsui-Petronas joint venture discovered two trillion cubic feet (50 Mtoe) of recoverable resources of natural gas in South Sumatra (Repsol, 2019).

COAL

Indonesia produced 271 214 ktoe of coal in 2017. The majority (65%) was exported (EGEDA, 2019). Approximately 57% of Indonesia's total recoverable coal reserve is lignite, 27% is sub-bituminous coal, 14% is bituminous coal and less than 2% is anthracite. Most of the economy's coal reserves are in South Sumatra and Kalimantan, with relatively small deposits in West Java and Sulawesi. Indonesian coal's heating value ranges between 5 000 and 7 000 kilocalories per kilogram and is generally distinguished by low ash and sulphur content (typically less than 1%).

ELECTRICITY

Indonesia had 64 925 megawatts (MW) of electricity generation capacity in 2018. This was held by the state-owned electricity company (PLN), independent power producers (IPPs) and private power utilities. In 2018, 267 terawatt-hours of electricity was generated, of which 71% was supplied by PLN, the state electric company, 23% came from IPPs and 1.5% was imported from Malaysia through cross-border electric transmission lines between Sarawak in Malaysia and West Kalimantan in Indonesia. The power plants producing electricity in 2018 were coal-steam power plants (51%), gas power plants (combined gas-steam power plants, gas turbine power plants and gas engine power plants) (27%), renewable energy power plants (geothermal, hydro, biomass, biogas, municipal solid waste, solar and wind) (10%) and oil power plants (diesel power plants and oil-powered thermal plants) (12%) (MEMR, 2019a).

FINAL ENERGY CONSUMPTION

Total final energy consumption was 168 601 ktoe in 2017, an increase of 8.9% from 2016. The share of total final consumption by sector in 2017 was 25% for industry, 29% for transport, 39% for residential and commercial buildings and 6% for non-energy consumption. By fuel source, oil consumption accounted for the largest proportion of final energy consumption (excluding non-energy consumption) at 40%. Renewable energy was the second largest at 34%, and electricity was the third, at 12% (EGEDA, 2019).

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	450 505	Industry sector	41 599	Total generation	254 620
Net imports and others	-170 543	Transport sector	48 748	Thermal	222 604
Total primary energy supply	241 302	Other sectors	68 080	Hydro	18 632
Coal	57 053	Non-energy	10 174	Nuclear	0
Oil	85 963	Final energy consumption*	158 427	Others	13 383
Gas	32 213	Coal	8 246		
Renewables	65 977	Oil	63 100		
Others	96	Gas	14 720		
		Renewables	53 171		
		Electricity and others	19 189		

Source: EGEDA (2019) (data collected in December 2019).

* Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. Total final consumption includes non-energy uses. Half of the municipal solid waste used in power plants is assumed to comprise renewables.

ENERGY INTENSITY ANALYSIS

In 2017, Indonesia's primary energy intensity was 82 tonnes of oil equivalent per million USD (tonnes of oil equivalent/million USD), an increase of 2.2% from the previous year. In terms of total final consumption, energy intensity amounted to 57 tonnes of oil equivalent/million USD, an increase of 3.7% from the 2016 level. This was mostly driven by increasing energy consumption in the industry, transportation and building sectors.

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%) 2016 vs 2017
	2016	2017	
Total primary energy supply	80	82	2.2
Total final consumption	55	57	3.7
Final energy consumption excl. non-energy	52	54	2.2

Source: EGEDA (2019).

RENEWABLE ENERGY SHARE ANALYSIS

Renewable energy consumption was 158 427 ktoe, an increase of 7.4% from the previous year's level. The share of modern renewables was 8.2% (12 942 ktoe), representing an

increase of 6.0% from the previous year. Traditional biomass was 42 638 ktoe (26.9%) in 2017, a slight decrease from 2016.

There remains scope for Indonesia to accelerate the update of renewable energy in final energy consumption. On 2 March 2017, the Indonesian Government issued Presidential Regulation No. 22/2017 regarding the National General Plan of Energy that includes a policy target for achieving 23% of renewable energy sources in the energy mix by 2025. In 2018, electricity generation from renewable energy was 13% of the total electricity generation mix (MEMR, 2019b).

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	147 528	158 427	7.4
Non-renewables (Fossils and others)	135 319	145 485	7.5
Traditional biomass*	42 678	42 638	-0.09
Modern renewables*	12 209	12 942	6.0
Share of modern renewables to final energy consumption (%)	8.3%	8.2%	-1.3%

Source: EGEDA (2019).

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), employing inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (e.g. hydro and geothermal energy), including biogas and wood pellets, are considered modern renewables, but data on wood pellets are limited.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

THE ENERGY LAW

Indonesia enacted the Energy Law (Law No. 30/2007) 10 August 2007, which contains principles on energy resilience, security of energy supply, sustainable energy practices, energy conservation, and energy efficiency. The Energy Law outlines the national energy policy (Kebijakan Energi Nasional, or KEN); the roles and responsibilities of the central government and regional governments in planning, policymaking and regulation; energy development priorities; energy research and development; and the role of businesses.

KEN addresses energy supply (to meet the economy's needs), energy development priorities, and the utilisation of indigenous energy resources and energy reserves. The Energy Law mandates the creation of a National Energy Council (Dewan Energi Nasional, DEN). The tasks of the DEN are:

- Drafting and formulating the KEN
- Establishing the National Energy Plan, a national energy policy to meet long term national energy demand and to prioritise domestic energy resources development to improve energy security
- Establishing mitigation actions toward situations of energy crisis and emergency

- Supervising implementation of national and provincial energy policies.

The assembly of DEN members is chaired by the President of Indonesia. The DEN is headed by the minister responsible for energy affairs and has 15 members: seven ministers and high-ranking government officials responsible for the supply, transportation, distribution and use of energy; and eight members from industry, academia, expert groups, environmental groups and consumer groups.

The government implemented KEN under Government Regulation No. 79/2014 after obtaining approval from the parliament (the Dewan Perwakilan Rakyat) on 17 October 2014. KEN is intended to create energy security and resilience through an energy management strategy that will be implemented through 2014–50.

On 2 March 2017, the Rencana Umum Energi Nasional (RUEN) or General Plan of Energy was released. The RUEN is the implementation of the KEN. The RUEN is drafted by the government, through the Ministry of Energy and Mineral Resources (MEMR), in a process that involves related ministries, other government institutions, state-owned companies in the energy sector, and regional governments. Academia, other energy stakeholders, and public input are also considered. The RUEN is used by the central and provincial governments as a guideline for developing long-term electricity development plans and other relevant energy policies up to 2050.

ENERGY MARKETS

Indonesia has reformed its energy sector through a series of new laws over the past decade: the Oil and Gas Law (Law No. 22/2001); the Geothermal Energy Law (Law No. 21/2014); the Mineral and Coal Mining Law (Law No. 4/2009); and the Electricity Law (Law No. 30/2009).

These laws were established to promote an increased role for business in the energy supply chain. Fair competition, open energy market opportunities (as an alternative to monopolistic energy markets), direct contracts between energy producers and buyers, and a transparent regulatory framework are focal points.

THE OIL AND GAS LAW

Indonesia's oil and gas industries were reformed in 2001 under the Oil and Gas Law (Law No. 22/2001). The law required that the state-owned oil company, Pertamina, relinquish its governmental roles to the new regulatory bodies. The law also mandated the termination of Pertamina's monopoly in upstream oil and gas activities.

The regulatory bodies BP MIGAS and BPH MIGAS were created to address upstream and downstream oil activities. A fiscal contractual system formed the basis of exploration and production activities, relying mainly on production-sharing contracts (PSCs) between the government and private investors. Investors include foreign and domestic companies as well as Pertamina.

On 13 November 2012, the constitutional court declared that the existence of BP MIGAS conflicted with the Constitution of 1945 and ordered its dissolution. The government subsequently issued an umbrella regulation for the establishment of upstream oil and gas working unit (SKKMIGAS) in January 2013. MEMR controls the operation of SKKMIGAS and its strategic decisions, and has assumed all the roles and responsibilities of BP MIGAS.

BPH MIGAS has supervisory and regulatory functions in the downstream oil and gas sector. It aims to ensure the availability and distribution of fuel throughout Indonesia and to promote gas utilisation in the domestic market through fair and transparent market competition.

THE MINING LAW

On 12 May 2020, the parliament passed a new revision on the minerals and coal mining law (No. 4/2009). The revised mining law obligates the mining license holders to conduct mandatory explorations in their assigned concession area to increase national reserves of minerals and coal. The revised law also opens the opportunity to conduct offshore mining activities beyond the previous boundary of 12 nautical miles off the coast.

Mining license issuance is now managed at the national level (rather than by the provinces) and there are additional requirements on lease holders to protect the environment and support local communities. Majority foreign owners of licenses must also divest after 10 years of production. Stake divestment is offered on a priority basis. First, to the central government of Indonesia, then provincial and regional governments, then state-owned enterprises, and finally to Indonesian privately-owned companies.

The revised mining law provides incentives for the license holders of metal and coal mining to develop downstream mining processing facilities (smelting and coal gasification) to create added value. The law offers 30-year permit guarantees with unlimited renewals for the mining license holders.

THE ELECTRICITY LAW

Under Law No. 30/2009, the electricity industry consists of electricity business entities, which are title holders of electricity supply business licences, or Izin Usaha Penyediaan Tenaga Listrik (IUPTL). The IUPTL integrates electricity supply, power generation, transmission, distribution and retailing of electricity. Indonesia's electricity systems retain vertically integrated configurations. Within these configurations are several licenced systems, such as PLN's numerous power systems, provincial government-owned systems, and private sector power systems. Licence holders of specific electricity supply types (such as the IPPs, which are licence holders in power generation for the supply of electricity to the public) participate in the vertically integrated systems.

The MEMR issued three government regulations (GRs) related to electricity, namely: GR No. 14/2012 on electricity supply businesses activity, GR No. 42/2012 on the buying and selling of electricity across Indonesia's borders and GR No. 62/2012 on electricity support businesses.

THE GEOTHERMAL LAW

Geothermal development activities are defined as mining activities under the Geothermal Law No. 27/2003. According to the forestry law, no mining activities can occur in protected forest areas. This has been a major barrier to developing geothermal electricity in Indonesia.

To coordinate the development of geothermal resources for electricity generation in conserved forest and protected forest areas, the government issued Geothermal Law No. 21/2014 on 17 September 2014. Under the new law, geothermal development activities are not considered as mining activities.

The government has changed the permit scheme from a 'geothermal mining permit' to a 'geothermal permit'. This new law states that geothermal energy can be developed in previously restricted areas after obtaining a permit from the Ministry of Forestry. Permit holders can now undertake geothermal activities in national parks, major forest parks, and natural tourism parks based on Ministry of Environment and Forestry regulations.

The government also issued PP 7/2017, Geothermal Utilisation for Indirect Use, which is the implementing regulation of Law 21/2014.

OIL AND GAS

The Indonesian government regulation on the cost recovery of the upstream oil and gas industry has been revised to the Government Regulation No. 27/2017. Favourable tax

incentives in the revised regulation are expected to attract investment in the upstream oil and gas development.

The PSC regime (outlined in the earlier section on 'The Oil and Gas Law') was introduced in Indonesia in the mid-1960s and reportedly became the fiscal system of choice for many economies over many years. Worldwide, slightly over half of those governments whose economies produce hydrocarbons now use PSCs in some form.

In a PSC, title to the hydrocarbons passes to the contractor at the export or delivery point. Indonesia's third-generation PSC introduced a new contract feature called 'first tranche petroleum' (FTP). The contractor's share of FTP is taxed, and the remaining production is available for cost recovery. Some industry analysts view FTP as a royalty (Johnston, 1994).

Indonesia has other types of joint contract schemes for oil and gas, such as technical assistance contracts (TACs) and enhanced oil recovery (EOR) contracts. A TAC or a PSC contract is typically used for established producing areas. Operating costs are recovered from production, and the contractor does not typically share in production. A TAC can cover both exploitation and exploration if it involves an area where the Indonesian Government has encouraged exploration. In accordance with oil and gas law, existing TACs will not be extended. In addition, participants in the PSCs, TACs and EOR contracts may also enter into separate agreements known as joint operating agreements and joint operating bodies.

THE GROSS SPLIT SCHEME

On 13 January 2017, the government issued Ministerial Regulation No. 8 of 2017 on PSCs. A gross split was subsequently enacted on 22 January 2017, which has more efficiently and effectively attracted investors to the upstream oil and gas sector (MEMR, 2017b). The regulation has the following features:

- Contractor take = base split +/- variable components +/- progressive components
- Government take = government share + bonuses + contractor's income tax
- The base split shall constitute the baseline in determining the production split during the Plan of Development ("PoD") approval. These splits are:
 - a) for oil: 57% (Government of Indonesia); 43% (contractor)
 - b) for gas: 52% (Government of Indonesia); 48% (contractor)
- The variable components are adjustments for the status of the work area, the field location, reservoir, supporting infrastructure, etc.
- The progressive components are adjustments for oil price and cumulative production
- The "actual" production split shall be agreed on a PoD rather than a production sharing contract basis
- Depending upon field economics the MEMR has the authority to adjust (to a maximum of 5%) the production split in favour of either the contractor or the Government of Indonesia.

On 29 August 2018, the government revised Ministerial Regulation No. 8/2017 in response to feedback from the oil and gas industry. The revision provided a fiscal incentive for the existing upstream oil and gas operators for PoD Phase II. In addition, the government introduced Government Regulation No. 53/2017 about Tax Rules for Gross Split PSCs. The key features for the pre-production period (i.e. exploration and development), exploitation and commercial production are:

- An exemption from import duty on goods used in relation to oil and gas operations,
- A 100% reduction in land and buildings tax,
- Non-collection of value-added tax on the import and local procurement of goods and services used in oil and gas operations,

- An exemption from Article 22 on the import of goods entitled to an import duty, and
- Operating costs as a cost reduction component of taxable income can be extended up to 10-years beyond the concession contract period.

In the PSCs scheme, cost recovery is eligible until the end of the PSC contracts.

In 2018, 42 oil and gas fields had adopted the gross split PSCs, including Eni SpA for East Sepinggan, West Natuna block, Exploration Ltd in the Duyung block, Medco E&P Tarakan in Tarakan Block, PT Medco CBM Pendopo in Muralim block, and Sangan-Sangan Block, PH Sangan-Sangan.

The Government of Indonesia has announced that from 2020 the contractor has the flexibility to choose PSCs based on cost recovery or gross split. Contractors can choose cost recovery if the development risk is high (as in offshore oilfields) or gross split (as in mature oilfields operation or contract extension). The Indonesian Government expects that the new incentive will increase foreign and domestic investment in upstream oil and gas development.

SOLAR ROOFTOP REGULATION

Ministerial Regulation No. 49/2018 regarding the utilisation of rooftop solar by electricity customers of PT PLN (Persero) was issued on 1 December 2018. The regulation allows electricity consumers of PLN to sell excess electricity production from solar photovoltaic (PV) to the electricity grid of PLN on a net-metering basis. The rooftop solar regulation is expected to increase the share of renewable in the electricity generation mix and to help Indonesia meet its 23% renewable share in generation mix by the 2025 target (MEMR, 2018b).

The ministerial regulation allows for electricity customers to export excess solar production to the PLN grid and receive a price equal to 65% of electricity purchased from PLN. The accumulated energy that is sold to PLN will be used to reduce electricity bills in subsequent months.

For industrial consumers that wish to install rooftop solar, PLN will charge capacity and emergency fees. Fees are in accordance with the Ministerial Regulation No. 01/2017 regarding the Power Plant Parallel Operation with PT PLN (Persero) electric grids.

POWER PURCHASES FROM RENEWABLE ENERGY POWER PLANTS BY PLN

Ministerial Regulation No. 50/2017 regarding the Utilisation of Renewable Energy Resources for Electricity Generation was issued on 8 August 2017. The regulation introduced a ceiling price and electricity purchase mechanisms for renewable energy sources. Subsequent revisions (Ministerial Regulation No. 53/2018) set a ceiling price and created an electricity purchase mechanism for biodiesel-generated electricity.

The purchase of electricity from renewable energy sources, such as solar and wind, is carried out through direct selection based on quota capacity. The purchase of electricity from other renewable energy sources such as geothermal, biomass, biogas, municipal solid waste as well as hydro power will be conducted through the mechanism of the reference price and direct selections.

For areas where the generation cost is above the average national generation cost, the purchase price of electricity is a maximum 85% of the generation cost on the relevant local grid. If the generation cost in the local grid equals or is below the average national generation cost, the electricity purchase price is equal to the generation cost in the local grid.

The electricity system generation cost used as the purchase price of electricity in the power purchase agreement is the electricity system generation cost of the previous year. Electricity is purchased using the Build Own Operate and Transfer scheme.

PARTICIPATION OF REGIONAL GOVERNMENT IN UPSTREAM OIL AND GAS BUSINESS

Contractors in PSCs are obligated to offer a 10% participating interest (PI) to regional-owned enterprises (BUMD) (Ministerial Regulation No. 37/2016) (MEMR, 2016c).

Details of the regulation:

- Since the approval of the first plan of development (POD1), the contractor (PSC) has an obligation to offer PI 10% to BUMD
- Onshore or offshore fields located in administrative areas of more than one province are subject to the agreement among relevant governors. If no agreement exists, then the MEMR determines the number of PIs offered to each province
- In the period of 10 days from the date of receipt of the approval of POD1, the Chief of SKKMIGAS is obliged to submit a letter addressed to the governor to review the preparation of BUMD that will accept the PI 10% offer
- During the Period 1 year, the governor will deliver, with a copy to the Minister, a letter of appointment to BUMD, which will accept the PI 10% offer indicated by the Chief of SKKMIGAS
- If the governor does not submit a letter of BUMD appointment, it is assumed that the party is not interested, and the PI 10% offer will be declared closed
- If the PI 10% offer for BUMD is declared closed, contractors are required to offer it to State-Owned Enterprises (SOEs)
- The contractor (PSC) pre-finances the obligation amount of BUMD
- SOEs have an obligation to organise finance complying with normal business practices
- Shareholding enterprises and 10% PI cannot be traded or transferred or pledged.

UPSTREAM

The Special Task Force for Upstream Oil and Gas Business Activities (SKK Migas) administered 216 upstream oil and gas PSCs, consisting of 115 onshore PSC agreements, 69 offshore PSCs, and 32 combined onshore and offshore PSC agreements (SKKMIGAS, 2018). To increase production of oil and gas, the Government of Indonesia has approved the development of oil and gas in new fields through multiple major projects. There are eleven oil and gas upstream development projects that have been approved by SKKMIGAS, as follows (SKKMIGAS, 2018):

- Jambaran Tiung Biru in East Java — Pertamina EP Cepu
- Tangguh Train 3 in Bintuni Bay, Papua — BP Berau Ltd
- Abadi in Arafura sea of Halmahera — INPEX Masela Ltd
- Madura BD, MDA and MBH oil and gas field projects in East Java — Husky — CNOOC Madura Ltd
- Bison Iguana Gajah Puteri in Natuna — Premier Oil Natuna Sea B.V.
- Merakes of Makassar Strait in South Sulawesi — Eni East Sepinggan Ltd
- Asap Merah and Kido in West Papua — Genting Oil Kasuri Pty Ltd
- Terang Sirasun Batur Fase-2 in East Java — Kangean Energy Indonesia Ltd
- Bukit Tua Phase-2B and phase-3 in East Java — Petronas Carigali Ketapang II Ltd
- YY oilfield in West Java — Pertamina Hulu Energi ONWJ

- Badik and West Badik in North Kalimantan — Pertamina Hulu Energi Nunukan Company.

TRANS SUMATERA JAVA GAS PIPELINE INTERCONNECTION

Most natural gas interconnecting pipelines from Sumatera to Java were completed in 2019. The remaining portions of gas interconnecting pipelines are two gas pipelines between Cirebon and Semarang in Java, and between Medan and Dumai in Sumatera. A 255-km gas pipeline construction from Cirebon to Semarang commenced on 7 February 2020 and is expected to be completed in 2022. The Trans Sumatera Java gas pipeline supports natural gas demand for the industry and power sectors in Sumatera and Java.

An LNG-receiving and regasification terminal in the Teluk Lamong port in East Java also commenced operations in 2019. The government has mandated PLN, the state electric company, to convert, in 2020, 52 dual fuelled diesel-gas power plants to gas-fired power plants (MEMR Decree number 13/2020). The total capacity of the converted power plants is 1 697 MW, with most located in Eastern Indonesia. Natural gas for the converted power plants will be supplied from domestic gas production and LNG facilities, including BP-Tanggung, Donggi-Senoro, Bontang and Corridor Blocks. MEMR Decree number 34 K/16/MEM/2020 mandates an adequate supply of gas for domestic demand.

CITY GAS NETWORK DEVELOPMENT PROGRAM

The MEMR has rolled out a city gas development program that aims to connect three million households by 2025 and five million households by 2030. The city gas is developed in regions that have indigenous sources of natural gas, mainly in Sumatera, Java, Kalimantan and the Sulawesi islands of Indonesia. The program will largely displace liquid petroleum gas (LPG) consumption. The number of households with gas connection has increased from 200 000 in 2014 to 464 000 in 2018.

Most connections (326 000 households) were funded by the government, with the remaining (138 000 households) developed by the state oil and gas companies (Pertamina and Perusahaan Gas Negara) and the private sector.

MEMR expanded the city gas network by 78 000 household consumers in nine provinces in 2019, from Aceh to West Papua. Bontang City in East Kalimantan will be fully integrated with the city gas network by 2020.

COAL GASIFICATION PROGRAM

Indonesia's coal gasification program contains two main projects. The first is a coal gasification program to produce synthetic dimethyl ether (DME) gas. In 2019, the state-owned energy companies (PT Bukit Asam and Pertamina) and PT Chandra Asri Petrochemical, formed a joint venture to build a USD 3.1 billion coal to urea-DME-polypropylene processing plant. The aim is that the production of the synthetic gas will provide feedstock for PT Chandra Asri Petrochemical plants.

The second coal gasification project is to convert low-rank coal to DME to use as a substitute for liquefied petroleum gas for cooking in the residential and commercial sectors. The project is between PT Bukit Asam and Pertamina, and Air Products and Chemical Inc. Total investment is expected to reach USD 2.7 billion. Coal gasification to DME is currently undergoing Front End Engineering Design. This is scheduled to be completed in 2020 and will then be followed by facility construction. The plants are expected to begin operating between 2023 and 2024.

MINERALS AND COAL MINING

According to the geological agency of the MEMR, proven coal reserves in Indonesia were 26 billion tonnes in 2017. The coal reserves are in Kalimantan (15 billion tonnes), Sumatera (11

billion tonnes) and Sulawesi (0.12 billion tonnes). With production of 461 million tonnes per annum, existing coal reserves could last 56 years.

Coal production was 557 million tonnes in 2018, a 21% increase from 2017. Domestic coal consumption was 21% of the total production at 115 million tonnes. The remaining 79% was exported to 28 economies. China (48 million tonnes), India (44 million tonnes) and Japan (21 million tonnes) bought most of Indonesia's coal in 2017. The Indonesian Government is continuing to promote coal export policies, but is also committed to securing domestic supply through the Domestic Market Obligation policy.

GEOTHERMAL

The Indonesian Government has provided fiscal incentives to promote geothermal development. These incentives are mostly delivered via the taxation system and mostly relate to the investment and income taxes as follow (MoF, 2014):

- A corporate income tax holiday (from five to ten tax years). When the period of corporate income tax exemption ends, developers are given a 50% reduction of corporate income tax for two tax years
- Investment tax allowance for geothermal energy. The allowance includes reduced net income tax of 30% of the total investment (5% a year for six years), accelerated depreciation, and an income tax rate of 10% (or lower if certain conditions are met). Note, geothermal developers may only have a tax holiday or an investment allowance, not both
- Exemption from value-added tax for the importation of machinery and equipment, not including spare parts
- Exemption from import duty for machinery, goods and materials, to be used for construction and development (certain conditions apply)
- Exemption from Withholding Income Tax Art. 22 for the importation of machinery and equipment, not including spare parts

To implement Law No. 21/2014 on geothermal energy, the government issued Government Regulation No. 28/2016 regarding procedures for geothermal production bonuses (MEMR, 2016b). The regulation states:

- Production bonus is a financial obligation that geothermal developers must pay to local governments, based on gross revenue from the sale of geothermal steam and/or power from geothermal power plants
- Geothermal developers are required to provide bonuses for geothermal production after the completion of the first unit of commercial production to the general treasury account of the local government as determined by the MEMR
- Production bonuses amount to 1% of gross revenue from the sale of geothermal steam, or 0.5% of the gross revenue from the sale of electricity
- Provisions concerning the procedures for reconciliation and production bonus percentage (alongside other details) are available in the MEMR

ENERGY EFFICIENCY

GOVERNMENT REGULATION ON ENERGY CONSERVATION

As called for by the Energy Law (Law No. 30/2007) 16 November 2009, the government issued Government Regulation No. 70/2009 regarding energy conservation. The regulation mandates:

- The introduction of an energy manager, energy audits and an energy conservation program for final energy users of 6 ktoe or greater

- The implementation of energy efficiency standards and energy labelling
- Government incentives in the form of tax exemptions, fiscal incentives for the importation of energy-saving equipment, and low-interest lending rates to encourage investments in energy conservation
- Government disincentives in the form of written notices advising compliance, public announcements of noncompliance, monetary fines and reduced energy supply for noncompliance

To implement the energy conservation regulation throughout Indonesia, the government issued Ministerial Regulation No. 14/2012 on energy management, which states:

- Energy producers who consume 6 ktoe per year or greater shall carry out energy management and have an obligation to establish an energy management team
- Energy/energy source users who use less than six ktoe per year shall carry out energy management and/or implement energy savings
- Energy conservation programs shall consist of short-term programs (improvements in operating procedures, maintenance and installation of simple device controls), medium- to long-term programs (increasing the efficiency of equipment and fuel switching) and continuous improvement of awareness and knowledge of energy conservation techniques
- Energy audits shall be conducted on at least the main energy-consuming appliances and equipment at least once every three years
- An annual report on energy management implementation shall be provided by energy/energy source users to ministers, governors and regents, or mayors within their respective jurisdiction
- Energy/energy source users that have reduced their specific energy consumption by at least 2% per year during a three-year period will be eligible for rewards

The government is in the process of revising the Government Regulation No. 70/2009 on Energy Conservation. The new regulation is expected to expand the scope of mandatory energy management. In the next revision, the scope of mandatory energy management will include energy users with energy consumption lower than six ktoe so that sectors beyond industry are incentivised (e.g. the building and transport sectors).

The MEMR introduced the nationally appropriate mitigation actions (NAMAs) program which focuses on increasing the efficiency of air conditioning and process cooling supply in the industry and commercial building sectors (Green Chiller). MEMR has collaborated with GIZ of Germany to develop an efficient air conditioning and process cooling supply since 2014. Through the GIZ cooperative project, safety and energy efficiency standards have been issued for green chillers with the following standards: The National Standard (SNI) ISO 817-2018: Refrigerant – Designation and Safety Classification; SNI 6500-2018: Fixed Installation Refrigeration System – Safety and Environmental Requirement; and SNI 8476-2018: Method of Rating and Testing for Performance of Liquid Chilling Packages Using the Vapour Compression Cycle.

Indonesia has also issued standards and regulations for energy efficiency in buildings. These include: The National Standard (SNI) No. 03-6390-2011: Energy Conservation for Air Conditioning Systems in Buildings; SNI 03-6197-2011: Energy Conservation for Lighting Systems in Buildings; SNI 03-6389-2011: Energy Conservation for Building Envelopes; and SNI 03-6196-2011: Procedures for Energy Audits in Buildings.

The Minister of Manpower Decree No. 53/2018 issued the Establishment of Indonesian National Working Competency Standard (SKKNI) for energy auditing. Implementation of all standards is undertaken by provincial and municipality governments. Each building, whether

existing or new, must conform to the green building standard to obtain or renew its building permit. Some buildings are also participating in the Greenship Program of the Green Building Council Indonesia. The Greenship Programme deals with:

- Appropriate Site Development
- Energy Efficiency & Conservation
- Water Conservation
- Material Resources & Cycle
- Indoor Air Health & Comfort
- Building & Environment Management.

RENEWABLE ENERGY

On 17 October 2014, the government issued the new national energy policy under Government Regulation No. 79/2014 to replace the existing national energy policy, established by Presidential Regulation No. 5/2006. The aim of this policy is to:

- achieve energy elasticity for GDP of less than one by 2025
- achieve a reduction of final energy intensity by 1% per year up to 2025
- realise an optimum primary energy consumption mix where the share of new and renewable energy will be at least 23% by 2025 and at least 31% by 2050.

As part of the government's commitment to mitigate climate change, the MEMR has developed a renewable energy project in the form of a NAMA, known specifically as the Debottlenecking Project Financing for Small-scale Renewable Energy (DEEP). DEEP aims to promote on-grid renewable energy, particularly bioenergy-based power plants, by increasing the institutional capacity of financial institutions and project developers. Its activities will include technical assistance as well as financial facilities for renewable energy developers. In addition to this project, Indonesia is currently developing another NAMA project, which focuses on small-scale renewable energy (mini/micro-hydro power plant).

BIODIESEL MANDATORY PROGRAM

In 2008, Indonesia passed Ministerial Regulation No. 32/2008 regarding the supply, utilisation and trading of biofuel as an alternative fuel. The Biodiesel Mandatory Program has four objectives: i) to increase energy security through increasing the share of domestic fuel utilisation, ii) to reduce the consumption and import of oil products, iii) to increase the economic value added of the agriculture industry through down-streaming the biofuel industry, and iv) to support the domestic agriculture-based economy. To reduce the consumption and import of oil products, the government revised Ministerial Regulation No. 32/2008 through Ministerial Regulation No. 12/2015 on 18 March 2015 (MEMR, 2015).

The regulation sets mandatory targets for the percentage share of biofuels with regard to the share of total fossil consumption (biofuel blend), as shown in Table 5.

Table 5: Minimum obligations for biofuel use (% blend)

Sector	April 2015	Jan 2016	Jan 2020	Jan 2025
Biodiesel				
PSO transport	15	20	30	30
Non-PSO transport	15	20	30	30
Industrial and commercial	15	20	30	30

Electricity generation	25	30	30	30
Ethanol				
PSO transport	1	2	5	20
Non-PSO transport	2	5	10	20
Industrial and commercial	2	5	10	20
Straight vegetable oil fuel				
Industry	10	20	20	20
Marine	10	20	20	20
Aviation	–	2	3	5
Electricity generation	15	20	20	20

Note: PSO = public service obligation fuel means subsidised fuel.

Source: (MEMR, 2015).

After the Biodiesel Mandatory Program was implemented in 2008, the blending rate gradually increased to 15% biodiesel (B15) in 2015 and 20% biodiesel (B20) in 2016. B20 was widely implemented at the national level in 2016. Indonesia is a pioneer in biodiesel utilisation in APEC.

Biodiesel production capacity has increased with the introduction of the B20 Mandatory Program. Domestic biodiesel consumption in 2019 reached 6.3 giga litres (GL). This is equivalent to USD 3.4 billion in avoided crude and diesel oil import costs. The mandatory biodiesel blending rate had increased to 30% by 1 January 2020. Biodiesel consumption is expected to reach 10 GL in 2020. Biodiesel production capacity was recorded at 12 GL in 2018 (MEMR, 2019c).

Government support for the implementation of biodiesel blending is regulated through Presidential Decree No. 66/2018 on the Collection and Utilisation of the Palm Oil Plantation Fund and MEMR Regulation No. 41/2018 on the Provision and Utilisation of Biodiesel in the Financing Framework of the Indonesian Oil Palm Estate Fund. The Indonesia Palm Oil Estate Fund (BPDPKS) protects producers of crude palm oil (CPO) from financial loss as a result of price differences between CPO-based fuel and diesel fuel.

GEOTHERMAL

Indonesia's total geothermal capacity was 2 230 MW in 2019, which is 8.8% of total geothermal potential of 25 387 MW (MEMR, 2019c). The 85 MW Muara Laboh geothermal power plant is the latest plant, beginning operation in December 2019.

Geothermal power plants are mainly in 11 volcanic locations across six islands (Sumatera, Java, Bali, Sulawesi, Maluku and East Nusa Tenggara). Indonesia now has the second highest installed geothermal capacity in the world, behind the US. Indonesia has identified 15 128 MW of additional geothermal power potential from capacity expansions and from new geothermal projects at 64 sites (EBTKE, 2018).

Geothermal power projects in Indonesia attract investment from local, international and multilateral development agencies. In 2019, the Indonesian Government injected USD 50 million equity for the expansion of the 120 MW Geo Dipa geothermal power projects in Central Java. Project financing will be from the Asian Development Bank and commercial banks.

HYDROPOWER

Indonesia's hydropower capacity was 5 739 MW (including 370 MW of micro- and mini-hydro) in 2018, which is 7.6% of the total hydropower potential of 75 GW (DJK, 2019). In PLN's RUPTL 2019–28, total hydropower capacity additions are 9 543 MW (including mini-hydro and pump-storage plants). Of this capacity, 3 558 MW will be developed by IPPs, 2 688 MW by PLN, and the remainder (3 001 MW) is yet to be decided.

Additional hydropower projects include the 88 MW Peusangan and 174 MW Asahan III in Sumatera, considered as strategic projects to reduce the levelised cost of electricity in the Sumatera power grid. Three pump-storage power plants in Java—the Upper Cisokan plant (1 040 MW) in West Java, the Matenggeng plant (900 MW) at the border of West and Central Java and the Grindulu plant (1 000 MW) in East Java (PLN, 2019)—are important for the technical performance and stability of the Indonesian electricity grid, particularly the Java-Bali grid.

Under PLN's Electricity Power Supply Business Plan 2019–28 (*Rencana Usaha Penyediaan Tenaga Listrik*, or RUPTL), hydropower capacity is expected to increase by 8 009 MW between 2019 and 2028. Capacity additions for mini-hydro power plants amount to 1 534 MW (PLN, 2019).

Large hydropower projects include the 900 MW Kayan hydropower project in North Kalimantan that will provide electricity supply to the Tanah Kuning Industrial Park Integrated Ferronickel Complex. The government provides support for hydro power development through various actions, including transmission line expansion, given that large hydropower potential is located far from large consumption centres.

WIND POWER

Indonesia has large wind power potential, especially in West Java, South Sulawesi, West Nusa Tenggara, East Nusa Tenggara and Maluku. The 70 MW Sidrap wind power project that commenced operation in February 2018 is a milestone in the development of utility-scale wind power in Indonesia. It is followed by the 72 MW Tolo I wind farm, the expansion of the 72 MW Tolo II wind farm in Sulawesi and the 10 MW Sukabumi project in Java.

Electricity prices of wind power plants that are operated by IPPs are determined in accordance with the MEMR regulation No. 53/2018 regarding the Utilisation of Renewable Energy Resources for Electricity Generation.

NUCLEAR ENERGY

According to article 11 of Government Regulation Number 79 Year 2014 regarding national energy policy, nuclear energy can be utilised for the purpose of energy security and for reduction of carbon emissions. Renewable energy technology and renewable fuels have priority over nuclear if economically viable. However, nuclear power is considered as the last option to support the economy's clean energy and renewable energy ambitions, and must meet strict safety regulations.

Indonesia has developed an indigenous nuclear fuel cycle, though certain elements are still at the laboratory stage. The economy has a well-established nuclear research program, which spans nearly five decades. The National Nuclear Energy Agency (BATAN) currently operates three nuclear research reactors, specifically the GA Siwabessy 30 MW pool-type materials testing reactor in Serpong; the Kartini-PPNY 100 kilowatts (kW) Triga Mark-II reactor in Yogyakarta; and the Bandung 1000-kW Triga Mark-II reactor in Bandung.

CLIMATE CHANGE

Indonesia supports the objectives of the United Nations Framework Convention on Climate Change (UNFCCC) to prevent atmospheric concentrations of anthropogenic gases exceeding a level that would endanger the existence of life on earth. In December 2015, at the Conference

of the Parties (COP) 21 of the UNFCCC in Paris, the Government of Indonesia submitted its Intended Nationally Determined Contribution. Indonesia unconditionally pledged a 29% GHG emission reduction by 2030 compared with the business-as-usual (BAU) level and a reduction of up to 41% with international support. The BAU level has been projected to be approximately 2 869 GtCO_{2e} in 2030 based on its level in 2010 (1 334 GtCO_{2e}). This has been updated from the national energy policy owing to increasing coal-fired power plant utilisation.

In November 2016, the Government of Indonesia submitted the first Nationally Determined Contribution (NDC) document to the UNFCCC. The document included a target to increase the energy sector contribution to CO₂ emissions reduction from 6% to 38%. The main contribution is to come from the forestry sector, including peat fire prevention and mitigation (59% of the contribution). Waste, agriculture, industrial processes and product use will contribute 3% (UNFCCC, 2016).

To achieve a 29% reduction of CO₂ emissions in 2030, the government has adopted the following strategies for carbon emissions reduction for electricity supply:

- Prioritising electricity supplies from renewable energy sources while ensuring the cost competitiveness of electricity
- Fuel switching from oil to gas and biodiesel
- Adopting advanced cleaner coal technologies such as ultra-supercritical and considering Carbon Capture and Storage when the technology reaches a mature stage of development.

NOTABLE ENERGY DEVELOPMENTS

ELECTRICITY

THE 35 GW ELECTRICITY GENERATION PROGRAM

To provide sufficient electricity supply for economic growth and also to increase the economy's electrification ratio, the government launched the 35 GW Electricity Program for Indonesia in May 2015. The procurement process is expected to be completed in 2019. Commercial operation dates will vary between projects (PLN, 2018). Additional planned capacity stands at 43 GW. In the program, 57% of the capacity comes from coal-fired power plants, 36% from combined cycle gas, 6.1% from hydropower and 1.2% from geothermal.

To realise the program's ambitions, revised Presidential Regulation No. 14 was issued in 2017 to accelerate electricity infrastructure development. The regulation incorporates land acquisition secured by the government. Moreover, it establishes a ceiling price for electricity purchase; shortens the procurement process; streamlines the permit process (the number of electricity permits has been reduced from 52 to 29); and establishes a one-stop service for permits under the Investment Coordinating Board Agency (BKPM) (DJK, 2015b).

Subsequent electricity development programs supported by regulations to accelerate electricity infrastructure development have improved electricity services in Indonesia. There are no longer electricity supply deficits where the electricity reserve margins are varied among electricity grids in Indonesia.

Total installed capacity of electricity in January 2020 was 69 GW. An additional 4.2 GW was contributed from this program in 2019 (MEMR, 2019b).

ELECTRIFICATION RATIO

The Government of Indonesia has rapidly increased Indonesia's electrification rate from 84% in 2014 to 99% in 2019. The government has a target to achieve nearly 100% electricity access by 2020. The electrification program includes the expansion of transmission and distribution networks to reach remote villages in Eastern Indonesia.

The Lampu Tenaga Surya Hemat Energi (Energy Efficient Solar Power Lamp) program has reached 2 510 villages that were yet to access electricity. Grid expansion was being implemented to reach remote regions by the end of 2019. In 2018, 252 552 LTSHE units were distributed to villagers in some of the least developed regions (mainly in East Nusa Tenggara, North Maluku, Central Maluku, Papua, and West Papua).

ELECTRICITY TRANSMISSION NETWORK CONNECTIVITY

Electric transmission connectivity expansion in the Sumatera grid and Sulawesi grid was completed in 2019. The Sumatera grid expansion project consists of a network expansion to 275 kV and an additional 2 933 kilometres of transmission from Lahat in South Sumatera to Sarulla in North Sumatera. This will significantly increase electricity supply reliability in the Sumatera grid and reduce the cost of electricity production by suppressing the operation of oil-based power plants. Sumatera has abundant sources of renewable energy for electricity generation, including hydro (16 GW), geothermal (13 GW), solar (68 GW), wind (6 GW), and biomass (15 GWe) (RUEN 2017).

The Sulawesi transmission grid expansion involves transmission network expansion of 3 767 kms, with a total transfer capacity of 2 648 mega-volt amperes (MVA). This will enable electricity transfer and power exchange between West, Central and South Sulawesi. The completion of the Sulawesi transmission grid will enhance renewable energy development in the region, especially wind power, which currently accounts for 210 MW.

UPDATE OF THE PLN ELECTRICITY SUPPLY BUSINESS PLAN 2019-2028

The MEMR issued ministry decision 1567 K/21/MEM/2018 on 13 March 2018 that consists of the following changes to the previous electricity supply business plan:

- There will be a 23% share of renewable energy in the electricity generation mix in 2025 while the share of coal, gas, and oil will be 54%, 22% and 0.4% respectively
- A plan for additional power generating capacity to give a total capacity of 56 024 MW
- The expansion of transmission line capacity of 63 855 kilometre circuits (kms) while distribution network expansion is 526 390 kilometre circuits (kms)
- The development of 151 424 MVA of high voltage substations and 50 216 MVA of distribution substations

The PLN (state electric company) electricity supply business plan outlines transmission and distribution grid expansion projects to electrify isolated areas with centralised solar PV. For areas that have an unreliable supply of electricity (less than 12 hours of electricity supply per day), PLN is developing hybrid power systems of renewables (solar PV, wind, and biomass) and diesel power plants.

PLN is developing smart grid systems to increase the penetration of variable renewable energy (solar PV and wind power). For isolated areas where the electric distribution network from the existing grids will not be developed in the next two to three years, PLN will develop micro-grids mostly based on solar PV. For existing diesel power plants (accounting for 4% of the total fuel mix in 2018), PLN is planning to increase the biodiesel blending rate share.

UPSTREAM OIL AND GAS

Indonesian upstream gas production is forecast to exceed the projected domestic demand between 2030 and 2040. On 19 February 2019, the Repsol-Mitsui-Petronas joint venture discovered natural gas in South Sumatera. There is at least two trillion cubic feet (Tcf) of recoverable resources, the largest gas discovery in Indonesia for 18 years (Repsol, 2019). The location is close to the existing Grissik gas processing plants and the Sumatera-Java integrated gas transmission system. The joint venture can utilise the existing gas processing and network

infrastructure to expedite the development of the new gas field. Gas production from the Sakakemang block is expected to commence in 2022.

On 27 May 2019, the PoD for Masela gas block located in the Arafuru Sea in Eastern Indonesia was agreed between SKK Migas (Indonesia's oil and gas regulator) and INPEX Corporation of Japan. The development of the Masela gas block is expected to cost USD 18–20 billion. The development will incorporate a large-scale onshore LNG plant (annual processing capacity of 9.5 million tons) and gas processing plant (annual production capacity 150 million standard cubic feet (MMSCF)). The LNG and gas plant and processing facilities are expected to begin operations in the late 2020s. LNG productions from the Masela gas block will supply the growing domestic demand as well as supply export markets, mainly in Asia.

On 19 February 2020, a memorandum of understanding was signed between INPEX Masela and two Indonesian state companies (Pupuk Indonesia and PLN). Pupuk Indonesia will buy 150 MMSCF per annum as a feedstock to its fertiliser production plants. PLN agreed to buy between 2–3 Mtoe of LNG per year for generating electricity from its gas power plants.

Development of Kedung Keris oilfield by Exxonmobil Cepu Limited was completed in 2019 and the oilfield has begun crude oil production of 10 000 barrels per day.

NEW ERA OF ELECTRIC VEHICLES IN INDONESIA

The Indonesian Government will facilitate a transition from gasoline internal combustion engine (ICE) vehicles to electric vehicles (EVs) in the transport sector. The regulatory framework for this initiative is provided by Presidential Decree No. 55/2019 on the Acceleration of Battery-based Electric Motorised Vehicles. The government program aims for 20% of the vehicle market to be EV by 2025. EVs will curb air pollution in urban areas and reduce transport oil consumption.

Batteries are the major cost component for EVs. The government is collaborating with foreign and domestic investors to develop a domestic lithium battery industry to support their EV aspirations. The Indonesian Government introduced a policy to stop exporting nickel ore on 1 January 2020 to secure domestic nickel supply for lithium-ion battery manufacturing.

Charging infrastructure is currently being installed by state companies and the private sector as part of a 2019 to 2025 pilot program. Transjakarta, the operator of the largest rapid bus transit system in the world is currently converting its 1 347 bus fleet to EVs (UN Environment, 2019).

PLN launched a Trade In EL-MO program in 2020 to promote electric two-wheelers through trade-ins. Bluebird, the private taxi operator, purchased 200 EVs for its fleet in 2020 to add to the 30 EVs already in operation. The firm has found that EV taxis have lower operation and fuel costs than ICE taxis.

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PT PLN (Persero)—www.pln.co.id

SKKMIGAS, Satuan Kerja Khusus Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi—www.skspmigas-esdm.go.id

Statistics Indonesia (Badan Pusat Statistik, BPS)—www.bps.go.id

UNDP Indonesia—www.id.undp.org

JAPAN

INTRODUCTION

Japan is in East Asia, and comprises several thousand islands, the largest being Honshu, Hokkaido, Kyushu and Shikoku. Most of its land area, approximately 377 800 square kilometres (km²), is mountainous and thickly forested. Japan is the third-largest economy in the world after fellow APEC economies, the United States and China. In 2017, real GDP was approximately USD 4 933 billion (2011 USD purchasing power parity [PPP]). The population of 127 million people enjoy per capita income of USD 38 907. GDP per capita grew 2.1% in 2017, relative to 2016.

Energy resources are modest, which means that Japan imports nearly all its fossil fuels to sustain economic activity. Proven energy reserves¹ include approximately 44 million barrels of oil, 21 billion cubic metres (bcm) of natural gas and 350 million tonnes (Mt) of coal.

Table 1: Key data and economic profile

Key data ^a		Energy reserves	
Area (thousand km ²)	377	Oil (million barrels) ^b	44
Population (million)	127	Gas (billion cubic metres) ^b	21
GDP (2011 USD billion PPP)	4 933	Coal (million tonnes) ^c	350
GDP (2011 USD PPP per capita)	38 907	Uranium (kilotonnes U)	–

Sources: ^a EGEDA (2019); ^b Conglin Xu and Laura Bell (2019); ^c BP (2019).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Japan's total primary energy supply was 432 million tonnes of oil equivalent (Mtoe) in 2017, which represents an annual increase of 1.2%. Oil contributed the largest share (41%), followed by coal (27%) and natural gas (23%). In 2017, net imports of energy made up 93% of the total primary energy supply.

Japan was the fourth-largest oil consumer in the world and third among the APEC economies in 2017 (182 Mtoe per day), following the United States, China and India (BP, 2019). Almost all oil was imported. Dependency on Middle East oil declined in the early and mid-2010s, due to oil imports from Russia, via expansion of the Eastern Siberia Pacific Ocean pipelines. More recently, oil imports from Russia and other Asian regions have decreased, making Middle East dependency bounce back to 87% in fiscal year² (FY) 2017. Saudi Arabia, the United Arab Emirates and Qatar were the three largest suppliers of oil to Japan (METI, 2019a). In 2017, the primary oil supply was 176 Mtoe, a decrease of 0.4% from the previous year.

In FY2017, Japan consumed 122 Mt of steam (or thermal) coal and 71 Mt of coking coal. Almost all this coal was imported, making Japan one of the world's largest coal importers. The power generation and cement industries are the main use cases for steam coal, whereas steel production relies on coking coal. Japan's main steam coal suppliers are Australia (72% in FY2017); Indonesia (12%); and Russia (11%). The top suppliers for coking coal are Australia (48%); Indonesia (24%); and Canada (9%) (METI, 2019a).

¹ Oil and natural gas figures are as of January 2020. Coal figures are as of the end of 2018.

² The fiscal year starts in April in Japan.

Like coal, natural gas resources are scarce in Japan. Domestic production stands at 2.9 bcm and are located in Niigata, Chiba and Hokkaido prefectures. In FY2017, imports in the form of liquefied natural gas (LNG) supplied almost the entirety of domestic demand. These imports were from Australia (32%), Malaysia (17%), Qatar (12%) and Russia (8%) (METI, 2019a). LNG imports to Japan accounted for 26% of total global LNG trade in 2018 (BP, 2019). Electricity generation, and reticulation as a city gas and as an industrial fuel, are the main use cases for natural gas in Japan. The primary natural gas supply was 101 Mtoe in 2017, a decrease of 0.8% from the previous year.

Japan had 263 gigawatts (GW) of installed generating capacity by Electricity Utility as of September 2019 (METI, 2019c) and generated 1 040 612 gigawatt-hours (GWh) of electricity in 2017. Fossil fuels—coal, gas and oil—constituted 79% of generated electricity. Renewables, including hydro, solar, wind and geothermal, accounted for 18% of generation. The remaining share was nuclear power, which almost doubled from 18 terawatt-hours (TWh) in 2016 to 33 TWh in 2017. The large increase was due to the restart of the Takahama nuclear power plant.

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	41 263	Industry sector	86 386	Total generation	1 040 612
Net imports and others	400 830	Transport sector	70 753	Thermal	819 899
Total primary energy supply	432 032	Other sectors	101 046	Hydro	82 854
Coal	116 476	Non-energy	34 622	Nuclear	32 912
Oil	175 991	Final energy consumption*	258 185	Others	104 947
Gas	100 896	Coal	21 308		
Renewables	23 974	Oil	117 113		
Others	14 695	Gas	29 768		
		Renewables	4 671		
		Electricity and others	85 327		

Source: EGEDA (2019) (data collected in December 2019).

* Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. Total final consumption includes non-energy uses. Half of the municipal solid waste used in power plants is assumed to comprise renewables.

FINAL ENERGY CONSUMPTION

Final energy consumption (excluding non-energy) increased 0.8% to 258 Mtoe in 2017. Oil constituted the largest share at 45%; electricity and others accounted for 33%; gas was 12%; and coal, 8%. Renewables grew 2.5% in 2017, though its share of final energy consumption was still small at 2%.

Non-energy uses amount to an additional 35 Mtoe of final energy consumption (with growth of 3.9% for 2017). Including non-energy means the final consumption is 293 Mtoe. The industry sector uses 30% of this final consumption, followed by the transport sector at 24%. The residential sector's final energy consumption increased by 4.1% in 2017 to account for 16% of the final consumption. The commercial sector accounted for 17% of the final consumption.

ENERGY INTENSITY ANALYSIS

Japan's energy intensity has gradually decreased in the last few decades (EGEDA, 2019). Primary energy intensity continued this trend in 2017 and fell by 0.8%. The final energy

consumption intensity also decreased by 0.7% in 2017. The Japanese government has been implementing energy efficiency policies since the 1979 Energy Conservation Law was enacted. These policies have led to improvements for the industrial, building (commercial and household), and transport sectors in terms of energy intensity (final consumption basis).

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%) 2016 vs 2017
	2016	2017	
Total primary energy supply	88	88	-0.8
Total final consumption	60	59	-0.7
Final energy consumption excl. non-energy	53	52	-1.1

Source: EGEDA (2019).

RENEWABLE ENERGY SHARE ANALYSIS

In 2017, the share of modern renewables in final energy consumption increased 9.8%. The total share is still relatively small at 6.5%. Incremental growth of renewable electricity installations (following the introduction of the feed-in tariff (FIT) system in 2012) combined with declining consumption, has contributed to larger shares in recent years.

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	256 026	258 185	0.84
Non-renewables (Fossil fuels and others)	240 950	241 493	0.23
Traditional biomass*	1 083	1 119	3.32
Modern renewables*	15 076	16 692	11
Share of modern renewables to final energy consumption (%)	5.9	6.5	9.8

Source: EGEDA (2019).

**Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on), including biogas and wood pellets, are considered modern renewables although data on wood pellets are limited.*

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

The Ministry of Economy, Trade and Industry (METI) is responsible for designing energy policy for Japan. Within METI, the development of mineral resources, securing stable supplies of energy, promoting efficient energy use, and regulating electricity and other energy industries are the responsibilities of the Agency for Natural Resources and Energy.

Before the Great East Japan Earthquake in March 2011 and the subsequent Fukushima Daiichi nuclear power plant accident, the aim of Japan's energy policy was to achieve the '3E' goals. Specifically, energy security, economic efficiency and environment. Japan has since reshaped

its goals to '3E+S'. This is the original goal, with safety added as an additional condition. The responsibility for determining the safety of nuclear facilities was transferred to the Nuclear Regulation Authority (NRA), an independent commission affiliated with the Ministry of the Environment (MOE), in September 2012.

Japan's energy policy is based on the Basic Act on Energy Policy of 2002. The core principles involve securing of stable supply, environmental suitability, and utilization of market mechanisms. The Basic Act on Energy Policy requires the government to formulate a Strategic Energy Plan with a comprehensive, long-term vision to realise targeted energy balances. The plan is reviewed at least every three years to accommodate changes in international dynamics and the effectiveness of previous policies. The first Strategic Energy Plan was in 2003 and it has since been revised four times.

The current plan (2018) is the fifth, and largely upheld plans for 2030 laid out in the fourth edition, with additional proposals for 2050. The long-term vision is based on two main pillars. The first pillar is sincere repentance for the Fukushima Daiichi nuclear power plant accident. The government reaffirms its intentions to reduce dependency on nuclear generation to the lowest extent possible, and to take the initiative in resolving the many issues related to nuclear power use. The second pillar is energy independence, coupled with Japan's commitment to leading global decarbonisation. The importance of renewables as low-carbon and domestic energy sources is reiterated, alongside coal as a stable and cost-effective transitional baseload, and natural gas as the main flexible middle-load power source. Energy technologies are hailed as a valuable Japanese 'resource', which can contribute to safety, decarbonisation, and international competitiveness.

These ideas, and the recognition that innovative technologies may be available by 2050, have led the government to approach industry and academia to accelerate innovation while simultaneously achieving the existing '3E+S' for 2030.

The existing 2030 goals are in line with Japan's Nationally Determined Contribution (NDC) of 26% emission reduction (compared to 2013 levels) for the Paris Agreement. These goals will be pursued through implementing stringent energy efficiency standards, promoting the maximum penetration of renewables, improving the efficiency of thermal power plants, while maintaining the lowest nuclear energy share possible.

Strategies to promote innovation to 2050 incorporate technological concepts such as artificial intelligence and the "Internet of Things" for development of regional energy grids and demand-side networks. The strategies also highlight structural reform of the electricity and gas markets. Such reforms will encourage a multitude of actors to join the market, creating a globally competitive environment which drives innovation. Introducing hydrogen or heat as alternative forms of secondary energy is another path to an innovative energy future.

The Long-term Energy Supply and Demand Outlook of Japan was released in July 2015 (METI, 2015a). Power source mix, primary energy demand and supply, and energy-related CO₂ emissions for FY2030 are discussed, to show how the '3E+S' policy in the Strategic Energy Plan can be realised. The outlook assumes that the following goals will have to be met: 1) improving self-sufficiency rate (including renewable and nuclear sources) to the level (approximately 25%), higher than before the Great East Japan Earthquake (approximately 20%); 2) lowering electric power costs than at present; and 3) contributing to an energy-related greenhouse gas (GHG) reduction target comparable to EU and the U.S., and leading the world.

The outlook presents a well-balanced power source mix where nuclear constitutes 20–22% of the total generated electricity, renewables 22–24%, LNG 27%, coal 26% and oil 3%. The share of nuclear is lower than before the earthquake (when it was around 30%). For renewables, the two largest sources are hydro (a range of 8.8–9.2%) and solar (7%).

ENERGY MARKETS

OIL

Japan aims to decrease its oil dependency, partly because of its experiences during the oil crises in 1973 and 1979. However, oil still dominates the total primary energy supply of the economy. The share of oil was approximately 40% in 2010, and increased to 47% in 2012 due to the loss of nuclear generation and incremental oil-fired generation after the earthquake. The share of oil declined to 41% in 2017. Securing a stable supply remains one of Japan's major energy policy issues.

Japan imports almost all its oil via maritime tankers. In preparation for possible disruptions, Japan has emergency oil stockpiles and independently developed resources. Japan also maintains close ties with oil-producing economies to manage maritime supply emergencies.

The Japan Oil, Gas and Metals National Corporation (JOGMEC) manages Japan's state-owned oil stockpile. As of October 2019, Japan held the equivalent of 234 days, including state-owned stocks, private sector stocks and joint oil storage programs with oil-producing economies (PAJ, 2019). Japan's stock is well in excess of the International Energy Agency's 90-day net import requirement. JOGMEC also provides financial and technical assistance to Japanese oil industries for the exploration and development of oil and natural gas fields both domestically and abroad.

The Japanese government regulates domestic refining capacity. Regulations are aimed at raising the residue processing capacity³ to approximately 50% of the total distillation capacity from FY2014 to FY2016. Oil refining companies were able to comply with the regulation mainly by reducing distillation capacity (METI, 2017a). The Japanese government is encouraging the production of higher-value oil products, such as gasoline and naphtha rather than asphalt, from residues through regulations adopted in October 2017. The number of oil refineries in Japan decreased from 40 in 1996 to 22 in March 2019, and the refining capacity decreased from 5.3 to 3.5 million barrels per day (PAJ, 2019).

Competition continues in the domestic oil production market. The Japanese Government aims to establish a fair and transparent market in terms of quality and prices, where oil product retailers interact with final consumers.

NATURAL GAS

Demand for natural gas increased rapidly from 14 Mtoe in 1990 to 31 Mtoe in 2012. Natural gas demand has steadied to be at 30 Mtoe in 2017 (EGEDA, 2019). Natural gas is supplied almost entirely by imports in the form of LNG. A stable and secure supply of LNG is important for Japanese energy policy.

Recent deregulation of the gas and electricity markets has seen Japanese gas and electric utilities intensify efforts to reduce their costs. These companies benefit from securing LNG supply on flexible terms, so that they can be more responsive to short-term market conditions. However, such flexible supply terms are difficult to reach a settlement. The LNG Producer-Consumer Conference is used as a platform of discussion between LNG suppliers and consumers to develop flexible LNG markets (METI, 2017b). Japan has also been seeking alternative suppliers. For example, the economy promoted technological developments in the production and processing of methane hydrate, which is abundant in the oceans surrounding Japan and is considered a future energy resource.

The Fourth Strategic Energy Plan designated the period from 2014 to 2018–2020 as a time to reform electricity and gas systems in order to achieve a more liberalised and competitive market. Amendments to the Gas Business Act were enacted in June 2015 to fully liberalise the retail market by 2017 and unbundle the gas pipelines owned by three city gas utilities—Tokyo Gas, Osaka Gas and Toho Gas—by April 2022 (METI, 2015b). The Fifth Strategic Energy Plan

³ Such as RFCC (Residual Fluid Catalytic Cracking), FCC (Fluid Catalytic Cracking), hydrocracking, and SDA (Solvent De-asphalting).

discusses setting a requirement on the share of gas developed by Japanese interests. Increasing the credibility of price evaluation processes, and invigorating the forward market are priorities.

The annual LNG Producer-Consumer Conference has been held since 2012 as a platform to exchange ideas and enhance cooperation between producer countries and consumer countries (METI, 2017b). The sixth conference held in October 2017 focused on: 1) producer-consumer cooperation in LNG markets in Asia; 2) new LNG opportunities driven by innovation; 3) LNG as a transport fuel; and 4) flexible LNG markets and spot pricing. The METI minister announced that Japan will contribute to expand the LNG market in Asia. The government also announced consideration of a ten billion dollars joint investment in upstream, midstream and downstream LNG projects.

At the seventh conference, the Japanese Government declared that it would contribute to expand the LNG market by drastically increasing financial support through institutions such as JOGMEC and the Japan Bank for International Cooperation (JBIC). The government intends that this should add the scale of 50 Mt to the existing LNG market.

The 8th LNG Producer-Consumer Conference was held in Tokyo in September 2019. Almost 1200 participants joined including ministers, officials of international organisations, and executives from 32 economies and regions. Japan announced additional USD 10 billion fund and support for additional 500 LNG experts from both the public and private sectors to promote the LNG industry.

COAL

In 2017, coal had a 27% share of the total primary energy supply. Coal will continue to play an important role for power generation and the production of iron, steel, cement, and pulp and paper. Japan is the third-largest coal importer in the world after China and India. Japan's share of the total global consumption was approximately 3.1% in 2018 (BP, 2019).

The Fifth Strategic Energy Plan aims to make efforts to shift to the cleaner use of gas and fadeout inefficient coal use.. Japan will also help economies utilise at or above ultra-super critical pressure, provided that there is a request from economies for Japan's high efficiency coal-fired plant and these economies are forced to choose coal as an energy source from perspectives energy security and economic viability, taking into account OECD rules and in a form that is consistent with the energy policy and climate change measures of these economies.

ELECTRICITY

After oil, electricity was the second-largest contributor to total final energy consumption in 2017. The increased use of electrical appliances in homes, widespread use of personal computers and related information technology in offices, and a shift to more service-based sectors has led to increased electricity consumption in recent years.

Since 1995, the Japanese electricity market has been partially liberalised to ensure fair competition and transparency. Independent power producers were introduced in 1995, and the system of power producers and suppliers (PPS) and partial retail competition (for purchases over 2 000 kW) was made available in 2000. The scope of retail competition was expanded to include contracts larger than 500 kW in 2004, and larger than 50 kW in 2005 (METI, 2002). After the earthquake and subsequent Fukushima Daiichi nuclear power accident, Japan's electricity sector faced mounting pressure to deregulate even more, to create a more competitive and transparent system. The Electricity Business Act was amended in 2013, 2014 and 2015 to reform the market accordingly (METI, 2015b).

The latest reforms focus on three points: 1) establishing the Organisation for Cross-regional Coordination of Transmission Operators in April 2015; 2) ensuring full retail competition from April 2016; and 3) legally unbundling the transmission/distribution sector from 2020 and transitioning to overall liberalisation of retail prices thereafter. To avoid creating a monopoly situation after the

retail liberalisation in 2016, retail tariffs of designated utilities are being regulated temporarily. Deregulation will be gradual.

Japan's electricity market faces technical and institutional challenges due to the growing penetration of various forms of renewable power, especially solar photovoltaic (PV), owing to the FIT system which was launched in 2012. The government has initiated a wholesale market, a power reserve tender system, a non-fossil certificate market for FIT electricity, and a base-load capacity market (METI, 2019g). To ensure a secure and reliable electricity supply, real-time inter-regional supply-demand balance mechanisms and capacity markets will be introduced in FY2020 (METI, 2017c). New rules for inter-regional transmission lines, to switch from a 'first-come, first-served' basis to an auction-based system which prioritises producers with a lower spot market price, have also been in operation since FY2018.

HYDROGEN

The Fifth Strategic Energy Plan released in 2018 and the Basic Hydrogen Strategy released in 2017 (METI, 2017d) affirms the potential of hydrogen. To encourage cost-effective appropriation of hydrogen technologies, METI compiled the Strategic Roadmap for Hydrogen and Fuel Cells in 2014 and revised it in 2016 and 2019 (METI, 2016, 2019o). This roadmap summarises the means of hydrogen production, transport, and storage, with clear time frames. The revised roadmap sets the following short-term targets:

- The cost target for the installation of polymer electrolyte fuel cells is 800 000 JPY/kW by 2019 and 1 million JPY/kW by 2021 for solid oxide fuel cells
- The vehicle stock target for fuel cell vehicles is 4 million by 2020, 20 million by 2025 and 80 million by 2030
- The target number of hydrogen stations to be installed is 160 stations by FY2020 and 320 stations by FY2025 (the Basic Hydrogen Strategy envisions 900 stations by 2030)

Japan aims to use hydrogen for power generation in the 2030s and develop international hydrogen supply chains and domestic power-to-gas capacity for renewable hydrogen supply. Japan is already co-developing pilot projects such as 'HySTRA (CO₂-free Hydrogen Energy Supply-chain Technology Research Association)' with Australia (working on brown coal gasification with carbon capture) and 'AHEAD (Advanced Hydrogen Energy Chain Association for Technology Development)' with Brunei Darussalam (which involves steam methane reforming of off-gas). Future targets are set to establish a 'CO₂-free' hydrogen supply system so that cost of hydrogen-based electricity (including environmental value) drop to existing cost per kWh, and conventional gas stations, gas power plants and other traditional energy systems can be replaced.

The second Hydrogen Energy Ministerial Meeting held in September 2019 produced a Global Action Agenda. The agenda commits to 'Ten, Ten, Ten': ten million hydrogen powered systems, ten thousand hydrogen refuelling stations, in ten years. The agenda also promotes mobility infrastructure development, market expansion and hydrogen supply chains (METI, 2019i, 2019j, 2019k).

FISCAL REGIME AND INVESTMENTS

The Japanese Government recognises the need to encourage domestic petroleum companies to obtain upstream oil and gas equity shares overseas. JOGMEC offers technical support to domestic petroleum companies in areas such as geological structure studies and mining technologies. Both JOGMEC and JBIC offer financial support.

The government is concentrating on financial support for existing upstream projects in the short-term. In the medium term, the government will build a flexible and effective finance system through JOGMEC to reduce the geopolitical and technical risks for future projects.

ENERGY EFFICIENCY

The 1979 Energy Conservation Law, established after the oil crises, is the basis of all energy conservation policies in Japan. It requires energy efficiency improvements for the industrial, building (commercial and household), and transport sectors (METI, 2019b). The government has been implementing energy efficiency policies through regulation and economic incentives. The economy achieved a 40% improvement in energy intensity (final consumption basis) from 1980 to 2014.

Regulations include 1) regular reports on energy efficiency and efforts for energy intensity improvements of 1% per year for factories and business establishments with energy consumption of 1 500 kilolitre (crude oil equivalent) per year or more; 2) the Top-Runner Program, which was introduced in 1998 to establish energy efficiency standards to curb consumption in the residential, commercial and transport sectors; and 3) regular reports on energy efficiency implementation for scale-specified cargo owners and carriers. The law also requires factories and business establishments with an energy consumption of 3 000 kilolitre (crude oil equivalent) per year or more to appoint qualified energy managers. Economic incentives include subsidies, accelerated depreciation and tax reductions for installing efficient equipment or facilities, in addition to R&D subsidies for efficient technology such as high-performance heat pumps and insulation materials.

The earthquake in 2011 caused significant electricity shortages, and so the 1979 Energy Conservation Law was amended in May 2013 to strengthen energy efficiency and level the electricity load. Amendments include the development of new indicators and guidelines to evaluate the effectiveness of 'peak-shift' activities, and the expansion of the Top-Runner Program. The Top-Runner Program initially covered 11 items, including cars and air conditioners, and expanded to 32 items in 2019. Some items do not consume energy but can make significant contributions to efficiency or energy conservation, such as building insulation.

The revised Strategic Energy Plan established the following initiatives in 2014 (METI, 2014):

- Enhancing Japan's energy efficiency (already at the highest level in the world) by introducing the most advanced technologies for replacing equipment in the industrial sector
- Enhancing support and regulatory measures (including the Top-Runner Program) to increase the adoption of highly efficient equipment in each sector. Program coverage includes industrial refrigerators, printers, heat pumps, LED lamps and building insulation materials
- Replacing all lighting with high-efficiency lamps (including LED and organic electroluminescence lighting) on a flow basis by 2020 and a stock basis by 2030
- Achieving net zero emissions energy for newly constructed public buildings by 2020 and for all newly constructed buildings by 2030
- Raising the share of next-generation vehicle sales to between 50% and 70% by 2030, while promoting comprehensive measures, such as intelligent transportation systems
- Facilitate the development of an energy management system, such as a building energy management system, and encouraging the adoption of the ISO 50001 standard.

RENEWABLE ENERGY

In August 2011, the Act on Purchase of Renewable Energy-Sourced Electricity by Electric Utilities was approved by the National Diet, and took effect on 1 July 2012. It requires electric utilities to purchase electricity generated from renewable energy sources (certified solar PV, wind power, small- and medium-sized hydropower, geothermal and biomass) with fixed period contracts and prices.

The government enforced a partial revision to the act in April 2017 to facilitate the installation of authorised capacity and obligate general transmission companies to purchase FIT electricity, instead of retail companies as specified under the previous rules. The revision included changes to the FIT pricing system to allow the government to determine the purchase prices for the next several years. This is expected to promote the delivery of renewable energy with longer lead times, such as geothermal, wind, hydro and biomass, by improving the predictability of projects. The revision also allows the government to use auctions to determine the FIT prices. The government is already using the auction system for utility-scale solar PV and certain types of biomass. For other technologies, METI has announced purchase prices for the next three years (METI, 2019d). Table 5 shows the FIT prices from FY2018 to FY2021.

Table 5: Prices for feed-in tariffs from FY2019

Renewable Energy		Prices (JPY/ kWh)	Years
Solar	Over 500 kW	Determined by auction	20
	From 10 kW to 500 kW (for FY2019)	14 + tax ^a	20
	Less than 10 kW - FY2018 - FY2019	26/28 ^b 24/26	10
	Less than 10 kW (double generation) - FY2017 and FY2018 - FY2019	25/27 ^b 24/26	10
Onshore wind	- FY2018	20 + tax	20
	- FY2019	19 + tax	
	- FY2020	18 + tax	
	Replacement		
	- FY2018	17 + tax	
	- FY2019 and FY2020	16 + tax	
Offshore wind	Bottom- Fixed -FY2018 and FY2019	36 + tax	20
	-FY2020	Determined by auction	
	Floating (from FY2018 to FY2020)	36 + tax	20

Renewable Energy		Prices (JPY/ kWh)	Years
Hydro	From 5 000 kW to 30 000 kW (from October 2017 to FY2021)	20 + tax	20
	Facilities that utilise existing headrace (from FY2017 to FY2021)	12 + tax	
	From 1 000 kW to 5 000 kW (from FY2018 to FY2021)	27 + tax	20
	Facilities that utilise existing headrace (from FY2018 to FY2021)	15 + tax	
	From 200 kW to 1 000 kW	29 + tax	20
Facilities that utilise existing headrace	21 + tax		
Hydro	Less than 200 kW	34 + tax	20
	Facilities that utilise existing headrace	25 + tax	
Geothermal	Over 15 000 kW		15
	- New facility	26 + tax	
	- Replacement	20 + tax	
	- Replacement but reusing utilising underground equipment	12 + tax	
	Less than 15 000 kW		15
	- New facility	40 + tax	
- Replacement	30 + tax		
- Replacement but reusing utilising underground equipment	19 + tax		
Biomass	Methane fermentation gasification	39 + tax	20
	Unused woods (less than 2 000 kW)	40 + tax	20
	Unused woods (over 2 000 kW)	32 + tax	20
	General woods		20
	- (over 10 MW) FY2019 - (under 10 MW) FY2019	Determined by auction 24 + tax	
Liquid biomass from agricultural waste	Determined by auction	20	

Renewable Energy		Prices (JPY/ kWh)	Years
	Waste (excluding woods) - FY2018 to FY2021	17 + tax	20
	Recycled woods - FY2018 to FY2021	13 + tax	20

Source: METI (2019d)

Notes: a. consumption tax (10%); b. Solar PV, approved for grid connection in Hokkaido, Tohoku, Hokuriku, Chugoku, Shikoku, Kyushu and Okinawa areas is obliged to be installed with a suppression control system. Higher purchase prices are applied to this case.

Costs incurred by the utilities in purchasing renewable energy-sourced electricity are borne by all electricity consumers, via a surcharge to support renewable development. The surcharge has been calculated from May 2018 to April 2019 as follows (METI, 2019e):

Surcharge for renewable energy = Monthly electricity consumption (kWh) × 2.90 JPY

The surcharge from May 2019 to April 2020 is:

Surcharge for renewable energy = Monthly electricity consumption (kWh) × 2.95 JPY.

FIT rates and contract periods are determined according to factors such as the type of renewable power, the form of installation and the scale of renewable energy sources. An independent committee recommends contract rates and periods, with these subsequently reviewed by METI.

Table 6 shows the renewable generation capacity authorised under FIT, as well as the capacity existing before FIT was introduced in June 2012 (METI 2019f). In six years, more than double the original capacity (20 600 MW) has been registered. If all the registered capacity is installed, the renewable generation capacity will be more than four times larger.

Non-residential solar PV has flourished in Japan. Authorised capacity constitutes 80% of newly installed capacity and 74% of the authorised capacity. Due to this development, FIT rates are being cut back or switched to an auction-based scheme for facilities with larger capacities.

Table 6: Installed generation capacity by renewable energy after the introduction of FIT (MW)

	Installed capacity		Authorised capacity under FIT
	By the end of June 2012	Newly installed under FIT (July 2012–December 2018)	July 2012–December 2018
Solar (Residence)	4 700	5 828	6 155
Solar (Non-residence. More than 10 kW)	900	37 221	66 507
Wind	2 600	1 111	7 092
Medium hydro	9 600	348	1 197
Biomass	2 300	1 520	8 730
Geothermal	500	23	84
Total	20 600	46 051	89 765

Source: METI (2019h).

NUCLEAR ENERGY

There were 54 commercial nuclear reactors in Japan in 2010, the year before the Fukushima Daiichi nuclear power plant accident. In November 2019, there were 33 commercial reactors, due to decommissioning of the Fukushima Daiichi nuclear power station⁴ and 18 other reactors: Tsuruga Unit 1, Mihama Unit 1 and Unit 2, Shimane Unit 1, Genkai Unit 1 and Unit 2, Ikata Unit 1 and Unit 2, Ohi Unit 1 and Unit 2, Onagawa Unit 1, Tokai Unit 1, Hamaoka Unit 1 and Unit 2 and Fukushima Daini Units 1-4. Facility age and additional costs to meet the new safety regulations led to these retirements.

2014 was the first year that nuclear power plants did not contribute to the electricity supply since their introduction. Ohi Unit 3 and Unit 4 ceased operations for periodic inspections in September 2013, and no nuclear reactors were restarted until August 2015.

The Sendai nuclear power plant became the first reactor to restart under the new regulatory scheme. In October 2016, the NRA gave final approval to Ikata Unit 3, Mihama Unit 3, Sendai Unit 1 and Unit 2 and Takahama Units 1 to 4 to restart under the newly established safety regulations. For Takahama Units 1 and 2, the NRA approved a 20-year licence extension, the first instance under the current scheme.

Several nuclear reactors in Japan face challenges due to district court decisions. In March 2016, the Ohtsu district court suspended the operation of Takahama Units 3 and Unit 4, which had newly restarted. The suspension was overturned by a subsequent ruling of the Osaka high court. In January 2020, the Hiroshima high court suspended the operation of Ikata Units 3, which had newly restarted. As of July 2020, nine commercial reactors have begun operating again: Sendai Unit 1 and Unit 2, Ikata Unit 3, Takahama Unit 3 and Unit 4, Ohi Unit 3 and Unit 4 and Genkai Unit 3 and Unit 4 (Sendai Unit 1 and Unit 2, Ikata Unit 3, Takahama Unit 3, Ohi Unit 3 underwent a few months of temporary suspension for periodic inspections) (METI, 2019I).

Japan adopts nuclear fuel cycle policy including fast reactor development. The Government decided to decommission the prototype fast breeder reactor in December 2016 and decided on a “Policy of Fast Reactor Development” at the same time. Based on the policy, Japan subsequently decided on a “Roadmap of Fast Reactor Development” in December 2018. Based on the policy, Japan continues fast reactor development by making use of knowledge of Monju and international cooperation with the United States and France.

The Fifth Strategic Energy Plan sets out visions for nuclear power to 2030 and 2050. By 2030, the government hopes to lower dependency on nuclear power to the maximum extent possible, while safely restarting existing plants which have been approved by the NRA. By 2050, safe nuclear reactors are viewed as a viable option for decarbonisation.

Siting process for geological disposal of high-level radioactive waste has not been started yet in Japan. In 2017, METI published a map that identified the Japanese scientific features to show potentially favourable geographic areas for geological disposal (METI, 2017e). METI and the Nuclear Waste Management Organization of Japan (NUMO) have been promoting communication activities to enhance public awareness and understanding of this issue such as holding dialogues with local communities or residents.

CLIMATE CHANGE

The Kyoto Protocol obliged Japan to reduce GHG emissions by 6% on average from the 1990 level between 2008 and 2012. Japan exceeded this commitment by reducing emissions by 8.4%. But the actual average annual GHG emissions during the commitment period increased by 1.4% compared with the 1990 base year, from 1 261 to 1 278 million tonnes of CO₂ equivalent. The main reasons were additional fossil fuel consumption after the earthquake and subsequent

⁴ A total of six reactors. The reactor owner (Tokyo Electric Power Company) decided to decommission units 1-4 in April 2012 and units 5 and 6 in January 2014.

nuclear plant shutdowns. Expansion of carbon sequestration capacity and reduction obtained through trading certified emission reduction credits made it possible for Japan to satisfy the commitment (MOE, 2014).

Japan introduced the Tax for Climate Change Mitigation in October 2012 to continue to reduce emissions (MOE, 2012). The tax is levied on crude oil/oil products, gas and coal. The tax rate was raised in FY2014 and FY2016 (Table 7)⁵. Revenue from this tax is used to promote energy efficiency, renewable energy, and the cleaner use of fossil fuels.

Table 7: Tax for the promotion of global warming countermeasures

	October 2012	April 2014	April 2016
Crude Oil/Oil Product (JPY/kL)	250	500	760
Gas (JPY/tonne)	260	520	780
Coal (JPY/tonne)	220	440	670

Source: MOE (2012).

Certain prefectural governments also have their own emission policies, such as the emission trading schemes found in Tokyo, Kyoto and Saitama. Tokyo focuses on the industry and commercial sectors, while Kyoto includes transport as well. For FY2015–19, Tokyo targets 17% reductions in commercial buildings and 15% reductions in factories. The reductions are based on the average emissions for the years FY2002–07.

The private sector is also working towards a low-carbon society. KEIDANREN (the Japan Business Federation), published a voluntary action plan (KEIDANREN, 2017). Phase I of the plan was published in 2013, with a focus on 2020 targets, and Phase II came out in 2015, with even more ambitious targets for 2030. Voluntary targets, such as CO₂ reduction, were formulated by 62 industries/companies in the industrial, commercial, transport and transformation sectors.

In July 2015, Japan submitted its Intended Nationally Determined Contribution (INDC) to the United Nations Framework Convention on Climate Change (UNFCCC, 2015), which later became its Nationally Determined Contribution (NDC) following the enforcement of the Paris Agreement in November 2016. The economy determined its emission reduction level based on the government's long-term energy supply and demand outlook. The declared ambition is to reduce GHG emissions by 26% in FY2030 compared with the FY2013 level, which was emissions of 1 042 Mt of CO₂ equivalent in 2030.

In the same month as Japan's INDC submission, a voluntary action plan was decided by 10 former general electric power companies, Japan Atomic Power Company, J-POWER and 23 PPS. The plan targets an emission intensity of 0.37 kgCO₂/kWh in 2030, which is consistent with Japan's Long-term Energy Supply and Demand Outlook and INDC. The government amended several laws to support the plan. For instance, efficiency standards on new fossil fuel plants are now 42% for coal-fired plants and 51% for LNG-fired plants on a higher heating value basis. Also, the energy supply for retail companies has been set to 44% non-fossil fuels for 2030 in the Act on Sophisticated Methods of Energy Supply Structure (METI, 2019b).

At the 25th session of the Conference of the Parties to the United Nations Framework Convention on Climate Change (COP 25) in Madrid, Spain in December 2019, Japan indicated that 28 local governments, including Tokyo, Kyoto and Yokohama, are aiming for net zero carbon emissions by 2050 (MOE, 2019a, 2019b).

⁵ Since April 2016, the tax has been JPY 289 per tonne of CO₂ for all sources. Specifically, by using the CO₂ emissions factor of each fossil fuel, the tax rate per unit quantity (kilolitre or ton) is set in order to make each tax burden equal to JPY 289 per ton of CO₂ emissions (MOE, 2012).

NOTABLE ENERGY DEVELOPMENTS

ELECTRICITY MARKET REFORM

The government initiated the non-fossil fuel certificate market for FIT authorised sources in 2018. The government also implemented new operational rules for inter-regional transmission lines in FY2018. The auction-based system has transitioned from a 'first-come, first-served' basis to prioritise producers with the lowest spot market price. Plans are for a base-load market in 2019, and real-time markets and capacity markets in FY2020.

FIFTH STRATEGIC ENERGY PLAN

The fifth Strategic Energy Plan was released in July, 2018. The importance of renewables is emphasised, alongside coal as a stable and cost-effective transitional baseload, and natural gas as the main flexible middle-load power source.

ROADMAP FOR CARBON RECYCLING TECHNOLOGIES

The Carbon Recycling Promotion Office was established at the Agency for Natural Resources and Energy in February 2019 to promote technological innovations involving the capture, storage and utilisation of CO₂. METI formulated the Roadmap for Carbon Recycling Technologies in cooperation with Cabinet Office, the Ministry of Education, Culture, Sports, Science and Technology (MEXT) and the MOE in June 2019. The roadmap clarifies the current technology status and issues concerning cost reductions. It also sets out cost targets for 2030 and 2050.

JAPAN-UNITED STATES STRATEGIC ENERGY PARTNERSHIP (JUSEP)

This partnership emphasises open and competitive energy markets to ensure secure energy supply and universal access to affordable and reliable energy to help eradicate poverty, fuel economic growth, and increase global security in the Indo-Pacific region and sub-Saharan Africa. Both economies prioritize development of a global market for liquefied natural gas (LNG), energy infrastructure development in the developing countries that promotes regional integration, and capacity building cooperation (METI, 2019m) (METI, 2019n).

COP 25 IN MADRID, SPAIN

Japan announced its achievement of reducing GHG emissions for five years in a row. The MOE minister also announced that Japan has the largest number of corporations and organisations supporting the Task Force on Climate-related financial Disclosures (TCFD) in the world (MOE, 2019d).

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USEFUL LINKS

Agency for Natural Resources and Energy—www.enecho.meti.go.jp/en/

Institute of Energy Economics, Japan—eneken.ieej.or.jp

Ministry of Economy, Trade and Industry—www.meti.go.jp/english/index.html

Ministry of the Environment—www.env.go.jp/en/index.html

REPUBLIC OF KOREA

INTRODUCTION

The Republic of Korea (Korea) is in north-east Asia between China and Japan. It has an area of 100 284 square kilometres (km²) and a population of 51 million people as of 2017. Korea's population density is very high, with an average of more than 526 people per km². Approximately 20% of the population lives in Seoul, Korea's capital and its largest city. The economy's geography consists of hills and mountains with wide coastal plains in the west and the south. The climate is relatively moderate, with four distinct seasons. Air conditioning is necessary during the tropical hot summers, and heating is required during the bitterly cold winters.

Over the past few decades, Korea has become one of Asia's fastest growing and most dynamic economies. The gross domestic product (GDP) increased at least 5.0% every year from 1990 to 2017, reaching USD 1.8 trillion (2011 USD purchasing power parity [PPP]) in 2017. GDP per capita (2011 USD PPP) in 2017 was USD 35 938, approximately three times higher than in 1990. Korea's major industries include semiconductors, shipbuilding, cars, petrochemicals, digital electronics, steel, machinery and parts and materials.

Korea has few indigenous energy resources. It has no oil resources except for a small amount of condensate, only 309 million tonnes of recoverable coal reserves and 7.1 billion cubic metres of natural gas. Thus, to sustain its high level of economic growth, Korea imports large quantities of energy products. It imported approximately 88% of its primary energy supply in 2017. In the same year, it was the world's fifth-largest importer of crude oil, the third-largest importer of liquefied natural gas (LNG) and the fourth-largest importer of coal (IEA, Aug. 2019)

Table 1: Key data and economic profile, 2017

Key data ^{a, b}		Energy reserves ^{c, d}	
Area (km ²)	100 284	Oil (million barrels)	–
Population (million)	51	Gas (billion cubic metres)	7.1
GDP (2011 USD billion PPP)	1 850	Coal (million tonnes)	309
GDP (2011 USD PPP per capita)	35 938	Uranium (kilotonnes U)	–

Sources: ^a UN (2019); ^b EGEDA (2019); ^c EIA (2020); ^d KOSIS (2019)

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Korea's total primary energy supply more than tripled between 1990 and 2017 from 93 million tonnes of oil equivalent (Mtoe) to 282 Mtoe. From 1990 to 2000, energy supply increased at an average annual growth rate of 7.3%, exceeding the economic growth rate of 6.9% for the same period. Likewise, per capita primary energy supply grew from 2.2 tonnes of oil equivalent in 1990 to 5.5 tonnes of oil equivalent in 2017. This increase was similar to that in Japan and most European economies.

In 2017, Korea's total primary energy supply decreased 0.1% from the supply in the previous year. In terms of energy sources, oil represented the largest share (39%), followed by coal (29%) and gas (15%). The remaining 17% of the primary energy supply came from nuclear and renewable energy sources. Energy imports accounted for approximately a fifth of Korea's total import value in 2017.

The oil supply in 2017 was 109 Mtoe, a 0.6% decrease over the previous year's level. In 2017, the economy imported 81% of its crude oil from the Middle East. Coal supply in 2017 totalled 83 Mtoe, a 1.4% increase from the previous year. Korea has modest reserves of low-quality, high-ash anthracite coal, which are insufficient to meet its domestic consumption. Thus, almost all of Korea's coal consumption is met by imports. Korea is the world's fourth-largest importer of both steam coal and coking coal. The main coal imports come from Australia, Russia, Indonesia, Canada, and the United States.

Since the introduction of LNG in 1986, natural gas use in Korea has grown rapidly. Natural gas supply reached 43 Mtoe in 2017. Most of Korea's LNG imports come from Qatar, Oman, Indonesia, Malaysia, Australia, and Brunei Darussalam. Korea began producing natural gas domestically in November 2004 after a small quantity of natural gas was discovered in the Donghae-1 offshore field in the south-east.

Korea's electricity generation in 2017 was 561 terawatt-hours (TWh), a 0.6% increase from the 2016 level. Generation by thermal sources, including coal, oil and natural gas, accounted for 70% of the total electricity generated, followed by nuclear energy at 26% and hydropower and other renewables at 3.0%.

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	49 090	Industry sector	48 380	Total power generation	561 225
Net imports and others	249 344	Transport sector	35 623	Thermal	393 251
Total primary energy supply	282 249	Other sectors	46 632	Hydro	2 820
Coal	82 598	Non-energy	52 509	Nuclear	148 427
Oil	109 093	Final energy consumption*	130 635	Others	16 727
Gas	43 214	Coal	8 090		
Renewables	4 845	Oil	45 336		
Others	42 499	Gas	22 168		
		Renewables	2 035		
		Electricity and others	53 006		

Source: EGEDA (2019) (data collected in December 2019).

* Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. Total final consumption includes non-energy uses. Half the municipal solid waste used in power plants is assumed to comprise renewables.

FINAL ENERGY CONSUMPTION

Korea's final energy consumption (excluding non-energy) in 2017 was 131 Mtoe, which was a 1.5% increase from the previous year. The industrial sector accounted for the largest share (excluding non-energy) at 37%, while the transport sector accounted for 27%. The remainder (36%) was used in other sectors (combined residential, commercial and agriculture sectors). In general, consumption in the industrial sector has weakened since the late 1990s, and consumption in the transport and commercial sectors has increased.

By energy source, electricity and others accounted for 41% of final energy consumption (excluding non-energy), followed by oil (35%), natural gas (17%) and coal (6.2%).

ENERGY INTENSITY ANALYSIS

Strong economic growth in 2017 meant that total primary energy supply energy intensity improved 3.0%. This was an economy-wide energy intensity level decrease of 4.8 toe / million USD. For final energy consumption (excluding non-energy), energy intensity improved by 1.6%, to 71 toe / million USD in 2017. This was mostly driven by lower energy consumption in the commercial sector, which had decreased 1.3% from the previous year.

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%) 2016 vs 2017
	2016	2017	
Total primary energy supply	157	153	-3.0
Total final consumption	100	99	-0.56
Final energy consumption excluding non-energy	72	71	-1.6

Source: EGEDA (2019)

RENEWABLE ENERGY SHARE ANALYSIS

In 2017, the share of modern renewable energy in final energy consumption was 2.6%, an increase of 12% from the previous year. Even with increased use of fossil fuels, modern renewables increased by 13% over the previous year's level, due mainly to expansion of solar power.

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	128 752	130 635	1.5
Non-renewables (fossils and others)	125 472	126 919	1.2
Traditional biomass*	337	375	11
Modern renewables*	2 943	3 341	13
Share of modern renewables in final energy consumption (%)	2.3%	2.6%	12%

Source: EGEDA (2019).

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass. This is because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial) using inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (e.g. hydro and geothermal energy), including biogas and wood pellets, are considered modern renewables, but data on wood pellets are limited.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

In the past, Korea's energy policy has focused on ensuring a stable energy supply to sustain economic growth. The government is currently seeking a new direction in energy policy with the aim of supporting sustainable development that fully considers the 3Es: energy, economy and environment.

The responsibility for energy policy development and implementation is divided among multiple government institutions. The Ministry of Trade, Industry and Energy (MOTIE), which succeeded the Ministry of Knowledge Economy (MKE) in 2013, is the primary government body for energy policy.

In 2006, the Korean Government established the National Energy Committee, which is chaired by the president and includes governmental and non-governmental experts. The committee's role is to deliberate upon and mediate major energy policies and plans. The committee is also responsible for the National Basic Plan for Energy, emergency preparedness, foreign energy resource development, nuclear energy policy, the coordination of energy policies and projects, the prevention and settlement of social conflict related to energy issues, the transportation of energy and the physical distribution plan, the effective execution of the energy budget, and energy issues within the United Nations Framework Convention on Climate Change (UNFCCC).

As part of its liberalisation efforts in the energy sector, in 2001, the government established the Electricity Regulatory Commission to take charge of regulations in the electric power sector and manage technical and professional competition policy. There is no regulatory commission for the gas industry. The Fair Trade Commission is Korea's anti-trust agency, and monitors monopoly problems and unfair business practices in the energy sector.

The Korea Energy Economics Institute (KEEI) develops energy policies related to the production of energy statistics. It also considers policies with regard to consumption and supply overviews, energy conservation and climate change, the petroleum industry, the gas industry, the electricity industry, and the new and renewable energy industry, among others. It is directly financed by the government.

The Korea Institute of Energy Technology Evaluation and Planning, funded by the government, is Korea's major energy technology research institute. Its mission is to contribute to growth across the economy by developing industrial core energy technologies and then deploying these technologies to related companies.

The Korea Energy Agency plays a key role to implement national energy policies for the improvement of energy efficiency, deployment of new and renewable energy, and tackable climate change issues with a smart and efficient demand side management.

In August 2008, faced with high energy prices and rising concerns over climate change, Korea announced a long-term strategy that would determine the direction of its energy policy until 2030.

On 4 June 2019, Korea launched the Third Energy Master Plan, which is the main official plan in the energy sector, with a timeframe extending to 2040 (MOTIE, 2019). According to the Third Energy Master Plan, final energy consumption will increase by an annual average rate of 0.8% between 2017 and 2040. In the same period, energy intensity in final energy consumption will decrease by an annual average rate of 1.1%. The economy has set a goal to reduce the final energy consumption by 19% and improve energy intensity by 38%.

The government has proposed the following five major policy strategies:

- To implement a paradigm shift towards an innovative energy consumption structure
- To ensure a transition to a clean and safe energy mix
- To expand the distributed and participatory energy system
- To strengthen global competitiveness for the energy industry
- To lay a foundation for energy transition.

Heavy dependence on the Middle East for its crude oil supply led the economy to pursue a policy of diversifying its oil supply in accordance with the 3rd Energy Master Plan. The state-owned Korea National Oil Corporation (KNOC) will continue to be responsible for the

economy's preparedness for an oil emergency by operating oil stockpiling facilities and pursuing stakes in oil projects around the world.

In the natural gas industry, the state-owned monopoly Korea Gas Corporation (KOGAS) will continue to be responsible for managing the import, storage, transmission and wholesale distribution of LNG. The electricity industry will continue to be dominated by the state-owned Korea Electric Power Corporation (KEPCO). It is possible that restructuring and liberalisation may evolve in the future, allowing more private participation in the oil, gas and electricity industries.

ENERGY MARKETS

MARKET REFORM

Korea has been restructuring its energy sector since the late 1990s when it introduced the principle of free competition in industries traditionally considered to be natural monopolies, such as electricity and natural gas. In January 1999, in a move to phase in competition in the electricity industry, the government announced the Basic Plan for Restructuring the Electricity Industry. The plan included the unbundling and privatisation of Korea's state-owned electricity monopoly, KEPCO.

Part of the plan has been implemented, including the establishment of the Korea Power Exchange and the Korea Power Commission in April 2001. The power generation part of KEPCO was split into six wholly owned companies—five thermal generation companies and the Korea Hydro & Nuclear Power Company Limited. The five thermal generation companies were to be privatised in stages. However, in July 2008, the government announced there would be no further privatisation of KEPCO and its five subsidiaries. At the end of 2015, 51% of KEPCO, a holding company, was owned by the Korean Government. KEPCO is still a dominant player in the electricity sector, controlling 70% of total power generation and 100% of transmission and distribution in Korea (KEEI, 2019).

The Korean Government has also made moves to restructure the gas industry. In November 1999, the government sold 43% of its equity in KOGAS and developed the Basic Plan for Restructuring the Gas Industry to promote further competition in the industry. The plan outlines a scheme to introduce competition into the import and wholesale gas businesses, promote the development of the gas industry, and enhance consumer choice and service quality. A detailed implementation plan was announced in October 2001. The plan covers ways to achieve the smooth succession of the existing import and transportation contracts, privatisation of import and wholesale businesses, stabilisation of prices and balance of supply and consumption, and revision of related legislation and enforcement (KEEI, 2002).

For competition in the import and wholesale sectors of KOGAS, a final decision on whether to split the sectors from KOGAS or introduce new companies will be made following discussions among stakeholders. Given the strong public interest in this sector, the existing public utility system is expected to be maintained. Competition in the retail sector, which is currently operated under a monopoly system within each region, will be introduced in stages in conjunction with the progress made in the wholesale sector. As of the end of 2019, no decision on the liberalisation of the gas market had been made.

OIL, GAS AND ELECTRICITY MARKETS

OIL

Given Korea's dependence on oil imports, the government prioritises securing supplies for both the short and long term. To ease short-term supply disruptions and meet International Energy Agency (IEA) obligations, the Korean Government has been increasing its oil stockpile since 1980. At the end of 2019, Korea held 205 million barrels in oil stock. This economy-wide stockpile capacity substantially exceeds the IEA's 90-day requirement.

The state-controlled KNOC has been actively exploring and developing oil and gas, both locally and abroad, to improve energy security. As of March 2020, it has conducted 32 projects in 15 Economies. Falls in global crude oil prices have hit its earnings and created significant financial stress. KNOC declared 2019 as the Year of Emergency Management and decided to focus on streamlining its operation for capital discipline, attracting foreign investments, and disposing of non-core projects.

Korea has also been trying to diversify its crude oil supplies. The number of supply sources increased from seven in 1980 to 30 in 2016. However, Korea's dependency on oil imports from the Middle East remains high (70% in 2019). Korea is also actively strengthening its bilateral relations with oil-producing economies as well as its multilateral cooperation through the IEA, the Asia-Pacific Economic Cooperation (APEC) forum, the Association of South-East Asian Nations (ASEAN)+3, and the International Energy Forum and Energy Charter to enhance its crisis management capabilities.

NATURAL GAS

Korea introduced natural gas-based city gas to the residential sector in the 1980s to reduce the economy's dependence on imported oil. Since then, gas use has grown rapidly and has replaced coal and oil in the residential sector. KOGAS has a monopoly over Korea's natural gas industry, including the gas import, storage, transport and wholesale businesses. Thirty-four city gas companies operate in the gas retail business in each region of the economy. KOGAS is the world's second-largest LNG buyer, and it also promotes the development of natural gas resources abroad in economies such as Australia, Canada and Iraq.

The Thirteenth Plan for Long-Term Natural Gas Demand and Supply, finalised by MOTIE in April 2018, projected natural gas consumption to increase by 0.81% per year from 2018–31 (MOTIE, 2018). By sector, the city gas sector's consumption of natural gas is projected to increase by 1.2% per year and the consumption of gas for power generation is also projected to increase by 0.2% per year.

ELECTRICITY

Korea's economic growth has led to a substantial increase in its electricity consumption over the past few decades. Throughout the 1990s, the average annual growth rate was 9.5%. Then, between 1990 and 2016, installed capacity increased five-fold, from 21 gigawatts (GW) in 1990 to 116 GW in 2017.

The Eighth Basic Plan for Long-term Electricity Demand and Supply (2017–31), finalised by MOTIE in December 2017, projects that electricity consumption will grow by 2.1% per year from 2017 to 2031 and that additional capacity of 16 GW will be required by 2031 (MOTIE, 2017a). This translates to approximately 124 GW of the total generation capacity for this period, taking decommissioning into account.

Korea's electricity industry is dominated by KEPCO, which was separated into six power generation subsidiaries in April 2001. These are Korea Hydro & Nuclear Power, which owns the economy's nuclear energy power plants and large hydroelectric dams; and five state-owned generating companies, which own the economy's thermal power plants. KEPCO retained the economy-wide transmission and distribution grids.

To rectify an energy supply and consumption structure that was overly dependent on oil, the construction of oil-fired power plants has been strictly controlled and the development of nuclear, coal and natural gas electricity generation units has been promoted. Gas-fired power plants were first introduced in 1986. Korea has been building nuclear energy power plants since the 1970s because nuclear energy is a strategic priority for the government. However, it announced its energy transition roadmap, which aims to replace nuclear and coal generation with renewables and natural gas, in October 2017. During the period of the Eighth Basic Plan,

five nuclear power plants are scheduled for construction and 12 nuclear energy power plants are scheduled for decommissioning. The share of total electricity production capacity from nuclear energy power plants is projected to decrease from 19% in 2017 to 12% in 2031.

FISCAL REGIME AND INVESTMENT

In December 2009, the Korean Government approved tax reforms to foster a business-friendly environment and promote investment. The tax changes included a reduction in corporate tax rates and an increase in tax benefits for R&D.

In 2009, the corporate tax rate was 22% on taxable income over KRW 200 million and 13% on taxable income below that amount. Under the tax reforms, these rates were scheduled to be reduced in 2010 to 20% and 10%, respectively. The tax reduction for the lower bracket was implemented as scheduled, while the implementation for the higher bracket was delayed. Since the year of 2018, the corporate tax rate has been 25% on taxable income over KRW 300 Billion, 22% on KRW 20 billion to KRW 300 billion, 20% on KRW 200 million to KRW 20 billion and 10% on taxable income below KRW 200 Million.

To promote investment in R&D, the government has increased its tax assistance for R&D. The measures include an R&D reserve fund, an increase in investment tax credits for R&D facilities and an increase in the deduction for R&D grants paid by corporations to universities from 50% to 100%.

ENERGY EFFICIENCY

The Korean Government has introduced policy measures to improve energy efficiency, including energy consumption management schemes for end users, adjustment of the energy pricing system, and the provision of incentives for companies to invest in energy efficiency. These policy measures, announced in June 2019, are part of Korea's long-term energy plan, which aims to achieve a 1.1% annual energy efficiency improvement through to 2040 from 2017. The Energy Efficiency Innovation Strategy, which was announced in August 2019, provides specific measures to transform the pattern of domestic energy consumption through developing and adopting most innovative technologies such as ICT-technologies for the industry, transport, and building sectors.

RENEWABLE ENERGY

In September 2014, the Korean Government announced the Fourth National Basic Plan for New and Renewable Energy (MOTIE, 2014c). According to the plan, the government aims to replace 11% of the total primary energy supply with new and renewable energy (NRE) by 2035. The development of solar and wind power as the main energy sources will also enable 13% of the total electric energy in Korea to be supplied by NRE by 2035.

In December 2017, the Korean Government released the 3020 Renewable Energy Initiative Implementation Plan (MOTIE, 2017b). According to the plan, renewable energy's share of the energy mix will increase from its level of 7% in 2016 to 20% by 2030, through the provision of 49 GW in new generating capacity. More than 90% of the new generating capacity is planned to come from solar and wind energy, and the remainder is planned to be supplied by hydro and bioenergy. According to the 3rd National Energy Master Plan, the share of renewables in power generation mix is expected to increase to 30-35% by 2040.

CLIMATE CHANGE

On 15 August 2008, Korea announced a new low-carbon, green growth vision aimed at shifting the traditional development model of fossil fuel-dependent growth to an environmentally friendly model. To realise this vision, the Presidential Commission on Green Growth was established in February 2009. The Framework Act on Low Carbon, Green Growth was subsequently submitted and took effect April 2010. This legislation provided the legal and institutional basis

for green growth. To implement this vision more effectively, the National Strategy for Green Growth was adopted in July 2009 together with the 1st Five-Year Plan for Green Growth.

The National Strategy for Green Growth calls for the construction of a comprehensive, long-term (2009–50) master plan to address the challenges caused by climate change and resource depletion. The strategy consists of three main objectives and ten policy directions:

- Mitigating climate change and achieving energy independence
 - Effectively reducing greenhouse gas emissions (MKE, 2009)
 - Reducing fossil fuel use and enhancing energy independence
 - Strengthening the capacity to adapt to climate change
- Creating new engines for economic growth
 - Developing green technologies
 - Greening existing industries and promoting green industries
 - Advancing the industrial structure
 - Engineering a structural basis for a green economy.
- Improving the quality of life and enhancing international standing
 - Greening the land and water and building a green transportation infrastructure
 - Bringing the green revolution into people's daily lives
 - Becoming a role model for the international community as a green growth leader

NOTABLE ENERGY DEVELOPMENTS

RESPONSE TO CLIMATE CHANGE

NEW BUSINESS MODELS TO RESPOND TO CLIMATE CHANGE

In July 2014, MOTIE introduced six new energy-related businesses based on emerging business models to reduce CO₂ emissions and increase energy efficiency (MOTIE, 2014b). MOTIE also established the Energy Efficiency and Climate Change Bureau for more efficient policy support. Plans for R&D in related technology and regulation reforms were announced in December 2014, April 2015 (Government of Korea, 2014b, 2015).

The six business models are the following:

- A consumption management service, which collects electricity saved from buildings and factories using electricity-saving devices and sells it to the electricity trading market
- An integrated energy management service, which connects finance, insurance and an energy management system (EMS) and provides systems maintenance for companies
- An independent micro-grid, which replaces diesel generators with NRE generators and an electricity storage system (ESS)
- Photovoltaic equipment rental, which lends photovoltaic equipment to households and receives payment through electricity gains
- A recharging service for electric vehicles, which provides paid recharging
- Used heat recycling from thermal power plants, which utilises used heat in diversified farming

These business models focus on reducing the consumption of fossil fuel electricity and on increasing R&D investments to develop related technologies, such as carbon capture and storage (CCS), ESSs and EMSs.

From the 3rd Energy Master Plan, the Korean government will promote the demand management market to create new businesses for real-time demand management by integrating 4th industrial Revolution technology, such as IoT, with energy devices and equipment. The considering business models including ESS- related like fast charging service, ESS recycling, Virtual Power Plant (VPP), Energy Service Company (ESCO) in connection with efficiency management systems such as the EERS & mandatory energy audit and energy management service providers for systemizing the post- installation management of EMS.

KOREA'S MITIGATION TARGET AND ITS AMBITION

In June 2015, the Korean Government announced its Intended Nationally Determined Contribution (INDC) towards achieving the objective of Article 2 of the UNFCCC. Korea plans to reduce its greenhouse gas (GHG) emissions by 37% from the business-as-usual (BAU 851 MtCO₂ equivalent) level by 2030 across all economic sectors based on the BAU projection of the Korea Energy Economics Institute's the Energy and GHG Modelling System (KEEI-EGMS).

According to the Climate Analysis Indicators Tool (CAIT) of the World Resources Institute (WRI), Korea accounts for approximately 1.4% of global GHG emissions, including land use, land use change and forestry (LULUCF). Korea's mitigation potential is limited because of its industrial structure, which comprises a large share of manufacturing (29% as of 2018), and the high energy efficiency of its major industries. Furthermore, given the decreased level of public acceptance following the Fukushima accident, there are now limits to the extent that Korea can make use of nuclear energy, one of the major mitigation measures available.

To meet its INDC, the Korean Government announced the Second Basic Plan of Climate Change in October 2019 that includes a basic roadmap to achieve the national GHG reduction to 536Mton by 2030 (Government of Korea, 2019). It provides comprehensive policy directions for expanding the use of renewable energy, strengthening energy demand management using IT-technology, expanding green building and electric/hydrogen car deployments, developing new technology to reduce energy consumption of industry sector.

ENERGY TRANSITION FROM NUCLEAR AND COAL TO RENEWABLES AND NATURAL GAS

In October 2017, the Korean Government released its energy transition roadmap that aims to reduce nuclear and coal use and replace them with increased use of renewables and natural gas (Government of Korea, 2017). Under the new energy roadmap, it will nullify plans to construct new nuclear reactors and will not allow life extensions for existing nuclear reactors.

The government aims to generate 20% of electricity from renewable energy sources by 2030. The share of natural gas is expected to be 19%, while those of coal and nuclear energy will be 36% and 24%, respectively.

THE FIFTH COMPREHENSIVE PLAN FOR NATIONAL ENVIRONMENT

In December 2019, the Korean Government announced its fifth comprehensive plan for national environment that contains the visions and long-term plans to cover the period from 2020 to 2040 for national environmental management. (Government of Korea, 2019) The plan sets out the following three main targets: a green environment full of life, a happy environment improving the quality of our lives, and a smart environment that transforms our economic and social systems.

According to the plan, the construction of new coal power plants will be stopped, and the number of existing facilities will be reduced considerably. Along with the reduction of coal power plants, ultrafine dust (PM_{2.5}) concentration will be reduced to the level recommended by WHO (10 $\mu\text{g}/\text{m}^3$) by 2040. To increase the sales rate of electric and hydrogen cars to 80% of the total

vehicle sales in 2040, the standards for emission and mileage of vehicles will be tightened, and the dissemination target of low emission vehicles will be gradually strengthened.

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USEFUL LINKS

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Korea Energy Economics Institute—www.keei.re.kr

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Korea Gas Corporation—www.kogas.or.kr

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World Resources Institute (CAIT Climate Data Explorer)—<http://cait.wri.org>

MALAYSIA

INTRODUCTION

Malaysia covers an area of 330 535 square kilometres (km²) and lies entirely in the equatorial zone. It is made of 13 states as well as three federal territories (MEA, 2018). In 2017, Malaysia's population stood at 31 million, an increase of 1.4% from 2016 (EGEDA, 2019).

Malaysia's gross domestic product (GDP) reached USD 848 billion (2011 USD purchasing power parity [PPP]) in 2017, an increase of 5.9% from 2016. GDP per capita increased by 4.5% to USD 27 272 in 2017 (EGEDA, 2019). The largest contributions to GDP were services (55%), manufacturing (23%), mining and quarrying (8.5%), agriculture (8.3%) and construction (4.6%) in 2017. The main export products were manufactured goods (82%), oil and gas (7.4%), and palm oil (5.8%) (MEA, 2018).

Malaysia's energy resources are modest compared to other APEC economies. The east Malaysian states hold nearly two-thirds of Malaysia's energy reserves according to Malaysia's National Energy Balance (NEB). Peninsular Malaysia holds the remainder. The economy's oil reserves (including condensate) are 4.7 billion barrels, with 37% in Sabah (EC, 2019a). There is an estimated 2.3 trillion cubic metres (tcm) or 83 trillion cubic feet (Tcf) of natural gas reserves, with more than half located in the Sarawak basin. Coal reserves are mostly located in Sarawak and Sabah, and are estimated at 1.9 billion tonnes (EC, 2019a).

Malaysia harbours a wealth of resources capable of generating renewable energy (RE). The Malaysian Government is working to transform the energy mix to one that comprises more RE, not only to ensure the continuity of supply, but also to address the pressing environmental concerns that come with a dependency on fossil fuels. Studies reveal that the current energy system can already accept solar photovoltaic (PV), and the Malaysian Government has a target of 20% renewables by 2025. Effective storage systems are necessary for increased penetration and to mitigate intermittency (EC, 2019b).

Malaysia is exploring small hydro technology, but hydro sites are long distances away from demand centres. Financial solutions are required to connect these resources to the grid system. The potential of biomass and biogas is also promising, but again, remote locations present a similar challenge. Empty fruit bunches (essentially palm oil plantation waste), offer increased supply and great value (EC, 2019b).

Table 1: Key data and economic profile, 2017

Key data ^{a, b}		Energy reserves ^c	
Area (km ²)	330 323	Oil (billion barrels)	4.7
Population (million)	31	Gas (trillion cubic metres)	2.3
GDP (2011 USD billion PPP)	848	Coal (million tonnes)	1938
GDP (2011 USD PPP per capita)	27 272	Uranium (kilotonnes U)	–

Sources: ^a MEA (2019); ^b EGEDA (2019); ^c EC (2019a).

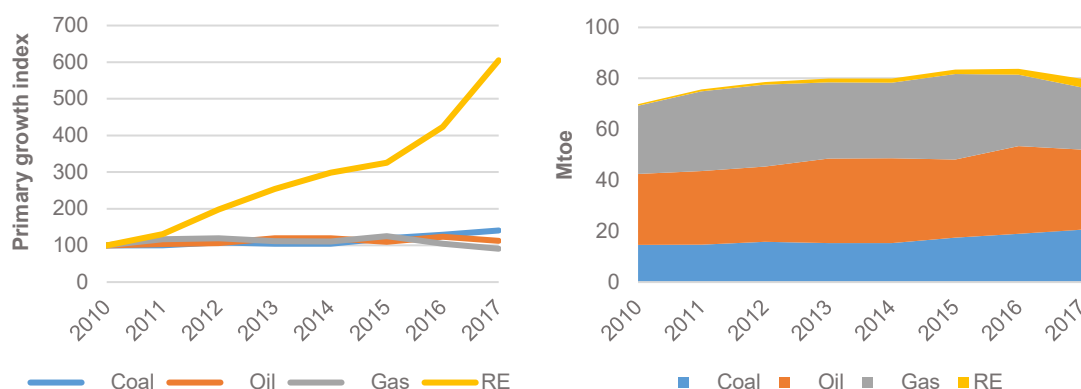
ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Malaysia's total primary energy supply (TPES) was 79 662 kilotonnes of oil equivalent (ktoe) in 2017, a decrease of 4.8% from 2016. The contraction was due to a 13% reduction in gas TPES, brought about by increased exports of LNG. Oil TPES also declined (8.7%), but was still the

largest share of TPES in 2017 at 40% (31 463 ktoe). Natural gas share was 31% (24 381 ktoe), while coal had a 26% share (20 559 ktoe). Renewable primary energy increased 43% in 2017, reaching 3 354 ktoe. Rapid growth for the last decade is partly due to the feed-in tariff (FIT) for RE, which is part of the National Renewable Energy Policy and Action Plan (NREPAP) introduced by the government in 2009.

Figure 1: Primary energy growth index and total primary energy supply, 2010–17



Source: EGEDA (2019) and APERC analysis

Malaysia has traditionally been a crude oil and natural gas energy exporter (both pipelines and LNG). The economy registered total energy exports¹ of 56 875 ktoe in 2017, an increase of 3.6% from 2016. Energy imports decreased by 1.3% to 48 108 ktoe, in 2017. Gas imports increased by 4.1%, while crude oil declined 6.6% (EGEDA, 2019).

OIL

Malaysia's oil reserves are the fourth largest in the Asia Pacific region and are mostly in offshore fields. Malaysia's continental shelf is divided into three producing basins, namely, the offshore Malay basin in Peninsular Malaysia in the west, and the Sarawak and Sabah basins in the east (EC, 2019a). The bulk of oil reserves are in the Malay basin, which produces light and sweet crude oil (EIA, 2017). Malaysia's average daily oil production was 660 thousand barrels per day (kbb/d) in 2017. In 2017, Sabah accounted for 42% of production, followed by Peninsular Malaysia (32%), and Sarawak (26%) (EC, 2019a).

Malaysia has five oil refineries with a combined capacity of 566 kbb/d (including condensate splitter capacity). Petrolim Nasional Berhad (PETRONAS), the state-owned oil company, has three refinery facilities that provide more than 50% of the total daily refinery production. Domestic petroleum sales were 74% petrol and diesel in 2017 (EC, 2019a).

Major oil storage, trading, bunkering, warehousing and manufacturing projects are located in Tanjung Bin, Tanjung Langsat and Pengerang districts, all in the state of Johor. Pengerang district will also accommodate the Pengerang Integrated Petroleum Complex (PIPC) (a PETRONAS Refinery), the Petrochemical Integrated Development (RAPID), and the DIALOG-Vopak Pengerang Deepwater Terminal (PDT). Malaysia is set to have a total of 10 million cubic metres of oil and gas storage by 2020 (JPDC, 2019).

The RAPID project began its commercial operation in the fourth quarter of 2019. RAPID will have a 300 kbb/day refining capacity. Peripheral petrochemical plants will generate additional value from petroleum products produced in RAPID.

¹ Total energy exports/imports are equivalent to the sum of LNG and piped gas exports/imports, crude oil exports/imports, petroleum products exports/imports and coal exports/imports.

Tapis, the Malaysian crude benchmark traded in Singapore, holds the title of the world's most expensive grade of oil. Its lightness (43-45° API) and extremely low sulphur content (0.04%) make for a highly valuable refining asset.

NATURAL GAS

Most of Malaysia's natural gas reserves are offshore in the eastern areas of Sarawak and Sabah in Peninsular Malaysia. Only 11% of these reserves are associated with oil basins (89% are non-associated). Sarawak holds slightly more than half the total reserves (59%), followed by Peninsular Malaysia (31%) and Sabah (15%). The average daily natural gas production was 6 801 million standard cubic feet per day (MMscf/d), an increase of 4% from 2016 (EC, 2019a). Most of the production was from Sarawak (61%), followed by Peninsular Malaysia (26%), and then Sabah (13%). Malaysia also imports piped natural gas from the Malaysia–Thailand Joint Development Area (MTJDA), and West Natuna, Indonesia; and LNG from Qatar, Brunei Darussalam and Algeria (EC, 2019a).

Malaysia is one of the world's largest LNG exporters. But a geographical mismatch between where natural gas is produced (Sabah and Sarawak), and the regions of highest consumption (Peninsular Malaysia), prompted Malaysia to build an LNG regasification terminal to facilitate LNG imports. Malaysia currently has two LNG regasification terminals located in Sungai Udang Melaka (capacity of 530 MMscf/d) and at Pengerang, Johor (capacity of 490 MMscf/d) (Petronas Gas, 2019). Malaysia imported approximately 1 983 ktoe of LNG in 2017, an increase of 42% over the 2016 level (EGEDA, 2019).

The Peninsular Gas Utilisation (PGU) network incorporates 2 623 km of pipelines that send gas to power plants and other industry customers across Peninsular Malaysia. There are also cross-border interconnections to Singapore and Songkhla, Thailand. The PGU pipeline network has the capacity to transport up to 3 500 MMscf/d. The system comprises six gas-processing plants with a combined capacity of 2 000 MMscf/d, producing methane, ethane, propane, butane and condensate (Gas Malaysia, 2019).

The Sabah-Sarawak Gas Pipeline (SSGP) is part of the Sabah-Sarawak Integrated Oil and Gas project developed by PETRONAS. The integrated project involves the development of offshore oil and gas fields in the Sabah and Sarawak states, and construction of onshore facilities to store, process and transport resources produced from the offshore fields. The SSGP and the Sabah Oil and Gas Terminal (SOGT) comprise the onshore portion of the project. The 512 km long SSGP transports gas from the SOGT to PETRONAS' LNG complex, at Bintulu in Sarawak. The pipeline runs 90 km through Sabah and 422 km through Sarawak (Hydrocarbon Technology, 2019).

COAL

Malaysia's coal reserves mostly comprise bituminous and sub-bituminous coal. Estimated reserves are 1 938 million tonnes (Mt), found in Sabah and Sarawak (EC, 2019a). Nearly two-thirds of these reserves are categorised as inferred. Most of the coal deposits are inland and face high extraction costs. This has led to limited production. Some areas also prohibit coal mining activities, such as the protected Maliau Basin in Sabah. The areas of production are Mukah, Balingian (the largest coal basin) with 2 million metric tonnes of production in 2017 and Merit Pila with 0.9 million metric tonnes (EC, 2019a).

Malaysia is the eighth largest net coal importer in the world in 2019, with coal net imports reaching 18.8 million tonnes (IEA, 2019). This reflects a rapid expansion of coal generation capacity, from 2000 to 2017, with coal consumption in the power sector increasing from 1.5 million tonnes of oil equivalent (Mtoe) to nearly 19 Mtoe. Coal generation capacity has expanded to meet increasing electricity demand and to reduce dependence on natural gas, which previously dominated generation with a share as high as 70% in the 1990s (EC, 2019a).

ELECTRICITY

Malaysia's total installed capacity was 34 183 MW in 2017, an increase of 3.5 percent from 2016. Manjung Five (1 000 MW), and Pengerang (600 MW) are two new power stations that began operating in September and October 2017 respectively. Government initiatives such as Large-Scale Solar (LSS), Net Energy Metering (NEM) projects as well as the FiT scheme also contributed to capacity growth (EC, 2019a).

Independent power producers (IPPs) own 60% of Malaysia's installed generation capacity. Government-linked utilities own 30%, cogeneration facilities 5%, self-generation facilities 4% and FiT & LSS 2% (EC, 2019a). Total electricity generation was 167 382 gigawatt-hours (GWh) in 2017, an increase of 7% from 2016. Thermal generation, mostly from natural gas and coal, constituted 83% of the total power generation, while hydropower and other fuels accounted for the remainder (EGEDA, 2019).

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	91 448	Industry sector	16 607	Total generation	167 382
Net imports and others	-11 786	Transport sector	21 498	Thermal	138 111
Total primary energy supply	79 662	Other sectors	8 340	Hydro	26 062
Coal	20 559	Non-energy	10 674	Nuclear	-
Oil	31 463	Final energy consumption*	46 445	Others	3 209
Gas	24 381	Coal	1 802		
Renewables	3 354	Oil	25 270		
Others	-96	Gas	6 176		
		Renewables	379		
		Electricity and others	12 817		

Source: EGEDA (2019) (data collected in December 2019).

* Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. Total final consumption includes non-energy uses. Half of the municipal solid waste used in power plants is assumed to comprise renewables.

FINAL ENERGY CONSUMPTION

Total final energy consumption grew 7.1% in 2017 to settle at 57 119 ktoe. The transport sector was the largest energy consumer, constituting 38% of the total final consumption (21 498 ktoe). Industry followed with a 29% share (16 607 ktoe), the non-energy sector with a 19% share (10 674 ktoe) and other sectors (residential, commercial and agriculture sectors) had a combined share of 15% (8 340 ktoe) (EGEDA, 2019).

Oil was the most consumed fuel, particularly in the transport sector, constituting 54% of the final energy consumption (excluding non-energy uses). Electricity was next with a 28% share, gas had a 13% share and coal accounted for 4%. There was a 12% growth in natural gas use in 2017. Oil consumption reversed its declining trend, and increased by 2.6% to 25 270 ktoe in 2017. Final energy consumption of renewables (biodiesel) decreased by 2.4% (EGEDA, 2019).

ENERGY INTENSITY ANALYSIS

Malaysia's primary energy intensity decreased from 104 tonnes of oil equivalent per million USD (toe/million USD) in 2016 to 94 toe/million USD in 2017, representing a 10% reduction. The reduction in 2017 marked the sixth consecutive year of primary energy intensity reduction for Malaysia. However, final consumption intensity increased by 1.2% to 67 toe/million USD in 2017 mostly due to non-energy consumption. Final energy consumption intensity would decrease by 4.6% if the non-energy sector were excluded (EGEDA, 2019).

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%) 2016 vs 2017
	2016	2017	
Total primary energy supply	104	94	-10
Total final consumption	67	67	1.2
Final energy consumption excl. non-energy	57	55	-4.6

Source: EGEDA (2019)

RENEWABLE ENERGY SHARE ANALYSIS

Since the introduction of the NREPAP in 2010, Malaysia's consumption of modern renewables has been increasing every year. The share of modern renewables in final energy consumption increased from 4.5% in 2016 to 5.6% in 2017. Modern renewables registered a 27% increase in final consumption in 2017.

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	45 994	46 445	0.98
Non-renewables (fossils and others)	43 938	43 824	-0.26
Traditional biomass*	-	-	-
Modern renewables*	2056	2621	27
Share of modern renewables in final energy consumption (%)	4.5%	5.6%	26%

Source: EGEDA (2019)

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on), including biogas and wood pellets, are considered modern renewables, although data on wood pellets are limited.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Malaysia recognises the importance of energy in achieving sustainable development. Energy policies have been developed following evaluation of Malaysia's current and future energy

needs. Malaysia's energy policies can be traced back to as early as the 1970s. The major energy policies implemented in the economy are as follows:

Policy	Role
Petroleum Development Act 1974	<ul style="list-style-type: none"> ▪ The Petroleum Development Act (PDA) was enacted in 1974 and vested legislative powers with Petroliaam Nasional Berhad or PETRONAS to streamline the oil and gas sector ▪ PETRONAS introduced production sharing contracts (PSCs) which ensured that the development of Malaysia's oil and gas resources would yield maximum benefits to the economy while ensuring that international oil companies also benefited by obtaining a fair return on their investments
National Petroleum Policy 1975	<ul style="list-style-type: none"> ▪ Making good use of the petroleum resources and prioritising the application of oil and gas resources to serve national needs by making available adequate supplies at reasonable prices to meet domestic consumption ▪ Providing a favourable investment climate in Malaysia, including introducing new opportunities for downstream activities ▪ Ensuring that Malaysians are adequately represented in terms of ownership, management and control in all phases of petroleum operations ranging from exploitation, marketing and distribution ▪ Affecting an optimum pace of social and economic exploitation of the oil and gas resources and accounting for the need for conservation of these assets and the protection of the environment
National Energy Policy, 1979	<ul style="list-style-type: none"> ▪ The Supply Objective To ensure adequate, secure and cost-effective energy supply through developing and utilising alternative sources of energy (both non-renewable and renewable) from within or outside the economy ▪ The Utilisation Objective To promote efficient utilisation of energy and discourage wasteful and non-productive patterns of energy consumption ▪ The Environmental Objective To minimise the negative environmental impacts on the energy supply chain i.e. energy production, conversion, transportation and utilisation
National Depletion Policy, 1980	<ul style="list-style-type: none"> ▪ Set the limit on the amount of oil and gas produced (650 000 barrels of oil per day and 2000 million standard cubic feet per day) ▪ Due to rapid economic development, the production levels of oil and gas have surpassed the set targets ▪ Focused on the supply side of energy; the demand side of managing the limited resources was ignored
Fuel Diversification Policy (commonly known as Four-Fuel Policy), 1981	<ul style="list-style-type: none"> ▪ To complement the National Depletion Policy, the Four-Fuel Diversification Policy was introduced in 1981. In 1980, 85% of the fuel used in the power plants to generate electricity was oil ▪ The policy was designed to reduce dependence on oil as an energy source and increase the share of gas, particularly in the power sector. Its aim was to ensure reliability and security of the energy fuel supply through having a mix of oil, gas, hydro and coal

Five-Fuel Policy (completing Four-Fuel Policy), 2001	<ul style="list-style-type: none"> ▪ Promoting the growth of small power generation plants that utilise RE ▪ Facilitating the expeditious implementation of grid-connected RE where small power producers, using RE as energy sources, can sell their excess electricity to utilities to be distributed through the national grid ▪ Promoting and encouraging the development of more efficient RE technologies
National Biofuel Policy, 2006	<ul style="list-style-type: none"> ▪ The Government of Malaysia released its National Biofuel Policy in 2006 with the stated objectives of utilising environmentally friendly and sustainable energy sources to reduce dependency on fossil fuels and to help stabilise the palm oil (CPO) industry ▪ In 2007, the Malaysian Parliament passed the Biofuel Industry Act, which included provisions from the National Biofuel Policy, to implement a biodiesel blend mandate
National Green Technology Policy, 2010	<ul style="list-style-type: none"> ▪ The National Green Technology Policy (NGTP) focuses on four pillars, namely Energy, Environment, Economy and Social. The NGTP has identified green technology as a key driver to accelerate the national economy and promote sustainable development ▪ The GT policy aims to facilitate the growth of GT and enhance its contribution to the national economy. This will increase Malaysia's capability and capacity for innovation and enhance its competitiveness in the global market, as well as conserve the environment and ensure sustainable development for future generations
National Renewable Energy Policy and Action Plan, 2010	<ul style="list-style-type: none"> ▪ The National Renewable Energy Policy and Action Plan aims to increase the use of renewable natural resources to contribute to the economy's electricity supply security and stable socioeconomic development.

Vision 2020 is a long-term development roadmap that will conclude by the end of the Eleventh Malaysia Plan (11MP) period. As a continuation, the Twelfth Malaysia Plan (12MP) will be formulated to ensure a more inclusive and meaningful development of the economy, in line with the formation of a prosperous society.

The 12MP will be aligned with the shared prosperity initiative encompassing three dimensions: economic empowerment, environmental sustainability and social re-engineering. The economic empowerment dimension includes new sources of growth, including Industrial Revolution 4.0, the digital economy, the aerospace industry, integrated regional development, and growth enablers such as sustainable energy sources and infrastructure connectivity. The environmental sustainability dimension incorporates the blue economy, green technology, RE, and the adaptation to, and mitigation of, climate change. Social re-engineering comprises enhancing societal values, improving the purchasing power of the people, building a resilient Bumiputera community, strengthening social security networks and improving the wellbeing of the people (MEA, 2019b).

ENERGY SECTOR STRUCTURE

Details of key ministries and government agencies for the Malaysian energy sector:

- The Ministry of Economic Affairs (MEA) sets the general direction and broad strategies for Malaysia's energy policies, such as formulating and implementing the national policy on energy and developing the oil and gas industry
- After the 14th General Election (GE-14) in 2018, the Ministry of Science, Technology and Innovation, the green energy and technology component of the Ministry of Energy, Green Technology and Water (KeTTHA), and the Ministry of Natural Resources and Environment

were restructured to form the Ministry of Energy, Science, Technology, Environment and Climate Change (MESTECC)

- The EC is a statutory body established in 2001 to serve as a regulator for the electricity and piped gas supply industries in Peninsular Malaysia and Sabah. The Commission's main functions are to establish technical and performance regulations for the electricity and piped gas supply industries; act as the safety regulator; and protect consumers by ensuring high-quality services as well as a regular supply of electricity and piped gas at reasonable prices
- The Sustainable Energy Development Authority (SEDA) Malaysia is a statutory body formed under the Sustainable Energy Development Authority Act 2011 [Act 726]. The key role of SEDA is to administer and manage the implementation of the FiT mechanism, mandated under the Renewable Energy Act 2011 [Act 725]
- In October 2019, the Malaysian Green Technology Corporation was rebranded as the Malaysian Green Technology and Climate Change Centre. The agency, under MESTECC, was set up to spearhead Malaysia's green technology uptake.

Other authorities involved in energy in Malaysia are:

- The Ministry of Primary Industries that oversees the biofuel development in Malaysia
- The Ministry of International Trade and Industry that promotes investment in Malaysia as well as assists the government to set gas prices for industrial use.

PETRONAS is Malaysia's national petroleum corporation, wholly owned by the Malaysian Government and created under the PDA of 1974. PETRONAS is vested with exclusive rights for the exploration and production of petroleum, whether onshore or offshore in Malaysia. It also has responsibility for the planning, investment and regulation of the upstream sector. Any foreign or private company wanting to explore and produce petroleum in Malaysia has to enter into a PSC with PETRONAS.

Malaysia's power industry is dominated by three vertically integrated utilities: Tenaga Nasional Berhad (TNB) serving Peninsular Malaysia; Sabah Electricity Sendirian Berhad in Sabah; and Sarawak Energy Berhad in Sarawak. These utilities undertake electricity generation, transmission, and distribution and supply activities in their respective areas. Various IPPs, dedicated power producers and cogenerators complement the three utilities.

ENERGY SECURITY

The energy industry recognises the importance of a secure energy supply as an essential element of economic development and vital for ensuring the continued growth of sustainable trade and industry. According to the World Economic Forum's (WEF) latest Energy Transition Index, Malaysia is ranked 31st, with system performance and transition readiness ranked at 68% and 55% respectively. The index measures an economy's readiness to transition into an equitable, sustainable and affordable energy future. The WEF indicated that Malaysia lags in terms of environmental sustainability and its energy system structure (The Malaysian Reserve, 2019).

Malaysia will continue to expand and optimise its fuel mix. The 12MP provides a roadmap to manage Malaysia's over-dependence on fossil fuel while gradually reducing its reliance on energy imports. According to NEB 2017, the Peninsular Malaysia system has a reserve margin of 36%, Sabah has 36% and Sarawak has 28% (EC, 2019a). This level of reserve margin ensures adequacy of generation capacity, allowing for scheduled maintenance and unplanned outages.

Regional energy cooperation under the Association of Southeast Asian Nations (ASEAN) framework also addresses energy security. Among the agreements reached on energy security is the ASEAN Petroleum Security Agreement signed in 1986 and updated in 2009. Its purpose

is to enhance petroleum security in the ASEAN region. ASEAN members, through the Trans-ASEAN Gas Pipeline (TAGP) and the ASEAN Power Grid (APG) projects, have entered into interconnection cooperation agreements on natural gas and electricity. The TAGP will provide the region with a secure supply of natural gas through pipelines and associated infrastructure. The APG will integrate the power grids of ASEAN members to enable regional sales of electricity. The APG will also optimise the development of energy resources in the region.

NATIONAL GREEN TECHNOLOGY POLICY

The Malaysian Government launched the NGTP in July 2009 in pursuit of a low-carbon economy. It is the basis for all Malaysians to enjoy an improved quality of life by ensuring that the objectives of the national development policies are balanced with environmental considerations. The policy is built on four pillars:

- Energy: seeking energy independence and promoting efficient utilisation
- Environment: conserving the environment and minimising detrimental environmental impacts
- Economy: enhancing national economic development through technology
- Society: improving the quality of life for all.

The following four sectors are the focus of the policy.

- Energy: the application of green technology in power generation and in energy supply side management, including cogeneration by industrial and commercial sectors, in all energy-consuming sectors
- Buildings: the adoption of green technology in the construction, management, maintenance and demolition of buildings
- Water and waste management: use of green technology in the management and use of water resources, wastewater treatment, solid waste and sanitary landfill
- Transport: incorporation of green technology into the transportation infrastructure and vehicles, particularly related to biofuels and public road transport (MESTECC, 2009a).

Among the policy's long-term goals is an increase in green technology and a significant reduction in energy consumption. Malaysia has earmarked the promotion of green technology through the establishment of the Malaysian Green Technology Corporation and this has become the lead agency of the ministry for the promotion, development and implementation of green technology.

As part of the effort to ensure continuous support for green technology projects, the Ministry of Finance (MOF) has agreed to the recommendation proposed by MESTECC for several enhancements and improvements to the scheme known as the Green Technology Financing Scheme (GTFS) 2.0 (GTFS, 2019).

The introduction of the MyHIJAU Labelling Program is intended to ensure the availability of green products and services in accordance with international standards and regulations. Currently, three agencies in Malaysia have been recognised as providing environmentally friendly certification schemes:

- SIRIM Eco Labelling by SIRIM Berhad for certifying the environmental attributes of green products and services
- Energy Efficiency Labelling by the EC for energy efficiency labelling of electrical appliances
- Water-Efficient Products Labelling by the National Water Services Commission or SPAN.

The Green Building Index (GBI) has been developed as a rating tool to promote green technology in the building sector. It is also intended to raise awareness among developers and

building owners about the design and construction of green and sustainable buildings. A GBI certificate is granted to developers and building owners who have satisfied the standards in six areas: energy efficiency, indoor environmental quality, sustainable site planning and management, materials and resources, water efficiency and innovation.

To encourage the adoption of green building design, the government intends to establish itself as the market leader in this field. All new government buildings have to adopt green features and designs, while existing government buildings will be gradually retrofitted. Other initiatives that are being implemented are the Government Green Procurement (GGP) and Green Township projects. The GGP integrates environmental considerations into the public sector procurement process to protect the natural environment, conserve resources and lessen the harmful effects of human activities. By 2020, the GGP will be implemented in all government offices and will ensure that 20% of the public sector's purchases of products and services are green-labelled. The Green Township project advocates the adoption of a Low-Carbon Cities Framework & Assessment System (LCCF) by city councils, developers and town planners. The project provides a systematic process and strategies for reducing carbon emissions in urban developments in accordance with the government flagship and ongoing projects.

Malaysia launched its Green Technology Master Plan (GTMP) to serve as a guide for the development of action plans, programs and projects for the 11MP and 12MP. Six areas have been identified as target areas: energy, manufacturing, transport, building, waste and water. Derived from the NGTP, the GTMP lists five major strategic thrusts to foster a 'green culture' in Malaysia (Table 5).

Table 5: GTMP strategic thrust

Strategic Thrust	Key Areas	Outcomes
Promotion and awareness	<ul style="list-style-type: none"> Tailored communication strategy Industry and business promotion via International Greentech and Eco Products Exhibition and other platforms Collaboration with primary and secondary educational institutions 	<ul style="list-style-type: none"> Improved awareness and receptiveness towards green technology Increase in business transactions, entrepreneurship and global value chain integration Improved knowledge of GT among the younger generation to drive behavioural change
Market enablers	<ul style="list-style-type: none"> (GGP) Green incentives Innovative financing Green cities International collaborations 	<ul style="list-style-type: none"> Strengthened industry readiness in the production of green products and services Improved financial feasibility of green projects and better affordability of green products and services Improved infrastructure readiness for green adoption Creation of export opportunities through regional collaborations
Human capital development	<ul style="list-style-type: none"> Capability-building in the public sector Capability-building in the private sector Collaboration with higher education institutions 	<ul style="list-style-type: none"> Improved knowledge among government officials Increase in recognition of skills and competencies Improved workforce readiness of fresh graduates
Research and development and commercialisation (R&D&C)	<ul style="list-style-type: none"> R&D&C funding Public-private partnership 	<ul style="list-style-type: none"> Demand-driven, market and result-oriented R&D&C projects Stronger collaboration between government bodies and research institutes in information sharing to enable efficient strategic planning and

	resource deployment	
Institutional framework	<ul style="list-style-type: none"> • Governance (policy leadership) • Policy planning • Policy implementation. 	<ul style="list-style-type: none"> • Strengthened governance to facilitate cross-sectoral cooperation among government bodies to improve the ease of doing business

Source: MESTECC (2017)

FINANCING AND INCENTIVE TAXATION TO INCREASE GREEN DEVELOPMENT

The government continues to support the development of green business with the reinstatement of the GTFS 2.0. New funds and financing amount to RM 2.0 billion for a period of two years from 2019 to 2020. The scheme will support six key sectors including Energy, Waste, Water, Building, Transportation and Manufacturing.

GTFS 2.0 will also provide a 60% government guarantee on the financial cost of green components financed by Participating Financial Institutions as well as a 2% rebate on interest/profit. The financing limit for the manufacturers and consumer categories is up to a maximum of RM 100 million and RM 50 million. One of the major improvements of GTFS 2.0 is the introduction of Energy Services Companies (ESCOs) that qualify for investment financing or assets related to energy efficient projects and Energy Performance Contracts (EPC). An ESCO is entitled to a maximum financing of RM 25 million for up to five years. This will stimulate the energy efficiency business, which is considered a new economic growth area.

GTFS 2.0 is critical for technology-based green projects to continue to grow, and to act as catalysts for climate change policy. The green technology market in Malaysia is growing fast, in line with industry demand. GTFS has assisted hundreds of companies to access financing and foster sustainable businesses. This scheme also provides an opportunity for financial institutions to get used to green business financing. To encourage the growth of green technology use, the government has also expanded the list of assets that meet the Green Investment Tax Allowance (GITA) requirements from nine to 40. This tax incentive was introduced in 2014 to increase the use of green technology equipment (GTFS, 2019).

Green technology tax incentives in the budget of 2014 were also introduced to strengthen the development of green technology. This occurred via GITA for the purchase of green technology equipment/assets, and the Green Income Tax Exemption (GITE) for green technology service providers (MyHIJAU, 2019).

Table 6: Scope of green technology tax incentives

Category	Scope
GITA Assets	Applicable for companies that acquire qualifying green technology assets and listed under the MyHIJAU Directory
GITA Projects	Applicable for companies that undertake qualifying green technology projects for business or own consumption
GITE Services	Applicable for qualifying green technology service provider companies that are listed under the MyHIJAU Directory.

Source: MyHIJAU (2019)

ENERGY MARKETS

MARKET REFORM

The Malaysian Cabinet has approved a 10-year master plan known as the Malaysia Electricity Supply Industry 2.0 (MESI 2.0) to reform the power industry. MESI 2.0 aims to liberalise the generation to distribution components of the power industry in Peninsular Malaysia, and to promote the use of green energy. The MESI 2.0 is targeted to:

1. Boost efficiency in the industry
2. Future-proof key processes, regulations and structure in the industry
3. Empower consumers by democratising and decentralising the electricity supply industry.

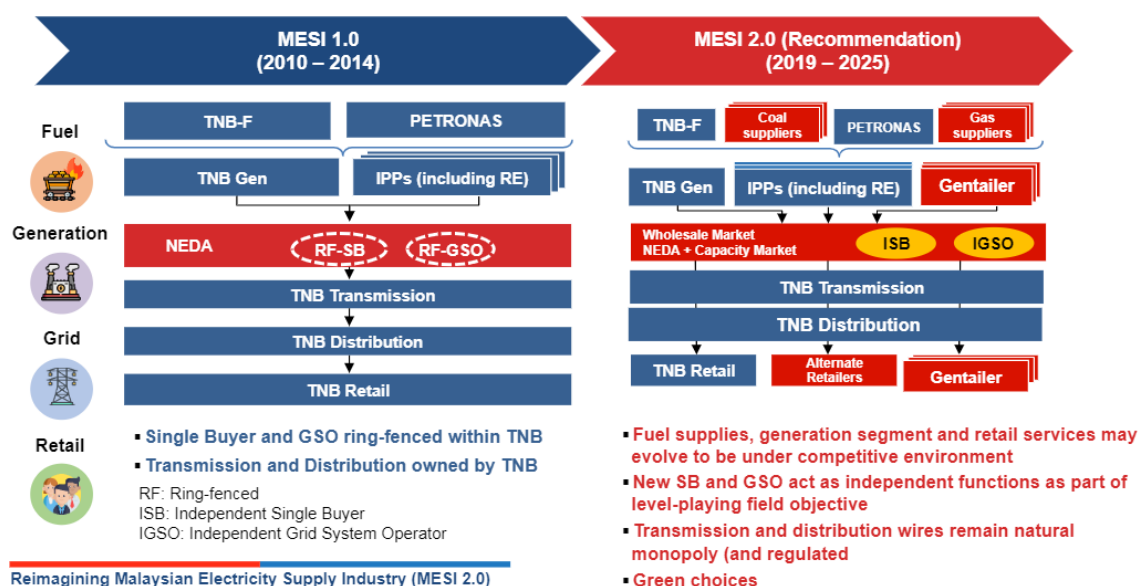
MyPower, the steering agency of MESI 2.0 is exploring green initiatives including solar photovoltaic, biomass, biofuel, coal generation, storage systems and smart metres to achieve the efficiency target. By exploring green initiatives, the sector aims to empower consumer energy use.

Table 7: Objectives and initiatives under MESI 1.0 and MESI 2.0

MESI 1.0		
No.	Objectives	Initiatives
1	Secure and reliable supply of energy	Generation of fuel security policy framework, ring-fencing of single buyer and system operator with market rules and regulatory oversight, gas third party access framework, new enhanced dispatch arrangement
2	Economically competitive tariff	Incentive-based electricity tariff regulation with regulatory accounts unbundling, performance incentive scheme and imbalance of cost pass-through mechanism
3	Environmentally sustainable	IPP generation efficiency sharing framework, competitive framework for new generation capacity development
4	Customer satisfaction/choices	Enhanced time of use and cost-reflective tariffs framework, gradual phasing-out of gas subsidy with stabilisation mechanism
MESI 2.0		
No.	Objectives	Initiatives
1	Efficiency	Optimal utilisation of market-based competition throughout the value chain, reduced government intervention, increased transparency, adoption of a more cost-reflective and time-based tariff, subsidisation of targeted consumers and increased cross-border trade
2	Future Proofing	Introducing market-based competition, adoption of new technologies, promotion of RE and the implementation of energy efficiency initiatives.
3	Consumer Empowerment	Incentivising changes in consumer consumption patterns and facilitating consumer participation as power producers.

Source: MESTECC (2019)

MESI 1.0 was launched in 2010 to reduce subsidies. MyPower's initial task was to revise the Power Purchase Agreement (PPA) with the IPPs to deliver a more transparent process of awarding contracts to the new IPPs. In 2012, the single buyer (SB) model and the grid system operator departments were introduced into the MESI structure. The SB model divides the generation sector into several economically independent power generating companies that compete to sell electricity to the SB.

Figure 2: Latest electricity market regulatory structure in Peninsular Malaysia

Source: MESTECC (2019)

MESI 2.0 aims to allow consumers to choose an electricity tariff that fits their electricity consumption patterns. Use during different times of the day, with a peak and off-peak season, will be the basis for choice. The former MESI implemented the Enhanced Time of Use scheme, though it was only available for industrial and commercial consumers.

There will be no additional non-risk PPA with MESI 2.0. New PPAs will be based on the energy generated instead of a fixed tariff. IPPs are required to source fuel autonomously. The government is expected to have its inaugural electricity supply auction in 2023. When the former PPAs end in 2045, the electricity supply industry will transition to an auction model. IPPs can procure coal and fuel from sources other than Tenaga Nasional Berhad, beginning in the second quarter of 2021.

Coal accounted for 56% of the total fuel mix in Peninsular Malaysia in 2018. The impact of removing Tenaga Nasional Berhad as the monopoly provider of coal is uncertain.

ELECTRICITY AND GAS MARKETS

Incentive-based Regulation (IBR) was introduced in early 2014 in Malaysia as part of the modernisation of the electricity supply industry. IBR provides structured, transparent and informed tariff setting, while appropriately accounting for utility capital expenditure and operational expenditure. Utility companies are now more transparent in supplying electricity, and have been incentivised to operate in a more efficient manner. The Energy Commission (ST) continues to audit utility companies while also addressing their concerns.

The main components of the IBR are:

- Determination of the regulatory period to ensure tariff revision is carried out periodically and consistently
- Determination of the regulated and non-regulated business for the utility and the separation of accounts
- Determination of financial performance and technical efficiency targets of the utility
- Implementation of the imbalance cost pass-through mechanism to enable recovery of fuel-related and other generation-specific costs

- Implementation of efficiency sharing mechanism to provide the utility with a continuous and sustained incentive to pursue cost efficiencies in every regulatory period (EC, 2019c).

IBR for pipeline gas was implemented in January 2016 for a trial run of one year, followed by the first regulatory period from 2017 to 2019. The introduction of the IBR for gas will support liberalisation of the natural gas industry, and gradually align Malaysia's gas prices to freely determined market prices (EC, 2016).

ENERGY EFFICIENCY

The 11th Malaysia Plan (2016-2020) focuses on sustainable use of energy through the introduction of the National Energy Efficiency Action Plan (NEEAP) 2016–2025. Energy efficiency strategies will be pursued via well-coordinated and cost-effective implementation of industrial, commercial and residential energy efficiency measures.

It is estimated that implementation of the NEEAP 2016-2025 will save 52 233 GWh of electricity over 10 years. Electricity demand is projected to decrease by 8% with a reduction of 34 million tonnes CO₂ equivalent greenhouse gas (GHG) emissions. Public and private expenditure under NEEAP 2016–2025 is expected to reach RM 6.3 billion with a direct monetary saving of RM 18.5 billion.

To enhance energy efficiency and the ESCO industry, RM 21 million has been approved and allocated under the 11th Malaysia Plan in the form of Energy Audit Conditional Grants. These grants are open to existing commercial and industrial buildings consuming more than 100 000 kWh per month. The initial intention was to only offer the grants to the largest electrical energy consumers in the economy, specifically those affected by the Efficient Management of Electrical Energy Regulation (EMEER) 2008. However, the grants are actually open to smaller installations as well. Applicants can receive as much as RM 100 000 for conducting an energy audit.

Over 100 facilities in the industrial and commercial sectors are anticipated to benefit from these grants. The key condition is that recommendations by the ESCOs will be implemented, and that facilities must agree to achieve 5% annual energy savings over three years. Implementation was completed in 2018 and is currently in a Monitoring and Verification stage, continuing to 2020. The grants create awareness about EPC. Financial institutions are involved so that they can observe and follow the progress of different projects and then employ EPC contracts on a commercial basis.

The first meeting of Green Technology and Climate Change 2017 approved the establishment of an EPC Fund which will be a catalyst for the nascent energy service industry. The Malaysian Debt Venture (MDV), a subsidiary of the Malaysian Government under the MOF, will lead the financing initiative for energy efficiency projects by providing a fund of RM 200 million to facilitate EPC. The EPC fund will be supported by a credit guarantee fund of RM 12 million contributed by MESTECC and the JKR-Building Sector Energy Efficiency Project, funded by the United Nations Development Program-Global Environment Facility (UNDP-GEF).

The government has also provided RM 5.8 million to lower the facility financing rate of 8.0% to 7.0% per annum. Financing provided by MDV together with the credit support will increase the implementation of energy efficiency projects in the building sector and spur sustainable ESCO growth. The funds will assist ESCOs to obtain finance from commercial financial institutions and strengthen their financial credit profile. The success of the EPC financing model will enhance stakeholder confidence in ESCOs, especially commercial institutions that can provide finance via the EPC method.

The increased investment in the green technology sector is likely to lead to beneficial economic outcomes. These projects can act as showcases for others to emulate and will position the ESCO industry as a sustainable business model.

Malaysia is developing a comprehensive Energy Efficiency and Conservation Act in pursuit of achieving energy efficiency and conservation initiatives. The proposed Act will outline necessary measures to promote energy efficiency including target setting, communication, and education. The Act will also initiate steps to reduce GHG emissions, from a regulatory standpoint.

RENEWABLE ENERGY

FEED-IN TARIFF

Malaysia's FiT system obliges Distribution Licensees (DLs) to buy electricity from Feed-in Approval Holders for an agreed FiT rate. DLs pay for RE supplied to the electricity grid for a specific duration. By guaranteeing access to the grid and setting a favourable price per unit of RE, the FiT mechanism ensures that RE becomes a viable and sound long-term investment for companies, industries and individuals. Details of FiT are listed:

Table 8: The main terminologies in Feed-in-Tariff

Distribution Licensees	<ul style="list-style-type: none"> • Companies holding the licence to distribute electricity (e.g. TNB, SESB, NUR)
Feed-in Approval Holder	<ul style="list-style-type: none"> • An individual or company who holds a feed-in approval certificate issued by SEDA Malaysia • The holder is eligible to sell renewable energy at the FiT rate
FiT rate	<ul style="list-style-type: none"> • Fixed premium rate payable for each unit of renewable energy sold to Distribution Licensees • The FiT rate differs for different renewable resources and installed capacities • Bonus FiT rate applies when the criteria for bonus conditions are met
Indigenous	<ul style="list-style-type: none"> • Renewable resources must be from within Malaysia and are not imported from other countries
Duration	<ul style="list-style-type: none"> • Period in which the renewable electricity could be sold to distribution licensees and paid with the FiT rate • The duration is based on the characteristics of the renewable resources and technologies • The duration is 16 years for biomass, and 21 years for biogas resources, small hydropower and solar photovoltaic technologies.

Source: SEDA (2019a)

Feed-in Approval (FiA) has to be granted by SEDA Malaysia to sell RE at the FiT rate. There is no preferential treatment for FiA applications.

Since the implementation of FiT in 2012, the installed capacity of RE in Malaysia has increased tremendously. The average growth of RE in Malaysia has been 33% per year. Solar PV reached 45% of total RE, followed by biomass at 25%.

Table 9: Annual power generation (MWh) of commissioned RE installations

Unit: MWh	2012	2013	2014	2015	2016	2017	2018
Biogas	98	12 963	19 772	16 989	17 143	16 320	11 680
Biogas (Landfill / Agriculture Waste)	7465	9804	31 844	41 122	70 486	198 985	170 802
Biomass	101 310	209 408	226 196	192 372	151 385	247 543	194 688

Biomass (Solid Waste)	3235	11 144	4348	18 090	36 752	19 304	4101
Mini Hydro	25 630	79 082	67 568	55 406	47 798	74 831	50 125
Solar PV	5319	50 757	184 284	263 875	316 965	426 835	360 514
Total	143 057	373 157	534 013	587 855	640 529	983 818	791 911

Source: SEDA (2019a)

LARGE-SCALE SOLAR

Malaysia is committed to establishing LSS projects (generating between 1 MW and 50 MW). But LSS projects have been capped at 1 000 MW over four years from 2017 to 2020, which works out to 200 MW per year in Peninsular Malaysia and 50 MW in Sabah. In March 2016, the Energy Commission announced that it was inviting Requests for Qualification to develop LSS projects with a total capacity of 250 MW (EC, 2019b).

In the second round of tenders (February 2017), the Energy Commission set an aggregate capacity target of 460 MW; 360 MW from Peninsular Malaysia and 100 MW from Sabah. The Commission received bids for a total generation capacity of 1632 MW, more than three times the target. A total of 41 bids with a combined capacity of 562 MW were shortlisted (EC, 2019b).

The third cycle of the LSS scheme began in February 2019. So far, the government has approved two LSS projects with an installed capacity of 958 megawatts (EC, 2019b).

THE NET ENERGY METERING

Peninsular Malaysia has about 4.1 million buildings, with large potential for rooftop solar PV. Solar PV systems help consumers save on electricity bills and contribute to climate change solutions. The solar PV market also contributes to economic growth. Malaysia is recognised as the largest employer in PV solar in the ASEAN region. More than 54 300 people worked in the industry in 2018, up from 40 300 in 2017. Malaysia is one of the top three PV manufacturers in the world.

The MESTECC has introduced solar PV initiatives to encourage Malaysia's RE uptake. One of the key issues highlighted by the PV industry is the need to change NEM from net billing to true net energy metering. This will improve the return on investment of solar PV under NEM. Effective 1 January 2019, true NEM was adopted, allowing excess solar PV generation to be exported back to the grid on a "one-on-one" offset basis (SEDA, 2019b).

The quota allocation for the NEM is 500 MW to the year 2020. The new NEM scheme is only available to Peninsular Malaysia and applicants must be TNB customers. NEM is executed by the MESTECC, regulated by the Energy Commission (EC), and SEDA Malaysia is the implementing agency (SEDA, 2019b).

NEM allows TNB (domestic, commercial, industrial and agricultural) consumers to be producers and consumers of electricity. NEM was first implemented in late 2016. Until the end of 2018, the total approved capacity was only 28 MW. In the first six months of 2019, SEDA approved 21 MW.

CLIMATE CHANGE

Malaysia is a signatory to the United Nations Framework Convention on Climate Change (UNFCCC), and it ratified the treaty on 17 July 1994. Subsequently, the National Climate Committee was established in 1995. This is composed of different Malaysian Government agencies and stakeholders from business and civil society groups. The purpose of the National Climate Committee is to guide national responses to climate change mitigation and adaptation.

At the 2015 United Nations Climate Change Conference in Paris, Malaysia's prime minister made a pledge to reduce the emissions intensity of the economy's GDP by 45% by 2030 relative to the emission intensity of GDP in 2005. The 45% figure comprises 35% on an unconditional basis and a further 10% conditional upon receipt of climate finance, technology transfer, and capacity building from developed economies (UNFCCC, 2015). The sectors covered under this emission intensity reduction target are energy, industrial processes, waste, agriculture, land use, land use change and forestry (LULUCF).

Two significant policies approved in 2009 support this goal: the NGTP and the National Climate Change Policy (NCCP). These policies strengthen the national agenda on environmental protection and conservation. The NCCP has three main objectives. First, to address climate change through the efficient management of resources and enhanced environmental conservation, while improving economic competitiveness and quality of life. Second, to integrate responses into national policies, plans and programs to strengthen resilience against the potential impact of climate change. Third, to strengthen institutional and implementation capacity to harness opportunities to reduce the negative impact of climate change more effectively (MESTECC, 2009b).

The Government of Malaysia announced the establishment of the National Council of Climate Change Action in October 2019.

NOTABLE ENERGY DEVELOPMENTS

PENGERANG INTEGRATED PETROLEUM COMPLEX

The Pengerang Integrated Petroleum Complex (PIPC) will contribute value to the downstream oil and gas value chain in Johor. The PIPC is one of the largest investments in the Pengerang district. The project will house oil refineries, naphtha crackers, petrochemical plants, and an LNG import terminal and regasification plant. Oil refining facilities will add value to imported crude oil via the Pengerang Deepwater Terminal (PDT). New high-value, high-demand products and by-products, such as polymers, pharmaceutical products and plastics, will be created from the refined feedstock (JPDC, 2019).

PETRONAS' Pengerang Integrated Complex (PIC) forms part of Johor's larger PIPC. The PIC is designed to produce premium differentiated petrochemicals to meet domestic demand for petroleum products. PIC consists of the Refinery and Petrochemical Integrated Development (RAPID) and six associated facilities, namely: the Air Separation Unit, Pengerang Deepwater 2 (PDT2), Pengerang Cogeneration Plant, the Raw Water Supply Project RAPID (PAMER), Regasification Terminal 2 (RGT2), and Centralised and Shared Utilities & Facilities.

The refinery and steam cracker provide the feedstock to the petrochemical plants. The refinery has a capacity of 300 000 bpd and the steam cracker will have a combined annual production capacity of more than 3Mtpa of ethylene, propylene and C4 – C6 olefin products. RAPID will position Malaysia as a leader in Asia's chemical products market and provide Malaysia with the opportunity to venture into premium differentiated and specialty petrochemicals, along with the rapidly developing automotive, pharmaceutical and consumer product sectors (PETRONAS, 2019a).

FLOATING LIQUEFIED NATURAL GAS

PETRONAS has developed the world's first floating liquefied natural gas (FLNG) project, PFLNG Satu. PFLNG Satu is located 180 kilometres offshore of Bintulu, Sarawak, first produced LNG in December 2016, and delivered its first cargo a few months later. Production is 1.2 million tonnes of LNG per annum. With a design life of 20 years, the PFLNG Satu can be redeployed to other fields as they become depleted. FLNG projects allow for access to gas reserves in remote and stranded fields which are otherwise deemed economically unfeasible (EC, 2018).

PETRONAS' second FLNG facility, PFLNG Dua, is scheduled to be completed in early 2020. It will open new sources of supply as it is designed to extract gas from deepwater gas reservoirs at depths of up to 1500 metres. PFLNG DUA will be moored over the Rotan Gas Field which is at a water depth of 1300 metres. Production capacity is 1.5 million tonnes of LNG per annum (PETRONAS, 2019b).

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Prime Minister's Office—www.pmo.gov.my

Ministry of Finance—www.treasury.gov.my

Ministry of Economic Affairs—www.mea.gov.my

Ministry of Energy, Science, Technology, Environment and Climate Change—www.mestecc.gov.my

Ministry of Primary Industries—www.mpi.gov.my

Ministry of International Trade and Industry—www.miti.gov.my

Ministry of Water, Land and Natural Resources—www.kats.gov.my

Energy Commission—www.st.gov.my

Sustainable Energy Development Authority—www.seda.gov.my

Malaysia Green Technology Corporation— www.greentechmalaysia.my

Green Technology Financing Scheme— www.gtfs.my

MyHIJAU—www.myhijau.my

Malaysian Palm Oil Board—www.mpob.gov.my

PETRONAS—www.petronas.com

Tenaga Nasional Berhad—www.tnb.com.my

Sabah Electricity Sdn.Bhd.—www.sesb.com.my

Sarawak Energy Berhad—www.sarawakenergy.com.my

Single Buyer Department—www.singlebuyer.com.my

Grid System Operator—www.gso.org.my

Malaysia Energy Information Hub—meih.st.gov.my

MEXICO

INTRODUCTION

Mexico is a federal republic bordered by the United States of America to the north, Belize and Guatemala to the south, and the Atlantic and Pacific Oceans on the east and west. For cultural and historic reasons, Mexico has been commonly regarded as a Latin American economy, whereas its geographical location and economic integration are in North America.

Mexico is rich in fossil and renewable energy resources over its land area of approximately 2 million square kilometres (km²) (INEGI, 2020). There are diverse climatic conditions across the Mexican geography ranging from arid to humid, and high to moderate temperatures. Mexico is home to 127 million people, making it the 11th most populated economy in the world and the sixth most populated economy in the Asia Pacific Economic Cooperation (APEC) region (UN, 2019). Mexico City, the capital, is the world's fifth-largest urban centre, with more than 22 million people (UN, 2018). After Mexico City, the other most important cities are Guadalajara and Monterrey, located in the west-central and north-eastern sides of the territory, respectively.

Economic reforms and free trade agreements introduced since the 1990s have resulted in macroeconomic stability, increased flows of foreign direct investment, and the development of a robust manufacturing industry. Mexico is the 11th largest economy in the world and the sixth largest economy in APEC, economically comparable with Spain or Australia (World Bank, 2020). Most Mexican exports (77%) are manufactured products (World Bank, 2019b).

Mexico grew at a compound annual growth rate (CAGR) of 2% between 2000 and 2017, with real gross domestic product (GDP) in 2017 being USD 2 240 billion (purchasing power parity [PPP] constant 2011). Per capita GDP growth was significantly lower for the same period at only 0.63% CAGR (EGEDA, 2019). Income inequality remains a challenge, as reflected in Mexico's Gini coefficient rating of 45.4 in 2018, and 42% of the population living in poverty in 2018 (CONEVAL, 2019). Mexico's population and economy are projected to continue expanding, driving up energy demand.

Energy, particularly oil, is a significant component of the Mexican economy. However, in 2018, crude oil accounted for only 6.6% of Mexico's total export value compared with 17% in 2008 (World Bank, 2019a). Crude oil provided 43% of total government revenue in 2008, but only 16% in 2019, owing to a decline in domestic production and world oil prices. Mexico's public budget relies heavily on oil revenues (Banxico, 2020). Moreover, Mexico has the lowest rate of tax revenue as a share of GDP (16%) among the 35 Organisation for Economic Co-operation and Development (OECD) members (OECD, 2019).

Table 1: Key data and economic profile, 2017

Key data ^{a, b, c}		Energy reserves ^{d, e}	
Area (million km ²)	2.0	Oil (billion barrels)	5.8
Population (million)	127	Gas (trillion cubic metres)	0.2
GDP (2011 USD billion PPP)	2 240	Coal (billion tonnes)	1.2
GDP (2011 USD PPP per capita)	17 949	Uranium (kilotonnes U)	1.8

Sources: ^a World Bank (2020); ^b EGEDA (2019); UN (2019) ^d BP (2020); ^e NEA (2018).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

In 2018, Mexico's total primary energy supply was 183 085 kilotonnes of oil equivalent (ktoe), a 1.7% increase from the 2017 level. This increase was driven by increasing energy imports due to a continuing fall in domestic crude oil production, which peaked in 2004. Fossil fuels constituted 90% of the primary energy supply of the economy, with other non-fossil sources, such as nuclear and renewable energy, constituting the remaining 10% (IEA, 2019).

Mexico has abundant fossil and renewable energy resources. In 2018, Mexico's fossil fuel reserves stood at 7.7 billion barrels of crude oil (the 19th largest in the world and the 5th in APEC), around 200 billion cubic metres (bcm) of natural gas, and 1.2 billion tonnes of coal (BP, 2020). Potential for renewable energy development is estimated, conservatively, at 2 593 gigawatts (GW) of predominantly wind and solar resources, which are still largely untapped (SENER, 2017).

OIL

Mexico is a major oil producer, producing 1.7 million barrels per day (Mbb/D) of crude oil in 2019, of mostly the heavy type (CNH, 2020). This volume was 7.2% lower than that in 2018, mostly because of the decline in several major fields, the property of the state-owned oil company, Petróleos Mexicanos (Pemex), which still produces about 98% of crude oil in Mexico.

Mexico's oil production has been in steady decline since it peaked at 3.4 Mbb/D in 2004, reaching a 39-year record-low in 2019 at 1.7 Mbb/D (CNH, 2020). This fall in production was mainly due to the depletion of Mexico's largest asset, the Cantarell supergiant field, but was also a result of the insufficient resources allocated to exploration activities. At its peak in 2004, Cantarell produced 2.1 Mbb/D, more than 60% of Mexico's total crude oil production. By 2019, Cantarell produced less than 0.16 Mbb/D, representing only 9.3% of Mexico's production (SIE, 2020b).

Mexico is a net crude oil exporter. About 66% of its domestic crude oil production was exported in 2019, mostly to the US (SIE, 2020b). Historically, Mexico has been one of the largest crude suppliers to the US after Canada and Saudi Arabia. However, Mexico's crude exports to the Asia Pacific region have more than tripled since 2014, accounting for 0.31 Mbb/D in 2019 (SIE, 2020b).

Despite being a large crude oil producer with a domestic distillation capacity of 1.6 Mbb/D in six refineries located across its territory, Mexico is a net importer of oil-based products, especially gasoline (SENER, 2018b). Increasing domestic demand for oil products and decreasing production in refineries has meant that net imports of gasoline and diesel have almost doubled in the past ten years, accounting for 75% and 67% of demand for each fuel in 2019, respectively (SENER, 2020a).

GAS

Since 2005, natural gas has been the fastest-growing fuel in Mexico's primary energy supply, rising from 46 108 ktoe to 68 698 ktoe in 2018 (IEA, 2019). This increase represents an ongoing shift to natural gas, mostly in power generation. While gas demand has been growing steadily, domestic production has been decreasing since 2009, when it peaked, falling to 31 bcm in 2018 (IEA, 2019). More than three-quarters of Mexico's production is associated with crude oil (CNH, 2019). Domestic production is enough to cover roughly half of Mexico's demand, with the rest met by imports. Most gas imports to Mexico come from neighbouring low-cost production shale gas from the US.

Natural gas imports have dramatically increased in the past decade, rising from 13 bcm in 2009 to 57.4 bcm in 2019, registering a record high every year (CNH, 2020). In 2019, the vast majority 50.8 bcm (88.5%) of these imports were piped from the US (BP, 2020). The remainder is imported

as LNG, mainly from Peru and the US, to one of Mexico's three regasification terminals: Altamira on the Gulf Coast and Ensenada and Manzanillo on the Pacific Coast (SENER, 2020d).

In 2018, total gas supply rose to 68 698 ktoe, driven by rising demand from power generation plants. The growing demand was met by imports, with domestic gas production continuing to decline, due to asset depletion and declining reserves (IEA, 2019).

While Mexico holds the sixth-largest shale gas reserves in the world, environmental and social concerns, investment uncertainty, and cost-competitive imports from the US, have prevented major shale gas development in Mexico (IEA, 2013, 2017).

COAL

Coal has a relatively small share of Mexico's primary energy supply, compared to most APEC economies, representing 7% of total supply in 2018 (12 003 ktoe) (IEA, 2019). Coal is predominantly used in the power sector. While Mexico is a coal producer with reserves of around 1.2 billion tonnes, the economy is a net coal importer, with most of these imports coming from Colombia and the US.

Table 2: Energy supply and consumption, 2018

Total primary energy supply (ktoe)		Total final consumption (2017) (ktoe)		Power generation (GWh)	
Indigenous production	151 071	Industry sector	37 348	Total power generation	341 283
Net imports and others	32 000	Transport sector	51 421	Thermal	270 743
Total primary energy supply	183 085	Other sectors	28 337	Coal	29 144
Coal	12 003	Non-energy	5 233	Oil	35 598
Oil	82 248	Final energy consumption*	122 338	Gas	205 641
Gas	68 698	Coal	3 331	Renewables	56 536
Renewables	16 559	Oil	72 982	Hydro	32 526
Hydro	2 797	Gas	15 133	Solar	3 199
Wind, solar, etc.	13 762	Renewables	7 430	Wind	13 074
Others	3 563	Electricity and others	23 381	Geothermal, etc.	5 366
Nuclear	3 563			Others	154
				Nuclear	13 675

Source: EGEDA (2019) (data collected in December 2019) and IEA (2019).

*Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to comprise renewables.

ELECTRICITY

Electricity generation in Mexico has grown by an average of 2.7% annually since 2010, totalling more than 341 terawatt-hours in 2018, mostly derived from thermal power plants (IEA, 2019). Natural gas-fuelled plants accounted for 60% of total generation, oil-fuelled plants for 10%, and coal-fuelled for 8.5%. Renewable energy accounted for 17% of total generation, with solar and wind combined accounting for 4.7% in 2018.

Solar and wind generation have increased their share very rapidly in the past five years. In May 2020, wind generation accounted for 5.7% of total generation while solar PV accounted for 4.5% (CENACE, 2020b). Installed power capacity was around 79 gigawatts (GW) in 2018 (SENER, 2019b). Natural gas was the dominant fuel in power capacity, with 44% of the total share, followed

by oil with 17%, hydropower with 16%, coal with 6.8%, wind with 7.5%, solar with 4.4%, and the remaining 3.7% comprising nuclear and other renewables (SIE, 2020a).

Mexico has 13 international interconnections, 11 of them with the United States, one with Guatemala and one with Belize (IEA, 2017). Mexico's electricity system is served via four separate grids. The National Interconnected System is the main grid, covering most of Mexico except for the Baja California Peninsula. Another system serves the north of that peninsula and has two interconnections with the United States. Two isolated systems serve the sparsely populated central and southern portions of the Baja California Peninsula.

FINAL ENERGY CONSUMPTION

In 2017, total final consumption (this includes final energy consumption plus non-energy uses of energy products) in Mexico grew by 0.5%, reaching 122 338 ktoe (IEA, 2019). This increase was mainly driven by a 6.5% growth in industrial demand. The transport sector remained Mexico's largest end-use sector (42%), followed by the industry sector (31%), the buildings sector (18%) and agriculture and non-specified sectors (5.5%) (EGEDA, 2019). Non-energy consumption (mostly petrochemicals) accounted for the remaining 4.3%.

By energy source, oil-based products reduced their share to 56% of the total, mostly consumed in transportation. Electricity was the second-largest fuel (19%), including 3.1% of renewable-generated electricity. Natural gas accounted for 12% and coal for 2.7%. Direct final use of renewables accounted for 6.1% of the total. Most of this use refers to the combustion of traditional biomass in the residential sector (EGEDA, 2019).

ENERGY INTENSITY ANALYSIS

Since 1989, Mexico has implemented initiatives to improve its energy efficiency, which is reflected by a long-term trend reduction in its energy intensity levels. Primary energy supply intensity improved by 4.6% from 2016 to 2017 as shown in Table 3. Total final energy consumption intensity improved by 1.6% in 2017. The energy intensity improvement was larger when excluding non-energy consumption such as petrochemistry, plastics and others.

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%)
	2016	2017	2016 vs 2017
Total primary energy supply	84	80	-4.6
Total final consumption	56	55	-1.6
Final energy consumption excl. non-energy	53	52	-1.4

Source: EGEDA (2019).

RENEWABLE ENERGY SHARE ANALYSIS

Modern renewables in Mexico increased to 9.2% in 2017, driven by renewable electricity coming from wind and solar-photovoltaic capacity additions. The share of renewables in final energy consumption increased from 4.1% to 4.4% in 2017. Traditional biomass decreased by 0.5%, continuing a downward trend since 2010. Traditional biomass still accounts for 5.1% of final energy consumption, concentrated in the residential buildings sector and particularly in low-income households where it is the main source of energy.

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	116 374	117 102	0.6
Non-renewables (Fossil fuels and others)	111 653	111 912	0.2
Traditional biomass*	6 008	5 979	-0.5
Modern renewables*	4 721	5 190	9.9
Share of modern renewables to final energy consumption (%)	4.1%	4.4%	9.2%

Source: EGEDA (2019).

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial) using inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (e.g. hydropower and geothermal), including biogas and wood pellets, are considered modern renewables, but data on wood pellets are limited.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Mexico's energy policy links closely to the oil industry. Up until 2013, the Mexican energy sector was dominated by two state-owned vertically integrated companies: Pemex (*Petróleos Mexicanos*) in the oil and gas industry and CFE (*Comisión Federal de Electricidad*) in the electricity sector. Pemex monopolised the upstream, midstream and downstream activities with participation of private actors limited to services and contracts with the state-owned company. Similarly, CFE enjoyed a monopoly along the value chain except for limited private participation in power generation.

In 2013, a major series of legislative changes (including to the constitution) reorganised the energy sector in a bid to attract private and foreign investment. The restructure aimed to transition these state monopolistic structures to a market approach with increased competitiveness and transparency. Both Pemex and CFE remained wholly owned by the state but were unbundled along the value chains. Subsidiaries were created that adopted stronger corporate governance with independent board members.

With the participation of new players, the National Hydrocarbons Commission (CNH) and the Energy Regulatory Commission (CRE) had their mandates expanded and capacities strengthened. A set of new institutions were created to accommodate the needs and challenges of new market conditions. The National Centre for Energy Control (CENACE) is the independent electricity system operator, and the National Centre for Natural Gas Control (CENAGAS) is the natural gas independent system operator.

Additionally, some completely new institutions were born such as the Agency of Security, Energy and Environment (ASEA), responsible for environmental protection in the oil and gas industry, and the Mexican Oil Fund for Stabilisation and Development, an oil sovereign fund responsible for holding all royalties and resource rents from the oil and gas upstream sector.

Energy policy in Mexico is led by the Ministry of Energy (*Secretaría de Energía*, or SENER). The Minister of Energy also holds the title of chairman of the boards of both Pemex and CFE. Moreover, the CEOs for both state-owned companies are appointed directly by the President of

Mexico. SENER develops an energy sector program with the main energy goals and strategies to be enforced at the beginning of every six-year presidential term.

A new six-year presidential administration led by Andres Manuel Lopez Obrador began in December 2018. The President's proposals regarding the energy sector were based on achieving energy self-sufficiency and "rescuing" state-owned companies CFE and Pemex. Over the past year and a half, the current administration has brought about a clear policy shift. The new priorities include increasing Pemex oil and gas production, building a .034 Mbbl per day refinery and increasing CFE's market share in power generation.

In June 2020, SENER published a draft version of the 2020-2024 Energy Sector Program (PROSENER) which describes its general objective as 'reaching energy self-sufficiency as a necessary condition for energy security and national sovereignty' (SENER, 2020c). Moreover, the Program argues that recent solar and wind energy plants (most of them owned and operated by utilities other than CFE) have led to a 'disordered' growth in capacity, with this having detrimental impacts on the reliability of the electricity system (SENER, 2020c).

In sum, the current Mexican energy strategy prioritises self-sufficiency and a prominent role of state-owned companies over energy infrastructure development and materialising renewable energy potential using market-led mechanisms.

OIL AND GAS

Like most APEC economies, the state is the owner of all oil and gas reservoirs in Mexican territory. The state was the sole participant in upstream activities for many years through Pemex. But legislation change in 2013 meant that private companies can now enter into exploration and extraction contracts with the Mexican state, through competitive bidding processes organised by CNH, the upstream regulator.

The CNH has awarded 110 contracts in three bidding rounds, to more than 70 companies from 20 economies to explore and extract oil and gas since July 2015 (CNH, 2019). As of 2019, cumulative revenue from these contracts has amounted to more than USD 2.2 billion for the Mexico government while committed private investments accounted for USD 4.6 billion.

However, in one of the current administration's first major policy decisions, SENER cancelled two oil and gas bidding rounds that were under way and declared that any future bidding processes were cancelled until further notice (CNH, 2018).

With no oil and gas upstream auctions planned by the government, the participation of private companies in the upstream oil and gas sector is now restricted to incumbent contracts or to *ad-hoc* partnerships with Pemex. This leaves Pemex with a dominant position in the oil and upstream sector with little space for investment and participation by other companies. Increasing Mexico's oil and gas production through Pemex is one of the key objectives of this administration and is an essential element of their energy self-sufficiency goal. SENER assigned 64 areas for exploration and production in 2019, accounting for around 1 000 million barrels of oil equivalent (Mboe) of 3P reserves (SENER, 2019d).

Oil products

The 2013 legislative reforms also allowed private participation in the oil and gas midstream and downstream sectors, including refining, transportation, storage, distribution and retail. For petroleum products, some activities have transitioned to a market approach model, with a growing number of participant companies.

Mexico has a domestic refining capacity of 1.6 Mbbl per day (77 Mtoe per year) in six refineries, all of them wholly owned by Pemex. Due to the ageing refining infrastructure and lack of maintenance, the average refinery utilisation rate stood at 40% in 2019 (SENER, 2019c). Simultaneous increased demand for petroleum products has meant Mexico is now a major net importer of petroleum products.

In 2019, Mexico imported 970 Mbbbl per day of oil products, with gasoline accounting for 63% of these imports (SENER, 2019c). Imports accounted for 76% of gasoline consumption, 70% of diesel consumption, and 63% of LPG consumption in Mexico in 2019. Pemex used to be the sole importer of these products. Private companies have recently entered the market and have considerably increased their oil products imports, accounting for 14% of gasoline, 30% of diesel and 70% of LPG total imports in 2019 (SENER, 2019c).

The draft energy plan considers reliance on fuel imports from the US as detrimental to Mexico's energy security. However, the US Gulf Coast refineries are highly efficient and offer low-cost transportation of petroleum products to Mexico. These facts are not acknowledged by the plan. One of the reasons for Mexico's low refinery output (operating at around 40% of capacity) is that the refineries were configured originally to process light crude oil, whereas most of Mexico's crude production is heavy. The current administration strategy is to reconfigure all six refineries to increase their capacity and to build one of this administration's emblematic infrastructure projects, the 0.33 Mbbbl/d Dos Bocas refinery. The USD 8 billion refinery is being built with government funds and will be owned and operated by Pemex.

While in terms of infrastructure Pemex remains as the largest player, owning most oil pipelines and storage capacity, the state-oil company has conducted seven open seasons, granting third-party access to its free-capacity (SENER, 2018). New market players have demonstrated interest by developing midstream pipeline, storage and distribution infrastructure projects. As of 2019, oil products pipeline and 42 storage and distribution facilities for petroleum products were at some point of development, some of them already operational (SENER, 2019c).

For multiple decades, fuel prices (especially for gasoline and diesel) were subsidised without accounting for refining, importing, distribution and other associated costs. This contributed to losses for Pemex and acted as a regressive subsidy for taxpayers. The liberalisation of gasoline and diesel markets (with cost reflective pricing) occurred gradually across Mexico, and was fully completed in 2017 (SENER, 2018)

Natural gas

The natural gas industry has also transitioned from the Pemex vertically integrated monopoly, although midstream gas infrastructure, unlike petroleum, did have some private sector participation with the construction and operation of pipelines and LNG-receiving terminals since the late 1990s.

CFE, the electric utility, played a key role in increasing the share of natural gas in Mexico's energy mix by carrying out an oil-to-gas transition in its power plant fleet. CFE guaranteed demand in sites with no access to gas by contracting with private companies, rather than financially troubled Pemex, to construct new gas pipelines. The 2013 reforms also strengthened the regulatory responsibilities of the CRE, the regulator.

In a move to liberalise gas markets, CRE forbade companies from simultaneously engaging in both marketing and transporting natural gas. In response, Pemex transferred its natural gas pipelines—more than 10 000 kilometres (km), which make up around 90% of Mexico's natural gas pipeline network—to CENAGAS in 2015 (Pemex, 2012 and 2015).

Since 2011, private investment of around USD 12 billion has led to a 50% increase in the gas pipeline network (more than 5 800 km of new pipelines) and the addition of eight interconnections with the US, particularly with the Eagle Ford and Permian tight gas-abundant basins (SENER, 2019d). As of October 2019, at least four pipelines were still under construction; with delays of more than two years because of opposition from local communities, environmental groups, or indigenous groups resulting from concerns surrounding the Free Prior Informed Consent (SENER, 2019d).

Pemex was mandated to transfer 70% of its marketable natural gas volume to other companies, allowing clients to choose another provider or stay with Pemex. While gas demand keeps growing, driven mostly by power generation but also coming from industrial users, most

residential consumers in Mexico have no access to this fuel. Some regions like the Yucatan peninsula have recently seen gas shortages, putting severe stress on power generators and causing blackouts in 2019 (Robinson & Hilfiker, 2019).

ELECTRICITY

Since 1960, the whole electricity value chain, including generation, transmission, distribution and retail had been a state monopoly in Mexico. In 1992, an amendment allowed private companies to operate in the generation segment through power purchase agreements with CFE, which was later expanded to self-supply and cogeneration. In 2013, Mexico's electricity sector began to undergo a profound transition from a largely monopolistic structure to a competitive electricity market structure.

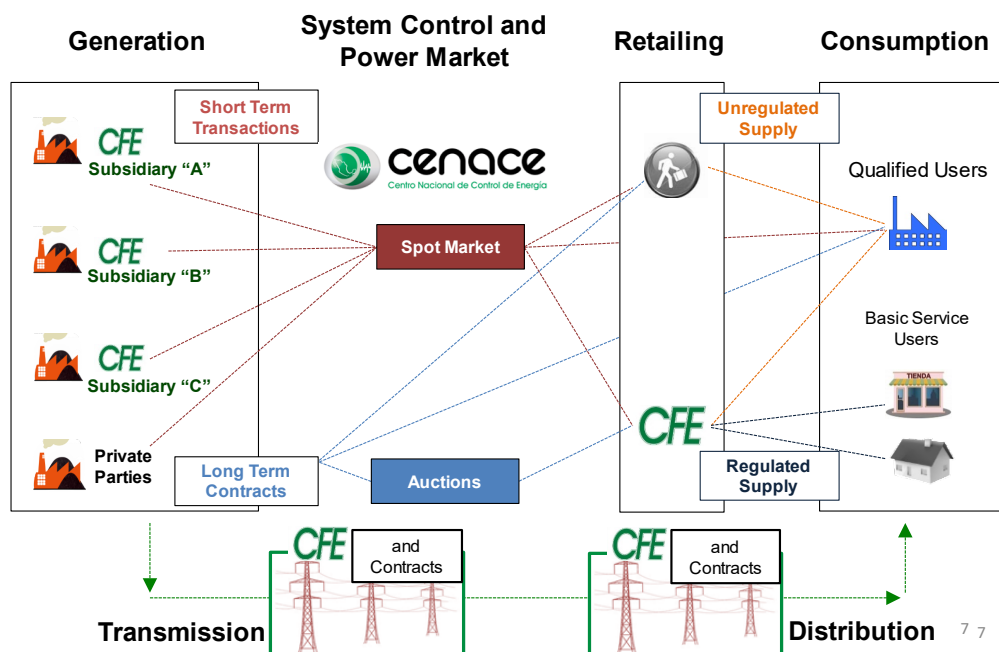
The current legal framework allows private companies to participate and compete in generation and supply activities. Private companies can participate in the supply segment for large consumers (more than 1 MW). Supply to retail consumers, transmission and distribution and nuclear power generation has been maintained as an exclusive responsibility of CFE. However, private companies, in association with CFE, can participate in the expansion of the transmission and distribution grids. CFE has been vertically unbundled and divided into 13 subsidiary and affiliate companies to cover all activities within the sector, including six power generation subsidiaries (SENER, 2019b).

In 2016, the Mexican Wholesale Electricity Market began operating guided by the principle that the lowest cost resources are dispatched first. Since March 2016, three auctions for long-term contracts have been held by CENACE to purchase energy, capacity and clean energy certificates. More than 7.5 GW of renewable generation capacity will be added by around 35 companies at a cost of USD 9 billion. Wind and solar-photovoltaic (PV) power account for more than 90% of the new capacity.

Prices obtained in these auctions were among the best in the world (USD 21 per megawatt-hour in the last auction, held in November 2017) due to a high level of participation and competition. In many cases, the renewable prices were more competitive than prices for fossil fuel-fired plants (CENACE, 2017).

In 2013, a market for clean energy certificates (CECs) was created in a bid to foster renewable and other clean energies. These green certificates are granted to companies that produce power from designated clean energy technologies. SENER established requirements to use a percentage of clean energy that all load-serving entities, including retailers and large consumers, must fulfil. Non-compliers must procure required shares of clean energy certificates from CRE-certified clean energy generators.

Figure 3: Mexico's electricity sector structure



The 2015 Energy Transition Law established as a goal that 25% of electricity generation must be 'clean' by 2018, 35% by 2024 and 50% by 2050. A controversial aspect of this law, however, is the inclusion of 'highly efficient' gas-fired combined heat and power generation as 'clean' energy. This is not consistent with international organisations, including the IEA, IRENA and APEC. Even with this criterion, Mexico's 'clean' energy generation accounted for 23% of total generation in 2018, falling short of the 25% goal (SENER, 2020b, 2020c, 2020a).

As of June 2020, the Mexican Wholesale Electricity Market has been operational, and CFE, vertically unbundled along the value chain, is competing with other generation companies. In the past five years, renewable energy has shown a remarkable growth in Mexico. From 2015 to 2019, 3.3 GW of solar PV and 2.7 GW of wind capacity were added to the grid, most via the three renewable energy auctions (IRENA, 2020).

Virtually all these renewable capacity additions are owned by companies other than CFE, displacing, when dispatched, more expensive generation plants, including those of CFE. In a similar decision to the one taken in the oil and gas sector, another of the first decisions of the current administration was to cancel the fourth renewable energy auction (CENACE, 2019). This was one of the first of a series of actions that made clear a policy shift in which the new priority of the power sector was CFE and preserving the "order and reliability in the system" (CENACE, 2020a; SENER, 2020b).

A key goal of the new administration is keeping CFE's share of power generation at a minimum of 54%, which was the level in 2018 (Bartlett, 2019). Nevertheless, all but a handful of recent renewable additions are owned by CFE; most of CFE's plants use fossil fuels. Given that recent solar and wind plants are often (mostly owned by private generators) dispatched first, CFE was expected to lose market share and to retire the oldest and most expensive capacity. In the draft energy plan, SENER has emphasised that intermittent renewable energy "affects the reliability of the system" and instead has to be balanced "in an ordered way" with baseload technology (SENER, 2020c). SENER has made several regulation changes targeted at increasing CFE's generation share.

In practice these regulation changes have meant a fundamental change in how electricity is dispatched, affecting renewable energy generators. Mexico's anti-trust body filed a constitutional

lawsuit against SENER at Mexico's Supreme Court, arguing the new regulations were "against competitiveness" and "favoured certain actors" (COFECE, 2020). There is an ongoing climate of uncertainty and confrontation that will probably affect investment and infrastructure development.

RENEWABLE ENERGY

Mexico has outstanding potential for renewable energy development due to its favourable geophysical characteristics. This potential remains mostly untapped. Mexico's renewable energy potential is conservatively estimated at 397 GW, allowing for social, environmental and infrastructure restrictions (SENER, 2017). This is more than five times Mexico's current installed capacity.

Mexico's solar radiation is 5.5 kilowatt-hours per square metre (kWh/m²), double that of Germany, for instance (SENER, 2017). However, Germany's installed solar capacity was 49 GW as of December 2019, almost 10 times higher than Mexico's 4.4 GW. Wind potential is estimated at 158 GW (compared with a capacity of 6.6 GW in 2019). Hydro power potential is 12 GW and geothermal potential is estimated at 0.25 GW (IRENA, 2020; SENER, 2017).

Recent policies have boosted the development of renewable energy. These policies include legal changes allowing private participation in power generation, the start of the wholesale market and the three renewable auctions undertaken by the power grid operator, CENACE. Solar PV and wind generation have grown exponentially. From 2015 to February 2020, the renewable generation share of total generation grew from 15% to 18%. Solar PV grew from 0.1% to 3.8% and wind from 2.8% to 7.8% (CENACE, 2020b).

Distributed generation has seen rapid growth, amounting to 0.81 GW at the end of 2019 (EH, 2020). Outside the power sector, direct use of renewables in applications including solar water heaters and bioenergy has also grown but at a slower rate (SENER, 2019b). There are currently no major biofuel support policies such as those in Brazil or Indonesia.

In legal terms there is a robust set of laws backing renewable development, they include: the Climate Change General Law, Energy Transition Law, Electrical Industry Energy Law, Geothermal Energy Law and the Bioenergy Promotions and Develop Law. Renewable energy is planned to play a fundamental role in achieving the clean energy generation goals stipulated in the Energy Transition Law.

Renewable energy development has not been a policy priority since 2018. SENER has modified regulations regarding the dispatch of solar and wind energy, on the basis that their intermittency 'may put at risk the reliability of the electrical system' (SENER, 2020b). The pace of future renewable energy development is uncertain.

NUCLEAR ENERGY

The Laguna Verde power plant has been in operation since 1990. It has two reactors with an installed capacity of 1.6 GW and it is owned and operated by CFE. Most of its uranium is sourced from Russia (SENER, 2019b). Mexico has no published plans for nuclear projects and SENER's most recent outlook cancelled previous plans to expand capacity by 2030 (SENER, 2019b).

ENERGY EFFICIENCY

Mexico has had energy efficiency programs since 1989. The institution responsible for promoting these programs and for providing technical advice is the National Commission for Efficient Energy Use (CONUEE). SENER and CONUEE jointly draft the National Program on the Sustainable Use of Energy (PRONASE), which frames Mexico's energy efficiency objectives and actions for every six-year presidential period. The PRONASE 2014–18, the latest published plan, includes design of programs for optimal energy use across sectors; regulations and standards for equipment and appliances made or marketed in Mexico; and strengthened governance of energy efficiency systems. SENER established Mexico's energy intensity goals: a 1.9% annual reduction in energy intensity from 2016 to 2030 and a 3.7% annual rate from 2031 to 2050 (CEPAL, 2018; CONUEE, 2018; SENER, 2016).

The updated PRONASE 2020-2024 is expected to be published in 2020, which aims to increase energy efficiency actions, aligned to the present administration's energy self-sufficiency goal (CONUEE, 2020).

ENVIRONMENTAL SUSTAINABILITY

Mexico's greenhouse gas (GHG) emissions represent 1.4% of the worldwide total (UNFCC, 2015). Mexico issued its first specific strategy in 2000. It was one of the first developing economies to exclusively issue a law dedicated to this subject, issued in 2012. Mexico promotes actions that protect the environment through lower carbon intensity in its domestic energy consumption and supply, as well as the reduction of polluting emissions from the electricity industry.

According to the Special Program for Climate Change 2014–18, the energy sector's impact on climate change is considerable, accounting for 61% of the established mitigation commitments. The program includes the goal of reducing a quarter of power generation emissions. The energy sector in Mexico is responsible for reducing methane emissions by 11% and black carbon emissions by 37%. Currently, an update of the program for the period 2020-2024 is under way and it is expected to be published by the end of 2020 (INECC, 2020a).

Since 2015, the ASEA has overseen and sanctioned operators across the oil and gas value chain (upstream, midstream and downstream). It monitors their compliance with industrial and operational safety measures; ensures plugging and abandonment of wells and facilities; and guarantees the control of polluting emissions and waste.

RESEARCH AND DEVELOPMENT

The Mexican state has specialised research centres focused on specific energy subsectors. The Mexican Petroleum Institute (IMP) supports the hydrocarbons sector, the National Institute for Electricity and Clean Energy (INEEL) supports research and innovation in electricity and clean energies, and the National Institute for Nuclear Research (ININ) supports research and development (R&D) on nuclear-based technology for power generation purposes.

Energy-related R&D in strategic areas has been enhanced by the creation of two trust funds, jointly managed by SENER and the National Technology Council (Conacyt):

1. the Trust Fund for Hydrocarbons oversees the Centre for Training in Development Processes and the Centre for Deep Water Technologies
2. the Trust Fund for Energy Sustainability has provided approximately USD 160 million for the creation of five Mexican Centres for Energy Innovation, specialising in bioenergy, wind energy, geothermal energy, wave energy and solar energy

In addition, the Trust Fund for Energy Transition and Sustainable Use, financed through the federal budget, aims to promote the use of renewable energy and energy efficiency.

NOTABLE ENERGY DEVELOPMENTS

Every six years, a new presidential administration with no right to re-election, starts in Mexico, normally bringing changes and shifts to energy policy. In December 2018, Andres Manuel Lopez Obrador started his tenure after a landslide electoral victory under an anticorruption, national and poverty-reduction platform. Since the election, there have been major changes in the energy sector.

The current government has prioritised energy self-sufficiency and a stronger role of state-owned companies with decreasing emphasis on renewable energy capacity additions, transitioning to more efficient and low-carbon technologies, and inducing efforts to increase private sector investment.

While the new administration has not made any amendments to the constitution or laws, the new government has made important changes to regulations in the oil and gas sector and the power industry. The current administration has also been wary of autonomous and specialised regulatory bodies, with President Lopez Obrador repeatedly stating they are only “autonomous from the people” and that they “defend private companies’ interests” (Político, 2019). Political pressure led to the head of the CNH and five commissioners of the seven-member CRE to quit, including its head commissioner (Político, 2019). A new group of commissioners appointed by the current administration has meant that regulation changes have been swiftly approved at the CRE.

OIL AND GAS

The key goal in the oil and gas sector for the current administration is to increase Mexico’s oil and gas production through Pemex, a necessary step for achieving energy self-sufficiency (SENER, 2020c). One of the first decisions on energy policy by the Lopez Obrador administration was the cancellation of the two oil and gas upstream auctions by the (CNH, 2018). This meant in practice closing the gate to major private companies on exploration and production activities for an indefinite period. The government provided an additional USD 3.6 billion to develop 20 “strategic fields” with the goal of increasing Mexico’s crude oil production by 37% by 2024 (SENER, 2020c). Crude production reached a 35-year minimum in January 2019 at 1.6 Mbbbl/D. Production has been growing modestly, reaching 1.7 Mbbbl/D in April 2020 (CNH, 2020).

Increasing Pemex’s oil and gas production through Pemex is one of the key goals of this administration. The government recently reduced Pemex’s tax by 11 percentage points to 54% by 2021 (Barrera & Martinez, 2019), effectively injecting USD 6.6 billion over the next two years (PEMEX, 2019). Even with this capital injection, Pemex missed its 2019 production goal of 1.8 Mbbbl per day from 17 strategic fields. Ratings agencies have downgraded Pemex’s credit rating to junk (Eschenbacher, 2020; S&P Global Platts, 2020).

Another key element of Mexico’s oil policy is boosting domestic refining. USD 25 billion has been assigned to refurbish the six existing Pemex-owned refineries. The construction of the emblematic Dos Bocas refinery, located in President’s Lopez Obrador’s home state of Tabasco, has been one of the landmark infrastructure projects of this administration. The 0.34 Mbbbl/D refinery will increase refining capacity by 25%, with a government funded investment of USD 8 billion (SENER, 2019a). There are some concerns and opposition concerning the project. Multiple studies by financial institutions, environmental activists and think-tanks have questioned its viability (IMCO, 2019; Stillman, 2019).

A related development in the midstream oil sector is the decision by the energy regulator, CRE, to leave without effects a previous resolution stipulating asymmetric regulation to Pemex. This had been designed as a strategy to transition from a Pemex-led monopolistic gasoline and diesel supply scheme to a competitive market. The resolution forbade Pemex from unilaterally setting prices for more than 30% of buyers and to report to the CRE the wholesale prices at its terminals (CRE, 2020). The CRE also postponed by five years the introduction of a diesel norm that limited the sulphur content of diesel sold by Pemex in Mexico (Eschenbacher, 2020). These regulatory changes benefit Pemex but affect the creation of a gasoline and diesel market.

Mexico is expanding around three-quarters of its natural gas pipeline network to better access inexpensive gas from Texas and to meet rising demand. Since 2012, 19 new gas pipelines and over 5 860 km have been added to Mexico’s gas pipeline network, with two of the largest large projects commissioned in 2019 (SENER, 2019a). However, in 2019, CFE’s CEO declared that the “take-or-pay” clauses were ill considered, and after threatening companies to start arbitration proceedings, initiated renegotiation. The government and the pipeline companies reached a settlement, with CFE claiming to have saved USD 4.5 billion (Parkin & Montgomery, 2019).

Four pipelines were under construction as of the end of 2019, with delays due to opposition from local communities, environmental groups, and indigenous groups. These concerns relate to Free Prior Informed Consent, among other factors (SENER, 2019a).

ELECTRICITY

The Mexican electricity sector has been subject to a series of regulatory and policy changes in the last year. According to the government, these changes have been made to “reorder” the power sector with “corrective” measures aimed at benefitting the state-owned utility, CFE (SENER, 2020c). While there have not been amendments to the legal framework, there has been a de-facto change to the rules which has mostly affected generating companies with clean energy power plants in their portfolios, particularly those with intermittent technologies. Power generator associations, environmental associations and advocacy groups have sued SENER and CENACE, in a bid to revise the regulations. As of June 2020, the confrontation between power generators and the administration is still playing out in courts and tribunals, including the Supreme Court of Justice.

Despite the encouraging results of Mexico’s three long-term energy auctions—which saw prices for renewable energy below USD 20 per MWh—the Lopez Obrador administration suspended the fourth energy auction in January 2019 citing “energy planning, economic and technical considerations” (CENACE, 2019). These long-term auctions comprised exchanges in the wholesale market for capacity, energy and clean energy certificates. In late 2019, SENER announced that no energy auctions would be called thereafter until further notice (CENACE, 2019b). In another decision against increased private participation in the electricity sector, CFE cancelled tenders for two direct-current (DC) transmission lines. This was a USD 1.2 billion investment that would connect Mexico’s main wind power generation region with major cities in central Mexico and another line linking the National Interconnected System and Baja California system (Ramos, 2019).

In another policy shift, SENER announced that no CFE power stations will be retired, to ensure the “revival of CFE” (SENER, 2019e). Most of CFE’s power plants are based on fossil fuels and some of them are working beyond their operational lifetime. CFE’s generation subsidiaries have also been recentralised via a SENER regulation change (Deloitte, 2019; DOF, 2019b).

In October 2019, SENER proposed a modification to the clean energy certificates (CELs), a tailor-made financial scheme. The CELs aim to add renewable energy generation by obliging electricity companies to obtain a minimum amount of clean energies in a bid to meet climate goals. Non-compliance with the minimum threshold results in penalty fees. The regulatory change allows for CFE’s existing renewable generation capacity, mostly large hydropower and the Laguna Verde nuclear power plant, to be eligible for such certificates (DOF, 2019a). This has led to an oversupply of CELs and has removed the need for CFE’s supply subsidiary (CFE-SSB) to acquire additional CELs.

With no need to pay for CELs or to pay penalty fees, this change has reduced stress on CFE’s finances while also reducing the incentive for investments in renewable capacity development in Mexico (CIEP, 2020). Several private power generators challenged this regulation in court and on December 2019, court rulings halted the proposed modification to the CEL’s eligibility criteria until a final resolution is issued (Nava, 2019).

Two recent resolutions have proposed modifications to electricity network dispatch. The first resolution was issued by CENACE on April 2020. The resolution indefinitely suspended ongoing pre-operative testing on wind and solar generation plants and changed the rules for grid access. This added more must-run plants to the dispatch, reducing access for renewable plants already in operation (CENACE, 2020a). These provisions were included in CFE’s policy-list request to SENER and the CRE that was made public back in December 2019 (ED, 2019). They have since been justified as part of COVID-19 pandemic and lockdown measures. CENACE’s resolution was widely opposed. Private generators began legal proceedings and 23 of these companies were allowed to restart their pre-operational tests (ArgusMedia, 2020).

In May 2020, SENER published another resolution, “Resolution for Issuance of the Policy on Reliability, Stability, Continuity and Quality in the National Electric Grid” (DOF, 2020b). According to SENER, the main goal of this resolution is to guarantee electricity supply under the principle

of reliability and to “bring order” to the electricity market by creating a level playing field for CFE (DOF, 2020b). The resolution imposes stricter rules for new generation permits and additional restrictions for wind and solar plants. The concepts that serve as the basis of the SENER resolution—reliability, stability, continuity and quality—are only conceptually (and not technically) defined, leaving them open to potentially discretionary interpretation and application (Shearman & Sterling, 2020).

Energy experts, advocacy groups and generators have argued that this new regulation provides discretionary power to CENACE to benefit CFE. Private renewable generators have begun legal proceedings which challenge this regulation (Platts, 2020). COFECE, Mexico’s anti-trust body, filed a constitutional lawsuit against SENER at Mexico’s Supreme Court, arguing the new regulations were “against competitiveness” and “favoured certain actors” (COFECE, 2020). These regulatory changes and the subsequent judiciary processes against these regulations have caused an ongoing climate of uncertainty and confrontation that will very likely affect investment and infrastructure development.

RENEWABLE ENERGY

Renewable energy has grown remarkably in Mexico in the past five years, particularly solar and wind, but as explained above, this growth is at risk of coming to a halt. The current administration does not prioritise renewable energy, focusing instead on enhancing the role of state-owned companies and energy self-sufficiency. This puts Mexico in a very challenging situation as regards meeting both its domestic and international commitments, particularly as the economy did not meet its clean generation energy mix goal of 24% in 2018, as set out in the Energy Transition Law (DOF, 2020a).

According to SENER’s energy outlook, once most of the power plants from the three energy auctions are commissioned, it seems likely that most of the renewable energy growth will likely be restricted to CFE’s hydropower and geothermal capacity additions (SENER, 2019b). Private companies are looking to innovative business mechanisms such as private energy auctions. At least two such auctions are currently being planned.

ENERGY EFFICIENCY

Energy efficiency savings in Mexico were estimated to be 15 GWh for the first half of 2019 by CONUEE, Mexico’s energy efficiency agency (CONUEE, 2020). These savings are tied to energy efficiency programs, with some in place for many years. The programs relate to norms and standards in the energy end-use sectors (for example, industrial, residential and commercial), savings on facilities owned by the federal government, public lighting, and daylight savings (CEPAL, 2018).

ENVIRONMENTAL SUSTAINABILITY

In September 2016, Mexico ratified its Nationally Determined Contribution (NDC), committing to an unconditional reduction of 22% of its GHG emissions by 2030 in comparison to its business-as-usual 2013 baseline. On a conditional basis, this share increases to 40% if certain global measures to address climate change are put in place (UNFCCC, 2016).

Non-fossil fuel power generation and energy intensity goals mandated in the Energy Transition Law will positively impact emissions reduction if they are achieved. However, the 25% clean power generation goal, mandated by the Energy Transition Law (LTE, in Spanish), was not achieved in 2018 (SENER, 2020b, 2020a).

The Ministry of Environment and Natural Resources is responsible for updating Mexico’s NDC. They expect to submit the update in 2020. There are no publicly available details regarding the update (INECC, 2020). However, SENER’s policy priorities of revamping the role of Pemex and CFE places Mexico’s climate goals in an extremely challenging position. No emissions reduction or decarbonisation plans have been published to date. The recent regulatory changes afford a

lower than expected role of renewable energy. CFE's coal and fuel-oil plants are being supported to a larger degree (SENER, 2020c).

INTERNATIONAL COOPERATION

Mexico is a member and active participant of the United Nations, the IEA, the International Atomic Energy Agency (IAEA), the Nuclear Energy Agency (NEA), the International Renewable Energy Agency (IRENA), the International Energy Forum (IEF), the Latin American Organisation (OLADE), the Clean Energy Ministerial, the G20 and APEC (IEA, 2017).

Mexico also collaborates with the Organisation of the Petroleum Exporting Countries (OPEC) and is one of the 23 members of the OPEC+ alliance (Cohen, 2018; OPEC, 2017). In a very low-price environment arising from a demand shock caused by the COVID-19 pandemic and a supply war between Saudi Arabia and Russia, Mexico played a decisive role in the April 2020 OPEC+ meeting. The OPEC+ economies were close to reaching an agreement on cutting production by 10 million barrels per day (mb/d), using October 2019 as a baseline. The production cut was about 23% per economy, with Russia and Saudi Arabia cutting 2.53 mb/d each (OPEC, 2020b).

But Mexico opposed the proposal, rejecting its respective cut of 400 thousand barrels per day (kb/d), arguing that the resources and effort committed to stabilising production levels precluded its participation in a broader strategy to stabilise oil markets. In the April 9 declaration, OPEC+ clarified that the proposed cut remained conditional upon the acceptance of Mexico (OPEC, 2020b). After continued discussions, OPEC+ officially announced on April 12 an overall cut of 9.7 mb/d, accepting that Mexico would only implement a much lower cut of 100 kb/d.

This was the largest coordinated oil production cut ever agreed, both in terms of oil volume and the parties involved. Mexico participated in the following meeting, held in June 2020, and was not part of the agreement to extend the production cut (OPEC, 2020a).

Through SENER, Mexico has also maintained bilateral strategic cooperation initiatives with several economies on diverse energy topics.

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USEFUL LINKS

Banco de México (Banxico)—www.banxico.org.mx

Centro Nacional de Control de Energía (CENACE)—www.cenace.gob.mx

Centro Nacional de Control del Gas Natural (CENAGAS)—www.cenagas.gob.mx

Comisión Federal de Electricidad (CFE)—www.cfe.gob.mx

Comisión Nacional para el Uso Eficiente de la Energía (CONUEE)—www.conuee.gob.mx

Comisión Nacional de Hidrocarburos (CNH)—www.cnh.gob.mx

Comisión Regulatoria de Energía (CRE)—www.cre.gob.mx

Comisión Nacional de Seguridad Nuclear y Salvaguardias (CNSS)—www.cnsns.gob.mx

Instituto Mexicano del Petróleo (IMP)—www.imp.mx

Instituto de Investigaciones Eléctricas (IIE)—www.iie.org.mx

Instituto Nacional de Investigaciones Nucleares—www.inin.gob.mx

Instituto Nacional de Estadística y Geografía (INEGI)—www.inegi.org.mx

Petróleos Mexicanos (PEMEX)—www.pemex.com

Presidencia de la República—www.gob.mx/presidencia

Rondas México— <https://rondasmexico.gob.mx/>

Secretaría de Energía (SENER)—www.gob.mx/sener

Secretaría de Hacienda y Crédito Público (SHCP)—www.gob.mx/hacienda

Secretaría del Medio Ambiente y Recursos Naturales (SEMARNAT)—
<https://www.gob.mx/semarnat>

Sistema de Información Energética (SIE)—<http://sie.energia.gob.mx>

NEW ZEALAND

INTRODUCTION

New Zealand is an economy in the South Pacific comprising the North Island, South Island, and numerous outer islands. New Zealand's land area is similar to Japan's, though its population is relatively small, at 4.8 million people in 2017. This population enjoys a high standard of living with per capita gross domestic product (GDP) of USD 36 046 (2011 USD purchasing power parity [PPP]) in 2017. New Zealand has no electricity or pipeline connections to other economies due to its isolated location.

New Zealand is self-sufficient in all energy forms except for oil. Renewables make up a large share of supply and accounted for 82% of electricity generation in 2017. Hydro is the dominant renewable energy source, with support from geothermal and wind. Fossil energy proven and probable (2P) reserves are modest with 402 petajoules (PJ) of oil and 2 116 PJ of natural gas and liquefied petroleum gas (LPG) at the start of 2019 (MBIE, 2019). Estimated coal reserves stood at 7.6 billion tonnes at the end of 2018 (BP, 2019).

Table 1: Key data and economic profile, 2017

Key data ^{a, b}		Energy reserves ^c	
Area (km ²)	269 652	Oil (PJ)	402
Population (million)	4.8	Gas (PJ)	2 116
GDP (2011 USD billion PPP)	173	Coal (billion tonnes)	7.6
GDP (2011 USD PPP per capita)	36 046	Uranium (kilotonnes U)	–

Sources: ^a EGEDA (2020); ^b MBIE (2019); ^c BP (2019).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

New Zealand's total primary energy supply (TPES) was 21 million tonnes of oil equivalent (Mtoe) in 2017, a 0.70% increase from 2016. Renewable energy (geothermal, wind, solar and others) was the major contributor to TPES (41%), followed by oil (33%), gas (21%) and coal (5.6%) (EGEDA, 2019).

The share of geothermal in total final energy consumption is significantly smaller than the share of geothermal in TPES. This is because geothermal electricity generation has low efficiency of approximately 15% in New Zealand (MBIE, 2016).

New Zealand's energy self-sufficiency (indigenous production/primary energy supply) in 2017 was 77%. This continued a declining trend from the 2010 peak (92%) and has been largely due to falling domestic oil and gas production, combined with increasing demand for transport fuels. New Zealand's TPES has increased at an average annual rate of 1.1% since 2000 (EGEDA, 2019).

Coal is New Zealand's most abundant fossil energy resource. Almost all coal production is sub-bituminous and bituminous coal, though most of New Zealand's coal resources are in the form of low-value lignite. In 2017, annual coal production growth was 1.0%.

Oil is sourced from 19 fields in the Taranaki Region on the North Island (MBIE, 2019). The production of crude oil, natural gas liquids and condensate fell by 10% on an energy-equivalent basis in 2017 compared with the 2016 level. A downward trend will continue unless new fields are discovered and brought on stream (MBIE, 2018). The government announced a restriction to oil and gas exploration activities in 2018, which will reinforce the declining production trend (NZG, 2018).

Oil production peaked in 2008, underpinned by the development of offshore fields the Pohokura, Kupe, Tui and Mri, and onshore fields such as Cheal and Sidewinder (MBIE, 2015b). Most of New Zealand's oil is exported due to its high quality (it is 'sweet' and 'light'). Domestic oil demand is largely met through imported refined products. Heavier crudes are also imported and refined at New Zealand's only refinery at Marsden Point. Indigenous production accounted for 27% of the domestic oil consumption in 2017.

Natural gas is sourced from 17 fields, with 84% of production from just four of these (MBIE, 2020). The largest uses for gas are industrial heat, electricity generation and methanol and urea production. All the gas produced in New Zealand is domestically consumed since there are no liquefied natural gas terminals.

In 2018, outages at the largest gas field Pohokura resulted in a 34% fall in production. Other fields made up some of this shortfall, though overall production still fell 11% in 2018. The fall in gas production was accompanied by low hydro production as well, which led to significant price spikes in the wholesale electricity market. Even with the volatility in gas production, Methanex was recently successful in securing a gas supply contract for more than half of its production until 2029 (Methanex, 2019).

New Zealand has large renewable potential, primarily in the form of hydro, geothermal and wind energy. Geothermal heat can be used directly in industry; likewise, biomass is a viable source of heat in the residential and industrial sectors. Solar photovoltaic generation while comparably small is also viable with falling deployment and grid integration costs.

In 2017, New Zealand generated 44 213 GWh of electricity, a 1.3% rise on the 2016 level. Hydro accounted for 57% of this generation. Other renewables accounted for 24% of generation (EGEDA, 2019). More than two-thirds of New Zealand's hydroelectricity is generated in the South Island. However, the main sources of load are in the North Island. Significant investment is required in the inter-island link to deliver this electricity. In contrast, all geothermal electricity was generated in the North Island.

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)	Total final consumption (ktoe)	Power generation (GWh)			
Indigenous production	16 016	Industry sector	4 446	Total power generation	44 213
Net imports and others	5 827	Transport sector	5 235	Thermal	8 271
Total primary energy supply	20 703	Other sectors	3 493	Coal	1 212
Coal	1 164	Non-energy	1 477	Oil	6.0
Oil	6 769	Final energy consumption*	13 174	Gas	7 053
Gas	4 246	Coal	568	Hydro	25 183
Renewables	8 524	Oil	6 311	Nuclear	0.0
Others	0	Gas	1 656	Other Renewables	10 759
		Renewables	1 292		
		Electricity and others	3 346		

Source: EGEDA (2019) (data collected in December 2019).

* Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to comprise renewables.

FINAL ENERGY CONSUMPTION

New Zealand's total final energy consumption increased by 1.6% in 2017 to 14 651 ktoe. Transport sector final energy consumption increased 6.5%, and was the driving factor behind the economy-wide increase. The industry, residential and commercial sectors all posted modest increases of between 0.79% and 1.5%. There was a decrease in other sectors (-1.9%). Transport and industry accounted for the largest share of final energy consumption, at 36% and 30%, respectively. Non-energy use purposes of energy amounted to 1 477 ktoe. Oil was the largest component of final energy consumption at 6.3 Mtoe (48%), followed by electricity and others at 3.3 Mtoe (25%), gas at 1.7 Mtoe (13%) and coal at 0.57 Mtoe (4.3%) (EGEDA, 2019).

Industry energy demand is dominated by a small number of large consumers: one aluminium smelting plant, one steel mill, one oil refinery, one methanol producer, two cement plants, several pulp and paper mills and a large dairy company (with multiple facilities). In 2017, the aluminium smelter used 11% of New Zealand's electricity, while the methanol producer consumed 28% of natural gas supply as a feedstock (MBIE, 2019). The pulp and paper industry meet half of their energy needs from wood and wood waste.

The increase in transport energy consumption (6.5% in 2017) continues an increasing trend since 2015. For the prior decade, transport energy demand was relatively flat. The light passenger vehicle fleet dominates transport, with significant contributions from heavy freight and air transport. Rail and water transport have small shares of consumption.

The transport sector consumed 83% of domestic oil and petroleum products in 2017. The residential, commercial and agricultural sectors accounted for 10% of oil consumption, while the industrial sector consumed the remaining 7% (EGEDA, 2019). The residential sector's main oil use is LPG for home heating purposes. The commercial and agricultural sectors mainly use diesel for machinery, backup electricity generators and motors.

ENERGY INTENSITY ANALYSIS

New Zealand's primary energy intensity in 2017 was 120 tonnes of oil equivalent per million USD (toe/million USD), an improvement of 2.4% from 2016. This was largely due to a large reduction in the use of gas for non-energy in 2017. Final energy intensity excluding non-energy only improved 0.23 this is .22%; final energy intensity including non-energy uses improved 1.5%.

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%) 2016 vs 2017
	2016	2017	
Total primary energy supply	123	120	-2.4
Total final consumption	86	85	-1.5
Final energy consumption excl. non-energy	76	76	-0.2

Source: EGEDA (2019).

RENEWABLE ENERGY SHARE ANALYSIS

New Zealand has made extensive use of renewable energy sources for many years, largely through hydroelectricity. The total share of renewable energy varies depending on variations in climate, especially rainfall. In 2017, the total share of renewable energy decreased to 29%, an annual fall of 3.8%. This fall was largely due to strong growth in non-renewables (4.6%), and a decline in modern renewables of 1.0%.

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	12 803	13 174	2.9
Non-renewables (fossil fuels and others)	8 758	9 165	4.6
Traditional biomass*	160	163	1.9
Modern renewables*	3 885	3 846	-1.0
Share of modern renewables to final energy consumption (%)	30%	29%	-3.8%

Source: EGEDA (2019).

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on.), including biogas and wood pellets, are modern renewables, although data on wood pellets are limited.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

The Ministry of Business, Innovation and Employment (MBIE), reporting to the Minister of Energy and Resources, is responsible for developing New Zealand's energy policies and energy strategies. The Ministry of Transport, Ministry for the Environment, and the Energy Efficiency and Conservation Authority, among others, assist the MBIE.

In November 2018, the government passed the Crown Minerals Amendment Bill, which ends all new offshore oil and gas exploration and limits onshore exploration to the Taranaki Region. In 2018 the existing 31 oil and gas exploration permits (22 of which are offshore) were at 'granted' status, and will continue to be honoured. The new legislation has increased exploration activities in areas that remain available for exploration, with the expectation of further restrictions on exploration in 2020.

In New Zealand electricity markets, five large electricity retailers service the majority of the market. In a sign of increasing competition, small and medium-sized electricity retailers are gaining market share (there are 44 electricity retailers in total). Three of the five large retailers are also generators with majority state ownership. These three enterprises were fully state-owned prior to the government privatising 49% of them in 2013 and 2014 to stimulate private investment in the sector.

Transpower, a state-owned enterprise, is the transmission grid owner and operator. Distribution is managed by 29 regulated natural monopolies that are each in charge of a specific region. The New Zealand Electricity Authority oversees the management of the electricity market through the development, administration and enforcement of the Electricity Industry Participation Code, which covers all aspects of the electricity market (EA, 2018a). However, the authority does not regulate electricity prices.

The New Zealand coal industry was dominated by the state-owned enterprise Solid Energy, until it went into receivership in 2015. The assets were sold to private sector interests, effectively ending the direct involvement of government in the industry (MBIE, 2017a).

The New Zealand Energy Efficiency and Conservation Strategy 2017–22 (NZECS), entitled 'Unlocking our energy productivity and renewable potential', was released in 2017. It is a companion to the New Zealand Energy Strategy (NZES) 2011–21: 'Developing Our Energy

Potential' (MBIE, 2012). The NZEECS aims to achieve a productive and low-emission energy economy. It sets the overarching policy direction for government support and intervention and guides the work program of the Energy Efficiency and Conservation Authority (EECA).

The NZEECS identifies three priority areas: renewable and efficient use of process heat; efficient and low-emission transport; and innovative and efficient use of electricity.

ENERGY MARKETS

New Zealand's energy sector has been subject to major reforms since the mid-1980s, coinciding with the introduction of broader economic reforms. The broader reforms are aimed at improving economic growth through improved economic efficiency, driven by clear price signals and where possible, competitive markets. The greatest change occurred in the electricity and gas markets. Vertically integrated utilities were separated into natural monopoly and competitive elements. Government-owned and operated electricity and gas monopolies were either corporatised or privatised, and the electricity market was deregulated.

The Electricity Authority is an independent regulatory body for the electricity sector. The Electricity Industry Act 2010 promotes competition. There are provisions for improving competition in both wholesale and retail markets, making improvements in security of supply, providing a fund to encourage customers to switch electricity providers, and providing better electricity market hedging arrangements (NZG, 2010a).

The government completed a review of the electricity sector in October 2019. The review investigated why residential electricity prices outpaced inflation, while commercial and industrial electricity prices remained flat. The first discussion document (September 2018) highlighted challenges relating to market power in a time of tight supply; electricity retail competition; and the challenges of integrating distributed generation and storage into the grid.

Following the review, the government has committed to:

- establishing an electricity consumer advocacy organisation
- working with non-government organisations to reduce energy hardship
- extending the role of the Electricity Authority (to give it more power to regulate access to distribution networks and greater information-gathering powers, to protect residential and small business consumers)
- granting powers to the Minister for Energy to take action if the Electricity Authority fails to do so
- phasing out low fixed charge tariff regulations
- reviewing institutional arrangements aimed at finding means of improved agency co-ordination and addressing market failures

Since 2004, New Zealand's gas sector has been co-regulated by the government and the Gas Industry Company, an industry body established under the Gas Act 1992. The Gas Industry Company pursues the government's objectives and goals as outlined in the Gas Act 1992 and the Government Policy Statement on Gas Governance. Its work is driven by ministerial requests and its own engagement with the gas sector (MBIE, 2014).

FISCAL REGIME AND INVESTMENT

In New Zealand, the ownership of petroleum resources (including natural gas), rests with the Crown, regardless of the ownership of the land. In contrast, some coal resources are privately owned (Rob Harris, 2004). The New Zealand Petroleum & Minerals (NZP&M) business unit within the MBIE manages the government's oil, gas, mineral and coal resources, known as the Crown Mineral Estate.

NZP&M was formed in May 2011 to maximise the gains to New Zealand from the development of its oil, gas, coal and mineral resources, while meeting the government's objectives for energy and economic growth. NZP&M's role is to efficiently allocate rights to prospect, explore and mine Crown-owned minerals. It is also responsible for managing and regulating these rights

and ensuring a fair financial return to the Crown. NZP&M is instrumental in promoting investments in the mineral estate. The Resource Markets Policy team of the Energy and Resource Markets Branch of MBIE advises the New Zealand Government on policy and operational regulation in the mineral estate.

Corporations earning income in New Zealand are taxed at a rate of 28% on profits. Corporations are also required to pay other taxes such as payroll and fringe benefit taxes.

Petroleum production, companies must pay an ad valorem royalty of 5% of the net revenues obtained from the sale of petroleum. Crown-owned coal production permits awarded since 24 May 2014 are liable for an ad valorem royalty of 2% of net sales revenue or 10% of the accounting profits, whichever is higher. Permits granted under previous minerals programs continue to pay royalties based on those programs (NZP&M, 2020).

New Zealand's environmental permitting process, known as 'resource consent', is governed by the Resource Management Act 1991 (RMA) and its subsequent amendments. A resource consent is required for any project that might affect the environment. Resource consents are generally obtained from regional, district or city councils, depending on the nature of the resources affected. The RMA specifies that the guiding principle of decision-making is sustainable management (MFE, 2015).

The Resource Management (Simplification and Streamlining) Amendment Act 2009 established the Environmental Protection Authority (EPA). The EPA was established to manage the complex decisions that were previously being shouldered by local government. The EPA receives resource consent applications for proposals of national significance and supports the boards of inquiry (or the Environment Court) in making decisions regarding these proposals (MFE, 2015).

The Resource Management Amendment Act 2009 streamlines the consent process by imposing strict deadlines for decisions.

The Phase 2 Review of the RMA was completed in 2017. The review of the Act was considered alongside the Conservation Act (1987) and the Exclusive Economic Zone Act (2012). The key change is the refocusing of the decision-making at the local government level to follow the established 'national direction' handed down by the central government in National Policy Statements when considering RMA applications.

ENERGY EFFICIENCY

New Zealand passed the Energy Efficiency and Conservation Act 2000, which led to the economy's first energy efficiency strategy and the establishment of the EECA to spearhead the strategy's implementation

In August 2017, the government released the latest NZEECS. The goal of the new strategy is for New Zealand to continue to increase energy productivity and reduce carbon emissions in accordance with New Zealand's international commitments, such as the Paris Agreements and the APEC intensity target. NZEECS also promotes renewable energy and the productivity value it can generate. The strategy focuses on three key areas with specific targets:

- Area 1: Renewable and efficient use of process heat. Target 1: Decrease industrial emissions intensity by at least 1% per year on average between 2017 and 2022
- Area 2: Efficient and low-carbon transport. Target 2: Electric vehicles should make up 2% of the vehicle fleet by the end of 2021
- Area 3: Innovative and efficient use of electricity. Target 3: 90% of the electricity will come from renewable sources by 2025 (MBIE, 2017b). The government has now increased this to 100% renewable by 2035

Some of New Zealand's major policies for promoting energy efficiency are:

- An electric vehicle support program (announced May 2017), with road user tax exemptions, government/private bulk purchasing programs and information campaigns. A contestable fund to match private funding for projects aimed at increasing electric vehicle (EV) deployment in New Zealand was also promoted (MT, 2017). More

information can be found in the government-sponsored website <https://www.electricvehicles.govt.nz/>.

- Fuel economy labelling for light vehicles
- A bespoke approach to support innovative and replicable energy efficiency projects, energy audits, and awareness of energy efficiency in business. These energy efficiency efforts are promoted through a publicised awards event
- A subsidy program, Warm up New Zealand, has delivered insulation retrofits for more than 300 000 homes since 2009. The government has also made amendments to the Residential Tenancies Act 1986 to include a requirement for rental properties to meet a minimum standard of insulation by July 2019
- A rating tool for commercial building energy and water efficiency was launched in 2014 to promote energy efficiency
- Minimum Energy Performance Standards and a labelling program are in place for appliances. This initiative is coordinated with Australia (EECA, 2017)

New Zealand released a draft government policy statement on land transport (known as the GPS) in 2018. The GPS allocates funds raised through petrol levies and road user charges, and has clear implications for energy efficiency. Funding that used to be for improving road infrastructure is now directed to a 'mode-neutral approach'. The approach allows for consideration of the most cost-effective solutions to achieve an objective.

The GPS is intended to improve the overall efficiency of the New Zealand transport system from an operational and energy perspective. The transport levy was raised by 3.5 cents per litre from 30 September 2018 and will increase 3.5 cents for the next two years to a total of 10.5 cents (New Zealand Government, 2018).

RENEWABLE ENERGY

New Zealand is well endowed with hydro, geothermal, wind, biomass and ocean energy. All current wind and geothermal capacity was developed without subsidies. The New Zealand Government has extended the target of generating 90% of its electricity from renewable sources by 2025, to 100% renewable electricity by 2035, providing energy security can be ensured. One of the existing instruments that helps ongoing development of renewable energy in New Zealand is the Emissions Trading Scheme, discussed in the 'Climate Change' section.

This government is currently developing its renewable energy strategy. There are five workstreams:

1. accelerating renewable deployment
2. improving efficiency and increasing renewables in process heat
3. investigating green hydrogen as an energy carrier
4. ensuring prices are fair and affordable
5. laying out the long-term vision for the oil and mining sectors

Biomass has been long used in New Zealand for residential heating and industrial process heat in the wood product, and pulp and paper manufacturing industries. Its low energy density and cumbersome gathering process means its use is limited or constrained; biomass is not the main form of energy in industrial applications. The energy strategy seeks to promote biomass as a renewable fuel for the commercial and industrial sectors by creating local markets to connect producers and consumers, among other strategies. The one billion trees by 2028 program will bring significant increases in the forestry sector and increases in the availability of biomass.

Hydropower is New Zealand's major source of renewable energy. Most favourable hydro sites have already been developed, and there is strong social opposition to additional hydro development. New Zealand is instead focusing on geothermal and wind energy. Several major renewable projects have been consented by government in recent years but lower than expected electricity demand growth has meant they remain undeveloped.

The government issued a National Policy Statement for Renewable Electricity Generation in 2011. This policy statement requires decision-makers at all levels of government, especially the local level, to recognise the economy-wide significance and make provisions for renewable electricity generation in their plans and policy statements (MFE, 2011b).

The government has also considered electric and plug-in hybrid electric light vehicles (EVs and PHEVs) as an option to increase renewables in transport. The Low-Emission Vehicles Contestable Fund is the primary mechanism of support for EVs and PHEVs. It provides 50% funding for projects that grow the supply and variety of EVs available, improve charging infrastructure availability and increase demand for EVs. The fund will support NZD 7 million worth of projects per year (EECA 2018).

The Ministry of Transport has consulted on how best to reduce emissions from the transport sector. There are currently two measures proposed, the clean car standard and the clean car discount. The clean car standard is a corporate average fleet emission standard (to be determined) that will apply to all vehicles imported into New Zealand. The clean car discount reduces the price for new low-emission vehicles and raises the price for inefficient vehicles. The proposal applies the scheme to all vehicles imported into New Zealand based on vehicle weight class. A policy decision may be made in late 2020.

NUCLEAR ENERGY

New Zealand law prohibits the development and use of nuclear energy, and there are no plans to revisit this stance.

CLIMATE CHANGE

The New Zealand Government is committed to climate change action. New Zealand's current Nationally Determined Contribution is to reduce greenhouse gas emissions by 11% below the 1990 levels by 2030 under the Paris Agreement. But there is an updated goal for New Zealand to be a net-zero emission economy by 2050.

Domestically, the Zero Carbon Act is the central policy tool to begin an economy-wide transition to net-zero carbon by 2050. The May 2019 amendment to the Climate Change Response act (Zero Carbon):

- established an independent Climate Change Commission (CCC)
- set a new domestic greenhouse gas emissions reduction target of zero carbon (excluding biogenic methane) by 2050
- established a framework for emissions budgets that act as stepping stone towards the 2050 target
- required the government to develop climate change mitigation and adaptation policies.

The policy is currently in a transitional period to get the new provisions operating and the first carbon budget to be issued by the CCC in 2021.

Another key climate change intervention is the Climate Change Response (Emission Trading) Amendment Act of 2008, which established New Zealand's emission trading scheme (ETS). The ETS places a price on greenhouse gas emissions to provide an incentive to reduce emissions. The scheme came into effect in 2008 and was amended in 2009, 2012, 2016 and 2019.

For energy, the point of obligation for the ETS generally lies with energy suppliers, not the end users. This means that only energy suppliers and a few large industrial facilities are directly involved with the scheme. The government is providing free units to energy-intensive trade-exposed industries to protect them from international competition that may not necessarily face a price on emissions.

Amendments in 2019 will remove concessions for highly and moderately energy-intensive trade-exposed industries from 2021. Credits that were grandfathered from the first phase of the Kyoto protocol will also be dissolved. Additional changes are currently under consultation. Operational and administrative changes will allow the New Zealand Government more control

over the supply of ETS units and will allow a greater degree of price control to unify the ETS and Zero Carbon portions of the Climate Change Response Bill. The expected result is higher carbon prices, which will increase renewable energy deployment and promote energy efficiency and electric transportation (MFE, 2020).

NOTABLE ENERGY DEVELOPMENTS

ELECTRICITY MARKET

Tiwai Point Aluminium Smelter (TPAS) accounted for 11% of New Zealand's electricity demand in 2017 (NZAS, 2019). The owner of TPAS has announced its intention to cease operation in 2021 due to failure to negotiate favourable electricity rates and low market prices for aluminium (NZAS, 2020). TPAS is located far away from the major demand sources in the North Island and the closure is unlikely to have a significant impact on the wider market without major transmission infrastructure upgrades.

On the supply side, nearly 600 MW of natural gas generation has ceased due to a stagnant market. New Zealand still has 480 MW of generation capacity capable of burning coal or gas. In 2017, coal accounted for 2.7% of generation supply. Coal use in the power sector is expected to be phased out by 2030 or as early as 2025, depending on market conditions (Genesis Energy, 2018).

The deployment of smart meters throughout the market is another development. As of March 2020, over 87% of all households had smart meters installed (EA, 2020). There are significant operational savings for electricity retailers in terms of not requiring as many meter readers, and centralised control of electricity delivery.

NEW PROJECTS

In 2019, two major wind farm projects were announced in the lower North Island. The two farms are estimated to generate a total of 1 295 GWh per year. These developments could almost double New Zealand's total installed wind capacity by the end of 2021.

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USEFUL LINKS

Climate Change Information, Ministry for the Environment—www.climatechange.govt.nz

Electricity Authority—www.ea.govt.nz

Energy Efficiency and Conservation Authority (EECA)—www.eeca.govt.nz

Environmental Protection Authority—www.epa.govt.nz

Ministry of Business Innovation and Employment (MBIE)— www.mbie.govt.nz

Ministry for the Environment —www.mfe.govt.nz

New Zealand Government (news and speeches from government ministers)—
www.beehive.govt.nz

New Zealand Parliament—www.parliament.govt.nz

New Zealand Petroleum & Minerals (formerly Crown Minerals)—www.nzpam.govt.nz

Transpower—www.transpower.co.nz

PAPUA NEW GUINEA

INTRODUCTION

Papua New Guinea (PNG) is an island economy located in the Pacific Ocean. Roughly 600 islands stretch from just south of the equator to the Torres Strait, near Cape York Peninsula, Australia. PNG is the largest of the Pacific Island countries with a total land area of 469 000 square kilometres (km²). The largest PNG islands are New Britain, New Ireland and Bougainville. Port Moresby is the capital, located in south-eastern New Guinea on the Coral Sea. PNG became totally independent in September 1975. Since independence, PNG has struggled to govern hundreds of diverse, once-isolated local ethnic groups within a viable single economy (Standish and Jackson, 2017).

PNG sits along the volcanically active 'Ring of Fire' and faces frequent earthquake and tsunami risks. Amidst the mountainous terrain, tropical rainforests, and scattered small islands lie the economy's rich natural resources dominated by gold, copper, oil, gas, timber and crops for agricultural export (coffee, cocoa, tea, palm oil and copra). Year-round, PNG has high temperatures and humidity combined with wet and dry seasons.

PNG's population is relatively young. Almost 36% of the 8.4 million population are younger than 15 (World Bank, 2019). PNG is one of the most culturally diverse economies in the world; thousands of distinct tribes speak over 800 indigenous languages, each with unique dances, and traditions. PNG's population mostly live in the rural areas; approximately 13% of the population live in urban centres. Population density is low at 18 people per km² (World Bank, 2018).

PNG's economy is characterised by two main sectors: the labour-intensive sector (agricultural, forestry and fishing) and the export-earning sector (minerals and energy extraction).

In 2017, PNG's real gross domestic product (GDP) was USD 33 billion (2011 USD purchasing power parity [PPP]), an increase of 1.5% from 2016. The economy experienced strong economic growth between 2010 and 2017, posting an annual average GDP growth rate of 5.4% (2011 USD PPP) (EGEDA, 2019). A resources boom, mainly in the extractive minerals and hydrocarbon sectors, has been a key driver of this growth. Receipts from mining and petroleum in 2017 constitute the bulk of PNG's export earnings (73%) and account for 20% of GDP. Per capita GDP in 2017 was the lowest among the Asia-Pacific Economic Cooperation (APEC) member economies at USD 3 881 (2011 USD PPP). The provision of basic services continues to be a challenge.

Table 1: Key data and economic profile, 2017

Key data ^a		Energy reserves (end 2018) ^b	
Area (km ²)	462 840	Oil (billion barrels)	0.2
Population (million)	8.4	Gas (tcm)	0.2
GDP (2011 USD billion [PPP])	33	Coal	—
GDP (2011 USD PPP per capita)	3 881	Uranium	—

Sources: ^a EGEDA (2019); BP (2019).

PNG became a member of APEC in 1993. The economy is also a member of the African, Caribbean and Pacific Group of States; the Non-Aligned Movement; the Pacific Community; the Pacific Islands Forum; the United Nations, and the World Trade Organization (The Commonwealth, 2017).

ENERGY SUPPLY AND CONSUMPTION

In 2017, renewables (primarily traditional biomass products) accounted for the largest share of total energy supply (48%), followed by crude oil and petroleum (42%), and gas (10%) (EGEDA, 2019). Indigenous energy annual production fell 1.3% to 6 167 kilotonnes of oil equivalent (ktoe) in 2017. Even with the slight fall, indigenous energy production in 2017 was still more than double that in 2013 (3 055 ktoe). A liquefied natural gas (LNG) export plant began operating in 2014, which led to the large increase in indigenous energy production. Natural gas supply increased from 127 ktoe in 2013 to 4 53 ktoe in 2017.

The Sepik Coal Basin may host economically viable coal resources, but its potential is yet to be understood. Exploration work and drilling programs are ongoing to determine the extent of coal reserves and resources (MRA, 2016). PNG has no uranium reserves.

Oil was discovered in PNG in 1987, and the first commercial production of crude oil began in 1992. Production peaked at 150 000 barrels per day (bbl/d) the following year. In 2017, oil production was 45 000 bbl/d (CIA, 2018). The Napa Napa Refinery is PNG's only oil refinery. In 2017, it produced 1 374 ktoe of petroleum products from a mix of domestic and imported crude oil.

According to Oil Search, there is approximately 283 billion cubic metres (bcm) of gas (undeveloped 2C contingent resource) within the Elk-Antelope and P'nyang fields. These resources have the potential to support two additional LNG trains with a combined capacity of 8 million tonnes per annum (MTPA). The recent Muruk discovery, located alongside the Hides field approximately 21 km from the nearest PNG LNG infrastructure, has also increased natural gas expansion and development potential (Oil Search, 2017).

The PNG LNG Project began commercial operations in 2014. The project is an integrated development that includes gas production and processing facilities in the Southern Highlands, and in the Hela, Western, Gulf and Central Provinces of PNG. It will provide a long-term supply of LNG to four major customers in the Asia region. There are more than 700 km of pipelines connecting the facilities, which include a gas conditioning plant in Hides and liquefaction and storage facilities near Port Moresby, with a capacity of 6.9 MTPA. Over the life of the PNG LNG Project, over 254 bcm of gas is expected to be produced (PNG LNG, 2014).

In 2017, PNG generated 4 523 gigawatt-hours (GWh) of electricity. The compounded annual growth rate (CAGR) since 2010 was 3.1%. Thermal generation, sourced mainly from diesel, contributed the largest share (70%). Renewables accounted for the remaining 30%, comprising hydro (20%) and geothermal and biogas (10%) (Table 2, EGEDA, 2019). The electricity system of PNG is characterised by small regional and town-level generation and distribution network systems. The majority are thermal generation systems, except for three hydro generation systems and two hybrid micro-hydro and diesel systems.

PNG has high quality, underdeveloped geothermal resources. Geothermal wells are scattered throughout the northern areas of the economy. The economy's first geothermal plant was established at the Lihir gold mine. The 56 megawatts (MW) of capacity is almost exclusively used by the Lihir mining company. Excess electricity is sold to the nearby community. There are plans to develop a 40 MW geothermal power plant in West New Britain Province, followed by a 50 MW plant in East New Britain Province. The Icelander group estimates proven geothermal reserves to be 4 000 MW (APEREC, 2017).

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	6 167	Industry sector	803	Total power generation	4 523
Net imports and others	-1 634	Transport sector	639	Thermal	3 177
Total primary energy supply	4 441	Commercial sector	308	Hydro	877
Coal	0	Residential sector	1 396	Nuclear	0
Oil	1 870	AFF and others NEC	101	Others	469
Gas	453	Non-energy	0	Total renewables	1 345
Renewables	2 118	Final energy consumption	3 246		
Others	0	Coal	0		
		Oil	1 274		
		Gas	0		
		Renewables	1 631		
		Electricity & others	342		

Source: EGEDA (2019) (data collected in December 2019).

* Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. Total final consumption includes non-energy uses. Half of the municipal solid waste used in power plants is assumed to comprise renewables.

FINAL ENERGY CONSUMPTION

In 2017, the total final energy consumption reached 3 246 ktoe, a 0.08% increase on the 2016 level, and a much lower growth rate than the 10-year CAGR of 1.9%.

The residential sector remained the largest energy user, accounting for 43% of the final energy consumption. The industrial sector (25%) and the transport sector (20%) were the next two largest energy-consuming sectors. Renewable energy contributed the largest share of final energy consumption (51%). Traditional biomass used in the residential sector for cooking, water heating and lighting accounted for half of the renewables share. Petroleum products accounted for 39% of final energy consumption, while electricity and other sources accounted for the remaining 10% (EGEDA, 2019).

Electrification remains limited to the main urban areas. A large proportion of the rural population rely on traditional biomass to meet their energy needs. Electric appliances remain uncommon, even where households are connected to a grid. For instance, only 7% of households in Port Moresby have air conditioners (ADB, 2015b). In 2016, the PNG Government, with help from Columbia University of the USA, prepared the National Electrification Rollout Plan (NEROP).

The NEROP outlines a target of 70% household electrification access by 2030. Households within 1 km of existing electricity distribution networks are the initial focus. Supplying electricity to the remaining homes is more of a challenge, requiring significant grid extensions to difficult terrain. The NEROP is expected to deliver grid electricity to 75% of the population and off-grid electricity to 25% of the population. Australia, Japan, New Zealand and the United States are providing funding support for the NEROP. Significant capital investment is required to achieve the electrification target (Freddy Mou, 2018).

The transport sector faces similar infrastructure challenges. Roads are currently limited to urban populations; intercity roads are few and in disrepair. Many locations can only be accessed through coastal or river barges.

ENERGY INTENSITY ANALYSIS

Given the small size of PNG's economy, energy intensity patterns are volatile and are significantly impacted by individual events. Final consumption energy improved by 15% between 2013 and 2015. The improvement was mainly due to the large increase in GDP brought about by LNG exports starting in 2014. Final energy consumption intensity has remained relatively stable since 2015, reaching 99 toe/million USD in 2017. Primary energy intensity improved by 4.3% in 2017 to 136 toe/million USD.

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%) 2016 vs 2017
	2016	2017	
Total primary energy supply	142	136	-4.3
Total final consumption	101	99	-1.4
Final energy consumption excl. non-energy uses	101	99	-1.4

Source: EGEDA (2019).

RENEWABLE ENERGY SHARE ANALYSIS

PNG is dependent on traditional biomass for cooking and lighting in the residential sector (particularly in rural areas), with this accounting for 48% of final energy consumption. Non-renewables account for 47% of final energy consumption and modern renewables account for the remaining 5%.

There has been a decline in the contribution of modern renewables since 2010. The contribution peaked in 2013 at 6.0%, and declined to 5.2% in 2017.

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	3 244	3 246	0.08
Non-renewables (fossil fuels and others)	1 508	1 514	0.40
Traditional biomass*	1 563	1 565	0.12
Modern renewables*	173	168	-3.1
Share of modern renewables in final energy consumption (%)	5.3%	5.2%	-3.1%

Source: EGEDA (2019)

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal, and so on), including biogas and wood pellets, are considered modern renewables, although data on wood pellets are limited.

STAKEHOLDERS IN ENERGY SECTOR

James Marape was appointed Prime Minister of PNG in May 2019. Prime Minister Marape is committed to fighting corruption, and getting better terms from companies seeking to undertake natural resource extraction in PNG. Negotiations for the development of the P'nyang gas field

have recently ceased after the government failed to negotiate improved terms for the PNG LNG Project.

Official information related to PNG energy policies is not readily available. Beyond government, the PNG Chamber of Mines and Petroleum is an active non-profit organisation that offers programs and projects aimed at nurturing PNG's resource potential.

The main players in the petroleum market include Talisman and its joint venture partners (active in the south-west of PNG), ExxonMobil, Oil Search (focused on the Fold Belt, the Hides, and the Angore and Juha gas fields), InterOil (Gulf region), Sasol, and Mitsubishi. The largest mining projects are Barrick Gold's Porgera gold mine, the Ok Tedi copper mine, Newcrest's Lihir gold mine, Newcrest-Harmony's Hidden Valley gold mine and China Metallurgical Corporation's Ramu nickel-cobalt project (MRA, 2016).

For electricity, most thermal and hydropower stations are owned and operated by the state-owned enterprise PNG Power Limited (PPL), formerly called the PNG Electricity Commission. The functions of energy stakeholders in PNG are discussed in the Policy Overview section.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

The PNG Government outlined its national development framework with the 2010 release of Vision 2050. Vision 2050 aims to create institutions that equitably distribute resources and opportunities, while diversifying the economy so that it is less reliant on the mining and energy sectors. The plan has seven pillars. Energy is directly related to the Environmental Sustainability and Climate Change pillar, and indirectly related to multiple other pillars. Key objectives are:

- To ensure 100% electricity generation from renewable and sustainable sources by 2050
- To reduce greenhouse gas (GHG) emissions by 90% from 1990 levels

There have been significant reviews of PNG's National Energy policy in response to Vision 2050. The National Transport policy and the Mining and Petroleum Act have also been reviewed to ensure they are consistent with Vision 2050.

The PNG National Energy Policy 2017–2027 (NEP) lays out plans for energy sector development, and signals reforms, particularly in the electricity sector. The NEP focuses on social, economic, environmental and energy security aspects of sustainable development, and seeks to:

- Strengthen institutional capacity
- Develop an integrated planning process for sustainable energy supply and utilisation
- Develop energy resources for the betterment of all citizens
- Promote an environment for long-term sustainable economic solutions in the supply of energy
- Encourage the involvement of the private sector in the development and provision of energy services
- Ensure that energy resources are developed and delivered in an environmentally sustainable manner
- Promote efficient systems and safety in energy supply in all sectors (transport, residential, commercial, industrial and agriculture)
- Diversify the development and utilisation of energy resources for the economy's well-being and economic prosperity.

The NEP lays out plans to restructure the Department of Petroleum and Energy (DPE) into three new governing, regulatory and community service bodies: the National Energy Authority of Papua New Guinea (NEA), the Energy Regulatory Commission (ENERCOM), and the Community Service Obligation Company. The NEA is responsible for domestic energy provision and for developing and implementing national energy policy. Such responsibilities involve oil exploration and development, energy transport and distribution, renewables development, electricity distribution and transmission infrastructure, and energy data collection. The NEA reports to the Minister for Petroleum and Energy.

ENERCOM will replace the Independent Consumer and Competition Commission (ICCC) and will be responsible for promoting competition in domestic energy markets by setting tariffs and licensing market participants. ENERCOM is also responsible for energy safety through the creation and enforcement of electrical and petroleum safety standards.

To support the work of these new bodies, a national energy fund will be established to aid:

- Energy infrastructure development
- Energy sector environmental disaster mitigation and response
- Hydroelectricity disaster risk mitigation
- Energy efficiency and conservation programs
- Promotion of renewable energy initiatives.

In addition to the formation of these new agencies, there are plans for reforms to the state-owned enterprise PPL. The NEP was critical of PPL because of the slow growth in electrification, low quality electricity infrastructure, and the high price of electricity. The NEP aims to make PPL more commercially orientated, and has long-term plans for establishing a competitive electricity market. The restructuring of the DPE has not occurred; at the date of publication it requires a separate bill to be passed by parliament.

The Mining and Petroleum Act is also being reviewed. A bill is expected to be introduced in 2020 to implement changes to royalties and infrastructure grants, among other changes.

In March 2010, the government launched the Development Strategic Plan (DSP) 2010–2030, which will provide a strategic planning framework focusing on extending economic growth benefits to the most disadvantaged regions and communities. In 2014, an addendum to the DSP was launched, called the National Strategy for Responsible Sustainable Development (StaRS) 2010–2030. This addendum emphasises the government's desire to reduce the economy's reliance on non-renewable resource extraction, and encourages the development of environmentally sustainable industries and low-carbon technologies in pursuing a more inclusive economic growth path (ADB, 2015a). The renewable energy section provides additional detail.

The Medium-Term Development Plan (MTDP) 2016–2017 (and preceding MTDP 2011–15) follows the National Strategy for Responsible Sustainable Development and PNG Vision 2050. The role of the mineral and gas industries is acknowledged as important for PNG's economic development, but the plan promotes clean energy and electricity to ensure negative environmental impacts are minimised. The third MTDP covers 2018 to 2022.

ENERGY MARKETS

PPL is PNG's state-owned vertically integrated company, and was created under the PNG Power Act 2002 to act as the economy's main utility providing electricity to all consumers. It has been granted the following licences by the ICCC: (1) generation, (2) transmission, (3) distribution, and (4) retailing of electricity. PPL operates three separate urban grids and 14 independent provincial systems. Small rural electricity systems (C-centres) and privately-owned facilities in rural areas are also in operation.

The three separate urban grids operated by PPL are 1) Port Moresby System (POM), 2) Ramu System and 3) Gazelle Peninsula System. PPL's independent provincial systems have the potential to be developed and expanded into separate small grid systems, and to then be integrated with the larger urban grids (APEREC, 2017).

PPL has an exclusive right to sell electricity within 10 km of its existing networks, and to sell individual customer loads of up to 10 MW within its network areas (PPL, 2014). The maximum load size can be decreased over time to foster retail competition (Lawrence Craig, 2017). The government (through the ICCC) plays an important role in the regulation of retail competition and electricity tariff regulation, particularly in rural areas.

FISCAL REGIME AND INVESTMENT

Kumul Consolidated Holdings (KCH) was formed by the Government of PNG under an Act of Parliament (2002, amended in 2012) for the state to act as the trustee, owner and all-encompassing authority for state-owned assets and enterprises. KCH has delivered major hydroelectric projects critical to the long-term energy security of the economy, for instance, the Ramu 2 Project (180 MW) launched in December 2016. The Naoro Brown Hydropower Project (60 MW), Karimui Hydro Dam Study (1 800 MW), POM IPP Project, Port Moresby Transmission Upgrade Project and Purari Hydro Project (2 500 MW), are all important for long-term energy security.

Kumul Petroleum Holdings Limited (KPHL) is PNG's national oil and gas company. The KPHL was created by an Act of Parliament through the Kumul Petroleum Holdings Limited Authorisation Act 2015. KPHL is mandated to protect and maximise the value of the economy's petroleum assets for the people of PNG. KPHL is responsible for managing PNG's 17% equity in the USD 19 billion PNG LNG Project through its subsidiary Kumul Petroleum (PNG LNG) Limited.

The Konebada Petroleum Park Authority (KPPA) was set up by the government under the KPPA Act 2009 as a 'free trade zone'. The role of KPPA is to coordinate planning and development, and to facilitate investment. Tax incentives are available to encourage foreign and domestic investment (APEREC, 2017).

PNG's mining and petroleum taxation is minimal in comparison to other resource-rich economies. The discretionary 10-year tax exemption for the Ramu Nickel mine and near-zero fiscal revenues from the new PNG LNG investment mean that tax revenues are unlikely to accrue until the mid-2020s. Profit-based royalty regimes and generous capital allowances are favourable for foreign investors. Discretionary exemptions granted to specific firms or projects create precedents that in turn build pressure to grant further exemptions to new investors and existing firms (World Bank, 2017b).

The International Monetary Fund provided technical assistance to the PNG Department of Treasury to review the economy's mining and petroleum taxation in 2013. The review's purpose was to determine the 'appropriateness of the mining and petroleum taxation arrangement compared to similar resource-rich countries' (CTR, 2014). In 2015, the government began a review of the electricity tariff methodologies to improve the competitiveness of the electricity system. Prices ranged from USD 0.24 per kilowatt-hour (USD 0.24/kWh) to USD 0.47/kWh in 2012 (ADB, 2015b). Government revenues from energy projects are from:

1. Royalties: 2% of the well-head value (payable to landowners and the affected provincial and local governments)
2. Development levies: 2% of the well-head value (payable to the affected provincial and local governments)
3. Income tax: 30% tax on the profits of the project (payable to the central government)
4. Dividends: government's share of profits from its 17% shareholding through Kumul Petroleum and 2.8% shareholding by the Mineral Resources Development Company held on behalf of landowners (World Bank, 2017b).

ENERGY EFFICIENCY

The NEP promotes energy efficiency through the following “principles” (APEREC, 2017):

Principle 7 - Promote efficient systems and safety in energy supply in all sectors (transport, residential, commercial, industrial and agriculture).

- (a) Ensure minimum energy performance standards for electrical equipment and adoption of building energy codes and other standards for safety.
- (b) Ensure safe transportation of energy products and wastes.
- (c) Promote solar power, solar thermal systems and LPG for residential, commercial and public institutions.

Principle 9 - Promote energy efficiency and conservation measures, and wise use of energy.

- (a) Draft and enforce an energy efficiency policy within one year of the National Energy Authority’s creation
- (b) Promote energy efficiency measures in all sectors (industrial, residential, agriculture and transport) of the economy in end-use of equipment and appliances
- (c) Promote minimum energy performance standards and appliance labelling for all electrical equipment and appliances in collaboration with PNG Customs Services, the National Institute of Standards and Industrial Technology, the ICCC and other relevant stakeholders
- (d) Promote the concept of energy-efficient buildings in accordance with the Building Act and Regulations
- (e) Promote energy audits in factories and industrial locations and demand-side management programs in all sectors of the economy

There have been efforts by international agencies to gather information on energy efficiency indicators. In 2014, the Asian Development Bank (ADB) funded the Promoting Energy Efficiency in the Pacific (phase 2) project conducted by the International Institute for Energy Conservation. The project undertook activities in the Pacific to improve energy efficiency. The activities were related to lighting, solar power, energy efficiency in hotels, and data collection. Analysis revealed that in an aggressive efficiency scenario, PNG could save more than 30% on the current level of consumption (ADB, 2015b).

Determining energy efficiency indicators remains difficult for PNG. PNG does not submit data to the Expert Group on Energy Data Analysis (EGEDA). Instead, economy-wide energy data estimates are reliant on estimates using sources such as the Joint Organisations Data Initiative database and Oil Search Limited’s annual reports.

RENEWABLE ENERGY

PNG hosted the fourth phase of the APEC Peer Review on Low-Carbon Energy Policy (PRLCE) in August 2017. PNG used Vision 2050 as a guiding framework for plans and programs relating to renewable energy: 1) The National Strategy for Responsible Sustainable Development for Papua New Guinea (StaRS under DSP 2010–2030), and 2) The Renewable Energy Plan (under the Electricity Industry Policy and NEROP) (APEREC, 2017).

The StaRS seeks to increase the renewable energy-based power capacity of the economy to 100% by 2050, through (DNPM, 2014):

- Inclusive green growth policy instruments to tap specific opportunities within spatial and resource systems
- Green energy investment frameworks and incentives

The renewable energy plan is initially focused on adding renewable energy-based capacity for power generation. It intends (APEREC, 2017):

- For geothermal energy, to extend the Gazelle Grid and cover the West New Britain Province. An additional 95 MW should be added to the Gazelle Grid by 2030 and another 110 MW to the Ramu Grid by 2050
- For hydropower, to increase capacity by 1 483 MW by 2030 and another 3 680 MW by 2050 for the POM and Ramu grids
- To deliver an additional 62 MW of biomass power to the Ramu Grid by 2 030 and another 34 MW by 2050
- To add 30 MW of wind power capacity to the POM and Ramu grids by 2030 and another 20 MW by 2050
- To have an extra 65 MW of solar power capacity by 2030 and to work to achieve another 35 MW by 2050
- To develop the first 5 MW from an ocean energy facility for the economy by 2022 and connect this to the POM grid.

The PRLCE provides details of potential energy resources for PNG, such as the 15 000 MW of hydropower and 4 000 MW of geothermal energy. Recent renewable development is limited to privately developed hydro and geothermal generation on mining sites.

NUCLEAR ENERGY

PNG has no nuclear energy industry, and there are no current plans to develop one.

CLIMATE CHANGE

PNG is a global leader in climate change negotiations. It is a member of many multilateral environmental agreements, including the Rio+20, the United Nations convention to Combat Desertification and the Convention on Biological Diversity. Over the past two decades, the PNG Government has also made efforts to address global climate change issues. PNG ratified the United Nations Framework Convention on Climate Change in 1993 and the Kyoto Protocol in 2002. It was also the first economy to respond to the Paris Agreement (COP 21), successfully submitting its Intended Nationally Determined Contribution (INDC) in 2015. In 2016, it changed its INDC into a nationally determined contribution.

Vision 2050 outlines a framework for PNG to reduce GHG emissions through forest management and the development of renewable energy resources. In 2015, PNG established the Climate Change and Development Authority to implement the Climate Change (Management) Act 2015.

In October 2017, in cooperation with the United Nations Development Program (UNDP), PNG launched the National REDD+ Strategy 2017–2027, which is part of the StaRS. Implementation will strengthen the sustainability of PNG's forest industries, support agricultural development, and improve land-use planning and management to ensure that the most important environments are protected. The strategy will also help reduce GHG emissions and the vulnerability of rural communities to climate change (UNDP PNG, 2017).

NOTABLE ENERGY DEVELOPMENTS

LNG PROJECTS

The PNG LNG Project began commercial operation in 2014, providing a long-term supply of LNG to major customers: China Petroleum and Chemical Corporation (Sinopec), Osaka Gas, Tokyo Electric Power Company and CPC Corporation (WEC, 2016). LNG output from the project reached 8.8 million tonnes (Mt) in 2018, which was 35% higher than the 6.5 Mt nameplate capacity (Oil Search, 2018).

A new Papua LNG project between Total, ExxonMobil and Oil Search will have two 2.7 mtpa trains developed in Caution Bay, north of Port Moresby. The plant will be supplied from the Elk and Antelope gas fields operated by Total.

RENEWABLE ENERGY DEVELOPMENT AND RURAL ELECTRIFICATION

PPL is the primary agency responsible for rural electrification in PNG. The government will fund and implement the Rural Electrification Policy with the help of Australia, Japan, New Zealand and the USA. Funding support was provided during the 2018 APEC leaders meeting in PNG (Freddy Mou, 2018).

To help realise the targets set in DSP 2010–2030, the NEROP was formulated with the support of the World Bank. One of the strategies set out in the plan involved geospatial analysis to determine the extent of lack of access to electricity. Strategies to deliver electrification in an efficient and cost-effective manner are as follows (APEREC, 2017):

- USD 150 million per year to electrify 70% of households by 2030
- 75% of households to be electrified will use a grid connection; the remaining 25% will be electrified via off-grid solutions
- Funding for this program could come from connection charges of USD 15 million per year, a government commitment of USD 23 million per year, development partners' grants and concessional loans of USD 91 million per year
- PPL taking responsibility for the grid extension. The private sector may participate to provide off-grid or mini-grid solutions through a new entity that will be established to manage implementation of the NEROP. The DPE will be responsible for policies, planning and monitoring of both grid and off-grid operations. The treasury will be responsible for administering donor funds to the appropriate implementing agencies via a transparent process
- A parallel exercise will be undertaken to analyse the additional investments needed in generation and transmission. Implementation of the NEROP will require 300 MW of additional capacity by 2030, which excludes additional commercial, mining and industrial projects. A tariff of USD 0.10–12/ kWh is projected

The World Bank, ADB, JICA, the Australian Government, and the New Zealand Government are supporting the NEROP implementation in areas of planning, grid reinforcement (and extension), as well as the financing of household connections (World Bank, 2017c). The ADB, together with DPE, formulated the PNG National Distribution Grid Expansion Plan to boost the government's efforts to connect households in rural areas to the electricity grid, by (SMEC, 2016):

- Upgrading and rehabilitating two hydropower plants (Rouna 1 and Sirinumu Toe-of-dam)
- Developing the 11 kilovolts (KV) distribution mesh network to extend the grid to approximately 3 000 additional households
- Strengthening the distribution network
- Constructing a new substation (Kilakila) with interconnecting 66 KV transmission lines
- Upgrading the existing substations.

INTERNATIONAL COOPERATION AND COMMITMENT

TOWARDS SUSTAINABLE DEVELOPMENT

PNG business and government leaders signed the Alotau Accord II. The accord will uphold principles reflected in the PNG Vision 2050 and StaRS. These leadership plans are articulated in the MTDP plan of 2018–2022. Strategies formulated under Vision 2050 are committed to achieving sustainable development for PNG (Government of PNG, 2018b).

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PERU

INTRODUCTION

Peru is a democratic constitutional republic with a multiparty system. This APEC economy is located in western South America, bordered by the Pacific Ocean, with Chile to the south, Ecuador and Colombia to the north, and Brazil and Bolivia to the east. With a land area of 1.3 million square kilometres (km²), Peru is divided into three geographical regions: the coast to the west, the mountain region (Andes Mountains) and the Amazonian region.

Peru has 25 administrative regions. In 2018, the population was 32.5 million, with 20.5% of inhabitants considered poor, and 2.8% under the extreme poverty line (INEI, 2019a). The major population centre of Peru is Lima, with 10.5 million people, which is nearly one-third of the total population. The urbanisation rate is 72% (INEI, 2019b).

Peru has followed an advantageous path in recent decades. Between 2000 and 2017, the Peruvian economy grew fast, with an average annual real growth rate of 5.1%. The economy has emerged to become an upper-middle-income economy, but challenges lie ahead if the economy is to avoid development bottlenecks related to productivity, diversification, informality, connectivity and institutional capacities (OECD, 2019).

In 2018, Peru's gross domestic product (GDP) was USD 409 billion (2017 USD purchasing power parity [PPP]), with GDP per capita increasing 2.2% to USD 12 782 from 2017 (WorldBank, 2019). Foreign reserves surpassed a record USD 64 billion and the fiscal balance amounted to a deficit equal to 2.3% of GDP (BCRP, 2018).

The industry sector contributes 31.5% to Peru's GDP (WorldBank, 2019). Peru has a large and dynamic mining industry, mainly engaged in copper and gold extraction. Mining exports amounted to 10% of GDP and 60% of the value of all exports in 2017, growing by almost 25% above 2016 levels (BCRP, 2018).

The importance of Peru's mining sector is substantiated by production levels of metallic and non-metallic minerals. Peru is the world's top silver producer, the fifth-largest gold producer, the second-largest copper producer, and an important supplier of zinc and lead (USGS, 2020). Large mining projects are expected to begin in the next few years, which could further increase the importance of the mining sector. The economy also has vast reserves of natural gas, although Peru is a net energy importer (EGEDA, 2019).

Table 1: Key data and economic profile, 2018

Key data ^a		Energy reserves ^{b, c, d}	
Area (million km ²)	1.28	Oil (billion barrels)	0.98
Population (million)	32.5	Gas (trillion cubic feet)	10.6
GDP (2017 USD billion PPP)	408.9	Coal (million tonnes)	9.9
GDP (2017 USD PPP per capita)	12 518	Uranium (kilotonnes U)	42

Sources: ^a WorldBank (2020); ^b BP (2019); ^c MEM (2019); ^d NEA (2016).

Peru has substantial proven gas reserves, which are estimated at 10.6 trillion cubic feet (Tcf). The most abundant gas reserves are located in Selva Sur (Ucayaly, Madre de Dios), Costa, Zocalo and Talara.

The Central Reserve Bank of Peru (BCRP) reported a flow of USD 6 175 million of foreign direct investment (FDI) for 2018, lower by USD 594 million compared to the amount obtained in 2017, mainly due to a scenario of low international prices and the slow recovery of domestic demand.

The total stock of FDI stood at USD 104 billion (46% of GDP) at the end of 2018 (UNCTAD, 2019).

Some potential barriers to investing in Peru include a high vulnerability to commodity prices, lack of infrastructure, and a slow and bureaucratic legal framework. One of the largest investment projects of 2017 was the acquisition of the Peruvian company Minera Miski by Mosaic for USD 1.4 billion (Santander Bank, 2019).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Peru's total primary energy supply (TPES) in 2017 was 24 082 kilotonnes of oil equivalent (ktoe), decreasing by 1.95% from the 2016 level. This fall was because of a decrease in oil supply (–3.4%) and gas supply (–13.5%), driven by a decrease in the import of both crude and oil products, which was more than proportional to the increase in oil, coal and the reduction of natural gas domestic production. Per energy source, in 2017, around 42% (10 191 ktoe) of the TPES was from oil, 30% from natural gas (7 180 ktoe), 2.9% from coal (706 ktoe), and 25% (6 004 ktoe) from renewable sources (APEC, 2020).

Owing to its scarce oil resources, Peru is a net oil importer because domestic production is insufficient to meet consumption. However, because most crude oil produced is of extra-heavy quality and domestic refineries are unable to process it, a substantial share of the domestic production is exported.

The proven gas reserves of the economy were 10.6 Tcf at the end of 2018 and are expected to increase to 31 Tcf based on information obtained from the Ministry of Energy and Mines (MEM). In 2004, the development of the Camisea gas field and associated 730 km pipeline to Lima drastically changed the Peruvian energy sector. This has allowed Peru to meet growing domestic demand and become a net natural gas exporter. The largest concentration of gas reserves is located in Selva Sur (Ucayaly, Madre de Dios), Costa, Zocalo and Talara.

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	23 883	Industry sector	5 681	Total power generation	53 091
Net imports and others	–254	Transport sector	8 111	<i>Coal</i>	779
Total primary energy supply	24 082	Other sectors	5 170	<i>Oil</i>	1 118
<i>Coal</i>	706	Non-energy	0	<i>Gas</i>	19 699
<i>Oil</i>	10 191	Final energy consumption*	18 963	<i>Hydro</i>	29 060
<i>Gas</i>	7 180	<i>Coal</i>	507	<i>Others</i>	2 435
<i>Renewables</i>	6 004	<i>Oil</i>	9 441		
<i>Others</i>	1.0	<i>Gas</i>	2 139		
		<i>Renewables</i>	2 883		
		<i>Electricity and others</i>	3 993		

Source: EGEDA (2019) (data collected in December 2019).

* *Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. Total final consumption includes non-energy uses.*

Natural gas exports are sent as liquefied natural gas (LNG) through the Peru LNG Melchorita export terminal (4.45 million tonnes per annum (Mtpa)), one of only two LNG export terminals on

the Pacific coastline of the Americas (the other is Alaska's Kenai LNG terminal). In 2017, Peru exported 5.6 bcm of LNG, which was equal to 48% of total natural gas production (BP, 2019). Since 2012, more than 95% of Peru's total gas production has come from the Camisea field (MEM, 2019a).

Peru's proven mineral coal reserves are around 5.2 million tonnes (Mt), with approximately 95% consisting of anthracite and the remainder of bituminous coal (MEM, 2019a). Most of the reserves are in the La Libertad, Ancash and Lima departments. Coal's primary role is in the industry sector (67.9%) and electricity production (32.1%). Peru is a net importer of coal, with 49% of its coal consumption in 2017 being met by imports (other bituminous coal) (IEA, 2019a).

Total renewable energy production in Peru in 2017 was 6 004 ktoe, which represents 25% of Peru's TPES. Production increased 20.4% from the previous year (4 987 ktoe), with growth in hydro, electricity and modern biomass (EGEDA, 2019).

In 2017, Peru's electricity generation totalled 53 091 gigawatt-hours (GWh), with 59,3% coming from renewable sources, 37% from natural gas, 2.1% from oil and 1.5% from coal (IEA, 2019a).

FINAL ENERGY CONSUMPTION

Peru's total final consumption decreased by 3.0% in 2017, reaching 18 963 ktoe. By sector, total final consumption in transport accounted for 43%, followed by industry (30%), residential (20%), and commercial (6.8%).

Oil products dominated final energy consumption in 2017, with 50% of the total share, primarily consumed by the transport and industry sectors (MEM, 2019a). Electricity and other sources (21%), renewables (15%), natural gas (11%) and coal (2.7%) consumed the remainder. Oil consumption decreased by 11.5% from 2016, and electricity use increased by 2.3% (EGEDA, 2019).

ENERGY INTENSITY ANALYSIS

Peru's energy intensity, measured as total primary energy supply intensity, has been declining since 2010. From 2016 to 2017, primary energy supply intensity improved by 4.4%. Total final energy consumption intensity improved 5.4% compared with the 2016 level. When non-energy is excluded, the improvement was the same.

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)			Change (%) 2017 vs 2016
	2015	2016	2017	
Total primary energy supply	67	64	61	-4.4
Total final energy consumption	51	51	48	-5.4
Final energy consumption (excl. non-energy)	51	51	48	-5.4

Source: EGEDA (2019).

RENEWABLE ENERGY SHARE ANALYSIS

Consumption of modern renewables increased by 29.4% from 2016 to 2017, predominantly driven by hydropower generation. The share of modern renewable in final energy increased significantly (33%) to 16.8% in 2017. Traditional biomass consumption increased 3.4% in 2017. It remains the most consumed fuel in the residential sector.

Table 4: Renewable energy share analysis, 2017

	2015	2016	2017	Change (%) 2017 vs 2016
Final energy consumption (ktoe)	18 733	19 545	18 963	-3.0%
Non-renewables (Fossil fuels and others)	16 519	17 079	15 772	-7.7%
Traditional biomass*	2 031	1 993	2 061	3.4%
Modern renewables*	2 214	2 466	3 191	29.4%
Share of modern renewables to final energy consumption	11.8%	12.6%	16.8%	33.4%

Source: EGEDA (2019).

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial) using inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (e.g. hydro and geothermal energy), including biogas and wood pellets, are considered modern renewables, but data on wood pellets are limited.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Peru's MEM is responsible for the formulation and evaluation of energy and mining policy and strategies as well as for environmental issues concerning these activities. The MEM was reorganised in 2018, dividing the former Vice Ministry of Energy into two new vice ministries. MEM's structure now has three vice ministries: the Vice Ministry of Hydrocarbons, the Vice Ministry of Electricity, and the Vice Ministry of Mines. The Vice Ministry of Hydrocarbons covers the entire oil and gas value chain, including related activities. The Vice Ministry of Electricity oversees energy efficiency, planning, rural electrification, environmental affairs, and of course, electricity.

In addition to the MEM, the Supervisory Agency for Investments in Energy and Mining (OSINERGMIN) is Peru's autonomous regulatory agency, created in 1996. OSINERGMIN is responsible for setting electricity tariffs and gas transportation rates. Its goal is to promote efficiency in the power and gas sectors at the lowest possible cost for the customer by designing and implementing effective regulations.

The government published the National Energy Plan 2014–2025 (MEM, 2014) detailing the policies and objectives to guide the energy policy of Peru. According to the plan, Peru's overarching goal is to have a reliable, continuous and sufficient energy system that can support sustainable development partly by promoting investments in infrastructure (e.g. transport, refinery and production) and exploration.

The National Energy Plan's main goals are to provide energy security and universal access to energy supply. Access includes improving the electrification rate to 100% by 2025 and developing energy resources with a social and environmental perspective (MEM, 2014). The government has also established energy efficiency goals via the same plan, focusing on:

- Establishing new labelling rules for electrical appliances, water heaters, lighting, engines and boilers
- Promoting an energy efficiency culture

- Strengthening the public transportation system and making it more energy-efficient
- Maximising the use of natural gas in power generation
- Promoting the substitution of LPG and diesel by natural gas

The National Energy Plan has not been updated since 2014. There is scope to update the goals based on more contemporary priorities. Some of the Energy Plan's goals are to increase the share of natural gas to 35% of total primary energy supply (TPES) by 2025 and expand access to natural gas networks in the coastal region (MEM, 2014).

The Social Energy Inclusion Fund aims to provide 1.2 million low-income families with access to LPG through discount coupons. The distribution of improved cooking stoves is also intended to encourage more efficient use of traditional biomass among low-income families. The improved cooking stoves are 50% more efficient in the consumption of traditional biomass, reducing CO₂ emissions and respiratory diseases (APEREC, 2017).

Peru aims to become an energy hub by developing integration projects with Ecuador, Colombia and Chile in electricity, Brazil in hydropower, and Bolivia in gas. However, no projects have materialised to realise this vision. Currently, Peru has electricity interconnections with Ecuador via two transmission lines (500 kilovolts [kV] and 220 kV), and Ecuador and Peru enjoy comfortable reserve margins.

A planned interconnection between the northern Chilean city of Arica and the southern Peruvian city of Tacna is part of the regional interconnection agenda. A technical study supported by the Inter-American Development Bank (IDB) was undertaken to assess the project. The IDB concluded that the project would have an overall rate of return on investment of up to 16%. When separated by economy, the rate of return would reach 16% for Chile and 15% for Peru. The regulatory framework and the Interconnections lines are expected to be commissioned no later than 2035 (CNE, 2019).

OIL AND GAS

Peru's energy production was relatively stable during the 1990s and early 2000s, with some crude oil and minimal natural gas production. Development of the Camisea natural gas field in 2004 revolutionised Peru's energy market, providing more than 98% of the economy's natural gas production and 60% of the natural gas liquids used for LPG production (APEC, 2018). Primary energy production more than doubled from 2005 to 2017, reaching a record of 13 Mtoe (EGEDA, 2019). Oil (42.3%) and natural gas (29.8%) became the largest components of TPES. Natural gas production is used primarily for electricity generation and LNG exports, while most oil is consumed by transport industries. Traditional biomass remains the main fuel in buildings, accounting for roughly 8.5% of TPES in 2017 (EGEDA, 2019).

Peru's crude oil production is unable to meet refining needs (74.3% of refinery intake is imported) (MEM, 2019a). At the same time, refining capacity is unable to meet domestic demand for oil products. The total capacity of Peru's seven refineries (216 000 bpd) is not enough to meet demand, resulting in net imports of some oil products as well.

Petroperu is investing USD 5 billion in its new Talara refinery, which is expected to increase the plant's refining capacity to 95 kbpd by 2021 from the current 65 kbpd, reaching a total 122 kbpd for all three operating refineries by the national oil company. At the end of 2019, 71% of the construction was complete.

The oil and gas industry has enormous potential. The government has set a goal of doubling oil production, adding 100 kbpd by 2023 (ProInversion, 2019a, 2019b). The recent approval of a new licence agreement with Tullow Oil (UK) is showcasing opportunities for new stakeholders to be part of the upstream sector (Yesquén, 2020).

ELECTRICITY

Peru's National Integrated Electrical System (SEIN) consists of more than 60 competing power generation companies. Electricity rates are mostly based on marginal costs and free-market forces. The SEIN accounts for 96% of electricity generation in Peru, the remainder coming from isolated systems and own-energy consumption (MEM, 2016).

Total power generation capacity was 13.3 GW in 2019. Gas-fired power accounted for 56% of this capacity mostly owing to the development of the Camisea gas field in 2004. Hydro power-based capacity also accounted for a large portion at 39%. Peru's power generation fuel mix is largely reliant on gas and hydro sources, and only marginal amounts of oil, coal and non-hydro renewables. In 2019, hydro resources accounted for 57% of power generation and natural gas for 37.6%. Wind reached a record generation of 3.6% and solar 1.4%. The remainder was divided among oil, biomass and coal (MEM, 2019b).

In 2019, only seven hydroelectric plants (168 MW) and two biomass power plants (36 MW) began commercial operation. Lower demand and oversupply are delaying the commissioning of new projects (COES, 2020).

Electricity production from thermoelectric plants during December 2019 was 20 313 GWh, 5.7% higher than that registered during 2018. Electricity production with wind power plants was 1 646 GWh, and with solar power plants was 762 GWh.

Strengthening of energy planning is a responsibility of the DGEE, including through a long-term energy planning system. The planning system will seek to strengthen Peru's energy security, raise the well-being of Peruvians, and develop the content of Peru's National Energy Policy. This Energy Plan will also use economic criteria for infrastructure development, supply security and environmental emissions criteria.

MEM is also developing a short-term electrical system operation simulation tool to assess both the effects of extreme events and the effect of intermittent renewable energy on the electrical system. This will help complement the planning system tools already in place.

The Ministry of Energy and Mines has recently created the Emergency Operations Centre (COE) of the Energy and Mining Sector through Ministerial Resolution N 123-2019-MEM / DM of 2019. This new unit has the purpose of guaranteeing a timely response to emergencies and disasters, within the scope of the Energy and Mining Sector.

RENEWABLE ENERGY

The Peruvian Energy Policy 2010-2040 aims to achieve a diversified energy mix with a rising share of renewables, contributing to lower carbon emissions. The power system has a significant amount of renewable energy, reaching a record 62% renewable electricity production in 2019. Only 5.0% is generated from non-conventional renewable sources other than hydropower (5.2 GW of installed capacity). Peru has non-hydro renewables potential of more than 35 GW, added to the hydropower potential of almost 70 GW (IHA, 2019).

Peru has successfully enacted laws and regulations to promote renewable energy. In the last decade, the OSINERGMIN has successfully conducted four renewable energy auctions, which have resulted in wind, solar and modern biomass renewable projects. Much of the non-hydro renewable energy potential remains untapped. The MEM cancelled a fifth auction scheduled for 2018 because several projects from previous auctions were still being developed, adding to surplus capacity in a lower demand environment (Phan, 2020).

In 2006, the law to promote the use of renewable energy provided a tax reimbursement on electricity sales coming from renewable sources. In 2008, the Peru Congress passed another law (1058), giving tax benefits to investing participants in electricity generation based on renewable energy, including hydropower. The Law on Promotion of Investment for Electricity Generation with Renewable Energies (LD 1002) was enacted in 2008 with regulations for implementing this law. Some of the incentives provided by the law are:

- To promote renewable energy for electricity production, except large-hydro power plants. This definition excludes hydropower plants larger than 20 MW
- The law defines biomass, wind, solar, geothermal, tidal energy and small hydro (less than 20 MW) as non-conventional renewable energy (NCRE) sources
- The Ministry of Energy will impose a minimum target for power generation coming from NCRE sources (the first target was 5%) every five years
- A firm price is guaranteed for bidders, who are awarded energy supply contracts for up to 20 years
- Renewable energy producers have priority of dispatch and open access to grid infrastructure

In September 2015, a legislative decree modified the regulation on electricity distribution, including the possibility of a feed-in-tariff system for those who generate their own electricity based on non-conventional renewable technologies.

The LD 1002 gave renewable energy producers the ability to have a market presence for the first time. Renewables still need an improved regulatory framework to enhance the market share of renewable energy stakeholders and the needs of increasing competition in the power sector. (Phan, 2020).

Table 5: Modern renewables under operation as of 31 December 2019

Renewable energy source	Installed capacity (MW)	2019 Generation (GWh)	2019 share of total generation
Photovoltaic	285	768	1.4%
Wind	376	1 646	3.1%
Hydropower	5 163	30 168	57%
Biomass	69	251	0.47%

Sources: MEM (2020).

CLIMATE CHANGE

Peru is one of the economies most severely affected by climate change. Peru's contribution to global carbon emissions is low, at around 0.11% of the CO₂ emitted globally in 2017 (IEA, 2019b). The nationally determined contributions (NDCs) are designed to reduce greenhouse emissions (GHG) by 20% by 2030, and even by up to 30% with international financing support (Ministry of Environment & MEM, 2015). The government has also set itself the goal of implementing far-reaching adaptation measures to cope with the consequences of climate change.

This translates into a GHG emissions reduction of 90 million tonnes of carbon dioxide (MtCO₂), 53% of which comes from the forestry sector, including land-use, land-use change and forestry (LULUCF) activities. Peru's increases in energy demand have meant a 35% increase in energy-related CO₂ emissions from 2005 to 2016. Additional policies are being developed across final consumption sectors:

- Industrial and Fishing Sectors: sectoral regulation establishes that wherever the natural gas connection is possible, fishmeal factories must use it instead of oil products. The MEM estimates that currently, one-third of energy demand in this sub-sector is met by natural gas due to this regulation
- Forestry Sector: since 2010, the forestry sector has a new regulatory framework, which aims to reduce deforestation and promote sustainable and efficient use of forestry resources

- **Waste Management:** the National Environmental Action Plan (PNAA) promotes the reuse, recycling and appropriate handling of solid municipal waste. The PNAA was implemented in 210 municipalities, recovering around 10 974 tons of solid waste per month

Peru started a project to support the implementation of national climate change goals. The German government commissioned this project as part of the International Climate Initiative. The execution of this project is managed by the Peruvian Ministry of Environment.

The first part of this project focused on developing and approving the "Road Map for NDC implementation" in 2019. This included 153 actions, with 62 on mitigation and 91 for adaptation. There was also a consultation process on the regulation of the framework law on climate change.

The Peruvian Climate Change Framework Law passed in 2018 provides the political framework for this process and defines the implementation responsibilities. One of the tasks of the Ministry of the Environment is to provide technical support for the regional governments and other ministries in implementing the adaptation and mitigation measures.

ENERGY SECURITY

Peru's heavy reliance on crude oil and oil product imports, lack of strategic diversification, heavy dependence on Camisea gas, and lack of redundancy in its transportation system are threats to energy security. Peru's widening crude oil reserve gap also highlights an opportunity to incentivise investments on the oil and gas upstream sector. Over half of domestic refining capacity is concentrated in a single refining complex, La Pampilla, while almost all other refineries and import terminals are located on the coast, where earthquakes and floods are frequent.

In the natural gas sector, the Camisea field is responsible for 95% of natural gas production and 60% of LPG production. A limited network of pipelines transports natural gas, which provides around 45% of Peru's electricity (MEM, 2019b). These sectors are exposed to disruption risks, particularly in the Amazon region, where there are no other transport alternatives, and where access is challenging.

According to the final report recommendations of the APEC Oil and Gas Security Exercise in Peru, held in November 2017, the MEM and Peru's other relevant energy security institutions should work cooperatively to enhance energy security (APEC, 2018). Other recommendations are to improve data quality and collection, to diversify crude oil and refined product import sources, and to implement and update the law that ensures energy security and promotes the development of the petrochemical industry (Law 29970).

ENERGY ACCESS

The National Plan for Rural Electrification 2016–2025 was established to provide energy access to vulnerable populations in remote rural areas. Peru has a diverse geography, with almost 25% of the people living in the Andes Mountains and the Amazon Region. Approximately 80% of the rural population has access to electricity. These regions gather the communities with the lowest income levels and, accordingly, the highest poverty rates. The plan expects to provide energy access for 3.3 million people by 2025, with investments of USD 1.2 billion in transmission and distributed generation systems.

In 2008, the MEM and the General Directorate of Rural Electrification (DGER) awarded the concession area to acciona.org to electrify zones that are not included in the rural electrification plan (Eras-Almeida et al., 2019). The Ministry of Energy and Mines reported on the execution of 13 rural electrification projects in border areas, the purpose of which is to provide electricity to the families settled there. According to Minister Juan Carlos Liu Yonsen, an investment of more than USD 70 million will be required. The project will be completed in 2021.

ENERGY EFFICIENCY

In 2000, the government passed the Law for the Promotion of the Efficient Use of Energy (Law 27345). The Peruvian government promoted energy-saving measures in the public sector, such as replacing less-efficient incandescent lamps with compact fluorescent lights and acquiring equipment with energy efficiency labels.

In May 2010, the Peruvian government created the General Directorate for Energy Efficiency (DGEE), within the Vice Ministry of Electricity (after the Ministry's restructure), as the technical-economic regulatory body for energy efficiency. The DGEE also leads the energy planning of the economy and is responsible for developing the National Energy Plan.

Over the last decade, several policies have been developed which relate to lighting systems, energy efficiency services (energy audits), replacement of boilers and engines, and the implementation of a labelling scheme for appliances. The initial deadline of these policies was 2018. The application of this plan has suffered significant delays.

Energy efficiency is one of the three pillars contributing to a reduction in GHG emissions in Peru. According to the current NDC pledges, energy efficiency policies can deliver a potential 5.4 MtCO₂e reduction by 2030.

NUCLEAR ENERGY

Although Peru does not use nuclear energy for electricity generation, a government-run atomic energy program has been operational since 1975. This program includes the construction of necessary infrastructure, human resources training and establishing the Peruvian Institute of Nuclear Energy. Peru has been a member of the International Atomic Energy Agency since its creation in 1957.

NOTABLE ENERGY DEVELOPMENTS

OIL AND GAS

Peru will become more dependent on both crude oil and oil product imports as rapid growth of the transport sector increases consumption. The Peruvian government is overhauling the existing facilities to address this challenge. Petroperu is investing USD 5 billion in its new Talara refinery, increasing the capacity to 95 kbpd by 2021 from the current 65 kbpd (ProInversion, 2019a; Yesquén, 2020). All three operating refineries operated by Petroperu will reach a total capacity of 122 kbpd. The refinery will be able to produce low sulphur fuels, as required by Peruvian regulations.

The government is also encouraging state-owned companies to become more active in hydrocarbon exploration and production projects. MEM plans to reduce the time required to obtain exploration permits and to facilitate communication with local communities to reduce protests against extractive activities (EY et al., 2019).

In 2019, domestic oil production increased by 30% and the government has approved Tullow Oil's entry by granting two offshore licences, Z-38 and Z-64. Tullow also agreed to acquire a 35% interest in the offshore exploration Block Z-38 in the Tumbes Basin off Peru through a farm-down from Karoon Gas Australia. Tullow and Karoon plan to drill an exploration well in licence Z-38 in mid-2020 (Yesquén, 2020).

Almost all gas production in Peru is transported by a single pipeline, the Camisea gas pipeline. To reduce the vulnerability of depending on a single gas transport system and to provide other regions with access to this fuel, the Peruvian government conceived the construction of an alternative gas pipeline transporting the Camisea field's gas to the South of Peru (EY et al., 2019; Yesquén, 2020). The Peruvian Southern Gas Pipeline project involves the transport of gas

produced in the Cusco Region to the southern coastal city of Ilo through a 1 000 km, 32-inch diameter pipeline system divided into three sections, making it one of the most significant infrastructure projects in the economy's history. The project initially had thermal power plants, a petrochemical complex, industry and residential users as potential clients.

In 2014, the Peruvian government awarded the contract to a consortium integrated by Brazilian company Oderbrecht and Spaniard Enagas. Construction started in 2015, but in January 2017, with 40% of the development complete, the Peruvian government ended the contract after the consortium failed to meet its financial deadline (WSJ, 2017). The consortium lost the trust of banks financing the construction because of the ongoing investigation on alleged corruption cases of Oderbrecht in Brazil, Colombia, Mexico, Peru and other economies. As of March 2019, construction has not resumed, leaving this critical energy sector project in limbo (ProInversion, 2019a, 2019b).

In 2019, the Peruvian the government initiated a new bidding process. The project entails a pipeline network system to distribute natural gas to the cities of Andahuaylas, Abancay, Huamanga, Huanta, Huancavelica, Huancayo, Jauja, Cusco, Quillabamba, Juliaca, Puno and Pucallpa, some of which are located in the Apurímac, Ayacucho, Huancavelica, Junín, Cusco, Puno and Ucayali regions (ProInversion, 2019b).

The project framework consists of the construction of a distribution grid of natural gas to provide natural gas to these markets. The project comprises the design, financing, construction, operation and maintenance of the natural gas distribution pipeline networks in seven regions of Peru's centre and south, and their transfer to the Peruvian State at the end of the concession period.

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USEFUL LINKS

Agencia de Promoción de la Inversión Privada—www.proinversion.gob.pe

Banco Central de Reserva del Perú—www.bcrp.gob.pe

Comité de Operación Económica del Sistema Interconectado Nacional—www.coes.org.pe

Instituto Nacional de Estadística e Informática—www.inei.gob.pe

Instituto Peruano de Energía Nuclear—www.ipen.gob.pe

Ministerio del Ambiente—www.minam.gob.pe

Ministerio de Economía y Finanzas—www.mef.gob.pe

Ministerio de Energía y Minas—www.minem.gob.pe

Organismo Supervisor de la Inversión de la Energía y Minería—www2.osinerg.gob.pe

Perú Ahorra Energía—<http://elcomercio.pe/noticias/ahorro-energia-156394>

Perúpetro. La Agencia Nacional de los Hidrocarburos—www.perupetro.com.pe

Planta de licuefacción de GNL Perú LNG. —

<http://portal.perulng.com/irj/go/km/docs/documents/PLNG%20Website/index.htm>

Portal de Cambio Climático—<http://cambioclimatico.minam.gob.pe>

Presidencia de la República del Perú—www.peru.gob.pe

Programa de Adaptación de Cambio Climático—www.paccperu.org.pe

Proyecto Camisea—www.pluspetrol.net/camisea.html

THE PHILIPPINES

INTRODUCTION

The Philippines archipelago now comprises 7 641 islands, (NGP, 2020), and covers a total land area of 343 448 square kilometres (km²) with a 36 289 km coastline. The Philippines is in South-East Asia, bordered by the Philippine Sea to the east and west, the Luzon Strait to the north and the Celebes Sea to the south. Luzon, Visayas and the Mindanao islands are the three major geographical divisions. Manila City, in Luzon, is the capital. The Philippines has many active volcanoes and frequently faces earthquakes as it is located along the 'Ring of Fire'.

Owing to its location along the Ring of Fire, the Philippines was the third-largest geothermal energy producer in the world in 2018, with 1 944 megawatts (MW) of installed geothermal power capacity. This places the Philippines behind the US (2 541 MW) and Indonesia (1 946 MW) (IRENA, 2019).

In 2017, the Philippines population reached 105 million, a 1.5% increase from 2016 (WB, 2019). Increasing urbanisation, a growing middle class, and a young population mean that the Philippines is one of the most dynamic economies in the APEC region. The Philippines posted a 6.7% increase to gross domestic product (GDP) in 2017, reaching USD 797 billion (2011 USD purchasing power parity [PPP]) (WB, 2019).

Business activities are buoyant, with notable expansion in the services sector, particularly in business process outsourcing, real estate, and the finance and insurance industries (WB, 2019). GDP per capita increased to USD 7 581 (2011 USD purchasing power parity [PPP]) in 2017. The government is committed to developing and utilising fossil fuel and renewable energy (RE) resources to ensure sufficient energy supply to meet growing domestic energy consumption. The Philippines has 215 million barrels (MMb) of oil (including condensate), 3.2 trillion cubic metres of natural gas, and 2 360 million tonnes (Mt) of coal reserves that are potentially recoverable (DOE, 2017a).

Table 1: Key data and economic profile, 2017

Key data ^{a, b}		Energy reserves ^c	
Area (thousand km ²)	343	Oil (million barrels)	215
Population (million)	105	Gas (trillion cubic metres)	3.2
GDP (2011 USD billion PPP)	797	Coal (million tonnes)	2 360
GDP (2011 USD PPP per capita)	7 581	Uranium	–

Sources: ^a(DOE, 2018a); ^b(EGEDA, 2019); ^c(DOE, 2017a).

Notes: oil, gas and coal reserves are defined as potentially recoverable.

The Philippines is continuing to pursue the goals set in the Renewable Energy Act of 2008 by updating the National Renewable Energy Program (NREP) and reviewing and monitoring the deployment of RE projects to ensure that stakeholders are delivering. The Energy Efficiency and Conservation (EE&C) Act of 2019 was signed into law by the President of the Philippines on 12 April 2019 to ensure energy efficiency programs are implemented effectively.

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

The Philippines total primary energy supply (TPES) grew by 5.8% to 58 535 kilotonnes of oil equivalent (ktoe) in 2017, to support the economy's strong economic growth. Approximately 50%

of this energy was from domestic production. RE accounted for the largest share of TPES (35%), followed by oil (34%), coal (26%), and gas (5.5%) (EGEDA, 2019).

RENEWABLE ENERGY

RE (hydro, geothermal, biomass and others) is a significant contributor to the economy's total indigenous production, and accounted for 35% of TPES in 2017. Among RE sources, geothermal (44%) and fuelwood and wood waste (39%) accounted for the largest shares of RE supply. In 2017, RE declined by 1.3% to 20 180 ktoe from the 2016 level (EGEDA, 2019). This was due to the reduction in geothermal energy following a strong earthquake in July 2017 (DOE, 2018b).

While geothermal contracted in 2017, all other RE sources expanded. Hydro rebounded 18% to 827 ktoe in 2017 (following a drop the year before). Bagasse (15%), wind (12%) and solar photovoltaic (9%) also experienced strong growth in 2017 (EGEDA, 2019). The feed-in-tariff target set by the RE law was a driving factor behind this growth.

FOSSIL ENERGY

Fossil fuels, specifically oil and coal, are large contributors to the Philippines primary energy mix, and are important to both energy consumption and power generation. Fossil fuels comprised 66% of TPES in 2017; three percentage points more than in 2016. Net imports in 2017 were 99% fossil fuels.

Oil accounted for 34% of the TPES (51% of total fossil fuels). The economy's oil supply requirements grew by 6.0% in 2017, reaching 19 651 ktoe (EGEDA, 2019). Although the total oil supply increased in 2017, indigenous oil production fell 11.5% which can be attributed to the low production output of the economy's major oilfields (the Matinloc, Galoc and Malampaya fields) (DOE, 2018b).

Coal recorded very strong growth in 2017, with coal TPES increasing 18.3% in 2017, to reach 15 475 ktoe. The large increase in coal supply was facilitated by coal imports, which amounted to more than 70% of coal supply in 2017 (EGEDA, 2019).

Natural gas declined 1.4% to 3 226 ktoe in 2017, accounting for 5.5% of TPES (8.4% of all fossil fuels). The Philippines is self-sufficient in natural gas. The offshore Malampaya gas field accounts for all indigenous natural gas production. Known gas reserves are expected to become exhausted by 2025.

ELECTRICITY GENERATION

Electricity generation increased 3.9% in 2017 to reach 94 370 GWh. Growth would have been higher were it not for frequent power outages from natural and man-made disasters (DOE, 2018b). Fossil fuels accounted for 75% of electricity power generation in 2017. Coal was the dominant fuel, accounting for 50% of total power generation in 2017. Natural gas continued to provide a substantial share of power generation, increasing by 3.5% in 2017 to 20 547 GWh (22% of total generation). Almost all natural gas power plants were on Luzon Island.

Oil-based power plants continued to decline, posting a very large 33% reduction in generation to 3 787 GWh in 2017 compared with 2016 (EGEDA, 2019). Oil continues to play an important role in augmenting the Philippines electricity supply during peak demand (DOE, 2018b).

Renewables accounted for the remaining 25% of the economy's power generation, increasing by 5.5% to 23 168 GWh in 2017. Geothermal power generation declined by 7.2% in 2017, though it was still the largest renewable generation source (44% of renewables). Strong growth in biomass (40.1%), hydro (18.5%), wind (12.1%), and solar (9.5%) offset the fall in geothermal power to deliver overall renewables growth. The surge in biomass, wind and solar can be attributed to the Philippines RE law and feed-in-tariff (FiT) policy.

Table 2: Energy supply and consumption, 2017

Primary Energy Supply (ktoe)		Total Final Consumption (ktoe)		Power Generation (GWh)	
Indigenous production	30 132	Industry sector	7 923	Total power generation	94 370
Net imports and others	29 274	Transport sector	11 824	Thermal	71 182
Total primary energy supply	58 535	Other sectors	14 077	Hydro	9 611
Coal	15 475	Non-energy	1 613	Nuclear	0
Oil	19 651	Final energy consumption*	33 824	Others	13 578
Gas	3 226	Coal	3 008		
Renewables	20 180	Oil	16 346		
Others	3	Gas	53		
		Renewables	7 728		
		Electricity and others	6 690		

Source: (EGEDA, 2019) (data collected in December 2019).

* Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. This is different from the total final consumption, which includes non-energy uses. Furthermore, half of the municipal solid waste used in power plants is assumed to comprise renewables.

FINAL ENERGY CONSUMPTION

The total final consumption of the Philippines (including non-energy) increased by 5.7%, to reach 35 438 ktoe in 2017. All sectors posted an increase in energy consumption in 2017. The largest growth was from non-energy consumption, which increased by 23.5% in 2017.

The economy's total final energy consumption [TFEC (which excludes non-energy)] increased by 4.9% to 33 824 ktoe (EGEDA, 2019). The expansion was mostly driven by the agriculture, forestry and fishery sectors (14.5% growth). Recovery from the El Niño-induced drought in 2016 led to high crop production. The Free Irrigation Act for farmers was also enacted into law, which spurred growth in energy consumption (PIDS, 2017). Final energy consumption of gas declined by 19% due to a shift in fuel use by the economy's largest refinery (DOE, 2017). In contrast, final energy consumption of coal increased 12%, to 3 008 ktoe in 2017. There were also final energy consumption increases in oil (5.9%) and electricity and others (4.9%) in 2017 (EGEDA, 2019).

Buildings (residential and commercial sectors combined) TFEC increased 5.1% to 13 561 ktoe in 2017 (38% of TFEC). Energy consumption in the buildings sector was driven by commercial sector growth (13.9% in 2017 to 4 402 koe). Commercial growth was spurred by travel receipts, transport services and insurance (PIDS, 2017). RE consumption in buildings posted a slight contraction (−0.1%) in 2017. While oil and electricity posted strong growth in 2017 at 17% and 4.5%, respectively.

In terms of fuel, oil accounted for 48% of TFEC, followed by RE (23%) and electricity and others (20%). The transport sector was the largest oil consumer (60% of total oil consumption in 2017). The large increase in coal consumption was mainly due to expansion in the manufacturing sector, particularly cement and basic metals (DOE, 2018b).

ENERGY INTENSITY ANALYSIS

The Philippines energy intensity continued to improve in 2017. All sectors posted energy intensity reductions which meant that total primary energy intensity improved by 0.9% and total final consumption energy intensity improved by 1.0%. Final energy consumption (excluding non-energy) energy intensity improved by even more (1.6%), which reflected strong growth in the non-energy sector.

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%) 2016 vs 2017
	2016	2017	
Total primary energy supply	74	73	-0.9
Total final consumption	45	44	-1.0
Final energy consumption excl. non-energy	43	42	-1.6

Source: EGEDA (2019).

RENEWABLE ENERGY SHARE ANALYSIS

Republic Act (RA) 9513 or the Renewable Energy (RE) Act of 2008 made possible the accelerated promotion and utilisation of renewable energy (RE) resources in the Philippines. Between 2010 and 2017, modern renewables increased by an average annual rate of 4.3%. In 2017, modern renewables increased 5.0% to 3 330 ktoe. In the context of rapidly increasing energy demand, the share of modern renewables to TFEC remained unchanged (9.8% share) in 2017. Continued strong growth in non-renewables (fossil fuels and others) is likely to accompany continued strong growth in modern renewables (EGEDA, 2019).

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	32 233	33 824	4.9
Non-renewables (fossil fuels and others)	23 007	24 454	6.3
Traditional biomass*	6 055	6 040	-0.3
Modern renewables*	3 171	3 330	5.0
Share of modern renewables to final energy consumption (%)	9.8	9.8	0.1

Source: EGEDA (2019)

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal, and so on), including biogas and wood pellets, are considered modern renewables, although data on wood pellets are limited.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

The Philippines government recognises the importance of energy for promoting inclusive growth and development. The Department of Energy (DOE) is addressing energy security and facilitating increased access to energy for all. DOE's plans and programs will improve productivity and spur rural development. President Rodrigo Duterte's *Ambisyon Natin 2040* lays out a 'strongly-rooted, comfortable, and secure life' for all Filipino's by the year 2040. The DOE devised eight Energy Sector Strategic Directions (ESSDs) to contribute to this vision in the energy space (Figure 1).

Figure 1: Eight Energy Sector Strategic Directions



Under the guidance of the ESSD, the government (through DOE), aims to:

- Ensure basic electricity access for all by 2022
- Adopt a technology-neutral approach to achieve an optimal energy mix
- Improve power supply reliability to meet demand needs by 2040
- Develop liquefied natural gas (LNG) in anticipation of the forthcoming depletion of the Malampaya Gas field
- Facilitate the completion of transmission projects by 2020
- Ensure a pro-consumer distribution framework for affordability, choice and transparency
- Streamline domestic policy to cut red tape
- Privatise the Power Sector Assets and Liabilities Management Corporation
- Promote efficient energy use among consumers through information, education and communication campaigns

The Philippine Energy Plan (PEP) also contributes to securing the economy's energy future. The latest PEP (2017-2040 horizon) was created after a thorough review of the current energy agenda as well as the inclusion of input from regional consultation conducted by the DOE. The formulation of the PEP paved the way for the identification of sectoral energy roadmaps, consisting of short-term (2017–2018), medium-term (2019–2022) and long-term (2023-2040) strategies (DOE, 2017b).

In 2018, the *Innovation, Resiliency and Sustainability* initiative was instituted in all areas of energy development. The initiative will ensure the government continues to forge strategic alliances with energy stakeholders (DOE, 2018c).

On *Innovation*, the government issued an Executive Order for “*Energy Projects of National Significance*” (EPNS). The EPNS ensures energy project applications do not need to wait for action from other permitting agencies. This shortens the processing period to 30 days upon submission of complete documentary requirements.

On *Resiliency*, the Philippine DOE Secretary signed the *Energy Resiliency Policy* to strengthen energy systems and facilities, as well as to ensure quick restoration of energy services during and after calamities. The Republic Act was also passed to provide financial assistance to electric cooperatives (EC) for disaster mitigation, preparedness, and the rehabilitation of damaged EC infrastructures.

For *Sustainability*, the government continues to encourage energy-efficient technologies, promote utilisation of RE sources and institutionalise energy efficiency and conservation as a way of life for every Filipino. These efforts include economy-wide information campaigns on energy as well as appliance product standards (DOE, 2018c).

ENERGY MARKETS

OIL AND GAS

The Philippine Conventional Energy Contracting Program (PCECP) promotes and encourages investments in the exploration of the economy's sedimentary basins. Global and local roadshows have showcased 14 pre-determined service areas to be offered in six petroleum basins.

There were 23 active petroleum service contracts at the end of 2018. The economy's oilfields produced 1.2 million barrels (MMb) of oil, 127 billion cubic feet (bcf) of gas and 3.4 MMb of condensate. A recent highlight to the economy's upstream oil and gas sector is the discovery of an oilfield in Alegria, Cebu, holding 28 MMb of oil (3.3 MMb recoverable). The field also has natural gas reserves of 9.4 bcf (6.6 bcf recoverable) which could fuel power plants connected to the local power grid (DOE, 2018c).

COAL

As of December 2018, the DOE administered and monitored 62 Coal Operating Contracts (COCs). Of these COCs, 31 were in the development and production stage and another 31 were in the exploration phase.

Coal production in 2018 reached 13 million metric tons (MMmt). Semirara Mining and Power Corporation accounted for 99% of this production (DOE, 2018c).

ELECTRICITY

Electric Power Industry Reform Act of 2001 (or Republic Act 9136)

The government continuously oversees the implementation of power sector reforms, as mandated in the Electric Power Industry Reform Act (EPIRA) of 2001. The act is principally involved with the privatisation of power sector assets. The Power Sector Assets and Liabilities Management Corporation issued a revised timeline for the completion of the sale of its remaining assets by 2022 (DOE, 2018d). In November 2018, the privatisation level of NPC generating assets in Luzon and Visayas had reached 87% (4 364 MW of 5 014 MW) (DOE, 2018d).

Wholesale Spot Market

The EPIRA also calls for the establishment of an independent market operator (IMO) to ensure the competitiveness and transparency of the Wholesale Electricity Spot Market (WESM). The DOE has drafted policy for the Philippine Electricity Market Corporation to follow in establishing the IMO. WESM Mindanao was launched in June 2017 to address the influx of generation capacity in the Mindanao grid. WESM Mindanao will develop a mechanism for the efficient scheduling, dispatch and settlement of energy transactions (DOE, 2018d).

Household Electrification

As of December 2017, almost 21 million households (of almost 24 million potential households) in the Philippines had access to electricity (88%). The Total Electrification Master Plan and targets set in PEP 2017-2040 and the Philippine Development Program 2016-2040 are aiming for 100% by 2022 (DOE, 2018c).

SECTORAL ROADMAPS 2017-2040

OIL AND GAS

Upstream Oil and Gas Roadmap 2017–2040

To increase indigenous oil and gas reserves by 2040 and fulfil the economy's energy requirements, the DOE developed short-, medium-, and long-term goals in the oil and gas roadmap (DOE, 2017c). The economy's economically recoverable reserves are expected to increase as exploration efforts expand.

The PCECP is a new scheme for prospective investors. The PCECP aims to maximise the exploration and development of indigenous petroleum and coal resources by awarding Petroleum Service Contracts and Coal Operating Contracts through transparent and competitive processes.

Downstream Oil Industry Roadmap 2017–2040

This roadmap aims to improve policy that governs the downstream oil industry. Improved policies are needed to ensure a continuous supply of high-quality petroleum products in the appropriate quantities. One of the strategies involves the development of fuel quality standards (DOE, 2017d).

Downstream Natural Gas Roadmap 2017–2040

This downstream natural gas roadmap aims to establish a world-class, investment-driven, and efficient natural gas industry that makes natural gas the preferred fuel of all end-use sectors (DOE, 2017e).

Pending the ratification of the Downstream Natural Gas Infrastructure Development Bill, The DOE released the Philippine Downstream Natural Gas Regulation (PDNGR) to establish rules and regulations governing the downstream natural gas industry. The PDNGR covers infrastructure siting, design, construction, expansion, modification, operation and maintenance. It also seeks to ensure the continued operations of gas-fired power plants once the Malampaya gas field runs dry. The PDNGR intends to transform the Philippines as a regional LNG trading and trans-shipment hub.

Among the natural gas infrastructures being monitored by the DOE is the integrated LNG import receiving/hub terminal located in Pagbilao, Quezon with a two 130 000 cubic metre LNG storage tanks and a 600 MW gas fired plant. Other proponents have finished feasibility studies for an LNG Floating Storage and Regasification Unit (FSRU). These infrastructures are expected to ensure the continuity of natural gas supply in anticipation of the eventual depletion of the Malampaya gas field by 2024.

A memorandum of understanding was recently signed between the DOE and the UP-Statistical Center Research Foundation. The agreement will provide DOE with funding from the United States for natural gas policy recommendations and capacity-building activities (DOE, 2018c).

COAL

Coal Roadmap 2017–2040

This roadmap aims to increase indigenous coal reserves of the economy to 766 MMmt and production to 282 MMmt by 2040 to contribute to the Philippines' energy requirements. A PCECP will also be issued to prospective investors for coal exploration (DOE, 2017f).

ALTERNATIVE FUELS

Alternative Fuels and Energy Technologies Roadmap 2017–2040

This roadmap provides long-term plans and strategies to manage energy resources using fuel diversification and energy technologies. The strategies promote commercialisation and private sector partnerships to build local capacity in emerging energy technologies (DOE, 2017g).

The Biofuels Act of 2006 specifies a mandatory 2% biodiesel blend (B2) and 10% bioethanol blend (E10) in all diesel and gasoline fuels sold in the Philippines since 2007. The Philippines plans to increase the biodiesel blend to 20% (B20) by 2025 and the bioethanol blend to 20% (E20) in 2020.

The DOE is determined to promote alternative fuels and advanced energy technologies to diversify the economy's energy sources and mitigate the adverse impacts of energy use on the environment. The government is pursuing projects to foster the use of advanced transportation technologies, such as liquefied petroleum gas (LPG), compressed natural gas, hybrid, plug-in hybrid, and electric vehicles (EVs). The DOE has drafted a framework for EV charging stations (DOE, 2018c).

ENERGY EFFICIENCY AND CONSERVATION ROADMAP 2017–2040

The DOE approved the implementation of the Energy Efficiency and Conservation Roadmap in July 2014 (revised 2017). The roadmap will provide sustainable and long-term policy directions on energy efficiency and conservation (DOE, 2017h).

The Philippines had already been implementing the National Energy Efficiency and Conservation Program (NEECP) for over a decade before the roadmap was formulated. The NEECP is an umbrella program to support energy efficiency and conservation in all sectors. The Philippines will continue to implement NEECP policies (to support the roadmap), namely:

- The Government Energy Management Program (GEMP) aims to assist government agencies to reduce their energy operating costs. DOE staff conduct on-the-spot energy audits on government offices, hospitals and academic institutions.
- Energy conservation campaigns disseminate information and increase energy use awareness among consumers, the media, local government units, and schools

The Philippines Energy Standards and Labelling Program is currently under review. The Standards and Labelling Program for Motor Vehicles is being developed in collaboration with international funding agencies.

Energy Service Companies (ESCOs) Accreditation assesses the technical, financial and legal capabilities of ESCOs. To date, there are currently 17 ESCOs accredited by the DOE.

The DOE has implemented the Philippine Industrial Energy Efficiency Project (PIEEP) in partnership with the United Nations Industrial Development Organisation and the Department of Trade and Industry. The PIEEP implements energy management schemes on buildings based on the ISO 5001 Energy Management System Standard Framework for Philippine industries: a systems optimisation approach, specifically for steam, compressed air, and pumping systems, is also being deployed (DOE, 2018c).

RENEWABLE ENERGY ROADMAP 2017–2040

This roadmap aims to increase RE installed capacity to at least 20 000 MW by 2040 (DOE, 2017i). Government efforts to promote and expand the use of RE as a clean and sustainable energy source for the public were demonstrated with the formulation and adoption of the NREP in 2011. The NREP outlines a strategy to facilitate greater private sector investment in RE development, including addressing the challenges to utilising renewables (DOE, 2011). Other policy mechanisms stipulated in the RE Act of 2008 are:

- FiTs

- Renewable Portfolio Standards (RPS)
- Green Energy Option Program
- Net Metering for RE

The ERC (Energy Regulatory Commission) promulgated the FiT rules and FiT rates based on set installation targets, as recommended by the DOE. The three-year FiT regime was extended for two years in December 2017 in order to achieve the 250 MW installation targets for biomass and hydropower technologies (DOE, 2018c). The extension embodied the government commitment to renewables set out in the RE law (RA 9513).

The RPS is a market-based policy requiring electric power industry participants to restore RE share in the energy mix to 35% by 2030–2040. Industry participants are the power generators, distribution utilities and electric suppliers.

The Green Energy Option Program enables end-users to choose RE resources as their primary source of energy.

Net Metering is a consumer based RE incentive scheme. Electric power generated by an end-user from an eligible on-site RE generating facility, and delivered to the local grid, can be used to offset electricity sold to that end-user.

The DOE had awarded a total of 839 RE projects under the RE law as of March 2018, with a potential capacity of 23 253 MW and installed capacity of 4 683 MW (DOE, 2018c)

NUCLEAR

Government policy is to study all potential energy resources to diversify the economy's energy supply mix and provide high-quality, reliable, adequate, secure and reasonably priced energy. In April 2018, DOE submitted a recommendation to the Office of the President for the inclusion of nuclear energy in the energy mix. Consultations will be conducted to assist the government to reach a decision on whether to accept the recommendation (DOE, 2018c).

CLIMATE CHANGE

In 2009, the government created the Climate Change Commission via the Philippine Climate Change Act of 2009 (RA 9729). The Climate Change Commission serves as the policymaking body under the Office of the President. The Commission's primary functions are to monitor and evaluate programs and develop action plans related to climate change.

In the twenty-first session of the Conference of Parties (COP21) of the United Nations Framework on Climate Change, the Philippines expressed an intention to reduce CO₂ emissions by 70% by 2030 relative to the level in 2000. This is relative to its business-as-usual scenario of 2000–30, as indicated in the economy's Intended Nationally Determined Contributions. The above-mentioned commitment is conditionally based on the availability of financial resources, technology development and transfer and capability building. Energy is one potential source of CO₂ reduction, together with the transport, waste, forestry and industry sectors (UNFCCC, 2015).

NOTABLE ENERGY DEVELOPMENTS

POWER AND RENEWABLE ENERGY

At EWG57, the Philippines provided details on the development of RPSs and the creation of Competitive Renewable Energy Zones (CREZs)¹:

- RPSs for on-grid areas

¹ candidate RE zones, which represent geographic areas characterised by high-quality, low-cost RE potential in addition to high levels of private-sector developer interest

From April to November 2018, information education campaigns were delivered to distribution utilities (DUs) in Luzon, Visayas, and Mindanao to help determine their minimum RE purchase requirements

- RPSs for off-grid Areas

RPS Rules for off-grid Areas were promulgated on 24 August 2018 and took effect on 29 September 2018. They are intended to rationalise the efficient use of the universal charge for missionary electrification (UC-ME) and to improve self-efficiency in power generation through integration of RE in the supply mix in off-grid and missionary areas

Participants are required to generate and/or procure, supply, and maintain a minimum percentage of RE in their energy portfolio. This is to help participants to meet the minimum RE requirement in their respective off-grid and missionary areas. The optimal supply mix is prescribed in the Missionary Electrification Development Plan.

The annual incremental RE generation in each of the off-grid or missionary areas after the baseline year 2018 must not be lower than one percent (1%) and the full implementation thereof must be for the year 2020.

Three information and education campaigns for RPS for off-grid areas, on the other hand, were conducted from October to November 2018 to ensure the compliance of mandated participants and successful implementation of the rules. With the assistance of the EU-Funded Access to Sustainable Energy Program, the simplified planning tool was developed to guide the mandated participants in determining the optimal supply mix (combined RE and conventional fuel) for attaining lower subsidies from the UC-ME.

- CREZs

The Philippine CREZ process supports the identification and establishment of candidate RE zones under the Philippine Development Plan. The plan supports the National Grid Corporation of the Philippines with planning and transmission line enhancements, for example, infrastructure upgrades, expansions or extensions. The framework directs transmission development to areas where potential RE resources are located.

ENERGY EFFICIENCY

On 16 January 2019, the EE&C Act was approved during the Bicameral Conference Committee Hearing held at the Senate of the Philippines. The Act aims to standardise energy efficiency and conservation measures in the economy by regulating the use of energy-efficient technologies in buildings. An inter-agency energy efficiency and conservation committee will be created to oversee the implementation of the GEMP, which aims to reduce government agencies' consumption of electricity and petroleum products (DOE, 2019).

UPSTREAM OIL

To maximise the exploration and development of indigenous petroleum and coal resources, Department Circular (DC) No. 2017-09-0010 introducing the "Philippine Conventional Energy Contracting Program (PCECP)" was issued 13 September 2017. The PCECP is a new contracting scheme for coal and petroleum exploration where two modes of awarding Service Contracts (SC) are envisioned. The first mode is through the nomination process which enables investors to apply for service/operating contracts anywhere in the country at any given time, while the other mode is through application in Pre-Determined Areas (PDAs), previously identified/delineated by the DOE.

The government passed the Tax Reform for Acceleration and Inclusion (TRAIN Law) to protect minimum wage earners. The TRAIN Law also affects the downstream oil industry through proposed increases in excise tax for alternative fuel vehicles (AFVs). The DOE Secretary issued directives to ensure the continuous and adequate supply of petroleum products.

The increase in excise tax for AFVs increases the cost of the vehicle. To ensure the success of AFVs, the DOE drafted a position paper which proposes to provide tax exemption for EVs. Excise taxes for other AFVs will be 50% lower than for conventional vehicles (DOE, 2018c).

PENDING ACTIONS

The DOE has been pursuing several legislative agendas to enhance the economy's energy policies and regulatory frameworks. The following energy bills have been filed or will be re-filed in both houses of congress:

- The Downstream Natural Gas Industry Development Act
- The LPG Industry Regulation and Safety Act
- Amendments to the EPIRA of 2001 or Republic Act No. 9136
- Amendments to the Petroleum Act of 1949 or Republic Act No. 387
- Amendments to Presidential Decree 87 or the Oil Exploration and Development Act of 1972.

Some of the energy bills are amendments to the existing framework or additional fiscal and non-fiscal incentives to encourage private investment.

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USEFUL LINKS

Asian Development Bank—www.adb.org

Climate Change Commission (CCC)—climate.gov.ph/

Department of Energy, Republic of the Philippines (DOE)—www.doe.gov.ph

Department of Science and Technology (DOST)—www.dost.gov.ph/

Department of Trade and Industry (DTI) —www.dti.gov.ph/

Department of Transportation and Communication (DOTC)/Land Transportation Franchising and Regulatory Board (LTFRB)—www.dotc.gov.ph

National Power Corporation (NPC)—www.napocor.gov.ph/

National Transmission Corporation (TransCO)—www.transco.ph/

Philippine National Oil Company (PNOC)—www.pnoc.com.ph/

Wholesale Electricity Spot Market (WESM)—www.wesm.ph/

World Bank— <https://www.worldbank.org/en/country/philippines>

RUSSIA

INTRODUCTION

Russia has the largest land area in the world, spanning over 17 million square kilometres (km²) (GKS, 2018a). The economy is in both Eastern Europe and Northern Asia. Russia shares land borders with 16 economies and has maritime boundaries with two more. Its territory is characterised by different geographic and weather conditions, including broad plains west of the Urals, coniferous forests in Siberia, tundra along the Arctic seaboard and uplands and mountains in the southern regions. Russia has vast natural resources including major deposits of coal, natural gas, oil and other minerals. Despite its huge land area, two-thirds of the economy is either too cold or too dry for productive agriculture.

From 1990 to 2008, the Russian population declined from 148 million to 143 million. From 2009 to 2018, the population increased to 147 million (EGEDA, 2019). Approximately 74% of the population resides in urban areas. Russia's average population density is 8.4 people per km², with nearly 80% of the population living in the European part of the economy (GKS, 2018a).

Goods manufacturing, trade and services are the main drivers of Russia's economic development, accounting for 60% of GDP (GKS, 2018a). However, the energy sector, and specifically the oil and gas industry, is key in the Russian economy. As of 2019, the oil and gas industry accounted for, almost 65% of total export revenues and 40% of public budget revenues (World Bank, 2019).

The 2009 global financial crisis and fall in crude oil prices had a great impact on Russia's GDP, which declined 7.8% from the 2008 level. The Russian economy benefited from very high oil prices, growing by an annual 2.9% rate during 2010–14 (EGEDA, 2019). However, in 2014, a sharp decline in the price of crude oil, and international sanctions imposed by the European Union and the US (following the annexation of Crimea) led to a two-year consecutive decline in GDP. The trend reversed in 2017 with 1.4% growth (EGEDA, 2019).

Table 1: Key data and economic profile, 2017

Key data ^{a, b}		Energy reserves ^{c, d}	
Area (thousand km ²)	17	Oil (billion barrels) ^b	107
Population (million)	144	Gas (trillion cubic metres) ^b	38
GDP (2011 USD billion PPP)	3 637	Coal (billion tonnes) ^c	162
GDP (2011 USD PPP per capita)	24 766	Uranium (kilotonnes U)	215

Sources: ^a GKS (2018a); ^b EGEDA (2019); ^c BP (2020); ^d NEA (2018).

Note: Data from the Nuclear Energy Agency (NEA) is used for uranium reserves recoverable at a production cost of less than 260 USD per kg.

Russia is the third-largest energy producer in both APEC and the world. In terms of proven reserves in 2019, Russia had the world's largest natural gas reserves (19% of the world total), coal (15%), oil (6.2%) and uranium (5.5%) (BP, 2020) (NEA, 2018). In 2017, 75 new oil and gas fields were discovered with 550 million tonnes (Mt) of crude oil and 890 billion cubic metres (Bcm) of natural gas reserves (MNRE, 2018).

Russia is one of the world's largest exporters of energy overall. In 2019, Russia was the world's largest exporter of natural gas, the second-largest exporter of crude oil, and ranked third for coal exports (BP, 2020). Russia is also a major refiner with 80 refineries accounting for a total refining capacity of over 310 Mt of crude oil per year (ME, 2018a).

In addition to fossil fuel resources, Russia has significant potential for renewable energy, including 27 000 Mtoe of solar, 5 400 Mtoe of wind, 800 Mtoe of forest biomass, 77 000 Mtoe of geothermal and 200 Mtoe of small-scale hydro (HSE, 2017). However, using this potential is restricted by the vast distances over which energy needs to be transported to reach consumers. Russian-labelled nuclear fuel is used at 75 commercial reactors (17% of the global market) with Russia providing 36% of the world's uranium enrichment services (Rosatom, 2017).

Russia has the world's largest and one of the oldest district heating systems, with centralised heat production and distribution networks in most major cities. The system has a high number of combined heat and power (CHP) plants. Heat losses, due to ageing infrastructure, account for 8.9% of heating energy (ME, 2018b).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Russia's total primary energy supply in 2017 was 732 million tonnes of oil equivalent (Mtoe), comprising natural gas (53%), crude oil and petroleum products (21%), coal (16%) and others, including nuclear and hydro (10%) (EGEDA, 2019).

Russia produced 546 Mt of crude oil and gas condensate in 2017 (ME, 2018c). The Ural Federal District accounted for over half of the total oil production. In that year, refineries consumed 278 Mt of crude oil as feedstock, supplying the domestic market with gasoline (35 Mt), diesel (37 Mt), fuel oil (15 Mt) and kerosene (9.7 Mt). The yield from refining increased from 72% in 2008 to 81% in 2017. Crude oil exports, including natural gas liquids reduced from 255 Mt in 2016 to 253 Mt in 2017, and exports of petroleum products dropped from the peak of 172 Mt in 2015 to 148 Mt in 2017 (GKS, 2018a).

Natural gas production increased from 641 Bcm in 2016 to 691 Bcm in 2017, the highest in 10 years (ME, 2018d). Exports of natural gas steadily increased from 174 Bcm in 2014 to 213 Bcm in 2017 (GKS, 2018a) or 30% of the production, including 11 Mt of liquefied natural gas (LNG) exports (ME, 2018e).

In 2017, Russia produced 411 Mt of coal, an increase of 6.0% from 2016, with 59% produced in the Kuznetsk Basin (ME, 2018f). In 2017, coal exports reached 190 Mt, growing by 62% from 2010 (GKS, 2018a). From 2000 to 2017, the share of coal for export increased from 17% to 44% even though the main coal-producing areas (the Kuznetsk and Kansk–Achinsk basins) are landlocked in the south of Siberia, 4000–6000 km from the nearest coal-shipping terminal for the Atlantic/Pacific markets.

Most of Russia's energy exports go to Western and Eastern Europe, including the Commonwealth of Independent States (CIS)¹. Since 2008, Russia has been actively diversifying its export routes towards the Asia-Pacific region, aiming to deliver crude oil, petroleum products, natural gas and coal to China, Japan, Korea, and South-East Asia.

Electricity production reached 1092 terawatt-hours in 2017, with 47% from gas-fuelled power plants, 19% from nuclear energy, 17% from hydropower, 16% from coal-fuelled power plants and the remainder from solar, wind and oil-fuel plants combined (EGEDA, 2019).

¹ CIS includes Azerbaijan, Armenia, Belarus, Kazakhstan, Kyrgyzstan, Moldova, Russia, Tajikistan, Turkmenistan (associated member) and Uzbekistan.

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	1 429 252	Industry sector	149 538	Total generation	1 092 171
Net imports and others	-664 083	Transport sector	95 861	Thermal	700 204
TPES	732 165	Residential sector	124 583	Coal	174 569
Coal	113 583	Commercial sector	39 303	Oil	6 975
Oil	153 965	Agriculture and others	9 298	Gas	518 660
Gas	388 335	Final energy consumption*	418 583	Hydro	185 013
Renewables	18 764	Coal	26 747	Nuclear	203 143
Others	57 518	Oil	91 244	Others	3 811
		Gas	125 638		
		Renewables	2 058		
		Electricity and others	172 897		
		Non-renewable	161 334		
		Renewable	11 563		

Source: EGEDA (2019) (data collected in December 2019).

* Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. Total final consumption includes non-energy uses. Half of the municipal solid waste used in power plants is assumed to comprise renewables.

FINAL ENERGY CONSUMPTION

In 2017, total final consumption in Russia was 488 Mtoe, including 69 Mtoe of non-energy use, an increase of 5.0% compared with 2016. All sectors showed growth in 2017. Industry remained the largest sector with 31% of total final consumption, followed by residential with 26% and transport with 20%. The commercial sector accounted for 8.1% of the total while agriculture, fisheries and others accounted for 1.9%. Electricity and heat are the largest energy source, accounting for 41% of final energy consumption (excluding non-energy), followed by natural gas (30%), oil and petroleum products (22%), coal (6.4%), and renewables (0.49%). Compared to 2016, all energy sources increased, except for coal and direct use of renewables.

ENERGY INTENSITY ANALYSIS

Russia has the single most energy-intensive system in the APEC region, and one of the highest uses of energy per million USD in the world. In 2017, both the primary energy supply and GDP grew, resulting in 0.93% growth compared to the previous year at 201 tonnes of oil equivalent per million USD (toe/million USD). Total final consumption intensity grew 3.4% from 130 toe/million USD in 2016 to 134 toe/million USD in 2017. If non-energy consumption is excluded, the growth is slower at 2.0%, highlighting the high intensity of the non-energy sector, mostly petrochemical industries.

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%) 2016 vs 2017
	2016	2017	
Total primary energy supply	199	201	0.9
Total final consumption	130	134	3.4
Final energy consumption excl. non-energy	113	115	2.0

Source: EGEDA (2019).

RENEWABLE ENERGY SHARE ANALYSIS

In 2017, the final consumption of modern renewables accounted for 11 639 ktoe or 2.8% of Russia's final energy consumption, a share marginally lower than in 2016. Modern renewable energy grew by 2.2% in 2017 with hydropower plants accounting for most of this. Other forms of modern energy including solar, wind, geothermal and bioenergy, remain limited, accounting for around 0.11% of total generation. In contrast, traditional biomass consumption remains relatively low at 0.47% of final energy demand, lower than other APEC economies.

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	403 938	418 583	3.6
Non-renewables (Fossil fuels and others)	392 546	406 944	3.7
Traditional biomass*	2 197	1 981	-9.8
Modern renewables*	11 392	11 639	2.2
Share of modern renewables in final energy consumption (%)	2.8%	2.8%	-1.4%

Source: EGEDA (2019).

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal, and so on), including biogas and wood pellets, are considered modern renewables, although data on wood pellets are limited.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Russia's official energy policy document is published regularly by the Ministry of Energy. In June 2020, the Russian Government published the 'Energy Strategy 2035'. The 2035 Strategy maintains Russia's external energy policy, without major changes: "to use the economy's energy potential to effectively maximise its integration into the world's energy markets, strengthen its position in these markets and maximise the benefits of energy resources to the economy" (ME, 2020). This in practice sends a clear message that the government's priority is to keep Russia as a major energy producer and one of the largest energy exporters. However, the strategy does not provide a clear take on the policies and

actions required for global priorities including the low-carbon transition, increasing renewable energy, boosting energy efficiency, and domestic market liberalisation (Mitrova and Yermakov, 2019).

The 'Energy Strategy 2035' is not fundamentally different from its predecessor, the 'Energy Strategy 2030', adopted in 2009. Its key objectives include "using nature's energy resources in the most efficient way and expanding the energy sector's potential for stable economic growth, improving the quality of people's lives and strengthening the economy's foreign trade (IES, 2010)". The strategy sets a policy framework within which more detailed industry-oriented medium-term, and short-term programs are developed.

Both documents highlight Russia's interest in improving the security of domestic energy supply and expanding energy exports. Efficiency improvements on the demand-side and along the entire energy supply chain are also touted. Improvements include a set of actions such as:

- the development of new hydrocarbon fields in remote areas and offshore
- the rehabilitation, modernisation and development of energy infrastructure, including the construction of additional trunk oil and gas pipelines to enhance the energy export capacity
- the diversification of export markets

Russia's nuclear energy industry remains a priority for the economy's development—the share of domestic nuclear power generation is expected to continue increasing. Russia is also interested in constructing nuclear reactors abroad. According to the 2035 Strategy, Russia aims to increase its nuclear-based power generation to between 19% and 22% by 2035 (ME, 2020). In contrast, the share of renewable energy (including large hydropower) in the power generation mix is projected to be 16% by the same year (ME, 2020). The plan expects coal-fired generation to increase its share and displace gas-fuelled power generation (ME, 2020).

The Energy Strategy 2030 calls for a 40% reduction in the energy intensity of the economy by 2030 (IES, 2010). Russia has one of the highest energy intensities in the world and with this objective it aims to improve the competitiveness of its domestic industries and stimulate economic development.

Under the general framework of the Energy Strategy 2030, medium- and long-term programs and industry-wide schemes were developed. These include the Federal Program for Development of the Nuclear Industry up to 2015, approved in 2006, and the general scheme of electric infrastructure development—a scheme relating to electricity network infrastructure and electricity plant locations—up to 2020, approved in 2008 and later extended to 2030.

In 2014, a general scheme for the development of the oil industry up to 2030 was approved. This provides for the comprehensive development of the oil sector through exploration and utilisation of associated petroleum gas, crude oil and petroleum products, and the construction of refining and transportation infrastructure.

The general scheme for the development of the gas industry up to 2030 was reviewed and approved in October 2010. The document defines a path for Russian's long-term gas industry development, covering all components of the gas industry: exploration, drilling, production, storage and transportation to consumers of hydrocarbons and refined products.

In June 2014, a long-term program for developing the coal industry up to 2030 was approved, specifying the basic provisions of the Energy Strategy 2030 to the coal industry. The main task of the program was to realise potential competitive advantages for Russian coal companies while implementing the government's long-term energy policy.

The Mid-Term Scheme on the Unified Energy System Development is a tool to coordinate federal, regional and local governments with private businesses and industry regulators. The

scheme is annually updated and provides a seven-year outlook for generation and transmission line projects (ME, 2018g). It includes an outlook on electricity consumption by region, and on maximum loads, generation capacity reserves, power exchange, retirement of old facilities, maintenance, retrofitting and commissioning of new generation and transmission facilities producing more than five megawatts (MW) capacity/110 kilovolts (kV) and higher voltages.

LAWS AND AUTHORITIES

The main federal legislation on specific energy-related industries includes laws in the following areas: subsoils (1992), functioning of the power industry (2003), power industry (2003), natural monopolies (1995), production sharing agreements (1995), energy conservation and energy efficiency increases (2009), gas supplies (1999), nuclear energy (1995) and heat supply (2010). Legislation on heat supply is the logical extension of power industry law because of the large number of CHPs where electricity and commercial heat are produced simultaneously.

As a rule, the Ministry of Energy (ME) of the Russian Federation is responsible for issuing regulations and instructions that implement the basic energy laws. The ME also coordinates current economic development with the long-term energy policy, except for the nuclear power industry.

Other major government institutions actively participate in the development and implementation of the regulatory framework regarding the production, supply, consumption, and export and import of energy. These include the Ministry of Natural Resources and the Environment of the Russian Federation; the Federal Environmental, Industrial and Nuclear Supervision Service; the Ministry of Industry and Trade of the Russian Federation; the Ministry of Economic Development of the Russian Federation; the Federal Agency on Technical Regulating and Metrology; the Federal Antimonopoly Service; the Federal Customs Service; and the Federal Tariff Service.

ENERGY SECURITY

Russia considers issues related to energy security to be a matter of global concern. Interdependence among energy exporters, importers and transition economies means that international relations are an effective mechanism for improving international energy security. The key approach for the Russian Government is to coordinate the actions of energy exporters and importers in emergency and/or crisis situations.

To facilitate international energy security cooperation, Russia is proposing to develop a Convention on International Energy Security that would consider the balance of interests of all actors in the international market. Infrastructure projects, such as new oil and gas export trunk-lines from Russia to its European and Asian markets, are important for energy security. The development of an international infrastructure for reliable maintenance of the nuclear fuel cycle, under strict International Atomic Energy Agency (IAEA) supervision, is another Russian contribution towards improving global energy security.

ENERGY MARKETS

One of the main issues in Russia is the gradual liberalisation of the natural gas and electricity markets. Coal and petroleum prices have already been partially liberalised. The government controls tariff-setting for power transmission lines and pipelines (gas, crude oil, petroleum products transportation systems and heat supply for the residential and commercial sectors) as well as energy tariffs in remote and isolated areas. The authorities set maximum regional tariffs for natural gas, electricity and centralised heat supply. One of Russia's objectives in the Energy Strategy 2030 is to complete the full liberalisation of domestic energy markets, where at least 20% of the energy is expected to be traded on commodity exchanges.

In 2006, the simultaneous liberalisation of natural gas and electricity prices by 2011 was approved. However, the implementation was delayed, and as of 2020, the electricity tariff for the residential sector is still regulated by the government.

The oil market in Russia has been deregulated since the 1990s, but crude oil and petroleum trading are not based on commodity exchanges. Most crude oil in the domestic market is traded on a term basis, in which prices are linked to international benchmarks. Petroleum is traded in irregular tenders, which allows producers to control the market. Regional petroleum storage plays an important role in establishing fuel markets. The government announced that it intends to make up to 25% of the compulsory purchases of the government's petroleum products supply through commodity exchanges, such as the St. Petersburg Oil Exchange established in late 2006. The Federal Antimonopoly Service has an element of control over oil and gas prices through its role in monitoring the market share of sellers, but it has no responsibility for regulating prices.

The government removed control over coal pricing in the early 1990s, and the coal market has since been liberalised. The transition to transparent, free-trading pricing mechanisms in domestic markets was originally scheduled to be completed in 2011, but the transition period has since been extended. The government will maintain control over the residential and commercial energy tariffs to eliminate cross-subsidies gradually.

OIL AND GAS

Russia's oil and gas industry was privatised in the 1990s. However, the government retained control over major oil and gas companies and crude oil and petroleum trunk pipelines. The Russian Government is the majority owner and controls the largest gas company, Gazprom, and the largest oil company, Rosneft.

As of 2018, the oil industry in Russia comprised 104 enterprises forming 11 vertically integrated companies (VICs) constituting 86% of the crude oil output. There are also 181 small-scale independent enterprises alongside operators of three production sharing agreements. The refining sector comprises 80 refineries with a total refining capacity of over 310 Mt of crude oil per year.

As for transportation, Russia's pipeline transport is underdeveloped relative to the potential oil and gas supply. In 2017, the total length of the pipeline system in the economy was 250 521 km, with 72% for gas, 21% for oil and the remainder for petroleum products.

The shift towards Euro-V emission standards has encouraged significant investment in the refining industry. Currently, only limited use of fuels that are non-compliant with this standard is allowed. Despite a small year-on-year decline in crude oil throughput by -0.80%, the refining utilisation rate has increased from 74% to 79% in the same period. New installations and modernisation of existing equipment are expected to help increase the yield to 81%.

The federal government remains the key shareholder in the economy's gas quasi-monopoly. Gazprom is by far the largest gas producer in Russia, with 67% of domestic production in 2019 (Gazprom, 2020). Gazprom also owns the totality of Russia's gas pipeline transmission network. The remainder of the Russian natural gas supply comes from the so-called 'independent producers' (7.3%), Novatek (8.4%), Rosneft (6.4%), Lukoil (3.0%) and other VICs (7.9%) (Gazprom, 2020).

In 2017, the ME in cooperation with the Ministry of Finance, with the active participation of the oil sector, introduced an oil excess profit tax. This new tax is designed to help sustain existing, and attract new, investment in oil mining. This is especially important for Russia as the production of its main oil-producing province, Western Siberia, is declining, from nearly 308 Mt per annum in 2010 to nearly 286 Mt oil per annum in 2016 (ME, 2017a).

COAL

The Russian coal sector was privatised in the 1990s, with foreign participation practically non-existent. Unlike the oil and gas sector, the coal industry has no large state-controlled companies.

There are no policy restrictions on coal exports. But the high transportation cost of coal reduces its competitiveness in external markets. Coal is the single-largest commodity transported by rail, accounting for nearly 30% of the total rail freight volume. Steam coal accounts for 78% of the total coal production.

In 2014, the government approved the coal industry development program until 2030. The main objectives are to ensure that Russian coal companies are reliable suppliers to the domestic market and that they develop their exporting potential (ME, 2017b).

At the end of 2017, 161 coal enterprises were operational in the Russian coal industry (53 mines and 108 open-pit mines), with a total annual production capacity of 453 Mt. Coal processing is performed by 65 processing plants and mechanical installations (ME, 2018h).

ELECTRICITY

Russia started restructuring its power industry in 2000. Federal laws and government decrees identified the main principles for the future functioning of the power industry under competitive conditions. All thermal generation and regional power distribution companies were privatised before July 2008. From July 2008, the generation and transmission assets in Russia were separated under binding regulations. Generation assets were consolidated into interregional companies of two types: seven wholesale thermal power plant generation companies (WGCs) and 14 territorial generation companies (TGCs).

Six thermal WGCs were constructed according to extraterritorial principles along with one state-owned holding company, RusHydro, which manages 53 hydropower plants. TGCs manage facilities in the neighbouring regions. The initial design of the WGCs provided them with roughly equal standing with respect to installed capacity, asset value and average equipment. Each WGC has power plants located in different regions of Russia to prevent possible monopoly abuse.

For transmission, the state-controlled Federal Grid Company was assigned the backbone transmission lines, whereas distribution grids are owned and operated by 11 interregional distribution grid companies. The Federal Antimonopoly Service is responsible for monitoring the long-distance power transportation market, whose threshold is less than 20% of the transmission line capacity per company. The wholesale power market infrastructure includes the following organisations:

- The Non-profit Partnership Administrator of the Trading System (NP ATS)
- The System Operator–Central Dispatch Administration of the Unified Energy System
- The Federal Grid Company of the Unified Energy System

The NP ATS of the wholesale power market was established in November 2001. The objectives of the NP ATS are to organise trade and arrange financial payments in the wholesale electricity and power markets; to increase the efficiency of power generation and consumption; and to protect the interests of both buyers and suppliers.

The NP ATS provides infrastructure services, which are related to the organisation of trade and the wholesale power market, and that ensure the execution and closing of transactions, and the fulfilment of mutual obligations. The system operator is 100% state-owned and exercises technological control within the power grids and provides dispatching services to wholesale market participants. The Federal Grid Company was established in 2002 and is 78% state-owned. It owns and operates the transmission lines, provides consistent technological management and is responsible for the reliability of power transmission services.

The free electricity trading market (one-day forward) was launched in November 2003 within the framework of the Federal Wholesale Electricity Market (FOREM). In September 2006, the regulated sector of the wholesale market was replaced by a system of contracts to be concluded between the buyers and sellers of electricity and electric power. In the FOREM, power generators and importers sell electricity and power to guarantor suppliers and distribution companies as well as to large consumers and exporters. In the distribution market, guarantor suppliers and distribution companies sell electricity and power to end-use consumers in the residential, commercial and industrial sectors.

Since 2008, the share of tariffs established by the regulatory asset base methodology for distribution grids has been increasing and is expected to become the major method for calculating middle-term tariffs. The transition to mostly market-based electricity prices still has a long way to go, with only 20% of electricity prices determined by the market at present, the rest being the result of state interventions (Mitrova and Yermakov, 2019).

RENEWABLE ENERGY

Russia's technical potential for renewable energy (RE), excluding large hydro, is estimated at 4 400 Mtoe per year or almost eight times more than Russia's current total final consumption. However, the economic potential is much smaller (approximately 240 Mtoe per year, nearly 250% of the total electricity production).

The government's policy goals and mechanisms to promote RE were introduced in January 2009 through the *Basic Directions of a State Policy of Renewable Energy Utilisation up to 2020* federal order. The major mechanisms to increase the share of renewables are feed-in tariffs and subsidies for grid connection. The government is expected to develop regulations for feed-in tariffs and grid connection subsidies for the compulsory share of RE in the wholesale market. By 2030, Russia is expected to generate between 80 to 100 billion kWh of RE, excluding large hydro, or roughly 4–6% of the economy's total generation.

In October 2010, the government published a ruling on federal subsidies for connecting RE generators to the power grid that would encourage 'green' energy production in Russia. Conditions of the ruling include that the nominal capacity of a single RE installation should not exceed 25 MW and that owners should not be under bankruptcy proceedings. At present however, this potential remains vastly untapped with renewable energy accounting for a negligible share of 0.35% of total power generation (EGEDA, 2019).

HEAT SUPPLY

Residential and commercial heat supplies have important social implications and are a major concern for local governments in Russia. Historically, the heat supply industry was subsidised by local budgets and thus has scope for considerable efficiency improvements. The Law on Heat Supply introduced in 2010 was designed to create investment opportunities, minimise energy losses and subsidies, and provide business incentives.

In July 2017, the government adopted changes to this law, allowing regional and municipal authorities to establish localised heat supply markets. In these liberalised markets, however, the government still regulates the maximum heat price for the final consumer, commonly referred to as the 'alternative boiler house price' (ME, 2017d).

NUCLEAR

Russia's nuclear industry restructuring started in 2001, when the state-owned company Rosatom took over all civil reactors, including those under construction, and their related infrastructure. In 2007, the new Law on Nuclear Industry was adopted, which provided a legal framework for industry restructuring by separating military and civil facilities and by introducing regulations for nuclear materials management. Russian business entities are now allowed to hold civil-grade nuclear materials, but they still fall under state control.

In April 2007, a single, vertically integrated, state-owned nuclear energy company was established, AtomEnergyProm (AEP). AEP's activities include uranium production,

engineering, design, reactor construction, power generation and research facilities. AEP holds a significant share of the world's enriched uranium and nuclear fuel supply, owns existing Russian nuclear energy plants producing 24 GW, and manages the construction of 14 reactors. There are seven reactors under construction in Russia, including one floating-type unit to power remote areas and seven reactors in Asian and European economies.

Russia holds important stakes in the international nuclear fuel market. Tenex, the state company responsible for the nuclear fuel cycle business, supplies all the Russian, Commonwealth Independent States', and Eastern European nuclear reactors. In addition, Tenex meets 40% of the nuclear fuel requirements of the US, 23% of Western Europe's and 16% of those of the Asia-Pacific region.

Russia has adopted a 'closed' fuel cycle, which includes spent nuclear fuel processing and the mandatory return of fissionable nuclear materials to the fuel cycle. To provide the legal framework for managing spent nuclear fuel and radioactive waste, the laws on environmental protection and the use of nuclear energy were amended in June 2010.

Rosatom's long-term strategy up to 2050 includes increasing safety in its nuclear energy plants, using fast reactors with a closed fuel cycle and mixed oxide fuel. In the period 2020–25, fast neutron reactors are expected to play an increasing role in Russia. The improved design will lead to an extended operating life of up to 60 years, a shorter construction period of up to 46 months and operating costs of less than RUB 1 per kilowatt-hour (kWh).

Following the commissioning of an 800 MW fast-breeder reactor (UNIT 4, Beloyarskaya Nuclear Power Plant), Rosatom is planning to construct a 1200 MW unit after 2020. The development of this technology is expected to broaden the range of acceptable fuels as well as reduce the amount of nuclear waste by establishing a closed nuclear fuel cycle (Rosatom, 2018).

For the development of nuclear energy for the next 20 to 25 years Russia has chosen three core reactor technologies:

- water–water energetic reactors (VVER)
- sodium fast neutron reactors
- high-temperature helium reactors

FISCAL REGIME AND INVESTMENT

In 2007, dozens of oil and gas fields were decreed to be 'strategic' fields. The strategic status makes the hydrocarbon deposits inaccessible to foreign companies unless they establish joint project operations with Russian companies. Under the current regulations, the strategic status has been applied to oilfields with reserves exceeding 70 Mt and gas fields with reserves exceeding 50 Bcm. In March 2009, regulations were adopted to compensate costs associated with the discovery and exploration of deposits under exploration licences, the further development of which is prohibited because of their strategic status.

Beginning in January 2009, tax holidays from the mineral extraction tax for crude oil production in East Siberia were extended to areas north of the Arctic Circle, Sea of Azov, Caspian Sea and Nenetsk and Yamal regions. In addition to the existing tax reductions for East Siberian oil, this has enabled the development of new capital-intensive projects in remote areas that lack energy infrastructure. From 1 January 2010, a zero export duty was introduced for crude oil extracted from East Siberia oilfields to maintain a stable market for Russian crude exported eastward to the Asia-Pacific region.

On 1 October 2011, a new tax regime for the oil industry called the '60–66' came into force in Russia. Under these rules, the duty on oil exports decreased by 7.4% to USD 411 per tonne, and fees for light and heavy petroleum products were set at 66% duty on crude oil. For several fields in Eastern Siberia and the North Caspian, a preferential export duty was enacted, which, as of October 2011, was set at USD 204 per tonne.

The size of the duty on exports of gasoline is currently set at 90% of the duty on crude oil. Before May 2011, the duty on export of gasoline was 60% of the duty on oil. The sharp rise in domestic prices and gasoline shortages in some regions led to the increase to 90%. The unification of tariffs on export of petroleum products at 66% will make exports less competitive for dark petroleum products and more profitable for light petroleum products; it will also encourage companies to increase the refining depth at their existing plants.

To facilitate coal exports, rare subsidies to the coal industry are provided under the railway's cargo tariff regulations for some export routes.

ENERGY EFFICIENCY

The energy intensity of the Russian economy is considerably higher than those of most developed economies. It is estimated that the introduction of energy efficiency (EE) measures will save over 300 Mtoe, including more than 160 Mtoe from energy extraction, transformation and transportation.

EE has increased in relevance in Russia. In 2008, a presidential decree set a target to reduce the energy intensity of Russia's GDP by 40% by 2020 compared with the 2005 level. Improving EE and energy savings was deemed a priority of the Energy Strategy 2030.

The Law on Energy Conservation and Increase of Energy Efficiency took effect in 2010. It sets a legal framework and promotes alternative fuel resources for electricity and heat generation. Example measures within the law are:

- adopting EE standards for equipment and buildings, including mandatory energy passports
- EE labelling of goods and the compulsory commercial inventory of energy resources
- improvements in EE monitoring, focusing on mandatory energy audits and the compulsory installation of metering systems
- creating a single and unified inter-agency information network and analytical EE system
- introducing incentives and tax benefits for Russia's heavy industries to replace energy-inefficient machinery

In accordance with the EE federal law and the program, all regions are required to prepare their own respective regional programs on EE improvements. Regional governments and the federal government will jointly finance the implementation of these programs.

In 2009, the Russian Energy Agency was established with 70 regional branches, within the Ministry of Energy of the Russian Federation. Its key tasks focus on operating the federal energy efficiency and energy-saving information system and on administering, monitoring and coordinating efforts for effective implementation of the EE law. In addition to these measures and policies for strengthening the EE legal framework, the federal government launched the following six pilot presidential energy-efficient projects:

- metering (installing metering devices and automation)
- developing EE in the government sector (piloting energy performance contracting in schools and public buildings)
- creating energy-efficient districts (targeting the residential sector)
- introducing energy-efficient lighting (replacing street lighting and other measures)
- small-scale cogeneration
- finding new energy sources (renewable and other non-carbon energy resources)

These projects are expected to be implemented across all regions once the pilots are completed successfully. Technical potential exists to save almost half of Russia's primary

energy consumption through energy conservation (ME, 2015). A major impediment to businesses improving their EE is the absence of appropriate financial mechanisms.

CLIMATE CHANGE

In 2016, the Russian Government signed a directive approving the Paris Agreement of the Conference of the Parties to the UNFCCC (UN Framework Convention on Climate Change) (RG, 2016). Russia's NDC main provisions include 'limiting anthropogenic greenhouse gases in Russia to 70–75% of 1990 levels by the year 2030' (UNFCCC, 2015).

Russia ratified the agreement in September 2019. Russia's NDCs have been qualified at best as a 'serious challenge' and at worse as 'critically insufficient' or 'symbolic rather than substantial' by different experts and advocacy groups (AC, 2020) (CAT, 2019) (Mitrova and Yermakov, 2019). The use of 1990 as a baseline means that there is scope for Russia to significantly increase its current emissions. This is because Russia's emissions fell significantly in the early 1990s with the collapse of the Soviet Union. Russia's emissions today are roughly half of what they were in 1990.

Russia's key environmental and climate policy has been outlined in the Climate Doctrine (Kremlin, 2009) and state policy in the field of environmental development of the Russian Federation for the period until 2030 (Kremlin, 2012). The State Environmental Protection Program for 2012–2020² outlines the implementation of these policies. In 2017, the 'Strategy for Environmental Protection in Russia until 2025' was launched, which includes an assessment of the status and threats to the environment and highlights key government targets, indicators and methods of environmental monitoring (Pravo, 2017).

On 21 July 2014, the Federal Law 'On amendments to the Law on Environment protection' was adopted by the government. Subsector-specific guidelines were adopted by respective federal agencies and ministries (BuroNDT, 2019).

² The State Environmental Protection Program does not include the indicators related to GHG emissions.

NOTABLE ENERGY DEVELOPMENTS

ENERGY POLICY

In June 2020, the Russian Government published its long-awaited Energy Strategy of the Russian Federation for the period until 2035. This is the main strategic energy planning document and replaced the Energy Strategy of Russia for the period until 2030.

The Russian Government published for the first time a greener economic path for the coming three decades, with a draft long-term, low-carbon development plan released in March 2020 (MED, 2020).

The draft strategy aims to reducing greenhouse gas emissions by 33% by 2030 compared to 1990 levels. This is a minimal improvement compared to Russia's NDC (25-30% over the same timeframe). Using 1990 as a baseline allows for a significant increase in emissions compared to 2019 levels as emissions fell significantly in the early 1990s. Russia's emissions today are roughly half of what they were in 1990.

POWER MARKET DEVELOPMENT

The Ministry of Energy of the Russian Federation presented concepts for a program of power sector modernisation up to 2020. The central theme of this modernisation is to introduce new technologies (both domestic and imported), increasing the reliability of electricity supply.

OIL AND GAS DEVELOPMENT

Russia is the second-largest crude oil exporter, which means that international crude prices are very influential on Russia's economic standing. The global oil industry was already facing low prices at the end of 2019, but this trend was exacerbated in the first half of 2020 by a catastrophic demand shock from the COVID-19 pandemic and simultaneous supply shock due to a price war between the two largest oil exporters. The COVID-19 pandemic has had brought catastrophic damage to demand for almost all petroleum products. At the same time, on the supply side, a Saudi Arabia vs. Russia price war began during the 7th meeting of the OPEC+ alliance in March 2020.

OPEC+ was created in 2016 when 23 exporting economies including the Organization of Petroleum Exporting Countries (OPEC) and 10 other exporters signed a Declaration of Cooperation to cut oil production to stabilise oil prices and expand their market shares. In March 2020, Saudi Arabia proposed a 1.5 million barrels per day (mb/d) production cut, an important increase compared with the 0.50 mb/d cut agreed in December 2019. Of this cut, OPEC would account for 1.0 mb/d, leaving Russia and the other nine partners with the remaining 0.50 mb/d.

Following speculation and tense negotiations, Russia rejected the OPEC proposal and prevented an agreement within OPEC+ to continue with any production cuts (OPEC, 2020a). This started a month-long price war between Russia and Saudi Arabia and put into question the continuity of OPEC+. With the worsening effects of the COVID-19 pandemic, the Brent price crashed to USD 22 per barrel at the end of March.

However, negotiations resumed on April 12 with a virtual meeting in which Russia and the other OPEC+ members agreed to cut 9.7 mb/d. This was the largest coordinated oil production cut ever agreed, both in terms of oil volume and the parties involved (OPEC, 2020b). Oil prices are projected to remain at low levels for the rest of 2020, but the OPEC+ appears to continue to act as a forum for Russia's energy diplomacy.

Russia is the largest natural gas exporter in the world, with most of these exports historically transported via pipeline to Europe. But Russia is developing infrastructure that will allow Russian companies to take gas to other markets, particularly Asia. One of the most relevant developments in the Russian energy sector in 2019 was the commissioning of the Power of

Siberia pipeline. This 3000 km long pipeline takes gas from the Siberian Chayandinskoye field to Northern China and has a capacity of 38 bcm per year (Gazprom, 2019). This enormous pipeline is the first piped interconnection with China and is the result of a bilateral agreement involving Gazprom and China National Petroleum Corporation (CNPC) that started in 2014.

Russia has also increased its LNG export capacity significantly in recent years. At the end of 2018, Russia had only one LNG terminal, Sakhalin 2 LNG, on the Pacific Coast. Since then, Novatek's huge 18 Mtpa Yamal LNG and 0.66 Vysotsk LNG have been commissioned (IGU, 2020). In 2019, Novatek started the construction of two more projects, Arctic LNG 2 and Portovaya LNG. The Arctic LNG 2 project envisages constructing three LNG trains at 6.6 Mtpa each. Its shareholders are Novatek (60%), Total (10%), CNPC (10%), CNOOC Limited (10%), and Japan Arctic LNG (10%) (Novatek, 2019). This will increase Russia's gas liquefaction capacity up to around 48 Mtpa by 2025, to fall just short of Qatar, Australia and the USA (IGU, 2020). This will contribute positively to the Russian Government's strategy of making Russia a top LNG exporter and reaching new markets, particularly in Southeast and South Asia.

Russia commissioned a 2.7 Mtpa receiving facility in early 2019, FSRU Kaliningrad terminal (IGU, 2020). FSRU Kaliningrad had not received any cargo as of early 2020, and it is in the Russian exclave of Kaliningrad, west of Lithuania.

RENEWABLE ENERGY DEVELOPMENT

Russia's updates on renewable energy have been mostly limited to the projections detailed in the 2035 Strategy, increasing the share of renewable-based power generation to 16% by 2035 (including large hydropower) (ME, 2020). Notable exceptions are the commissioning of a 35 MW wind farm in Ulyanovsk and the construction of a 201 MW wind farm in Murmansk (UNESCAP, 2019) (TMT, 2019).

CLIMATE CHANGE

In May 2019, the Action Plan on the Implementation of the Strategy of Environmental Security of the Russian Federation until 2025 was adopted. The plan defines activities and the timing of their implementation, in areas such as: (a) the introduction of innovative and environmentally-friendly technologies; (b) the development of efficient waste management; (c) the construction and modernisation of sewage treatment facilities; and (d) the creation and development of a system of environmental funds, etc. (UNESCAP, 2019).

In 2019, Russia ratified the Paris Agreement, the first global climate change treaty, which was signed by 197 UNFCCC members in December 2015 and entered into force in November 2016 (UNFCCC, 2019).

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USEFUL LINKS

OFFICIAL BODIES OF RUSSIA

- The Russian Government—<http://government.ru/en/>
- Ministry of Energy of the Russian Federation—<http://minenergo.gov.ru/en>
- Ministry of Natural Resources and Environment of the Russian Federation—
<https://www.mnr.gov.ru/english/>
- Federal Environmental, Industrial and Nuclear Supervision Service of Russia—
<http://en.gosnadzor.ru/>
- Ministry of Economic Development of the Russian Federation—
<http://economy.gov.ru/en/home/>
- Federal State Statistics Service of the Russian Federation—
http://www.gks.ru/wps/wcm/connect/rosstat_main/rosstat/en/main/
- Ministry of Industry and Trade of the Russian Federation—<http://minpromtorg.gov.ru/>
- Federal Agency on Technical Regulating and Metrology—<http://www.gost.ru/wps/portal/en>
- Federal Antimonopoly Service—<http://en.fas.gov.ru/>
- Federal Customs Service—<http://eng.customs.ru/>
- Federal Tariff Service—<http://www.fstrf.ru/eng>

ENERGY-RELATED NON-PROFIT AND STATE-OWNED BUSINESS INSTITUTIONS

- AtomEnergoProm—<http://atomenergoprom.ru/en/>
- Federal Grid Company (PJSC FGC UES)—<http://www.fsk-ees.ru/eng/>
- Rosseti, Public Joint Stock Company (PJSC ROSSETI)—<http://www.rosseti.ru/eng/>
- Association NP Market Council—<http://www.en.np-sr.ru/index.htm>
- Gazprom—<http://www.gazprom.com/>
- Rosneft—<https://www.rosneft.com/>
- RusHydro—<http://www.eng.rushydro.ru/>
- Transneft—<http://www.en.transneft.ru/>
- Transnefteproduct, JSC—<http://en.transnefteproduct.transneft.ru/>

STATE ENERGY-POLICY-RELATED RESEARCH CENTRES

- Russian Energy Agency—<http://rosenergo.gov.ru/>
- Analytical Centre for the Government—<http://ac.gov.ru/en/>
- Institute of Energy Strategy—www.energystrategy.ru/
- Centre for Energy Policy—<http://www.energy.ru/>
- Centre for Energy Efficiency—http://www.cenef.ru/art_11207_114.html
- The Energy Research Institute of the Russian Academy of Sciences (RAS)—
<https://www.eriras.ru/eng>
- Melentiev Energy Systems Institute (Siberian Branch of RAS) —<http://isem.irk.ru/en/>

MAJOR ENERGY-RELATED MEDIA IN RUSSIA

Official newspaper, *Rossiyskaya Gazeta*—<https://rg.ru/>

State information system on energy conservation and energy efficiency improvement—
<https://gisee.ru/>

Central Dispatching Department of Fuel Energy Complex—<http://www.cdu.ru/en/>

SINGAPORE

INTRODUCTION

Singapore is a city-state located in the south of the Malay Peninsula, between the Strait of Malacca and the South China Sea. This economy's land area is 722 square kilometres (km²), with a population of 5.6 million in 2017.

Singapore is completely urbanised and highly industrialised. It lacks domestic energy and mineral resources and has a small land size (a significant part of which is reclaimed land). Even so, the economy is diverse and has enjoyed impressive economic success. The success is largely due to financial activities, shipbuilding, petroleum, biotechnology, and Singapore being a regional hub for tourism. Singapore has also been expanding its role in international cargo and fuel shipping.

Singapore's gross domestic product (GDP) grew by 3.7% to USD 493 billion in 2017. The services industries accounted for 70% of GDP, goods-producing industries (manufacturing and construction) accounted for 27% and ownership of dwellings¹ accounted for the remainder. Manufacturing represented the largest sub-sector by percentage share of GDP (22%), followed by wholesale and retail trade (18%) and business services (15%) (SingStat, 2019).

Table 1: Key data and economic profile, 2017

Key data ^{a; b}		Energy reserves	
Area (km ²)	722	Oil (million barrels)	–
Population (million)	5.6	Gas (billion cubic metres)	–
GDP (2011 USD billion [PPP])	493	Coal (million tonnes)	–
GDP (2011 USD [PPP per capita])	87 760	Uranium (kilotonnes U)	–

Source: ^{a; b} Department of Statistics Singapore (2019); EGEDA (2019).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Singapore has no indigenous natural resources and imports all its fossil fuel requirements. Total energy imports (crude oil, petroleum products, natural gas, coal and other energy products) were 194 878 kilotonnes of oil equivalent (ktoe) in 2017. These imports were used to meet domestic energy requirements and to serve the needs of its oil refineries. Refined products are exported mainly to the Asia-Pacific Economic Cooperation (APEC) region (total energy exports were 101 628 ktoe in 2017) (EGEDA, 2019).

In addition to having a vibrant oil refining industry, Singapore also plays an important role in international shipping and aviation. International marine bunkers received 48 768 ktoe of Singapore's refined fuel and gas/diesel oil. Aviation bunkers received 8298 ktoe of aviation fuel.

¹ Ownership of dwellings refers to housing services provided by owner-occupiers and individuals who let out their residential properties.

Contributions to both international marine and aviation bunkers, while not included in energy exports, were equivalent to 56% of Singapore's total energy exports.

Singapore's total primary energy supply (TPES) in 2017 was 36 656 ktoe, 8.0% higher than in 2016. Oil constituted the largest share of TPES at approximately 71% (26 105 ktoe), followed by natural gas at 24% (8 931 ktoe), coal at 2.5% (899 ktoe) and renewables at 1.1% (319 ktoe) (EGEDA, 2019).

Singapore generated 52 387 gigawatt hours (GWh) of electricity in 2017, an increase of 1.4% over 2016 (EGEDA, 2019). Peak demand for electricity stood at 7188 megawatts (MW), a 0.55% annual increase (EMA, 2019a). There are seven main power producers in Singapore that contributed to the bulk of power generation (92%) in 2017. Auto-producers accounted for the remaining 7.6% of generation.

Total licensed generation capacity reached 13 616 MW in 2017. Steam turbine plants have been displaced by more efficient combined-cycle gas turbine (CCGT) power plants in recent years. This has meant that the share of CCGT in overall generation capacity increased from 46% (4534 MW) in 2005 to 77% (10 508 MW) in 2017. The share of steam turbine plants dropped from 48% (4640 MW) in 2005 to 19% (2555 MW) in 2017. Open-cycle gas turbine plants comprised 1.3% (180 MW) of the generation capacity in 2016, while waste-to-energy (WtE) plants accounted for the remaining 1.9% (257 MW) (EMA, 2019a).

The share of natural gas in Singapore's power generation fuel mix has increased to 95% (and has been this high since 2014). In 2017, petroleum products accounted for 0.70% of the mix, coal for 1.2%, while other fuels accounted for 2.9% (EMA, 2019a).

Total grid-connected solar PV installed capacity in Singapore increased 37% from 151 megawatt peak (MWp) in 2017 to 206 MWp in 2018. Solar capacity has since grown to 262 MWp midway through 2019 (EMA, 2019a).

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	653	Industry sector	6 840	Total power generation	52 387
Net imports and others	93 250	Transport sector	2 526	Thermal	50 764
Total primary energy supply	36 656	Other sectors	2 544	Hydro	–
Coal	899	Non-energy	12 765	Nuclear	–
Oil	26 105	Final energy consumption*	11 910	Others	1 623
Gas	8 931	Coal	173		
Renewables	402	Oil	6 173		
Others	319	Gas	1 295		
		Renewables	0		
		Electricity and others	4 269		

Source: EGEDA (2019) (data collected in December 2019).

* Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. Total final consumption includes non-energy uses. Half of the municipal solid waste used in power plants is assumed to comprise renewables.

FINAL ENERGY CONSUMPTION

Singapore's final energy consumption was 11 910 ktoe in 2017, a 2.3% annual increase. Oil remained the most-consumed fuel (6173 ktoe), with a share of 52%, followed by electricity and others (36%, 4 269 ktoe), natural gas (11%, 1295 ktoe) and coal (1.5%, 173 ktoe). The largest portion of final energy consumption was for non-energy uses (52%). The industrial sector accounted for 28% of total final consumption, other sectors (including residential and commercial sectors) accounted for 10% and the transport sector accounted for 10% (EGEDA, 2019).

ENERGY INTENSITY ANALYSIS

Singapore is contributing to APEC's objective of a 45% energy intensity reduction by 2035 below 2005 levels as set by APEC leaders in 2011. The economy's efforts to reduce energy intensity began in 2009 when the economy set an ambitious target to reduce energy intensity by 35% by 2035. The Inter-Ministerial Committee on Sustainable Development (IMCSD) formulated the Sustainable Singapore Blueprint as a guiding strategy for the economy's sustainable development (MEWR, 2014). Singapore strengthened its commitment to efficiency through its nationally determined contribution (NDC) in 2015, pledging to reduce energy intensity to 36% below 2005 levels by 2030 (NCCS, 2018a). Singapore recognises the importance of energy efficiency in creating a sustainable energy future (EMA, 2019c).

Government initiatives aim to assist the economy achieve APEC's 2011 target. The Energy Conservation Act 2013 (ECA) focuses on interrelated energy issues, including improving energy conservation, efficiency and intensity while reducing CO₂ emissions (Green Future, 2013). The act is helping Singapore achieve its intensity reduction target(s) by improving the energy performance of the economy's companies. Other initiatives are discussed later in this chapter.

Singapore's energy intensity increased in terms of primary energy as well as final consumption in 2017. Primary energy intensity was 71 tonnes of oil equivalent per million USD (toe/million USD) in 2017, a 4.1% increase from the previous year. Final energy intensity was 50 toe/million USD in 2017, a 1.7% increase. These increases were mostly driven by the large increases in non-energy use by the industrial sector. Final energy intensity decreased 1.3% to 24 toe/million USD if non-energy use is excluded.

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%) 2015 vs 2016
	2016	2017	
Total primary energy supply	71	74	4.1
Total final consumption	49	50	1.7
Final energy consumption excl. non-energy uses	25	24	-1.3

Source: EGEDA (2019).

RENEWABLE ENERGY SHARE ANALYSIS

Land scarcity and the absence of suitable geological conditions limit Singapore's options for renewable energy. Solar power and WtE are the main forms of renewable sources available, and Singapore has made efforts to pursue these options. Singapore aims to increase its solar deployment to 350 MWp by 2020 and to 2.0 GWp by 2030. These ambitions have accelerated the adoption of solar PV systems. The share of modern renewable energy in final energy consumption increased by 1.1% in 2017.

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	11 637	11 910	1.0
Non-renewables (Fossil fuels and others)	11 557	11 827	1.0
Traditional biomass*	0	0	-
Modern renewables*	80	83	6.9
Share of modern renewables in final energy consumption (%)	0.69	0.69	1.1

Source: EGEDA (2019).

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on), including biogas and wood pellets, are considered modern renewables, although data on wood pellets are limited.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

Singapore's 2007 National Energy Report set out strategies² to balance the objectives of energy security, economic competitiveness and environmental sustainability. The economy has since sought to secure this balance through multiple measures.

Natural gas has accounted for 95% of Singapore's power mix since 2014 (EMA, 2019a) and a tenth of its energy demand since 2009. To reduce its dependence on piped natural gas imports from Malaysia and Indonesia, Singapore began operating its first liquefied natural gas (LNG) terminal in May 2013. Regasification and storage capabilities, along with auxiliary services, such as reloading and boil-off gas recovery, have increased the share of gas in the energy mix, and have strengthened Singapore's role as an emerging LNG hub in Southeast Asia.

LNG development has enabled Singapore to diversify its gas supplies and satisfy growing natural gas demand. Singapore imported LNG from over 20 economies in the last five years, including Australia, Qatar, Indonesia, Equatorial Guinea and Trinidad and Tobago (UN, 2019). LNG imports make up 29% of natural gas imports (EMA, 2019a).

In November 2019, Indonesia announced that it will halt pipeline exports to Singapore from the Suban Field via the Grissik-Batam-Singapore pipeline when contracts expire in 2023, and divert the volumes for domestic use (ESDM, 2019)³. This will increase the need for LNG imports into Singapore. Singapore is yet to release a policy response to the import halt but did announce interest in increasing LNG regasification via an Expression of Interest for building a floating LNG terminal early in November 2019 (EMA, 2019b).

² Diversify Energy Supplies; Enhance Infrastructure and Systems; Improve Energy Efficiency; Strengthen the Green Economy; Price Energy Right.

³ Indonesia has not announced the fate of its Natuna-Singapore subsea gas pipeline, which also exports gas to Singapore.

Singapore's key strategy for diversifying its energy mix is the deployment of PV panels. The SolarNova program aggregates demand for solar energy 'across government buildings and spaces, to yield savings from economies of scale' while 'demonstrating solar energy's viability in Singapore' to 'catalyse further adoption by the private sector' (GOS, 2015).

Singapore has also become a global leader in floating solar PV research. Overcoming land constraints with innovative solutions will increase solar potential. More details on Singapore's progress are discussed later in this chapter.

Singapore is also intensifying efforts to promote efficient energy use and decrease CO₂ emissions. As part of its contribution to the post-2020 climate change agreement, Singapore intends to reduce emissions intensity by 36% from 2005 levels by 2030 and to stabilise emissions with the aim of peaking around 2030 (NCCS, 2018a). This pledge builds on its existing commitment to reduce greenhouse gas (GHG) emissions by 16% from the business-as-usual (BAU) level by 2020. Singapore is on track to meet this target and at COP25 announced its intention to update this pledge in 2020 (Strait Times, 2019). Singapore also introduced a tax on carbon emissions in 2019.

In 2019, the government unveiled its strategy for creating a sustainable energy future for Singapore, called the Future of Singapore's Energy Story. The Energy Story will harness "4 switches", energy efficiency and co-creation. The "4 Switches" to guide and transform energy supply are (EMA, 2019c):

1. Natural Gas

Natural gas is the cleanest fossil fuel and currently makes up 95% of Singapore's electricity mix. It will continue to dominate the energy mix as Singapore works to scale up the other switches. An attempt will be made to reduce the carbon footprint of natural gas by improving the efficiency of its gas-fired power plants.

2. Solar

Solar is Singapore's most promising renewable energy source. Building on its 2020 solar capacity target of 350 MWp, the government will work towards achieving a target of at least 2 GWp by 2030, aided by an energy storage deployment target of 200 MW after 2025

3. Regional Power Grids

Singapore will explore ways to tap regional power grids to access energy that is cost-competitive. This could be realised through bilateral cooperation or regional initiatives

4. Emerging Low-Carbon Alternatives

Singapore will explore emerging low-carbon solutions that could potentially reduce its carbon footprint. These could include carbon capture, utilisation or storage technologies and hydrogen

In 2016, the government formed the Committee on the Future Economy (CFE) to review and develop economic strategies for Singapore over the next decade. The CFE was tasked to build on the 2010 Report by the Economic Strategies Committee and to recommend strategies to maintain sustainable economic growth for Singapore. Recommendations made by the CFE, including energy-related strategies, will lay the foundation for Singapore's policy development over the next decade. In the report the CFE submitted in February 2017, the recommendations relevant to Singapore's energy developments were as follows (CFE, 2017):

1. Become a model city in sustainability

The report recommends more aggressive investment in R&D, project testbeds and the commercialisation of new energy solutions. On the supply side, Singapore should ramp up the deployment of solar PVs and invest in R&D for energy storage solutions and solar forecasting. These could support cost-effective deployment of solar energy and

enhance energy grid resilience. On the demand side, Singapore should continue to push for greater efficiency in energy usage through more energy 'smart meters' to encourage energy-saving behaviour through real-time feedback. Real-time information will also facilitate easier implementation of demand-side management (DSM) initiatives and will allow for the development of new business models

2. Strengthen competitiveness as a trading hub

Singapore is a successful regional trading hub for agri-commodities, metals and minerals, and energy-related commodities. Singapore should diversify trade flows and deepen its ecosystem of supporting services and financing. This will foster a liquid commodity derivatives marketplace and strengthen commodity trade financing

3. The government should purchase sustainable technologies to help enterprises build a track record

Such government-led demand has resulted in the development and adoption of smart and sustainable technologies in the past. As an anchor customer, the government could help industry build expertise and track records of enterprises in areas such as energy management and industrial water solutions

4. Raise ambitions in the adoption of sustainable urban solutions

To raise Singapore's renewable energy and urban mobility ambitions, the government should leverage the Green Mark standards to encourage solar PV adoption; explore large-scale floating PV deployment; develop standards to track renewable energy production/consumption; and produce urban mobility adoption plans

ENERGY MARKETS

The electricity and gas industries in Singapore were once vertically integrated, government-owned, and under the responsibility of the Public Utilities Board (PUB). Singapore began restructuring its electricity industry in 1995 to liberalise the market and promote competition. Major activities in this regard have included corporate and industry structural reforms; the creation of an institutional regulatory framework; and market rules for the contestable parts of electricity generation and retail sales of electricity (separate from the natural monopoly of electricity transmission at the ownership level). Later, in 2001, the gas market was also restructured to support the parallel liberalisation of the electricity market.

ELECTRICITY

In October 1995, PUB's electricity and piped gas undertakings were corporatised to introduce competition into the energy sector. The SP Group (formerly known as Singapore Power Ltd) was established under Temasek Holdings as a vertically integrated group of companies to take over these undertakings. The group included two power generation companies, namely PowerSenoko and PowerSeraya, an electricity transmission and distribution company (PowerGrid, now known as SP PowerAssets Ltd), and an electricity supply and utilities support services company (PowerSupply, now known as SP Services Ltd). In the same year, PUB took on the role of regulator for the electricity and gas sectors and Tuas Power was set up as a third independent power company directly under Temasek Holdings. In 2008 and 2009, Temasek Holdings divested its interests in all three of the power generation companies .

The Singapore Electricity Pool commenced operations in 1998 as a day-ahead electricity market to facilitate the trading of electricity between generation companies in a competitive environment. Additional reforms were made in 2000 to further liberalise the electricity industry. Key restructuring initiatives included the separation of ownership of the non-contestable part of the electricity market (the transmission and distribution grid) from the contestable part (power generation and retail), the establishment of a system operator and market operator, and the establishment of a real-time wholesale market.

The Energy Market Authority (EMA) was established in April 2001 to regulate the electricity and gas industries and promote competition. Under the EMA, the Power System Operator (PSO) is responsible for ensuring the secure operations of the power system. The Energy Market Company was established in the same year as the market operator, responsible for the operation and administration of the wholesale electricity market. In 2003, the National Electricity Market of Singapore (NEMS) was established to allow power generation companies to compete to sell electricity at half-hour intervals in the wholesale electricity market.

The EMA has progressively opened the retail market to competition since 2001 to give consumers the choice to buy electricity from the retailers of their choice. The Open Electricity Market (OEM) is the final phase of this process, targeted at opening the retail market to small consumers (EMA, 2019d). A zonal roll-out of the OEM across Singapore began in November 2018 and ended in May 2019. Residential and small business consumers are now able to choose to buy electricity from a retailer with a non-regulated price plan that best meets their needs, or can continue to pay the regulated rate. As of 31 August 2019, 40% of eligible accounts had opted to switch to a non-regulated retailer.

GAS

The passage of the Gas Act (Act 11) in 2001 marked the beginning of the restructuring of Singapore's gas industry. The act sets out the legal basis for separating the contestable part of the gas industry (gas retail and gas imports) from the monopolistic part (gas transportation). PowerGas Ltd, a subsidiary of SP Group, is the only gas transporter in Singapore, owning the natural gas and town gas pipeline networks. It provides open and non-discriminatory access to the gas pipeline networks. EMA licences and closely works with PowerGas to annually review the natural gas transmission network plan.

The Gas Network Code (GNC) came into effect on 15 September 2008, marking the start of Singapore's newly restructured gas market. The EMA developed and enacted the GNC in consultation with industry players. The GNC governs the activities of gas transportation, providing open and non-discriminatory access to Singapore's onshore gas pipeline network. The GNC outlines the common terms and conditions between the gas transporter (PowerGas Ltd) and gas shippers (industry players who engage the transporter to transport gas through the pipeline network). To ensure that the gas transporter is not in commercial conflict with common interests, PowerGas Ltd is banned from participating in electricity and gas businesses open to competition, such as gas importing, trading and retailing. Other gas industry participants are not allowed to transport gas.

Singapore imported 10 Mtoe of natural gas in 2018, with 71% piped natural gas (PNG) and 29% LNG (EMA, 2019a). Before the introduction of LNG in 2013, Singapore fully depended on PNG supplies from Indonesia and Malaysia. Four offshore natural gas pipelines—two from Malaysia and two from Indonesia—supply Singapore's PNG needs. City gas distributors and electric utilities such as Keppel Gas Pte Ltd, Senoko Energy Ltd, Sembcorp Gas Pte Ltd and Gas Supply Pte Ltd have historically been large shippers in these import lines.

The Government of Singapore first announced a plan to import LNG in 2006 to meet rising demand for electricity generation and to diversify its natural gas supply. The first Singapore LNG terminal, operated by Singapore LNG Corporation (SLNG), commenced operations on 7 May 2013, with an initial capacity of 3.5 million tonnes per annum (Mtpa). Capacity increased to 6.0 Mtpa in January 2014 when the third LNG tank, the fourth open rack vaporiser and two high-pressure booster pumps were brought into service. A secondary berth and gas engine generator were also completed at that time (SLNG, 2014).

The terminal's capacity rose to 11 Mtpa in 2018 after its fourth tank and additional regasification facilities became operational (SLNG, 2018). The LNG terminal is also capable of providing small-scale ancillary services, such as LNG trucking, cool-down and LNG break-bulk services, along with the receiving and reloading of small LNG ships. A nitrogen blending facility has also been commissioned for the terminal, which will enable SLNG to receive LNG of varying

specifications from diverse sources. SLNG is currently assessing whether demand exists to support a fifth LNG tank for use in 2022 or 2023 (SLNG, 2018).

Singapore has appointed LNG importers through a competitive Request-for-Proposal (RFP) process, awarding them exclusive 'franchises'. BG Singapore Gas Marketing, now part of Royal Dutch Shell, emerged as the winner of the RFP process and was selected to be the sole LNG importer to supply the first tranche of LNG to Singapore in 2008. In October 2016, Pavilion Gas Pte Ltd and Shell Eastern Trading (Pte) Ltd were appointed to meet the second tranche of Singapore's LNG demand. The second tranche of LNG imports commenced in October 2017. Both the appointed importers have exclusive rights to sell up to one Mtpa of LNG, or for three years, whichever occurs first (EMA, 2017a). To encourage gas-on-gas competition, the government now allows spot LNG imports. Total spot transactions are restricted to 10% of Singapore's long-term contracted gas supply. Controls have also been removed for PNG imports (EMA, 2016a).

ENERGY TECHNOLOGY/RESEARCH AND DEVELOPMENT

Singapore encourages energy R&D to spur new economic opportunities. There are multiple energy research centres in Singapore. The Solar Energy Research Institute of Singapore (SERIS) conducts industry-oriented R&D in solar energy technologies for the tropics. The interdisciplinary Energy Research Institute at Nanyang Technological University (ERI@N) and the Experimental Power Grid Centre (EPGC) are two other centres. The latter features a one MW experimental power grid capable of simulating different power network configurations in grid-like conditions.

The EMA has awarded over SGD 100 million to address industry-relevant challenges in areas such as power generation, energy storage, smart grids, and gas since 2011 (EMA, 2019e). In 2013, a testbed was established at Pulau Ubin, an island north-east of Singapore, to assess the impact of intermittent solar energy on the reliability of electricity supply within a micro-grid infrastructure. As a "Living Lab", the testbed also shows how micro-grid technologies and solutions could be adopted for off-grid communities in the region (EMA, 2017b). The EMA is also collaborating with the Singapore Institute of Technology (SIT) to establish Singapore's First Experimental Urban Micro-grid. This national infrastructure will enable the local research and business community to test new technologies and solutions in a controlled environment, while providing students with the opportunity to work with industry partners and energy start-ups (EMA, 2017c).

In 2017, EMA awarded SGD 6.2 million in grants to a consortium led by the National University of Singapore and Meteorological Service Singapore to develop a solar forecasting model, customised to Singapore's tropical conditions (EMA, 2017d). Together with SP Group, EMA awarded another SGD 18 million in grants to implement Singapore's largest grid-level Energy Storage System (ESS) testbed. The purpose of the ESS testbed is to better understand the feasibility of deploying grid-level energy storage technologies in Singapore's hot, humid and highly urbanised environment (EMA, 2017e).

To ensure industry relevance of R&D efforts, the EMA has partnered with agencies and industries to improve commercialisation and market translation of energy technologies. Examples of these efforts are:

- **ACCElating Energy Storage for Singapore (ACCESS):** The EMA launched the ACCESS program to facilitate the deployment of ESSs. The initiative aims to spur the adoption of ESSs by promoting use cases and business models, and to facilitate regulatory approvals for ESS deployment to help Singapore achieve its solar target (EMA, 2018a)
- **Inaugural EMA-ESG Joint Grant Call:** The EMA and Enterprise Singapore (ESG) jointly launched a Grant Call in 2018 for Small and Medium Enterprises (SMEs) to develop solutions for deploying solar energy and optimising energy consumption (EMA, 2018b)

- Sembcorp-EMA Energy Technology Partnership (SEETP): The EMA and Sembcorp refreshed a \$10 million R&D partnership that translates and commercialises energy research into technologies and solutions for Singapore's energy challenges (EMA, 2018c). In 2019, EMA and Sembcorp awarded a grant to Nanyang Technological University to develop Singapore's first Virtual Power Plant to coordinate distributed energy resources as a single utility-scale power station (EMA, 2019f)
- Collaboration with Korea Institute of Energy Technology Evaluation and Planning (KETEP): This is a joint R&D collaboration as part of an MoU between the Ministry of Trade and Industry (MTI) and the Republic of Korea Ministry of Trade, Industry and Energy. The EMA-KETEP Joint Grant Call encourages collaboration between Singapore and Republic of Korea actors to develop innovative solutions in ESSs or solar photovoltaics (EMA, 2019e)
- National Cybersecurity Grant Call: The EMA partnered with public agencies to launch a cybersecurity Grant Call to highlight cybersecurity capability opportunities and research areas to address the specific national security, smart nation and critical information infrastructure needs
- The EMA-PSA Singapore Joint Grant Call: The call invited industry-led R&D projects to develop smart grid and energy storage solutions that can effectively reduce overall energy use, costs, and the carbon footprint of the energy system (EMA, 2019e)

Against a fast-evolving energy landscape impacted by various innovative technologies, the EMA needs to ensure the workforce is competitive and equipped with relevant skillsets to meet the sector's needs. The EMA has established close partnerships with stakeholders, such as the Union of Power and Gas Employees, and education institutions, to not only attract the next generation of professionals but also to retain and develop the existing workforce through training programs, scholarships, and other initiatives.

The National Environment Agency (NEA) also supports environmentally focused energy research as part of efforts to help Singapore achieve environmental sustainability. The Singapore Environment Institute acts as the NEA's training and knowledge division (NEA, 2018). The NEA, in its capacity as Singapore's designated national authority for clean development mechanism (CDM) projects, issues a Letter of Approval (LoA) to CDM projects that meet Singapore's sustainable development criteria. The LoA supports the registration of the project by the United Nations Framework Convention on Climate Change (UNFCCC) CDM Executive Board (EB) (NEA, 2015).

ENERGY CONSERVATION

Singapore has taken measures to decrease its energy consumption through conservation via the ECA 2013. The act is jointly administered by the Ministry of the Environment and Water Resources and the Ministry of Transport.

The ECA requires companies that are large users of energy to implement energy management initiatives. Companies that consumed 54 terajoules (TJ) or more of energy in at least two out of the three preceding years are required to appoint at least one energy manager to monitor and report their energy use and GHG emissions. Companies also need to submit plans for energy efficiency improvement to relevant agencies.

The ECA consolidates energy efficiency-related legislation currently found in different acts, including the Mandatory Energy Labelling Scheme; Minimum Energy Performance Standards; and the Fuel Economy Labelling Scheme for passenger cars and light goods vehicles under the Environmental Protection and Management Act. Enhancements to the Act were announced in March 2017 to help Singapore achieve its Paris Agreement pledges. Enhancements include strengthening the measurement and reporting requirements for GHG emissions, requiring companies to undertake regular energy efficiency opportunity assessments, and introducing minimum energy performance standards for common industrial equipment and systems. The enhancements came into effect in 2018.

Singapore has also sought to decrease energy consumption by improving the energy efficiency of its industry, transportation, buildings and household sectors.

ENERGY EFFICIENCY

Singapore's geographical constraints limit the extent of alternative energy deployment, which means energy efficiency is a key strategy to mitigate GHG emissions. Energy efficiency also helps improve competitiveness, energy security and environmental sustainability. Singapore has adopted measures to improve energy efficiency and reduce energy use, where possible.

The government established the Energy Efficiency Programme Office (E²PO), a multi-agency committee led by the NEA and the EMA, in 2007. Its role is to promote energy efficiency in both the public and private sectors through legislation, incentives and information (NCCS, 2018b). Energy efficiency efforts target sectors such as power generation, industry, transport, buildings and households.

The E²PO promotes and facilitates energy efficiency in Singapore and has identified the following action areas (E²PO, 2014):

- Promoting the adoption of energy-efficient technologies and measures by addressing market barriers to energy efficiency
- Building capability to drive and sustain energy efficiency efforts and to develop the local knowledge base and expertise in energy management
- Raising awareness to stimulate energy-efficient behaviour and practices
- Supporting R&D to enhance Singapore's capability in energy-efficient technologies

The E²PO targets industry, transportation, buildings and households, through programs aimed at improving energy efficiency and reducing CO₂ emissions. Examples include the Building Control Act's Chapter 29 Part IIIB—Environmental Sustainability Measures for Existing Buildings (E²PO, 2015a); the 2013 Mandatory Energy Management Requirements (E²PO, 2015b); and the 10% Energy Challenge of 2008, aimed at encouraging households to save at least 10% of their energy use (E²PO, 2015c). Expanding the mass Rapid Transit System (RTS) has been the major emission-reduction policy for the transport sector (E²PO, 2015d).

Together with SP Group, the EMA has been raising energy efficiency awareness among primary and secondary school students. The mobile education unit program has engaged more than 72 000 students to date.

INDUSTRY

The industrial sector is the largest energy-consuming sector in Singapore. The Industry Energy Efficiency Roadmap, launched in June 2016, identifies and prioritises the technological potential and opportunities to reduce energy use below BAU levels up to 2030. It also provides guidance and insight to policymakers, industry leaders, academia and research institutes and other relevant stakeholders (NCCS, 2016). In October 2018, Singapore released its Enhanced Industry Energy Efficiency Package to encourage the industrial adoption of energy-efficient technologies and to reduce carbon emissions (EMA, 2018d).

Government initiatives to improve industry's energy efficiency are:

- The Energy Efficiency Fund (E2F): Facilitates the efficient design of new facilities, funds energy assessments, and assists industry to adopt energy-efficient equipment and technologies. The E2F provides up to 50% co-funding. In 2018, through the Enhanced Industry Energy Efficiency Package, the cap for subsidising the project costs related to the replacement of existing equipment was increased from 30% to 50% (EMA, 2018d)
- The Energy Efficiency National Partnership (EENP): Serves as a platform to help companies reduce energy consumption through courses and workshops, and provision

of energy efficiency resources, incentives and recognition. The program is voluntary. Since 2011, a National Energy Efficiency Conference has been held six times to provide participants with opportunities to learn and exchange best practices. As of September 2019, 291 companies had joined as partners. The EENP recognises excellence via annual awards

- The Energy Efficiency Financing Programme: Encourages industrial and manufacturing facilities to adopt energy-efficient equipment or technologies. A third-party financier provide funds and the energy savings are shared among all stakeholders
- The Accelerated Depreciation Allowance Scheme: This tax incentive scheme allows for early write-offs or depreciation of capital expenditures on qualifying energy-efficient equipment
- The Investment Allowance Scheme: A tax incentive scheme that encourages companies to invest in productive and energy-efficient construction equipment with a 30% deduction from the companies' taxable income. The allowance is 50% for construction companies if the equipment achieves a 20% productivity gain at the project or trade level (BCA, 2019a)
- The Energy Efficiency Improvement Assistance Scheme (EASe): The EASe encourages and helps companies identify potential energy efficiency improvement opportunities. Under EASe, up to 50% of the cost of appraisals for buildings and facilities will be co-funded
- The Energy Service Company Accreditation Scheme: The objective is to enhance the professionalism and quality of services offered by energy services companies. Designed to enhance confidence in the energy services sector and help promote the growth of the industry
- The Design for Efficiency Scheme (DfE): Introduced in 2008, this initiative encourages investors to incorporate energy and resource efficiency considerations into the development plans of their facilities. Under the DfE, up to 80% of the costs of conducting design workshops is subsidised
- Grants for implementation of energy efficiency improvements: The Grant for Energy Efficiency Technologies (GREET), and subsequent schemes such as the Resource Efficiency Grant for Energy, are co-funding schemes launched to incentivise owners or operators of industrial facilities to invest in energy-efficient technologies or equipment
- The Small and Medium Enterprise Energy Efficiency Initiative: Launched in 2013, this SGD 17 million initiative brings together existing government grants to help SMEs reduce their energy costs, increase productivity and promote energy efficiency. The grant provides funding for energy auditing, energy monitoring systems and energy efficiency project implementation (SEAS, 2017)
- The Energy Efficiency Technology Centre (EETC): The NEA and SIT set up the EETC at SIT to help SMEs discover and improve energy efficiency and build up local industrial energy efficiency capabilities (SIT, 2019)
- The Energy Efficiency Grant Call for Power Generation Companies (Genco EE Grant Call): Launched in 2018, this initiative aims to help power generation companies to improve their generation efficiency and reduce GHG emissions

TRANSPORT

Singapore has sought to increase the energy efficiency of its transport sector. The objective is embedded in the economy's land transport strategies which seek to integrate transport and land use planning, promote greater use of public transport and apply intelligent transport

systems to manage road use. Roads occupy 12% of Singapore's land area. With limited space, an integrated approach to land use planning and transport development is essential. The government has pioneered innovative policies such as a vehicle quota system and electronic road pricing (ERP) to reduce congestion, and a green vehicle rebate to encourage more fuel-efficient vehicles and trials of green technologies such as diesel-hybrid buses and electric vehicles (EVs).

Singapore's major efforts to increase transport efficiencies are:

- Investing in active mobility and public transport so that 75% of all journeys in peak hours are taken on public transport by 2030, up from 67% in 2016. The construction of cycling networks, the expansion of the rail network to 360 km by 2030, and the expansion of the public bus fleet by 1000 new buses under the Bus Service Enhancement Programme are examples of the investment
- Managing car ownership and usage by limiting the growth of vehicle numbers through the Vehicle Quota System (VQS), refining the ERP system with satellite-based technology to enable congestion pricing, and further developing solutions through its Intelligent Transport System. Singapore reduced the growth rate of the VQS to zero in 2018, effectively capping vehicle ownership, and plans to review the policy in 2020 (LTA, 2019a)⁴. LTA has plans to implement a new ERP system in late 2020 (LTA, 2019b)
- Testing new technologies such as the diesel particulate filter, diesel-hybrid buses, electric buses and cars, and buses equipped with rooftop gardens to reduce space-cooling requirements
- The Vehicular Emissions Scheme (VES): Effective 1 January 2018, this replaced the Carbon Emissions-Based Vehicle Scheme. The scheme encourages buyers to choose more fuel-efficient car and taxi models that emit fewer pollutants. Cars and taxis enjoy rebates or have surcharges levied based on their carbon dioxide, carbon monoxide, hydrocarbon, particulate matter and nitrogen oxide emissions (One Motoring, 2019). NEA extended the VES until the end of 2020 (NEA, 2019a)
- The Vehicular Emissions Label: Cars and light goods vehicles sold in Singapore must show a fuel economy label that provides information on the vehicle's fuel efficiency and carbon dioxide emissions to help buyers make better decisions. In 2018, the NEA and LTA replaced the fuel economy label with the vehicular emissions label for cars, which, in addition to fuel efficiency, provides information on vehicular emissions to help potential car buyers make informed decisions when choosing cleaner, more fuel-efficient car models (LTA, 2017)
- Green Mark for RTS: The RTS is the backbone of Singapore's public transport system and is the most energy-efficient means of commuter transport. By 2020, the length of the RTS network will be 278 km. The objectives of the Green Mark for the RTS framework are to promote sustainable and environmentally friendly RTS designs, and provide guidance in engineering standards, design and construction of new RTS lines. The framework considers effective use of energy, water conservation, environmental protection and sustainable development. In 2019, the LTA received the Building and Construction Authority (BCA)'s Green Mark Champion Award for its energy-efficient design of two depots. The BCA also introduced a new Green Mark scheme for transit stations, which will help increase the sustainability of transit over private vehicle use

⁴ The growth rate for goods vehicles and buses has been maintained at 0.25%.

- EVs: an inter-agency EV taskforce (EVTF) led by the EMA and the LTA has launched multiple EV test phases. For vehicle fleets:
 - Singapore launched an EV car-sharing program in collaboration with the Bolloré Group in December 2017 (BlueSG). At the end of 2019, this program was halfway to its goal of deploying 1000 shared EVs and 2000 charging points by 2020 (BlueSG, 2019)
 - HDT Singapore Taxi Pte. Ltd launched their first fleet of 50 electric taxis for trial in February 2017 and were subsequently issued a full taxi service operator licence in August 2018. They will increase their fleet size to 800 electric taxis by July 2022
 - LTA has awarded a tender for the supply of 60 electric buses. Electric buses will be deployed for service by 2020
- Promoting cycling and “last-mile” transport solutions: Singapore has extended its cycling network and has enhanced the cycling infrastructure. By 2030, all Housing and Development Board (HDB) towns will have a cycling network, taking the total length of cycling paths across Singapore to 700 km. Other elements of bicycle-friendly infrastructure, such as bicycle crossings and bike parking facilities, will encourage a cycling culture (LTA, 2019c). Singapore allowed bicycle and Personal Mobility Device sharing services in 2018 and 2019, respectively. However, in late 2019, Singapore prohibited e-scooters on footpaths, but continued to allow them on cycling paths and park connector networks.

BUILDINGS

The BCA, a statutory board under the Ministry of National Development, spearheads energy efficiency improvements in the building sector. In its third and latest Green Building Masterplan launched in September 2014, the BCA set out ambitious plans to accelerate its green building agenda and meet the target of greening 80% of the buildings in Singapore by 2030 (BCA, 2014). Energy efficiency initiatives in Singapore’s building sector are:

- The BCA Green Mark Scheme: This is a green building rating system that promotes sustainability in the established environment and raises environmental awareness among developers, designers and builders. Under this benchmarking scheme, buildings are assessed for energy efficiency, water efficiency, indoor environmental quality and environmental protection as well as other green features and innovations. It has been in place since 2005
- Building Control (Environmental Sustainability) Regulations: Enacted in 2008, these regulations require new buildings, and existing buildings undergoing major retrofitting to achieve the minimum Green Mark certified level if they have a gross floor area (GFA) greater than 2 000 square metres

Building Control Act’s Chapter 29 Part IIIB—Environmental Sustainability Measures for Existing Buildings: Introduced in 2012, this act requires building owners to comply with the minimum environmental sustainability standard (Green Mark standard) for existing buildings. They must submit periodic energy efficiency audits of building cooling systems, and submit information with respect to energy consumption and other related information, as required. In 2018 the BCA announced the creation of the BuildSG Transformation Fund (BTF), to consolidate existing schemes (BCA, 2019b):

- The Green Mark Incentive Scheme for Existing Buildings and Premises (GMIS-EBP): Launched in 2014, this encouraged SME tenants, and building owners with

at least 30% of SME tenants, to adopt energy efficiency improvement measures. The scheme ended 2019

- The Building Retrofit Energy Efficiency Financing (BREEF) Scheme: Retrofit financing for buildings to achieve the minimum Green Mark standard. Applicants can obtain financing from participating financial institutions and service the loans through energy savings. The BREEF will end in 2023
- The Green Mark GFA Incentive Scheme: Additional floor area offered to private developments with Green Mark Platinum or Gold Plus marks from April 2014 to April 2019 (encouraged the private sector to achieve higher Green Mark ratings)
- The Green Building Innovation Cluster (GBIC): A one-stop integrated research and innovation hub that accelerates the adoption of energy-efficient technologies and solutions through programs such as the GBIC Building Energy Efficient Demonstrations Scheme and the Super Low Energy Building Smart Hub
- The Public Sector Sustainability Plan: Launched in 2017, the government aims to achieve electricity savings of 15% by 2020 from the baseline electricity consumption in 2013. Each ministry is required to submit reduction targets and management plans to meet the targets. New public sector buildings with an air conditioned area of greater than 5000 square metres must attain the Green Mark Platinum rating, while existing public sector buildings with an air conditioned area of greater than 10 000 square metres must attain the Green Mark GoldPLUS rating by 2020.

HOUSEHOLDS

Improving household energy efficiency has been a major target for Singapore as part of its commitment to sustainable development that demands reductions in fossil energy consumption and CO₂ emissions. Households account for about one-sixth of the electricity consumed in Singapore. Energy efficiency programs for households (NEA, 2019b) are:

- The Mandatory Energy Labelling Scheme (MELS): Household appliances that are sold in Singapore must display an energy label. The number of ticks indicates efficiency (from one to five, with five being the most energy-efficient). The MELS helps consumers compare the energy efficiency of different appliances and make informed purchasing decisions. Refrigerators, air conditioners, clothes dryers, televisions and lamps are covered by the scheme. In 2019, the government expanded the lamp technology coverage of the scheme and mandated the display of energy labels in all print and digital publicity materials (NEA, 2019c)
- Minimum Energy Performance Standards (MEPS): The objective of MEPS is to raise the average energy efficiency of household appliances. The regulation encourages manufacturers to provide more energy-efficient appliances as technology improves. Household refrigerators, air conditioners, clothes dryers and lamps supplied in Singapore must meet the MEPS. In 2019, Singapore raised the MEPS for incandescent bulbs and introduced its first MEPS for fluorescent lamp ballasts
- The Residential Envelope Transmittance Value Standard: Established in 2008, residential buildings with a GFA of 2000 square metres or more must comply with the BCA residential envelope transmittance value standard
- The EMA, MEWR and SP Group announced three initiatives in November 2019 to empower households to increase their energy efficiency. First, all households will have advanced meters installed in the next five years to provide consumers with their half-hourly electricity usage. Second, the SP Group app offers analytical monitoring and rewards for adopting efficient habits. Last, a study on 1000 households by the EMA and

MEWR will help determine how customised energy efficiency reports encourage energy efficiency

RENEWABLE ENERGY

Singapore has limited options in terms of renewables because of its geological and geographical location. Hydro, wind, geothermal and tidal energy are not feasible, leaving solar PV systems and WtE as Singapore's main renewable energy sources. The economy has also been producing biodiesel since 2010 to help diversify its liquid energy demand.

Singapore currently has four electricity-generating incineration plants (Tuas IP 46 MW, Senoko WtE Plant two x 28 MW, Tuas South IP 80 MW and Keppel Seghers Tuas WtE Plant 22 MW) that incinerated 2.8 million tonnes (Mt) of waste in 2018 (MEWR, 2019a). Singapore is currently constructing a 120 MW WtE plant. WtE power facilities are chiefly concerned with waste management in Singapore. Limited landmass restricts landfill capacity. In its Zero Waste Masterplan, the economy committed to reducing its per capita landfill waste by 30% by 2030 (MEWR, 2019b). Achieving this may require higher WtE capacity.

Singapore solar initiatives are targeting 350 MWp of solar capacity by 2020 and 2 GWp by 2030. At the end of 2018 there were 2721 grid-connected PV installations with a total capacity of 206 MWp, comprising 928 residential (9.3 MWp) and 1793 non-residential (196 MWp) installations (EMA, 2019a). The active initiatives to support meeting these targets include:

- The SolarNova program aggregates demand for solar energy across government agencies in order to achieve economies of scale and drive the growth of Singapore's solar industry (HDB, 2017). The program generates an estimated 420 GWh of solar energy annually, equivalent to about 5% of Singapore's total energy consumption. HDB's current solar commitments generate an estimated 277 GWh of solar energy annually. Under the solar leasing business model, private solar PV system developers will design, finance, install, operate and maintain the solar PV systems. The power produced can power lifts and water pumps, and light-up corridors, staircases and common areas
- HDB has committed to the roll-out of 220 MWp of solar panels in about 5500 HDB blocks by 2020. As of August 2019, HDB has held four solar leasing tenders under the SolarNova program and committed to a total solar capacity of 236 MWp, exceeding its 2020 capacity commitment, for 4370 HDB blocks (HDB, 2019a). HDB is still targeting installations in 5550 blocks by 2020 and in late 2019 announced a new target of 540 MWp of solar panels by 2030 (HDB, 2018) (HDB, 2019b)
- All public housing blocks with at least 400 square metres of open roof space are designed with solar-ready roofs to enable more productive and efficient installation of solar panels on HDB rooftops. HDB also reviews developments currently under construction to assess if solar-ready roofs can be incorporated into their design
- The EDB and PUB conducted a pilot floating PV system testbed project at Tengeh Reservoir in October 2016. The testbed assessed the feasibility of installing floating solar PV systems as an alternative to rooftop-based installations (PUB, 2017). It is the world's largest test site for floating solar. The results showed that the system performed better than a typical rooftop solar PV system in Singapore because of the cooler temperatures of the reservoir environment. In June 2019, PUB announced its intention to deploy a 50 MWp floating solar PV system at Tengeh Reservoir by 2021, and indicated that it should have two, smaller 1.5 MWp beds deployed in the Bedok and Lower Seletar reservoirs in 2020 (PUB, 2019). In October 2018, EDB launched a Request for Information to explore the possibility of a 100 MWp floating solar PV system for private sector consumption, starting with studies at Kranji reservoir to

assess the environment impact and the technical feasibility of a floating PV system (EDB, 2018)

The EMA is designing policy to help integrate solar into Singapore's electricity system. Integrating intermittent supply sources presents the risk of destabilising the electricity system if back-up generators are not available to balance out potential supply shortfalls. Furthermore, without a pricing mechanism in place to compensate back-up capacity in the event of an intermittent shortfall, conventional generators are bearing the full costs of this risk. Two policies being considered are:

- The Intermittency Pricing Mechanism (IPM): The IPM is built on a causer-pays principle, where intermittent generators, renewable or conventional, pay for reserve capacity if their production shortfall requires back-up from the electricity system. The IPM will also signal investors to reduce reserve capacity costs by managing intermittency through measures such as DSM and the use of battery storage (EMA, 2018e). Recognising that ESSs are key enablers of higher solar deployment, EMA also published a policy paper in October 2018 to provide clarity on the treatment of ESSs in the regulatory framework
- The development of a Forward Capacity Market (FCM): the FCM is a competitive market-based auction to procure electricity capacity, one to four years in advance, with the goal of maintaining the reliability standard in the delivery period (EMA, 2019g). The demand curve for capacity will be constructed around the capacity needed to meet the required reserve margin above the projected peak demand in the delivery year. Resources will offer capacity at prices in dollars per MW-year and will be subject to penalties for failing to have the capacity available in the delivery period. Ascending capacity prices yield a supply curve and all capacity offers below the market-clearing price receive the market-clearing price. The design is currently in its consultation phase. A preliminary timeline has several compressed FCM auctions occurring quarterly in 2021, with deliveries ranging from 2023 to 2025, and two end-state auctions occurring annually in 2022 and 2023, with delivery in 2026 and 2027

In terms of biodiesel production, Finnish oil refining and marketing company, Neste, built the world's largest diesel refinery in Singapore in November 2010. The refinery produces renewable diesel products. In 2019, Neste began to expand its renewable diesel capacity by 1.3 mtpa. Upon completion in 2022, its capacity will approach 4.5 mtpa, and it will be able to produce over one mtpa of sustainable aviation fuel (Neste, 2019).

SUSTAINABLE DEVELOPMENT

Singapore's IMCSD unveiled its first sustainable development blueprint on 27 April 2009. The plan contains strategies and initiatives for achieving economic growth and a good living environment for Singapore over the next 20 years.

Improved efficiency in the use of resources such as energy, water and land will contribute to enhancing the city-state's competitiveness in the long run. The blueprint introduces efforts to improve air quality, expand green and blue spaces, conserve biodiversity, and enhance public cleanliness. These efforts will contribute to making the city a more liveable and attractive place, even as Singapore continues to grow and develop. Targets have been set to measure progress. The blueprint has a 20-year timeframe, with identified key goals for 2030. The blueprint's goal for the energy sector is to reduce energy intensity by 35% by 2030 from 2005 levels, with an intermediate goal of 20% by 2020 from the 2005 levels (BCA, 2010).

Singapore released 'an extension of the efforts outlined in the 2009 edition' via the Sustainable Singapore Blueprint 2015 (MEWR, 2015). A main objective is to turn Singapore into a 'hub for the cutting-edge business of sustainable development'. MEWR followed this blueprint up with a

Zero Waste Strategy in 2019; however, the strategy focuses on sustainable waste management rather than energy policy.

Singapore has taken steps to increase the solar share of its electricity generation as part of its sustainable development objective. The EMA has adopted a policy of proactively enhancing the required market and regulatory framework to facilitate the deployment of solar units.

NUCLEAR ENERGY

Singapore currently does not have a nuclear energy industry. The economy embarked on a pre-feasibility study of nuclear energy to evaluate the opportunities, challenges and risks of nuclear energy and its feasibility as a long-term energy option for Singapore in 2010. The study concluded that nuclear energy technologies, although safer than the older designs still in use in many economies, were unsuitable for deployment in Singapore given the economy's small size and high population density.

CLIMATE CHANGE

Singapore's CO₂ emissions account for 0.11% of global emissions. The economy is still progressing towards reducing its CO₂ emissions, though its options for non-CO₂ emitting energy are limited (confined to WtE and a small amount of solar). Nuclear energy is not a feasible option as mentioned above.

In 2009 under the UNFCCC, Singapore pledged to reduce emissions by 16% from 2020 BAU levels by 2030 conditional on the emergence of 'a legally binding global deal that obliges' economies to cut emissions, and if there were significant pledges from other economies (Green Future, 2010). . The economy set up the National Climate Change Secretariat on 1 July 2010 as a dedicated agency under the Prime Minister's Office to coordinate its domestic and international policies, plans and actions on climate change (NCCS, 2018c). Singapore ratified the Paris Agreement in September 2016, formalising its pledge to reduce emissions intensity by 36% from 2005 levels by 2030 and to stabilise emissions with the aim of peaking around 2030. Singapore expects to update this pledge in 2020 (Strait Times, 2019).

Singapore has reduced its grid-generated emissions through the adoption of natural gas and the reduced use of diesel-fired generation. By increasing the share of natural gas used in electricity generation from 19% in 2000 to 95% in the 2010s, Singapore has substantially reduced its emissions growth over. Singapore's efforts have resulted in improving its average operating margin grid emission factor from 0.53 kg CO₂/kWh in 2005 to 0.42 kg CO₂/kWh in 2018 (EMA, 2019a). Singapore has also increased the share of solar generation in the energy mix.

NOTABLE ENERGY DEVELOPMENTS

CARBON TAX

In 2017, the Government of Singapore announced the intention to implement a carbon tax starting from 2019. Singapore is the first Southeast Asian economy to implement a carbon tax. The policy aims to enhance Singapore's existing and planned mitigation efforts under the Climate Action Plan and stimulate clean technology and market innovation. In February 2018, the government finalised the details of the carbon tax mechanism as follows (NCCS, 2018d):

- The carbon tax will generally be applied upstream, on power stations and other large direct emitters that produce 25 000 tonnes or more of greenhouse gas emissions per year. This represents about 30 to 40 large emitters that contribute 80% of Singapore's greenhouse gas emissions. The government will further assess how to account for the remaining 20% of the emissions

- The initial carbon tax rate is SGD 5 per tonne of greenhouse gas emissions for a five-year period from 2019 to 2023 to allow companies time to adjust to the carbon tax and implement energy-efficient projects. The government will review the rate by 2023, with an intention to increase it to between SGD 10 and SGD 15 per tonne of emissions by 2030. Any increase will depend on international climate change developments, the progress of Singapore's emissions mitigation efforts, and economic competitiveness
- The carbon tax will apply uniformly to all sectors, without exemption. Taxable facilities will pay for the carbon tax through the purchase of carbon credits corresponding to their emissions, with the first payment in 2020, based on their 2019 emissions
- Over the initial five-year period, the government expects to generate about SGD 1 billion in carbon tax revenue (Singapore Budget, 2018). The revenue will help companies to improve their energy efficiency via initiatives such as the Resource Efficiency Grant for Energy (which replaced the Productivity Grant for Energy Efficiency in 2019) and the Energy Efficiency Fund

REGULATORY SANDBOX TO ENCOURAGE ENERGY SECTOR INNOVATIONS

In October 2017, the EMA implemented a regulatory sandbox framework in the electricity and gas sectors. The framework allows regulations to be relaxed, within defined parameters, in a sandbox that can accommodate new products and services for testing. It will also allow the EMA to assess the impact of new products and services before deciding on the wider regulatory treatment (EMA, 2017f). In 2019, the EMA enhanced its regulatory sandbox by introducing challenge statements to guide energy sector innovations, allowing for the joint support of grants and sandboxing (EMA, 2019h).

DEMAND-SIDE MANAGEMENT

In October 2016, the EMA signed an MoU with 16 partners for a pilot program, Project OptiWatt, to test the viability of DSM. Through DSM, energy consumption can be shifted from peak to non-peak times, reducing the maximum load on the energy. The project partners comprise institutes of higher learning, government agencies, companies, electricity retailers, research institutions and the electricity grid operator (EMA, 2017g). The EMA published the success stories and infographic on the key learning outcomes from this initiative on its website to increase consumer awareness and encourage the adoption of DSM. It also introduced a Demand Response (DR) program, where contestable consumers offer prices at which they are willing to reduce their electricity consumption in exchange for incentive payments. Incentive payments currently repay a third of the total savings back to DR providers (EMA, 2016b).

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Department of Statistics Singapore—<https://www.singstat.gov.sg>
Economic Development Board—<https://www.edb.gov.sg/>
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Public Utilities Board—<https://www.pub.gov.sg/>
Singapore Department of Statistics—<https://www.singstat.gov.sg/>
Singapore LNG Corporation (SLNG)—<https://www.slng.com.sg/website/index.aspx>
Solar Energy Research Institute of Singapore (SERIS)—<http://www.seris.nus.edu.sg/>
Temasek Holdings—<https://www.temasekholdings.com.sg>

CHINESE TAIPEI

INTRODUCTION

Chinese Taipei is an archipelago comprising Taiwan¹, Penghu, Kinmen and Matsu, located off the southeast coast of China and the southwest coast of Japan. With an area of 36 197 square kilometres (km²) (Ministry of the Interior, 2020), Chinese Taipei has a variety of geological formations and unique landscapes. Although only 20% to 25% of the land is arable, the subtropical climate permits multi-cropping of rice and the perennial growth of fruit and vegetables.

In 2017, Chinese Taipei's gross domestic product (GDP) was USD 1 201 billion and its per capita income was USD 50 971 (2011 USD purchasing power parity [PPP]). Its GDP grew at a compound annual growth rate (CAGR) of 4.4% during 2010–17. Chinese Taipei's economic structure has changed substantially over recent decades, shifting from industrial production to a more services-dominant economy. In 2017, the service sector accounted for 63% of GDP, followed by industry (36%), and agriculture (1.8%) (BOE, 2019a). Chinese Taipei is one of the most densely populated areas in the world, but its population growth rate has been relatively flat; the economy's population of 24 million grew at a CAGR of 0.37% during 2000–17 (EGEDA, 2019).

Lacking natural resources, Chinese Taipei is highly dependent on energy imports to meet domestic energy demand. According to the US Energy Information Administration, Chinese Taipei holds only 2.4 million barrels of oil reserves (EIA, 2016). Coal reserves in the economy are scarce, and owing to the high cost of mining, there has been no coal production in the economy since 2000.

Table 1: Key data and economic profile, 2017

Key data		Energy reserves ^c	
Area (km ²) ^a	36 197	Oil (million barrels) ^c	2.4
Population (million) ^b	24	Gas (billion cubic metres)	N/A
GDP (2011 USD billion PPP) ^b	1 201	Coal (million tonnes)	–
GDP (2011 USD PPP per capita) ^b	50 971	Uranium (kilotonnes of U)	–

Sources: ^a Ministry of the Interior (2020); ^b EGEDA (2019); ^c EIA (2016).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Chinese Taipei relies heavily on overseas energy resources. In 2017, imported energy accounted for 98% of the total energy supply in Chinese Taipei (BOE, 2019a), indicating low energy self-sufficiency as well as fragile energy security.

The growth of the total primary energy supply (TPES) in Chinese Taipei increased steadily through 2000 to 2010 and remained stable at about 109 million tonnes of oil equivalent (Mtoe) in 2017. Fossil fuels dominate TPES, comprising over 90% of the total. Oil contributes the largest share (39%), followed by coal (35%), natural gas (18%), renewable energy (1.9%) and other fuels (5.9%) (EGEDA, 2019).

¹ Taiwan is the name of the island, not the name of the economy.

In 2018, Chinese Taipei imported nearly 323 million barrels of crude oil, 3.3% higher than the 312 million barrels imported in 2017. The Middle East is the major supplier, accounting for 80% of the total oil imports, followed by the United States (14 %) and others (6.1%) (BOE, 2019a).

Australia and Indonesia are the major suppliers of coal, accounting for 50% and 26%, respectively of the total coal imports of 67 million tonnes (Mt) in 2018. About three-quarters of this fuel is used for power generation.

Indigenous natural gas only accounts for 0.78% of total natural gas supply in Chinese Taipei. Almost all gas demand is met by liquefied natural gas (LNG) imports. Qatar, Malaysia and Australia are the largest suppliers, accounting for 29%, 17% and 15% of the supply, respectively in 2018. LNG imports were 17 Mt in 2018, which was the 10th year of consecutive growth, 1.8% up from the previous year (BOE, 2019a).

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	8 677	Industry sector	23 708	Total generation	270 279
Net imports and others	104 460	Transport sector	12 380	Thermal	232 100
Total primary energy supply	109 106	Other sectors	11 848	Hydro	8 780
Coal	37 687	Non-energy	22 960	Nuclear	22 446
Oil	42 975	Final energy consumption*	47 937	Others	6 953
Gas	19 985	Coal	6 905		
Renewables	2 056	Oil	16 207		
Others	6 403	Gas	3 564		
		Renewables	574		
		Electricity and others	20 883		

Source: EGEDA (2019) (data collected in December 2019).

* Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. Total final consumption includes non-energy uses. Half of the municipal solid waste used in power plants is assumed to comprise renewables.

In 2017, electricity generation in Chinese Taipei reached 270 279 gigawatt-hours (GWh). Of the total electricity production, hydropower comprised 3.2%, thermal power comprised 86% (coal 47%, oil 4.7% and LNG 35%), nuclear power comprised 8.3%, others comprised 2.6% (0.64% wind power, 0.63% solar PV, 0.07% biomass and 1.2% waste). In terms of generating capacity, the Taiwan Power Company (TPC) contributes 64% of the total. The remaining electricity capacity is from independent power producers (IPPs) (17%) and auto producers (19%). IPPs and auto producers are required to sign power purchase agreements with the TPC. To expand foreign participation, the government permitted foreign investors to own up to 100% of an IPP in January 2002 (BOE, 2019a).

FINAL ENERGY CONSUMPTION

Total final energy consumption in Chinese Taipei was 70 896 ktoe in 2017, 0.79% lower than in 2016. The industry and the non-energy sectors are the two largest energy consumers at 33% and 32%. Most of this energy consumption is by chemical and petrochemical enterprises. The transport sector accounts for 17% of final energy consumption, and residential and commercial account for the remaining 16%. By energy source, electricity and others accounted for 44% of the final energy consumption (excluding non-energy), followed by oil (34%), coal (14%), gas (7.4%) and renewable energy (1.2%) (EGEDA, 2019).

ENERGY INTENSITY ANALYSIS

Energy intensity in terms of TPES in Chinese Taipei, has improved by 36% from 143 tonnes of oil equivalent per million USD (toe/million USD) in 2001 to 91 toe/million USD in 2017. Final consumption energy intensity has improved by a similar amount (34%) from 90 toe/million USD to 59 toe/million USD for the same period.

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%) 2016 vs 2017
	2016	2017	
Total primary energy supply	97	91	-6.8
Total final consumption	63	59	-7.0
Total final energy consumption excl. non-energy	43	40	-6.5

Source: EGEDA (2019).

RENEWABLE ENERGY SHARE ANALYSIS

Chinese Taipei has been promoting the use of renewable energy in power generation to reduce greenhouse gas (GHG) emissions. The use of modern renewable energy, including use for heat and electricity, increased by 19% from 1 115 ktoe in 2010 to 1 329 in 2017. The share of modern renewable energy in final energy consumption also showed an increase from 2.4% in 2010 to 2.8% in 2017.

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	48 062	47 937	-0.26
Non-renewables (fossils and others)	46 686	46 608	-0.17
Traditional biomass*	0	0	0
Modern renewables*	1 376	1 329	-3.4
Share of modern renewables in final energy consumption (%)	2.9	2.8	-3.2

Source: EGEDA (2019).

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on), including biogas and wood pellets, are considered modern renewables although data on wood pellets are limited.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

The Bureau of Energy (BOE) was established under the Ministry of Economic Affairs (MOEA) in 2004 and is responsible for formulating and implementing Chinese Taipei's energy policy. Chinese Taipei's Guidelines on Energy Development, revised in 2017, provides policy guidance for national energy development, energy policy programs, standards and action plans (BOE, 2017a).

The revised Guidelines are based on paragraph 2 of Article 1 in the Energy Administration Act; it aims to ensure balanced development in energy security, green economy, environmental sustainability and social equity to achieve nuclear-free homeland targets by 2025, as well as attain sustainable energy development. There are four guiding objectives:

- **Energy security:** strengthen energy saving on the consumption side, such as adopting a new economic development model of ‘innovation, employment and equitable distribution’ to continue with the optimisation and transition of industrial structure. Furthermore, diversify the energy mix, increase the share of self-produced energy as well as expand renewable energy installation to enhance the supply and security of low-carbon energy. Establish smart system integration, including the deployment of smart meters, and promote an overall improvement of regional power transmission and distribution systems
- **Green energy:** construct a green energy industrial ecological system, incorporating regulatory incentives, land acquisitions, financing mechanisms, and so on. Promote regional green energy applications, and integrate the development of smart cities and agriculture villages with Internet of Things opportunities. Innovate in green energy and carbon-reduction technologies, strengthen the research and development of technologies and the deployment of energy storage and the smart grid as well as accelerate the development of a cloud intelligent energy management system. Establish an environmental cost pricing mechanism through policy tools or market mechanisms such as cap and trade, and create a new green service economy to foster green production and green energy investment
- **Environmental sustainability:** improve air quality by taking the cap of total emissions from air pollutants as the basis for the planning of new power plants. Select an appropriate site for energy facility construction to avoid or reduce the impacts on environmentally sensitive areas. Continue GHG emissions control and establish a low-carbon environment. Achieve a nuclear-free homeland target while proposing plans for short-, mid- and long-term management and disposal policies for high-level and low-level radioactive wastes
- **Social equity:** promote energy democracy and justice by establishing mechanisms and incentives for public participation and risk communication, and introduce the participatory governance approach to energy policymaking. Additionally, the government will contribute to equity within and across generations while ensuring basic energy services for vulnerable groups, and equity and justice in energy use to avoid energy poverty. Promote domestic power market reform in phases, aiming to achieve the goal of ‘diversified supply, equity in usage and freedom of choice’.

The Guidelines also announced the formulation of an Energy White Paper to promote the energy transition. The Energy White Paper will articulate measures and policy tools for future energy development. The government aims to submit an annual accomplishment report to summarise the achievements outlined in the Energy White Paper, and to conduct periodic reviews every five years

ENERGY SECURITY

Chinese Taipei is almost solely reliant on energy imports (98% of energy supply is met by imports). Energy security has always been a priority for Chinese Taipei’s energy policy. There are three objectives to energy security in the Guidelines on Energy Development. First, to strengthen energy savings on the demand side. Second, to ensure diversification, energy autonomy and low carbon on the supply side. And last, to promote smart system integration (BOE, 2017a).

On the demand side, the government is focusing on energy efficiency improvements in the industry, transport, residential and commercial sectors. Expanding the implementation of energy

audits and raising energy efficiency standards for vehicles and buildings are priorities. The government is also promoting energy savings behaviours to facilitate greater public participation. In the power sector, demand response and load management measures such as Time-of-Use rates will improve energy savings, energy management and energy storage. The government also expects to introduce innovative business models to encourage user participation to curb peak-load demand.

There are three guiding principles of energy security on the supply side: diversification, self-sufficiency and low carbon. Diversification reduces the risks of energy import disruptions. Self-sufficiency can be improved through domestic energy development and Chinese Taipei energy development ventures overseas.

The state-owned Chinese Petroleum Corporation (CPC) is the sole company in charge of oil and gas exploration domestically and overseas. CPC launched upstream operations in 1959. There are 30 wells that are currently producing condensate and natural gas domestically. These wells are all located to the west of Chinese Taipei, in Hsinchu City, Miaoli County, Taichung City and Tainan City.

Domestically produced condensate accounts for 0.01% of total crude oil supply, and self-produced natural gas accounts for 10% of total gas supply. Almost half of self-produced gas is consumed for residential use. Besides onshore exploration, the CPC has also joined forces contractually with China National Offshore Oil Exploration (CNOOC) and Total to explore oil and gas in deep water in the Taiwan Strait. A 2D seismic survey was completed in 2018 and the data processing is now underway. Apart from oil and gas, the CPC also began drilling a geothermal well in Yilan County in November 2018 (BOE, 2019a) (CPC, 2019).

CPC is engaged in oil and gas exploration and development joint ventures with international oil companies in eight locations in Australia, Chad, Ecuador, Niger and the US. At the end of 2018, CPC had acquired 4.2 million barrels of crude oil and 100 million cubic metres of natural gas from 220 producing wells. Ventures in Ecuador and Niger account for the majority of this production (CPC, 2019).

According to CPC, onshore oil and gas reserves could be depleted in 10 years. CPC is accelerating overseas exploration, production and M&A activity in response. The CPC is active in joint ventures and/or acquisitions pertaining to oil and gas fields in South-East Asia and the United States, and aims to develop them for commercial production (CPC, 2019).

The third dimension of energy security is smart system integration. This involves the deployment of smart meters and the improvement of regional power transmission and distribution systems. Information and Communication Technology and the Internet of Things will enhance system integration and quality of service. The deployment of energy storage systems is also required to improve the reliability and stability of the power grid (BOE, 2017a).

In addition to energy security as detailed in the Guidelines on Energy Development, the Chinese Taipei government also governs oil and gas stockpiles (including emergency measures). The Petroleum Administration Act and Natural Gas Enterprise Act both specify price regulation and quota allocation for oil and gas during emergencies (BOE, 2019b) (Laws & Regulations Database of the Republic of China, 2014) (Laws & Regulations Database of the Republic of China, 2016).

The Petroleum Administration Act also requires that the strategic petroleum reserve (SPR) should be no less than 90 days (60 days from the private sector and 30 days from the government) of the average domestic sales and consumption. The overall SPR was 129 days in 2018.

For natural gas, the BOE only required natural gas businesses to have 15 days of storage capacity (no stockpile requirement). But a massive blackout in August of 2017 triggered discussions on the necessity of natural gas stockpiles. In 2018, the BOE revised storage capacity and stockpile requirements. Gas storage capacity is required to reach 24 days in 2027; gas security stockpiles are required to reach 14 days in 2027 (Table 5) (BOE, 2018a).

Table 5: Natural gas security stockpiles and storage capacity requirement

	2019	2022	2025	2027
Security stockpile required (days)	7	8	11	14
Storage capacity required (days)	15	16	20	24

Source: (BOE, 2018a).

ENERGY MARKETS

ELECTRICITY MARKETS

Chinese Taipei has three main transmission lines in terms of voltage: a 345 kV ultra-high transmission line which transports power from nuclear power plants as well as large-scale hydro and fossil fuel power plants; a 161 kV transmission line which transports power from medium-scale hydro and fossil fuel power plants, as well as large-scale renewable power plants; and a 69 kV transmission line which transports power from small-scale hydro and medium-scale renewable power plants. The TPC was responsible for all power generation, transmission, distribution and sales. Since then, private companies have established power plants, creating competition in the generation sector. As of December 2019, 25 IPPs owned nine fossil fuel plants, five hydro plants, 31 solar plants, and 181 wind turbines in Chinese Taipei (BOE, 2019c) (BOE, 2019d).

Chinese Taipei's target to be nuclear-free by 2025 is a prominent power policy. In 2017, the government announced an energy mix target for 2025 to accommodate nuclear retirement (currently 10% in the generation mix). The target is for 20% renewable energy, a reduction in coal to 30%, and an increase in natural gas to 50% (BOE, 2017b). To ensure power supply stability, the MOEA also set a 15% reserve capacity target and a 10% operating reserve target from 2019 to 2025 (MOEA, 2018).

Another important power policy is the amendment of the Electricity Act, passed by the Legislative Yuan. The amendment came into effect in January 11, 2017 and consists of a two-stage plan. The first stage is to promote liberalisation of the green energy market. The second stage will subsequently split the ownership of TPC with one subsidiary in charge of power generation and another responsible for electricity transmission, distribution and sales. The second stage will only begin once the first stage operational schemes and mechanisms become mature, roughly six to nine years after the amendment (EY, 2019a). The main amendments in the first stage are:

- **Power generation:** green energy is the priority with an initial move to allow sales of green energy to users via wheeling², direct supply and renewable energy vendors
- **Power transmission and distribution:** maintain the power grid as a state-run enterprise to ensure fair access for all users. Consumers have the freedom to purchase electricity from public power sales and private renewable energy producers
- **Supervision and management of electricity producers and the electricity market:** the central government authority will designate a regulatory agency to manage and supervise the market for electrical power, with rates charged by public power vendors subject to regulatory controls. An energy price stabilisation fund will also be established to minimise price volatility

² In electric power transmission, wheeling is the transportation of electric energy from within an electrical grid to an electrical load outside the grid boundaries

- **Preservation of TPC integrity:** following the division of its operations into separate lines of business, the TPC will reorganise as a parent holding company with a subsidiary responsible for power generation and another handling transmission and distribution, together with sales

The Smart Grid Master Plan (released 2012) is also relevant for electricity markets. It is a long-term plan covering 20 years from 2011-2030 with three stages of development. The plan has four objectives: to ensure a reliable power supply; to encourage energy conservation and emissions reduction; to enhance the penetration of green energy; and to develop low-carbon industry. The three stages of development are the technology test stage (2011-15), the technology implementation and promotion stage (2016-20), and the technology extensive application stage (2021-30). As of December 2019, significant accomplishments of the plan are (BOE, 2019e):

1. Intelligent substations: 190 intelligent substations were installed by the end of 2018. 110 more intelligent substations will be completed by 2020 and 303 more by 2030
2. Automatic power distribution switches: 24 000 automatic power distribution switches were installed by the end of 2018. An additional 4 000 switches will be completed by 2030
3. Advanced metering infrastructure (AMI): high-voltage AMI has been installed for 25 000 high energy-using consumers (accounting for 60% of total power supply). In 2018, 230 000 low-voltage AMIs were installed for households, with one million scheduled by 2020 and three million by 2024

FISCAL REGIME AND INVESTMENT

Chinese Taipei has limited indigenous energy resources. There is no formal policy on investment in upstream assets. To secure new energy sources, Chinese Taipei has invested in oil exploration both in the Taiwan Strait, and abroad, through CPC. Chinese Taipei also welcomes the participation of foreign investors in bidding on the IPP electricity market.

ENERGY EFFICIENCY

The BOE started drafting an Energy White Paper³ to facilitate energy transition as outlined in the Guidelines on Energy Development. In February 2018, the BOE released the Energy Saving Target and Roadmap implementation plan, aiming to improve energy intensity by 2.4% every year and electricity intensity by 2% every year between 2017 and 2025. The roadmap includes implementation plans for building envelopes in the residential, services⁴, industry, and transport sectors. It aims to reduce energy consumption to 5 Mtoe or 17 terawatt-hours (TWh) in these four sectors below the 2016 level by 2025 (BOE, 2018b).

- **Residential and services** (BOE, 2018c)
 - Target: to improve energy efficiency and reduce electricity demand by 6.5 TWh and oil consumption by 0.03 Mtoe from the 2016 levels by 2025
 - Roadmap: promote energy audits and provide consumption reduction counselling for services. Improve energy efficiency management for residential and services sector. Strengthen basic consumption reduction measures in local areas and expand public participation
- **Industrial sector** (BOE, 2018d)

³ The Energy White Paper is the consensus after several discussions between public and private sectors, but it has not yet been approved by the Executive Yuan.

⁴ The buildings sector classification in Chinese Taipei's Energy Saving Roadmap is different from APERC's classification, which splits buildings between residential and service subsectors. Chinese Taipei's roadmap also includes building envelopes as a separate sector.

- Target: to reduce energy intensity by 45% below the 2005 level by 2025. To reduce energy consumption by 2.3 Mtoe and CO₂ emissions by 7.0 MtCO₂ for 2016–25
- Roadmap: promote transition to lower-intensity industry by increasing the efficiency of manufacturing processes and retrofitting factories to use low-carbon fuels. Provide energy saving and CO₂ emissions reduction counselling for manufacturers. Promote regional resource integration and establish incentive mechanisms
- **Building envelopes** (BOE, 2018e)
 - Target: to improve and strengthen consumption reduction-related regulations and measures. Reduce energy demand by 0.63 Mtoe or 3.2 TWh below the 2016 level by 2025
 - Roadmap: improve design index by 10% for new building envelopes and add 500 green building materials and candidate certificates every year. Strengthen current measures for reducing the energy consumption of existing buildings. Promote transparency of building energy consumption. Develop internet-based demand reduction simulation tools to estimate consumption. Conduct zero-energy building feasibility studies
- **Transport sector** (BOE, 2018f)
 - Target: to reduce gasoline consumption by 0.85 megalitres (ML) and diesel consumption by 0.10 ML (640 toe and 84 toe) from the 2017 level by 2020. Increase electricity use by 406 MWh above the 2017 level by 2020. Reduce transport CO₂ emissions by 2 MtCO₂ below the 2017 level by 2020
 - Roadmap: withdraw 80 000 first- and second-phase heavy-duty diesel vehicles by 2019. Expand public transport capacity by 2% above the 2015 level by 2020 to serve 1.2 billion passengers per year. Improve fuel economy standards above the 2014 level by 10% for scooters, 30% for passenger cars and 25% for trucks by 2022. Complete rail electrification by 2022. Have 10 000 electric buses operating by 2030

RENEWABLE ENERGY

The two main renewable energy (RE) sources in Chinese Taipei are photovoltaic (PV) systems and wind power. To promote RE, the government announced the Renewable Energy Development Act in July 2009. The core strategy of the Act is the feed-in-tariff (FiT) system. The FiT tariff is reviewed annually (latest FiT in table 6).

Table 6: Feed-in-tariff in Chinese Taipei, 2019

Item	Type	Installed capacity (kW)	FiT (NTD/kWh) in Jan-Jun	FiT (NTD/kWh) in Jul-Dec	
PV	Rooftop	≥1 <20	5.8	5.8	
		≥20 <100	4.6	4.5	
		≥100 <500	4.3	4.2	
	≥500	not in parallel with	4.2	4.2	
		in parallel with power	4.7	4.6	
	Ground	≥1	not in parallel with	4.1	4.0
		in parallel with power	4.6	4.5	
	Floating	≥1	not in parallel with	4.5	4.4
		in parallel with power	4.9	4.9	
		≥1<30	7.98759		

Wind Power	Onshore	≥30	with LVRT	2.5438	
			without LVRT	2.5124	
	Offshore	≥1	20-year fixed tariff		5.5160
			two-stage tariff	first 10 years	6.2795
			second 10 years	4.1422	
Hydropower	Stream Type	≥1	2.8325		
Geothermal	-	≥1	20-year fixed tariff		5.1956
			two-stage tariff	first 10 years	6.1710
				second 10 years	3.5685
Biomass	with anaerobic digestion	≥1	2.5765		
	without anaerobic digestion		5.0874		
Waste	-	≥1	3.8945		
Others	-	≥1	2.1107		

Source: (BOE, 2019f).

The government amended the Renewable Energy Development Act in 2019. The amendment incorporates a 27 GW target for installed RE capacity in 2025, and also allows renewable energy producers to choose a FIT or sell their production directly in the market. See the Notable Developments section for details. The MOEA also announced plans for offshore wind development. This will add an additional 10GW of installed capacity through 2026-35 (addition of 1 GW of capacity annually) (Renewable Energy by BOE, 2019).

Table 7: Renewable energy targets by 2025

	Power Capacity (MW)		
	2019	2020	2025
Solar PV	4 019	6 500	20 000
Onshore Wind	717	800	1 200
Offshore Wind	128	520	5 738
Geothermal	0	150	200
Biomass	712	768	813
Hydro Power	2 092	2 100	2 150
Fuel Cell	-	22	60
Total	4 722	10 861	27 661

Sources: (MOEA, 2018) and (BOE, 2020).

PHOTOVOLTAIC SYSTEMS

There are short- and long-term plans for PV promotion. For the short-term, the BOE proposed a Two-Year Solar PV Promotion Project in 2016. The project target was to complete 1.52 GW of solar PV installation capacity by 2018. At the end of 2018, installed capacity reached 1.7 GW which surpassed the set target. The next short-term target is to reach 6.5 GW of solar capacity by 2020. This provides the foundation of the long-term target of 20 GW by 2025 (3 GW for rooftop and 17 GW for ground systems) (EY, 2019b).

WIND POWER SYSTEMS

Chinese Taipei is promoting both onshore and offshore wind power. By the end of 2018, Chinese Taipei had installed 717 MW of onshore wind turbines and will continue to expand the installation capacity to reach the target of 1 200 MW by 2025. For offshore wind power, the government had installed 128 MW capacity by the end of 2018. Chinese Taipei is expected to install up to 520 MW of wind farm capacity in shallow sea areas by 2020, and then develop wind farms in deep sea areas to reach the target of 5 738 MW in 2025 (BOE, 2019a) (BOE, 2019g).

NUCLEAR ENERGY

There are four nuclear power plants in Chinese Taipei: the Jinshan, Kuosheng, Maanshan and Lungmen Nuclear Power Plants. The first one was decommissioned in 2019, the second and third are in operation, and the fourth was sealed and closed in 2015. Total installed capacity of the three operational nuclear power plants reduced from 5 144 MW in 2017 to 4 508 MW in 2018 due to partial decommissioning. Nuclear output in 2018 was 27 682 GWh, accounting for 10% of the economy's total power generation mix, 23% up from previous year (BOE, 2019a). Additional decommissioning occurred in July 2019 (TPC, 2019).

In 2011, the nuclear disaster at Fukushima led to public fears regarding nuclear safety in Chinese Taipei. The government at the time released an energy policy to steadily reduce nuclear dependence. They aimed to achieve this by reducing electricity consumption and reducing peak loads, and by promoting alternative energy sources to ensure a stable power supply. In 2016, the newly elected government committed to a nuclear-free Chinese Taipei by 2025 (EY, 2016). The policy prohibits lifespan extensions for nuclear plants and outlines a decommissioning plan. Units 1 and 2 of the Jinshan plant have already been decommissioned in 2018 and 2019. Units 1 and 2 of the Kuosheng plant are planned to be decommissioned in 2021 and 2023, respectively; and units 1 and 2 of the Maanshan plant in 2024 and 2025, respectively (TPC, 2019).

CLIMATE CHANGE

GREENHOUSE GAS EMISSIONS

In 2017, Chinese Taipei produced CO₂ emissions that account for approximately 0.82% of global emissions (EPA, 2019a). The government believes that it has a moral obligation to reduce emissions even though the economy is not a member of the UN (and is consequently not eligible to sign the Kyoto Protocol).

Chinese Taipei is unable to undertake emissions trading to reduce GHG emissions or to pursue cost-effective emissions reduction plans. Alternative mechanisms are important for Chinese Taipei to reduce the impact of its GHG emissions.

The Basic Environment Act and Greenhouse Gas Reduction and Management Act (hereafter referred to as the Greenhouse Gas Act) led Chinese Taipei to submit its Intended Nationally Determined Contribution (INDC) to Executive Yuan in 2015 (EPA, 2015). The INDCs demonstrate Chinese Taipei's ambition to actively and steadily reduce its carbon emissions.

The government's INDC goal is for Chinese Taipei's 2030 GHG emissions to be 50% lower than they would have been if it conducted business as usual, and 20% lower than its 2005 level (MOEA, 2015). This will assist Chinese Taipei to reduce annual GHG emissions to less than half of the 2005 levels by 2050, as outlined in the Greenhouse Gas Act (Laws & Regulations Database of the Republic of China, 2015). In 2018, the government revised the Air Pollution Control Act to reduce air pollution and accelerate energy transformation. The revision seeks to restrict vehicle and factory emissions, improve air quality, and improve the management of pollution sources and pollution treatment (EPA, 2019b).

NOTABLE ENERGY DEVELOPMENTS

ENERGY TRANSITION PROMOTION SCHEME

Chinese Taipei began to promote an energy transition in 2016. In 2019, the MOEA announced the Energy Transition Promotion Scheme. There are four main principles (MOEA, 2019):

1. To promote green energy: the MOEA set a target of 20% of renewable energy in power generation by 2025, which incorporates 20 GW of installed capacity for PV and 5.7 GW of installed capacity for offshore wind power
2. To increase natural gas supply: demand for natural gas will increase in order to achieve a 50% share of power generation in 2025. Part of this increased demand will be due to gas-fired boilers replacing coal-fired boilers. Growing demand for natural gas will be met by:
 - (1) Expanding LNG-receiving capacity: CPC is carrying out an expansion project for the Taichung and Yung-An LNG terminals, and is also constructing a third LNG-receiving terminal. TPC is also planning to construct a fourth (Hsieh-Ho) and fifth (Taichung) LNG terminal
 - (2) Regulating the minimum days of natural gas storage capacity⁵ and security stockpile⁶. The minimum days of natural gas storage capacity and security stockpile will reach 24 days and 14 days by 2027
 - (3) Diversifying LNG import sources. The US is the most recent addition to the list of economies that supply Chinese Taipei with natural gas
3. To reduce coal-fired power generation: the building of new coal-fired power plants will end. The to-be-decommissioned coal-fired power plants will be replaced with gas-fired power plants
4. To achieve the nuclear-free target by 2025

AMENDMENT OF RENEWABLE ENERGY DEVELOPMENT ACT

The Amendments to Renewable Energy Development Act was passed on 12 April 2019, the first amendment since its promulgation in 2009. Highlights of the amendments are:

1. Target: the goal is to reach a total RE capacity of 27 GW by 2025, increased from 10 GW in the original version
2. Market liberalisation for renewable energy: the amendments enable renewable energy producers to sell directly to consumers. A liberalised market will allow generators to switch between a FiT and market-based system, instead of being limited by 20-year purchase agreements
3. Installation of renewable energy generation facilities: the amendments make it mandatory for large energy users to install their own renewable energy generation and energy storage facilities, purchase renewable energy certificates, or pay a cash allowance. Government agencies, public schools or state-run enterprises that build new constructions (or undergo expansion or renovation), must also prioritise renewable energy
4. Simplification of administrative procedures and regulation of grid connection: local governments are entitled to evaluate the potential for developing renewable energy

⁵ Days of natural gas storage capacity = (enterprise's own gas storage capacity + rental gas storage capacity – leased gas storage capacity) / the average of daily gas supply volume in past six years. If the enterprise is registered for less than six years, take the actual supply period for calculation.

⁶ Days of natural gas security stockpile = enterprise's gas stockpile at 8am / the average of daily gas supply in previous year.

- sources within their jurisdiction and may establish power generation facilities with an installed capacity of up to 2 000 KW, increased from 500 KW in the original version
5. Encouragement of mass participation: the central government will provide rewards for the development of citizen power plants and renewable energy power plants in aboriginal areas in the demonstration stage

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Taiwan Power Company—www.taipower.com.tw

THAILAND

INTRODUCTION

Thailand is known as ‘the window to South-East Asia’. The economy is surrounded by Myanmar, the Lao People’s Democratic Republic (Lao PDR), Cambodia to the north and east, and Malaysia to the south. Thailand has an area of 513 120 square kilometres (km²) and had a population of 69 million in 2017. Gross domestic product (GDP) in 2017 reached USD 1 127 billion (2011 USD purchasing power parity [PPP]), a 4.0% increase from 2016. GDP per capita increased by 3.7% for 2017 to USD 16 286 (2011 USD PPP). The largest contributors to Thailand’s GDP were services (56%) and industry (35%) (UN, 2019).

Thailand has limited domestic energy resources. At the end of 2017, Thailand had proven reserves of 300 million barrels of oil (bbl), 200 billion cubic metres (bcm) of natural gas and 1 063 million tonnes (Mt) of coal. Based on current rates of production, domestic supply will soon become depleted—oil resources within two years and natural gas within five years (BP, 2019). Most coal-fired power plants in Thailand use low-quality, domestically produced lignite. Thailand is highly dependent on energy imports, particularly oil, with approximately 87% of its oil and 28% of its gas supply coming from imports (EPPO, 2019).

Table 1: Key data and economic profile, 2017

Key data ^{a, b}		Energy reserves ^c	
Area (km ²)	513 120	Oil (million barrels)	300
Population (million)	69	Gas (billion cubic metres)	200
GDP (2011 USD billion PPP)	1 127	Coal (million tonnes)	1 063
GDP (2011 USD PPP per capita)	16 286		

Sources: ^a UN (2019); ^b EGEDA (2019); ^c BP (2019).

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Thailand’s total primary energy supply in 2017 was 138 201 kilotonnes of oil equivalent (ktoe), which was a 0.21% decrease from the 2016 level. Oil accounted for 40% of total primary supply, while gas and coal accounted for roughly 30% and 9.4%, respectively. Renewables and others accounted for the remaining 20%. Most of Thailand’s proven coal reserves are lignite coal, which has a low calorific value. For this reason, coal imports are relied on to meet energy demand for both the power and industry sectors. In 2017, the coal supply was 13 000 ktoe, a decrease of 2.6% from the previous year’s level.

The natural gas supply in 2017 was 41 225 ktoe, a 0.19% decrease from 2016. Natural gas is mostly used for power generation in Thailand, but it is also promoted in the transport sector as a replacement for conventional petroleum products, such as diesel and gasoline. Thailand has increased its reliance on imported natural gas in the form of piped gas from Myanmar and liquefied natural gas (LNG) from Qatar and Malaysia.

In 2017, total electricity generation was 185 510 gigawatt-hours (GWh). Thermal generation, mostly from natural gas and coal, accounted for 84% of Thailand’s power generation, with hydropower and others accounting for the remainder. In addition to domestic capacity, Thailand purchased power from the Lao PDR via transmission grid connections.

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	75 973	Industry sector	27 993	Total power generation	185 510
Net imports and others	68 689	Transport sector	28 680	Thermal	156 380
Total primary energy supply	138 201	Other sectors	20 159	Hydro	4 832
Coal	13 000	Non-energy	11 340	Others	24 298
Oil	55 910	Final energy consumption*	76 832		
Gas	41 225	Coal	5 303		
Renewables	26 060	Oil	34 867		
Others	2 006	Gas	5 821		
		Renewables	14 280		
		Electricity and others	16 561		

Source: EGEDA (2019) (data collected in December 2019).

* Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. Total final consumption includes non-energy uses. Half of the municipal solid waste used in power plants is assumed to comprise renewables.

NATURAL GAS

Thailand's proven gas reserves at the end of 2018 amounted to 6.1 trillion cubic feet (Tcf), consisting of 5.9 Tcf in gas fields in the gulf and 0.15 Tcf in onshore areas. Proven gas reserves fell by 0.35 Tcf (approximately 5.5%) over the course of 2018 (DMF, 2018). In 2019, domestic natural gas production (including the Thailand-Malaysia Joint Development Area, JDA) was 3 623 million standard cubic feet per day (MMscfd). This production met 72% of Thailand's gas demand. The remaining domestic consumption was supplied by imports from Myanmar (15%; 738 MMscfd) and imported LNG (13%; 658 MMscfd). Total natural gas supply in Thailand stood at 5 018 MMscfd (EPPO, 2020).

CRUDE OIL AND CONDENSATE

At the end of 2018, Thailand's proven reserves of oil and condensate stood at 293 Mbbbl (137 Mbbbl of crude and 156 Mbbbl of condensate). The gulf accounted for 245 Mbbbl of these reserves while 47 Mbbbl were located onshore. Proven reserves declined by 30 Mbbbl (10%) from the previous year's level. Rising oil prices led concessionaires to increase their production over the reserve replacement and resulted in a reduction of proven reserves. Total investment expenditure in petroleum exploration in 2018 (Baht 105 679 million) has continued to decline for four consecutive years since 2014 (Baht 221 618 million) (DMF, 2018). The accumulated domestic oil production in 2019 was 125 889 barrels per day (bbl/d). The major crude oilfields in Thailand are Erawan, Sirikit, Tantanwan, and Jusmin (EPPO, 2020).

COAL/LIGNITE

Thailand's lignite (low-grade coal) reserves are sufficient for 72 years of current use (BP, 2019). Total indigenous lignite output in 2019 was 14 Mt. Domestic lignite production comes from two major sources. One source is the mine of the Electricity Generating Authority of Thailand (EGAT), and the other is private mines. EGAT's lignite is produced from the Mae Moh mine in Lampang Province and is used as fuel for power generation at the Mae Moh Power Plant for the northern part of Thailand.

Lignite from private companies is mainly used in the cement, paper, food and textile industries. In 2019, the proportion of lignite/coal combustion in the power sector was 61% and in the industrial sector the proportion was 39%. Most of the imported coal is sub-bituminous and bituminous. Coal imports have been increasing to replace domestic lignite resources. Coal

imports are also increasing due the competitive price of this fuel (relative to other energy sources) (EPPO, 2020).

ELECTRICITY

EGAT used to be the sole power producer in Thailand. Later, the government promoted the private sector's role in power generation to encourage competition. Independent power producers (IPP) and small power producers (SPP) have taken part in the power supply industry since 1994, which has led to an improvement in power generation and service quality. Renewable generation is currently being promoted and has resulted in a growing number of very small power producers (VSPP) using renewable energy as the main fuel to supply power to the grid.

In 2019, the economy's power-generating capacity stood at 45 297 megawatts (MW), an increase of 1 923 MW from 2018, with EGAT contributing 33%; IPPs 33%; SPPs 21%, and 13% from imported electricity from Lao PDR and exchange with Malaysia (EPPO, 2020). EGAT's contribution to generation capacity fell from 60% in 2005 to 33% in 2019.

FINAL ENERGY CONSUMPTION

Thailand's total final consumption in 2017 was 88 172 ktoe, an increase of 0.26% from 2016. The transport sector was the largest energy-consuming sector, accounting for 28 680 ktoe or 33% of total final consumption. The second-largest energy consumer was the industry sector, with final energy consumption falling 3.9% to 27 993 ktoe. The non-energy category accounted for 13% of total final consumption (11 340 ktoe). This is primarily made-up of energy products that are used as feedstock (for example in petrochemical endeavours) instead of for energy purposes. By fuel type, oil accounted for 45% of the final energy consumption (excluding non-energy uses) in 2017, followed by electricity and others (22%), renewables (19%), gas (7.6%) and coal (6.9%).

Natural gas consumption decreased by 4.4%, to 5 821 ktoe in 2017, whereas oil consumption increased 0.52% to 34 867 ktoe in 2017. Coal consumption also increased to 5 303 ktoe in 2017 (0.77% annual increase). Domestic electricity and other energy consumption increased by 1.8% in 2017 to 16 561 ktoe (EGEDA 2019).

ENERGY INTENSITY ANALYSIS

Thailand's energy intensity (energy consumption/GDP) in terms of primary energy in 2017 was 123 tonnes of oil equivalent per million USD (toe/million USD). This represents a 4.1% improvement relative to 2016. The energy intensity of final energy consumption excluding non-energy also improved to 68 toe/million USD in 2017 (3.3% improvement).

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%) 2016 vs 2017
	2016	2017	
Total primary energy supply	128	123	-4.1
Total final consumption	81	78	-3.6
Total final energy consumption excl. non-energy	71	68	-3.3

Source: EGEDA (2019)

RENEWABLE ENERGY SHARE ANALYSIS

Modern renewable consumption increased 6.3% in 2017, whereas traditional renewables decreased by 2.4%. The decrease in non-renewables (0.21%) means that the proportion of renewables to final energy consumption increased by 5.7%. The share of modern renewable in final energy consumption is now 15%.

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	76 416	76 832	0.54
Non-renewables (Fossil fuels and others)	60 170	60 043	-0.21
Traditional biomass*	5 502	5 369	-2.4
Modern renewables*	10 744	11 421	6.3
Share of modern renewables in final energy consumption (%)	14%	15%	5.7%

Source: EGEDA (2019).

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal, and so on), including biogas and wood pellets, are considered modern renewables, although data on wood pellets are limited.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

The Ministry of Energy's aim is to support sustainable energy management that ensures the economy has sufficient energy to meet its needs. The ministry is responsible for:

- establishing energy supply security
- promoting the use of alternative energy
- monitoring energy prices and ensuring that prices are at levels appropriate to the wider economic and investment situation
- effectively saving energy and promoting energy efficiency
- supporting energy research and development domestically and internationally while simultaneously protecting the environment and mitigating climate change
- structuring the energy database centre to systematically consolidate and standardise Thailand's energy-related information

The Ministry of Energy is the main government institution responsible for energy policy in Thailand. There are six departments and four state enterprises that sit beneath it:

- The Office of the Minister coordinates with the cabinet, the parliament and the general public
- The Office of the Permanent Secretary establishes strategies, translates policies of the ministry into action plans, and coordinates international energy cooperation
- The Department of Alternative Energy Development and Efficiency (DEDE) promotes the efficient use of energy, monitors energy conservation activities, explores alternative energy sources and disseminates energy-related technologies
- The Department of Energy Business (DOEB) regulates energy quality and safety standards, the environment and security, and improves standards to protect consumers' interests
- The Department of Mineral Fuels (DMF) facilitates energy resource exploration and development

- The Energy Policy and Planning Office (EPPO) recommends economy-wide energy policies and planning
- EGAT is the state power-generating enterprise
- PTT Public Company Limited (PTT) and the Bangchak Petroleum Public Company Limited (BCP) are two autonomous public companies
- The Energy Fund Administration Institute (EFAl) is a public organisation
- The Energy Regulatory Commission (ERC) and the Nuclear Energy Study and Coordination Office (NESC) are two independent organisations

Energy policy established under the government of Prime Minister Prayut Chan-o-cha and presented to the National Legislative Assembly of Thailand on 12 September 2014, has reformed energy prices to reflect actual costs and taxes for different types of fuels and different groups of consumers. The reform promotes energy efficiency, consumer awareness and efficient behaviour change.

On the supply side, the government will proceed with new surveys and exploration for oil and gas, both onshore and offshore. Construction of fossil fuel power plants and renewable energy initiatives will be pursued by state-owned enterprises and the private sector. There will be open consultation with the public that appropriately addresses environmental concerns. The development of energy resources with neighbouring economies is also a priority (The Royal Thai Government, 2014).

In 2015, Thailand achieved an important milestone in energy policy development by integrating all major energy policy plans into a single comprehensive plan: the Thailand Integrated Energy Blueprint (TIEB) (EPPO, 2016a). The TIEB aims to balance economic, ecological and security concerns, and consists of five long-term plans. These plans are the power development plan (PDP 2015) (EPPO, 2016b), the Energy Efficiency Plan 2015 (EEP 2015) (EPPO, 2016c), the Renewable and Alternative Energy Development Plan (AEDP 2015) (EPPO, 2016d), the Gas Plan 2015 (Kaewtathip, S, 2017, DMF, 2016) and the Oil Plan 2015 (EPPO, 2016e).

The proposals have been updated and synchronised to cover the period from 2015 to 2036. The PDP 2015 incorporates the EEP 2015 energy efficiency target to reduce energy intensity by 30% from the 2010 levels and includes a target of the AEDP 2015 to develop renewable energy generating capacity of approximately 20 gigawatts (GW) or 20% of the total generating capacity by 2036.

ENERGY SECURITY

The government's energy security policy will intensify energy development for greater self-reliance, with a view towards achieving an adequate and stable energy supply. This will be done by:

- advancing the exploration and development of energy resources at domestic and international levels
- negotiating with neighbouring economies at the government level for the joint development of energy resources
- developing an appropriate energy mix to reduce supply, price volatility and production cost risks
- encouraging electricity production from potential renewable energy sources, particularly from small-scale or very small-scale electricity generating projects
- investigating other alternative energy sources for electricity generation

All five plans under the TIEB contribute to energy security. The PDP 2015 aims to strengthen the energy security of power-generating systems in Thailand by diversifying the fuel mix to be less dependent on natural gas and electricity imports, and by setting reserve margins at a minimum of 15%. The PDP 2015 includes 89 672 GWh energy savings identified in the EEP

2015. The largest share of savings is expected to be delivered through a variety of compulsory measures such as building energy codes, factory and service energy codes, minimum energy performance standards (MEPS), high energy performance standards (HEPS), and promotion of LED use.

The electricity consumption savings identified in the EEP 2015 amount to 22% of business-as-usual (BAU) levels. Renewable energy generation targets from the AEDP are also included in the PDP 2015. Generating capacity of 20 GW from solar, biomass, wind, hydro and waste-to-energy are expected by 2036 (20% of total generation). The new gas and oil plans will help to ensure long-term energy supply alongside the PDP 2015.

In 2019, the Ministry of Energy introduced a revised power development plan, PDP 2018. The formulation of PDP 2018 has been designed to ensure that public opinion and the environmental impact of local pollution are taken into consideration when new power plants are installed.

Thailand's domestic energy resources are likely to become depleted soon—oil within two years and natural gas in five years (BP, 2019). To maintain energy security, Thailand needs to pursue new explorations. Since 1971, the DMF has launched 20 concession bidding rounds, with the latest announced in 2007. In 2014, the DMF invited bids for exploration and production rights for the Erawan and Bongkot gas exploration concessions; however, the initiative was halted.

The Petroleum Act has since been amended (with the government's energy reform), and in late 2018, re-bidding for both these concessions was successful. PTT Exploration and Production Plc (PTTEP) and the UAE's Mubadala Petroleum together represented the winning joint venture for the Erawan (G1/61) concession contract starting in 2022. PTTEP also won the concession for Bongkot (G2/61), with the contract to begin in 2023.

To secure natural gas supply for the long term, Thailand has entered into contracts to buy LNG from multiple LNG suppliers. Qatar Liquefied Gas Company Limited (Qatargas), delivered its first LNG cargo to Thailand in January 2015. The long-term commitment is 2 Mt of LNG per year for 20 years. Petronas delivered its first cargo in July 2017 (commitment for 1.2 Mt of LNG per for 15 years). PTT has also concluded a gas sales agreement to acquire 2.6 Mt of LNG per year from Mozambique's Rovume A1 project to begin 2022–2023 (African Century, 2017; Bangkok Post, 2017; Reuters, 2017).

EGAT also imported a 65 kt LNG spot shipment from Petronas in December 2019 and planned another 65 kt LNG spot shipment for April 2020. These transactions promote spot transactions in the LNG market which increases Thailand's supply security (Reuters, 2019; The Star, 2019).

The Ministry of Energy recently entered a power purchasing agreement with Lao PDR to import 9 000 MW of electricity, mostly hydropower, by 2030 (Bangkok Post, 2019). This is an increase over the previous MoU signed in 2007 which Thailand agreed to buy 5 421 MW of electricity from Lao PDR, 3 578 MW of which came from hydropower and coal-fired power plants. The remaining 1 843 MW came exclusively from hydropower, Xe Pien Xe Namnoy hydropower project (354 MW), Xayabury Dam (1 220 MW) and the Nam Ngiep project (269 MW) (The Nation, 2016).

FISCAL REGIME AND INVESTMENTS

ENERGY PRICES

The government's energy price policy aims to monitor and maintain energy prices at appropriate, stable and affordable levels. It will do this through:

- setting a transparent and justifiable fuel price structure that supports the development of energy products and that best reflects actual production costs
- managing prices through market mechanisms and the oil fund to promote the economical use of energy
- encouraging competition and investment in energy businesses, including the improvement of service quality and safety

The government is supervising the pricing policies and price structure of oil, LPG and natural gas for vehicles (NGV), including refining and marketing margins. The energy price policy will ensure that domestic energy prices reflect actual production costs, while being competitive with the energy prices of neighbouring economies. The oil fund will be used to ensure prices for the general public are fair and reasonable. The recent decline in oil prices has created an opportunity for Thailand to restructure fuel pricing and reduce energy cross-subsidies.

INVESTMENT

The government is creating a favourable environment for investment, transparent competition and internationally accepted energy-related standards in the energy industry. The Thailand Board of Investment is the entity responsible for developing investment procedures and processes. The government is also liberalising Thailand's markets to facilitate the involvement of private enterprise in electricity, refining, gas separation, and both domestic and overseas oil and gas exploration and production.

ENERGY EFFICIENCY

The first long-term energy policy on energy efficiency, the Energy Efficiency Development Plan (EEDP), was launched in 2011 with a target of reducing energy intensity by 25% in 2030 from the 2010 level. This is equivalent to a reduction in final energy consumption of 20% by 2030 (38 200 ktoe). The Energy Efficiency Action Plan (EEAP) has also been developed under the strategic framework of the EEDP. The EEAP was approved by the National Energy Policy Committee (NEPC) and endorsed by the cabinet in early 2013. The plan articulates 67 initiatives.

Most of the initiatives are sector-wide. Sector-specific measures are mainly for the transport sector (18 initiatives), industry sector (five initiatives), large and small commercial buildings (five initiatives) and the residential sector (five initiatives). Total energy savings are expected to be 38 845 ktoe, with 16 257 ktoe from the industrial sector, 15 323 ktoe from the transport sector, 3 635 ktoe from the small commercial building and residential sector, and 3 630 ktoe from the large commercial building sector.

The EPPO has also completed the development of a 10-year R&D master plan for energy efficiency to complement the EEAP and EEDP framework.

The EEDP has been updated to use the same timeframe as other energy plans (2015–36) and is known as the Energy Efficiency Plan 2015 (EEP 2015). The EEP 2015 has set a target of reducing energy intensity by 30% by 2036 from the 2010 levels. This savings target amounts to 56 142 ktoe, consisting of 7 641 ktoe of electricity (or 89 672 GWh) and 44 059 ktoe of heating. These savings are in addition to what was already achieved through 2013 (4 442 ktoe in savings). The new savings equate to a 30% reduction in BAU energy consumption in 2036 (EPPO, 2016c).

The EEP 2015 set the targets of energy reduction for four major economic sectors: industry; commercial and governmental buildings; residential; and transportation. They are categorised into three strategic areas with 10 specific measures as follows:

COMPULSORY PROGRAM

- To enforce the Energy Conservation Promotion Act B.E. 2550 (2007), which outlines an energy management system (based on energy consumption reporting and verification) imposed on 7 870 buildings and 11 335 factories with transformer sizes of 1 000 kW (1 175 kVA) and up
- To implement mandatory energy efficiency evaluations for newly built and renovated buildings, such as building energy codes (BEC), leadership in energy and environmental design (LEED) and Thailand's rating of energy and environmental sustainability (TREES)
- To implement HEPS and MEPS for equipment and appliance labelling to provide consumers with options for highly energy-efficient equipment and appliances

- To implement energy efficiency resource standards (EERS) or minimum standards for large energy businesses (including power producers and distributors). These energy conservation measures will flow through to end-use energy consumers, and bring about beneficial energy efficiency investment

VOLUNTARY PROGRAM

- To support the operation of energy service companies (ESCOs). An energy efficiency revolving fund, tax incentives and soft loan and grants will alleviate the technical and financial risks of entrepreneurs wishing to implement energy conservation measures
- To promote the wider use of LEDs for streetlights and households through public relations campaigns and price mechanisms
- To promote energy conservation programs in the transportation sector through an effective pricing structure, increasing the fuel efficiency of automobile engines, increasing efficient infrastructure and logistics systems, and launching electric vehicle fleets to replace inefficient older generation cars
- To promote R&D that improves energy efficiency and reduces technological costs for equipment or appliances, production processes and materials

COMPLEMENTARY PROGRAM

- To support the development of professionals in energy conservation fields. These professionals will be responsible for energy management and operations, verification and monitoring, consultancy and engineering services, and the planning, supervision and promotion of energy conservation measures
- To introduce measures that foster public awareness and encourage energy consumption behaviour change

Details of these EEP 2015 targets are shown in Table 5.

Table 5: The EEP 2015's Targets for 2036

Energy Efficiency Measures	Saving Targets in 2036, ktoe
Compulsory Program	10 972
1. Enforcement of the Energy Conservation Promotion Act B.E. 2550 (2007)	5 156
2. Energy efficiency evaluations for buildings (BEC, LEED and TREES)	1 166
3. Enforcement of HEPS and MEPS for equipment or appliances	4 150
4. Implementation of EERS for energy businesses	500
Voluntary Program	40 728
5. Support ESCOs by using financial tools	9 524
6. Promote the wider use of LEDs for streetlights and households	991
7. Promote energy conservation programs in the transport sector	30 213
8. Promote R&D to improve energy efficiency and technological costs	-
Complementary Program	
9. Support the development of professionals in the energy conservation field	-
10. Introduce measures that foster public awareness.	-
Total	51 700

Source: DEDE (2015)

The EEP 2015 has recently been reviewed and revised to EEP 2018 covering 2018-2037. The EEP 2018 has set the target of reducing energy intensity by 30% by 2037 from the 2010 levels.

This savings target equals 54 371 ktoe, which is equivalent to a 4 000 MW reduction of electricity and a CO₂ reduction of 170 MtCO₂. The plan focuses on energy management, process improvement, and high efficiency to encourage improvements in industry, buildings, households, transportation, and agriculture (AEITF, 2020).

RENEWABLE ENERGY

The Ministry of Energy is keen to develop alternative and renewable energy to secure new energy resources and provide affordable energy to all Thais. There have been multiple revisions to the renewable and alternative development plan during the past decade. The 10-Year Renewable and Alternative Energy Development Plan 2012–21 (formerly the 15-Year Renewable Energy Development Plan 2008–22 (REDP)) set a target of an increase in the share of renewable and alternative energy to 25% of total energy consumption by 2021.

The AEDP will encourage the use of indigenous resources, including renewable and alternative energy (particularly for power and heat generation), and support the use of transport biofuels such as ethanol-blended gasoline (gasohol) and biodiesel. The plan also strongly promotes community-scale alternative energy use, encouraging the production and use of renewable energy at the local level. It also rigorously promotes R&D in all forms of renewable energy.

The Thailand government has set up incentive programs and mechanisms to encourage investment. For example, the Fund for Energy Services Companies supports renewable energy development projects. Additional investment grants are available from the Energy Conservation Fund. Some of the earlier successful initiatives, such as the revolving fund, will be terminated.

The AEDP timeframe was updated to 2015–36 in 2015. The AEDP 2015 had a renewable energy target share of 30% of final energy demand (FED) by 2036. The target is equal to 39 388 ktoe, which can be divided into power generation of 19 684 MW (5 588 ktoe), heating of 25 088 ktoe and biofuels of 8 712 ktoe. Renewable energy development in Thailand is predominantly in solar, biomass, and biofuels. The breakdown of the 2015 target is shown in Table 6.

Table 6: The AEDP's Targets for 2036

Type of Energy	Targets in 2036	
Electricity	5 588	ktoe
	19 684	MW
1. Municipality Waste	500	MW
2. Industrial Waste	50	MW
3. Biomass	5 570	MW
4. Biogas (Sewage/Waste)	600	MW
5. Small Hydropower	376	MW
6. Biogas (Energy crop)	680	MW
7. Wind	3 002	MW
8. Solar	6 000	MW
9. Large Hydropower	2 906	MW
Heating	25 088	ktoe
1. Waste-to-Energy	495	ktoe
2. Biomass	22 100	ktoe
3. Biogas	1 283	ktoe
4. Solar	1 200	ktoe
5. Others (for example, geothermal, pyrolysis gas, and so on)	10	ktoe
Biofuels	8 712	ktoe
1. Biodiesel	14	million litre/day
2. Ethanol	11	million litre/day
3. Pyrolysis Oil	0.5	million litre/day

4. Compressed Biogas (CBG)	4 800	tonne/day
5. Others (for example, bio oil, hydrogen, and so on etc.)	10	ktoe
Renewable Energy Consumption	39 388	ktoe

Sources: AEDP 2015, DEDE (2016)

The AEDP 2015 was again reviewed and revised (now AEDP 2018) and covers 2018–2037. The AEDP 2018 has maintained the target for a renewable energy share at 30% of FED by 2037 but has increased the target power generation from biomass, biogas, and solar hybrid to 1 933 MW, and has adjusted the ratio of biofuel down (AEITF, 2020).

NUCLEAR ENERGY

In the most recent development to revise PDP 2015 to PDP 2018, the government has withdrawn nuclear power from future energy plans. The Thailand 20-Year Power Development Plan (PDP 2010) had included 5 GW of nuclear power, aimed at ensuring a sufficient energy supply and diversifying the power energy mix. Subsequent revisions to the PDPs had continued to incorporate nuclear power, but at lower and lower capacities. These plans have been superseded by changing the economics of generation technologies and community attitudes to nuclear power.

CLIMATE CHANGE

Climate change is an important issue in Thailand, even though Thailand only accounts for a small proportion of greenhouse gas (GHG) emissions. According to Thailand's Second National Communication, 67% of GHG emissions are from the energy sector. At the COP20 in Lima, Thailand pledged a pre-2020 contribution of 7–20% GHG emission reduction from BAU levels in the energy and transport sectors.

Thailand recognises that a long-term and continuous effort is required to address climate change. The Climate Change Master Plan 2015–50 provides a framework for measures and actions over the long term to achieve climate-resilient and low-carbon growth in line with a sustainable development path to 2050. This framework plan has already been approved by the cabinet. Relevant agencies are formulating specific sector plans to address the overarching goals.

Thailand submitted its Intended Nationally Determined Contribution (INDC) to the United Nations Framework Convention on Climate Change. Thailand's INDC is for emissions reductions of 20% from the current BAU levels by 2030 (ONEP, 2015). The ambitious targets in the PDP 2018 Rev.1, AEDP 2018, and EEP 2018 will contribute to realising this national objective.

NOTABLE DEVELOPMENTS

THAILAND'S THIRD LNG IMPORT TERMINAL

The surge in global natural gas demand has meant Thailand faces natural gas shortfalls. Thailand is seeking to increase LNG import capability to help cope with future LNG demand 36 mmt by 2037. Current LNG regasification capacity is 12 mmt, with a new terminal to provide an additional 7.5 mmt by 2022.

A proposed third LNG import terminal was initiated by the Industrial Estate Authority of Thailand (IEAT) and Gulf MPT LNG Terminal Co. This new LNG regasification plant is worth USD 1.3 billion with first-phase capacity of 5 mmt. Commercial operation is scheduled for 2025 (NGI, 2019).

REVISED POWER DEVELOPMENT PLAN 2018

In February 2020, the Ministry of Energy introduced a revised power development plan, PDP 2018 Rev. 1, maintaining a target of 77 211 MW of installed capacity by 2037, a 9% increase on the target set in PDP 2015. Under the PDP 2018 Rev. 1, 56 431 MW of new capacity will be installed over the period 2018-2037. The proportion of natural gas in the energy mix will rise to a 53% share of all electricity generated by 2037 while the share of renewables will remain at 20% and coal's contribution will fall to 12% (AEITF, 2020; Krungsri Research, 2019). The new plan can be revised every five years to reflect technological changes occurring in the power sector (Bangkok Post, 2019).

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USEFUL LINKS

Department of Alternative Energy Development and Efficiency (DEDE)—www.dede.go.th

Department of Mineral Fuels (DMF)—www.dmf.go.th

Electricity Generating Authority of Thailand (EGAT)—www.egat.co.th

Energy Policy and Planning Office (EPPO)—www.eppo.go.th

Ministry of Energy (MoEN)—www.energy.go.th

Prime Minister's Office—www.opm.go.th

UNITED STATES

INTRODUCTION

The United States (US) is the world's second-largest economy, with a gross domestic product (GDP) of USD 18 trillion (2011 USD purchasing power parity [PPP]) in 2017 (World Bank, 2019). The US spans 9.9 million square kilometres (km²) (Census, 2010) and had a population of 325 million in 2017. Since 2000, the economy's population has grown at 1.0% per year. Per capita GDP in 2017 was USD 54 471, the fourth-highest among the Asia Pacific Economic Cooperation (APEC) member economies (World Bank, 2019).

The US enjoyed economic expansion from 1990 to 2000, recording annual growth of 3.4% in real terms, which then slowed to 1.9% from 2000 to 2017. In 2017, economic growth was 2.2%, up from 1.6% in 2016 (World Bank, 2019).

The US is the second-largest producer and consumer of energy in APEC. In 2017, the US had 61 billion barrels of proved oil reserves, 12 trillion cubic metres (tcm) of natural gas reserves and 251 billion tonnes of coal reserves (BP, 2018; BP, 2019).

Table 1: Key data and economic profile, 2017

Key data ^{a, b}		Energy reserves ^{c, d}	
Area (million km ²)	9.9	Oil (billion barrels)	61
Population (million)	325	Gas (trillion cubic metres)	12
GDP (2011 USD billion PPP)	17 711	Coal (billion tonnes)	251
GDP (2011 USD PPP per capita)	54 471	Uranium (kilotonnes U)	47

Sources: ^a Census (2010); ^b World Bank (2019); ^c BP (2018), BP (2019); ^d NEA (2018).

Notes: Oil reserves comprise crude, condensate and natural gas liquids. Coal reserves are defined as known economically recoverable quantities. Uranium reserves are considered to be reasonably assured resources at USD 130/kg U.

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

The total primary energy supply in the US in 2017 was 2 155 million tonnes of oil equivalent (Mtoe), including production and net imports. This represented a 0.4% reduction compared with the 2016 level. The decline mainly resulted from a 3.2% decrease in coal supply and a 1.4% decrease in natural gas supply in 2017. By fuel type, 37% of the supply came from crude oil and petroleum products, 30% from natural gas, 15% from coal and the rest from other sources such as nuclear energy, hydropower and geothermal energy. Only 8% of the economy's primary energy requirements in 2017 came from net imports. The share of net energy imports has declined from a peak of 32% in 2006 (EGEDA, 2019).

Primary oil supply in the US was 790 Mtoe in 2017, an increase of 0.8% from the 2016 level (EGEDA, 2019). In 2017, total proved oil reserves increased by 22% to 61 billion barrels. The US was the world's largest crude oil and natural gas liquids and condensate producer, averaging 13 million barrels per day (bbl/d) (BP, 2019). Almost two-thirds of US crude oil was produced in

the southwestern states of Texas, New Mexico and Oklahoma, plus the offshore Gulf of Mexico in 2017. Significant amounts were also produced in North Dakota, California, and Alaska (EIA, 2019e).

The US imported 2.9 billion barrels of crude oil in 2017. More than 60% of US imports came from the Western Hemisphere: Canada, Mexico, Venezuela, and Columbia. Another significant source of imports was the Mideast—Saudi Arabia and Iraq (EIA, 2019f). Oil import dependence, measured as petroleum net imports as a share of products supplied, was 19% in 2017, the lowest since 1967 (EIA, 2019g).

US primary natural gas supply was 644 Mtoe in 2017, a decrease of 1.4% from 2016. The economy's natural gas supply grew by 17% from 2010 to 2017 (EGEDA, 2019). In recent years, the production of inexpensive gas reserves from shale formations has resulted in an abundant supply and low wellhead prices (EIA, 2019d). The US held approximately 6.1% of the world's natural gas reserves in 2017 (BP, 2019).

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	1 992 570	Industry sector	261 423	Total generation	4 263 676
Net imports and others	174 072	Transport sector	625 379	Thermal	2 691 535
Total primary energy supply	2 155 229	Other sectors	488 329	Hydro	302 362
Coal	330 746	Non-energy	145 326	Nuclear	838 861
Oil	790 278	Final energy consumption*	1 375 131	Others	430 918
Gas	643 934	Coal	17 014		
Renewables	162 449	Oil	626 337		
Other	227822	Gas	322 270		
		Renewables	81 591		
		Electricity and others	327 920		

Source: EGEDA (2019) (data collected in December 2019).

* Final energy consumption and the corresponding breakdown by fuel type do not include non-energy uses. Total final consumption and the corresponding breakdown by sector includes non-energy uses. Half of the municipal solid waste used in power plants is assumed to comprise renewables.

In 2017, the US exported more natural gas than it imported for the first time since 1957 (EIA, 2018c). Lower-48 liquefied natural gas (LNG) exports began in February 2016 from Sabine Pass, Louisiana, with capacity expanding to four liquefaction units in 2017. Sabine Pass added an additional unit in 2018, and two more plants in Cove Point, Maryland, and Corpus Christi, Texas also began operation. In 2019, two more plants began operating in Cameron, Louisiana, and Freeport, Texas. In October 2019, annual LNG export capacity was 63 bcm (EIA, 2019j).

Primary energy supply of coal in the US totalled 331 Mtoe in 2017. This was a 3.2% reduction from 2016, partially due to renewables taking market share from coal in power generation (EGEDA, 2019). More than 70% of US coal production in 2017 came from five states, the three largest being Wyoming, West Virginia, and Pennsylvania (EIA, 2019k).

The US was the fourth-largest coal exporter in the world in 2017, following Australia, Indonesia, and Russia (BP, 2019). Primary coal exports amounted to 88 million tonnes (Mt), an increase of 61% from the 2016 level, but still below the 2012 peak of 114 Mt. More than half of exported coal was metallurgical, with most of the rest being steam coal. Europe was the largest importer of US

coal, constituting more than 40% of US net exports. Coal imports have declined from a peak of 33 Mt in 2007 to 7.1 Mt in 2017 (EIA, 2019k; 2019l).

At the beginning of 2017, the US had 47 kilotonnes of uranium reserves recoverable at less than USD 130 per kilogram, the fifth-largest reserves in APEC (NEA, 2018). In 2017, US production of uranium concentrate was 1.1 million kilograms, far below the 1980 peak of 20 million kilograms. Uranium concentrate production continues to decline in the face of declining prices, which were USD 44 to 55 per kilogram in 2017 (EIA, 2018d).

Total renewable energy supply in the US in 2017 was 162 Mtoe or 8% of the total primary energy supply. Supply increased by 4.1% from the previous year's level, with growth in hydro, wind, and photovoltaics. The largest renewable supply sources were biomass and liquid biofuels (EGEDA, 2019).

The US produced 4.3 million gigawatt-hours (GWh) of electricity in 2017, 63% of which came from fossil fuel plants, 20% from nuclear energy, and 17% from renewable energy (EGEDA, 2019).

FINAL ENERGY CONSUMPTION

In 2017, total final consumption in the US was 1 520 Mtoe, an increase of 0.2% from 2016, primarily because of non-energy consumption growth. While total final consumption includes non-energy, it excludes the heat of transforming primary energy into its final form—mostly in burning fossil fuels to generate electricity. The transport sector accounted for 41% of the total final consumption. The remaining proportion was consumed mostly by the residential and commercial sectors (32% combined share; defined as 'other' in Table 2), the industrial sector (17%), and the non-energy sector (10%). In terms of final energy consumption by fuel (excluding non-energy), petroleum constituted 46%, while electricity and natural gas constituted 24% and 23%, respectively. Coal contributed a modest 1.2% (EGEDA, 2019).

ENERGY INTENSITY ANALYSIS

US energy intensity significantly improved in 2017 (energy intensity is the amount of energy an economy uses or consumes for every dollar of GDP it produces). Primary supply intensity improved by 2.5% to 122 tonnes of oil equivalent per million USD (toe/million USD) in 2017, compared with 2016. Total final consumption intensity improved by 2.0% for the same period. Final energy consumption intensity, excluding non-energy, improved by 2.6% (Table 3).

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%) 2016 vs 2017
	2016	2017	
Total primary energy supply	125	122	-2.5
Total final consumption	88	86	-2.0
Final energy consumption excl. non-energy	80	78	-2.6

Source: EGEDA (2019).

RENEWABLE ENERGY SHARE ANALYSIS

The share of modern renewables consumed in the US increased to 9.2% in 2017, an increase of 0.5 percentage points from the previous year. In 2017, the consumption of modern renewables increased by 4.9%. Production of energy from hydro, wind, and photovoltaic (PV) sources increased, while that from municipal solid waste decreased. The use of modern biomass was largely unchanged in the power sector, while that of traditional biomass decreased significantly in the residential and commercial sectors (reflected by the large decrease in Table 4).

Table 4: Renewable energy share analysis, 2017

	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	1 380 881	1 375 131	-0.4
Non-renewables (fossil and others)	1 249 464	1 238 839	-0.9
Traditional biomass*	11 176	10 157	-9.1
Modern renewables*	120 241	126 135	4.9
Share of modern renewables in final energy consumption (%)	8.7	9.2	5.3

Source: EGEDA (2019).

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on), including biogas and wood pellets, are considered modern renewables, because data on wood pellets are limited.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

JURISDICTION AND POLICY

Within the US Government, oversight of the production, transformation, transmission and consumption of energy is shared by several agencies in the executive branch. Supervision of natural resource development falls under the Department of the Interior (DOI). Energy-related research, development and deployment takes place mainly under the auspices of the Department of Energy (DOE). The Federal Energy Regulatory Commission (FERC) oversees the interstate transmission of energy, and the Environmental Protection Agency (EPA) regulates the environmental impact of energy transformations throughout the economy. The Department of Transportation (DOT) also plays an important role as the regulator of vehicle fuel economy. Compared with many Asian economies, the US Government has a more limited role in the energy sector and its involvement is more decentralised.

All these federal agencies influence energy policy, but it is the US Congress that is responsible for creating the laws that govern the activities of these agencies and for setting the rules for energy markets. Several major legislative packages have defined the economy's energy policies since the 1990s.

The Energy Policy Act of 2005 (EPAAct) was the first major piece of energy legislation passed since the Energy Policy Act of 1992 (US Congress, 2005; 1992). This was soon followed by the Energy Independence and Security Act of 2007 (EISA), the last piece of comprehensive energy legislation passed by the US Congress (US Congress, 2007). The American Recovery and Reinvestment Act of 2009 (ARRA) also dramatically increased funding for many federal energy programs (DOE, 2012). Key elements of these acts are described below.

As part of the federal system of government, the 50 state governments have a significant role in energy supply and consumption. On the supply side, states often regulate the environmental impact and safety of resource extraction and power generation, while on the demand side they regulate utility prices, safety and service.

ENERGY SECURITY

According to one ranking of large energy-consuming economies in 2016, the US was the most energy-secure economy in APEC (GEI, 2018). Oil import dependence, measured as net imports as a percentage of product supplied, peaked at 60% in 2005. By 2018, US import dependence declined to 11% by the same measure (EIA, 2019g).

As a member of the International Energy Agency (IEA), the US is obligated to maintain reserves equivalent to at least 90 days of the previous year's net imports (imports minus exports) (GAO, 2018). In 1975, the US established a strategic oil stockpile, called the Strategic Petroleum Reserve (SPR). The SPR comprises 60 storage caverns in underground salt dome formations located at four sites in Texas and the Louisiana Gulf Coast, and is the largest government-owned stockpile in the world (DOE, 2016a). At the end of 2018, 649 million barrels of crude oil were contained in the SPR, the equivalent of 277 days of net crude and petroleum product imports (based on average 2018 levels). This is more than triple the IEA reserve requirement (EIA, 2019g). Unlike most IEA members, the US relies on publicly owned reserves to meet its obligations, and holds most of its reserves as crude oil (GAO, 2018).

The recent rise in crude oil production and the resulting increase in number of days that production can cover crude and petroleum product imports, led Congress to pass seven laws from 2015 to 2018 that will reduce the amount of oil stored in the SPR to less than 400 million barrels by the start of 2029. The sales are designed to fund a variety of programs (CRS, 2019a).

In addition to the SPR, the DOE established a Northeast Home Heating Oil Reserve in 2000. Since 2011 it has stored 1 million barrels of ultra-low sulphur distillate fuel oil. DOE established a 1-million-barrel Northeast Gasoline Supply Reserve in 2014. These provide consumers with supplemental sources of home heating oil and gasoline in the event of supply shortages (GAO, 2018). The US Government does not hold strategic reserves of natural gas.

In December 2015, growing US crude oil production also prompted Congress to lift a 40-year-old ban on the export of crude oil (BIS, 2016).

FISCAL REGIME AND INVESTMENT

US fiscal policy related to the energy sector is complex. This section provides a limited introduction to the taxation of energy commodities and to the many fiscal incentives that shape energy-related investments. Energy-producing businesses are taxed like other US corporations, at a maximum statutory federal rate of 21%, and state rates range from 0% to 10%. However, tax rules result in different effective tax rates (US Congress, 2017a; CBO, 2005). A detailed discussion of the taxation of energy businesses is beyond the scope of this overview, but some provisions specifically related to energy investments are described here.

Royalty payments on the production of oil, gas and coal are made to the owner of mineral resources, which is sometimes the government. The US Office of Natural Resources Revenue collected USD 9.8 billion in royalty and other payments for extraction on federal lands in 2018. Royalties from crude oil accounted for 77% of the revenue collected from activities related to energy production on federal lands in 2018, while natural gas royalties accounted for 12% and

coal for 6%. Federal royalties are disbursed to federal, state and other funds. The US Treasury received the largest share of money in 2018 (USD 3.5 billion) (ONRR, 2019).

Downstream, sales of some important energy commodities such as gasoline and diesel are taxed by state and federal governments. The federal tax on gasoline and diesel is approximately USD 0.05 per litre (18.4 cents per gallon) and USD 0.06 per litre (24.4 cents per gallon), respectively. The average of state gasoline taxes is USD 0.07 per litre (25.45 cents per gallon), 38% higher than the federal tax. The average state diesel tax is also USD 0.07 cents per litre (27.06 cents per gallon), 11% higher than the federal tax. There is also approximately USD 0.01 per litre of other state taxes on gasoline and diesel (EIA, 2020b). Some states have also introduced a 'public goods charge' on retail electric and natural gas sales, the proceeds of which fund energy efficiency programs.

A variety of tax incentives have been introduced by the federal and state governments to promote investments in energy-related infrastructure. Tax expenditures often provide more government financial support to energy than direct expenditures and research and development (R&D) support (EIA, 2018f). Two key federal instruments are investment tax credits (ITCs) and production tax credits (PTCs). ITCs allow taxpayers investing in certain qualified energy facilities to reduce their tax burden by some fraction of the amount invested. Similarly, PTCs reduce the taxpayers' tax burden by an amount proportional to the energy production of the facility over a defined period. The types of facilities qualifying for ITCs range from coal gasifiers to wind turbines (IRS, 2018a).

RESEARCH AND DEVELOPMENT

The scope of energy-related R&D supported by the US Government has expanded from a nuclear energy and basic science focus in the 1960s to fossil fuels, energy efficiency, renewable energy and carbon sequestration. Much of this expansion occurred in the immediate aftermath of the 1973 oil crisis. In the five years following the crisis, spending on energy-related R&D more than tripled. New support for fossil energy, renewable energy and improved efficiency absorbed much of the increase. Although the amount of spending declined sharply during the 1980s, the broader scope was preserved (Dooley, 2008).

The DOE is the lead federal agency for energy R&D activities. It funds 17 laboratories as well as the research conducted at 300 universities across the US. Currently supported research ranges from particle physics to materials science (DOE, 2017b). Total government spending for energy-related R&D peaked in FY2009 at USD 3.8 billion with the passage of the ARRA, a one-time economic stimulus. After FY2009, US federal funding for energy R&D slid to USD 2.2 billion in FY2012 before increasing to an estimated USD 3.5 billion in FY2018 (NSF, 2019a). State governments spent an additional USD 397 million on energy R&D in FY2018, with more than 60% spent by the State of California (NSF, 2019b). Some business leaders in the US have argued that the government should more than double spending on energy R&D to address US energy challenges (AEIC, 2018).

ENERGY MARKETS

American consumers spent an estimated USD 1.1 trillion on energy purchases or 5.8% of GDP in 2017 (EIA, 2019g). Government plays many roles in this large market, such as those of resource owner, industry regulator and supporter of R&D.

UPSTREAM DEVELOPMENT

The DOI's Bureau of Land Management (BLM) administers more than 2.8 million km² of onshore underground mineral estates (BLM, 2018a). Approximately 103 000 km² was leased for oil and gas development in 2018 (BLM, 2018b). The Bureau of Ocean Energy Management (BOEM), another office of the DOI, leases another 1.3 million km² of offshore oil and gas resources (BOEM, 2019a). The BLM and BOEM also lease more limited onshore lands and offshore areas for the development of above-ground energy resources such as solar and wind.

While the US Government plays a large role in leasing surface and mineral rights, it is not the sole owner of such rights. Unlike most other economies, individuals and state governments also own and lease surface lands and underground mineral rights for energy extraction (DOI, 2017a). In 2018, only 21% of crude oil and 14% of natural gas were produced from federal lands (calculated from ONRR, 2019 and EIA, 2019g). State and federal governments share the regulation of upstream development. State oil and gas commissions prevent the waste of resources and protect public safety in state territories (IOGCC, 2004). In the federal offshore territory, the offices of the DOI exercise similar responsibilities.

The EAct promoted the domestic production of oil by removing some regulatory barriers and offering incentives for production from deep-water resources, low-production wells and unconventional sources. The law excluded underground injection of hydraulic fracturing fluids from the Safe Drinking Water Act of 1974, which allowed the exploitation of tight sand and shale hydrocarbon resources. Congress also encouraged the development of unconventional oil resources to reduce US dependence on foreign oil imports (US Congress, 2005).

After more than 40 years of debate, Congress authorised the opening of the Coastal Plain of the Arctic National Wildlife Refuge Section 1002 area to leasing, drilling and production as part of its 2017 year-end tax cut legislation (US Congress, 2017a). The BLM is proposing to open up 1.6 million acres of the coastal plain to oil and gas drilling in at least two lease sales. The BLM estimates that the area could produce 1.5 to 10 billion barrels of oil over the lifetime of the wells (BLM, 2019c). Alaska crude oil production is expected to increase by almost 900 000 barrels per day after 2030, as a result of this legislation (EIA, 2018e).

The BOEM has also approved a conditional permit for the first artificial island for oil and gas production in federal waters offshore Alaska (BOEM, 2018). Similarly, the BLM is moving to expand drilling in the National Petroleum Reserve in Alaska (BLM, 2019a).

In 2017, President Trump set a goal of achieving not just energy independence but “energy dominance,” by which he meant for the US to become a net energy exporter (White House, 2017c; 2017f). The DOI subsequently proposed opening more than 90% of federal offshore waters to drilling in 2018. Current policy places 94% of the Outer Continental Shelf off limits. There have been no offshore Atlantic lease sales since 1983 and none off the Pacific coast since 1984. In 2019, the US District Court for Alaska blocked part of Trump's 2017 executive order to open the Arctic and Atlantic Oceans for drilling (CRS, 2019b).

The Trump administration has also taken a variety of actions to make it easier to drill for, and produce oil and gas on federal lands, for instance, reducing the royalty rate to 12.5% for shallow offshore Gulf of Mexico lease sales (BOEM, 2017; 2019b); speeding up the process of granting permission for onshore drilling (DOI, 2017b); and proposing to streamline the issuance of oil and gas drilling permits in national forests (USFS, 2018).

Two tax incentives that have been historically important to the upstream oil and gas industry are depletion allowances and expensing exploration and development costs, including intangible drilling costs. A depletion allowance is a tax deduction to compensate for the depletion or ‘using up’ of natural resource deposits such as oil or natural gas. Intangible drilling costs include all the necessary expenses made by an operator in the drilling and preparation of wells, such as survey work, ground clearing, drainage, wages, fuel, repairs, supplies and so on, but are not expenses for the final operating well. This provision allows energy producers to deduct exploration and development costs including intangible drilling costs in the year spent as a current business expense, rather than depreciate them over time (IRS, 2018b). Deductions for depletion allowances were estimated at USD 670 million and for exploration and development costs, at USD 930 million in fiscal year 2019 (OMB, 2020).

Enhanced oil recovery receives substantial support from the federal government, as well. Spending on tertiary recovery receives a 15% tax credit (Section 43) adjusted for the price of oil (IRS, 2018c). In fiscal year 2019 the government spent an estimated USD 510 million on this credit. (OMB, 2020).

The EPA regulates waste from crude oil and natural gas exploration and production under the Resource Conservation and Recovery Act. Many states also regulate this waste (EPA, 2016a). Concerns about the impact of hydraulic fracturing on drinking water led the EPA to conduct an extensive study of this process. In December 2016, the EPA concluded that hydraulic fracturing can affect drinking water under some circumstances (EPA, 2016b). Nevertheless, in 2017, the BLM withdrew a rule proposed in 2015 to regulate hydraulic fracturing on federal lands, finding that all 32 states with federal oil and gas leases have regulations that address hydraulic fracturing (BLM, 2017).

The federal government plays a larger role in the production of coal than in the production of oil and gas. In 2018, 41% of US coal was produced from federal lands (calculated from ONRR, 2019 and EIA, 2019g). President Trump has encouraged 'reviving America's coal industry' (White House, 2017a) through multiple actions, for instance, cancelling a rule to protect streams from the mountaintop removal of mining waste (US Congress, 2017b), ending a moratorium on leasing federal lands for coal mining (BLM, 2019b), and proposing amended regulations for the disposal of coal ash, saving the utility sector about USD 40 million per year (EPA, 2019a).

DOWNSTREAM OIL

The US had almost 130 000 km of crude oil pipelines in 2018 and 101 000 km of oil product pipelines (PHMSA, 2019b). Interstate crude oil pipelines need the approval of state authorities; no broad federal approval is required. The Pipeline Safety and Hazardous Materials Administration (PHMSA) within the DOT sets minimum federal safety standards for pipeline facilities and transportation (CRS, 2016). The FERC sets oil pipeline rates and access conditions (FERC, 2016a). The export of crude oil and petroleum products is largely unregulated (BIS, 2016).

President Trump is promoting oil pipeline construction. During his first week in office, Trump issued presidential memoranda to advance the construction of the Keystone XL and Dakota Access oil pipelines (White House, 2017b; 2017e). Keystone XL is a 1 900 km crude oil pipeline to connect oil sands production in Alberta, Canada to refineries on the US Gulf Coast.

In 2019, President Trump issued a new permit for Keystone XL and the State Department published a draft environmental impact statement for public comment (State, 2019a). A group of environmental organisations filed suit against the US Army Corps of Engineers, alleging they had failed to adequately analyse Keystone XL's effects on local waterways, lands, wildlife and communities (USDMT, 2019). The Dakota Access Pipeline, a slightly longer project from North Dakota to Illinois, began operation in 2017 (ETP, 2017). However, in 2020 a U.S. District Court judge ordered a more extensive environmental review of the project (USDCC, 2020).

The US had 132 operating petroleum refineries with a capacity of 19 million barrels per calendar day at the beginning of 2019. Gross inputs to US refineries averaged 17 million barrels per day in 2018, the highest annual average on record and the fifth consecutive year of record-high inputs. More than half of all US refinery capacity is located on the US Gulf Coast; the Midwest has the second-largest refinery capacity. One new small refinery began operating in Texas in 2018 (EIA, 2019m; 2019n). In 2018 the US had the largest refinery capacity and throughput in the world (BP, 2019).

NUCLEAR ENERGY

The US generated more nuclear energy than any other global economy in 2019 (WNA, 2020). At the end of 2019 the U.S. had 96 operable commercial nuclear units, down from a peak of 112 units in 1990. The average utilization rate rose to more than 93% in 2019 (EIA, 2019g). Many nuclear plants have applied to the U.S. Nuclear Regulatory Commission (NRC) for 20-year extensions of their operating licenses initial 40-year license, enabling them to operate for 60 years. By late 2019, the NRC had approved active license extensions for 88 nuclear reactor units, and operators of three more units had informed the agency of their intention to seek extensions between 2022 and 2024 (NRC, 2019a). At the end 2019, the two-reactor Turkey Point Generating

Station in Homestead, Florida, received the first subsequent license renewal by the NRC to operate for up to 80 years (NRC 2019b). By the end of 2019 operators of six reactors had announced plans to retire them between 2020 to 2025 (NRC, 2020a; DOE, 2020; NRC, 2020b; CPUC, 2019).

The US Government supports the nuclear industry through various means, including legislative and financial. DOE supports research, development, and demonstration of nuclear energy technologies, while the NRC provides regulatory oversight of the industry. The Energy Policy Act (EPA) of 2005 included provisions important for revitalizing the American nuclear power industry. It extended the Price–Anderson Nuclear Industries Indemnity Act of 1957 (the Price–Anderson Act) limiting the legal liability of nuclear operators. EPA 2005 also authorized loan guarantees in support of the deployment of advanced nuclear technologies (US Congress, 2005). From 2014 to 2019, DOE issued USD 12 billion in loan guarantees to support the construction of two Westinghouse AP1000 Generation III+ reactors at the Alvin W. Vogtle Electric Generating Site in Waynesboro, Georgia (DOE, 2019b). Under the Bipartisan Budget Act of 2018 the Vogtle project also qualifies for an advanced nuclear PTC of 1.8 cents for each kWh of electricity produced and sold (US Congress, 2018a).

These actions are consistent with the president’s goal to revive and expand the nuclear energy sector (White House, 2017c). In 2018, the president signed the Nuclear Energy Innovation Capabilities Act to encourage partnerships between the DOE and private companies to develop new nuclear technologies (US Congress, 2018b).

RENEWABLE ENERGY

Incentives to promote renewables have been established at the federal, state and local levels for utilities and homeowners. At the utility level, a federal PTC is available on an inflation-adjusted per-kilowatt-hour basis for electricity generated primarily by wind through 2020 (Section 45). Utilities may elect an ITC in lieu of a PTC. A utility/commercial ITC primarily for solar (Section 48) phases down from 30% in 2017 to 10% in 2022 onwards (EIA, 2016b). In Fiscal Year 2019 the cost of the PTC was estimated at USD 4.23 billion, while the ITC cost USD 3.71 billion (OMB, 2020). A related residential ITC for small wind energy, geothermal heat pumps, solar electric, and solar water heating (Section 25D) phases down from 30% in 2017 to 22% in 2021 (CRS, 2018). In Fiscal Year 2019 the cost of this provision was estimated at USD 1.98 billion (OMB, 2020).

Federal loan and loan guarantee programs also encourage the development of renewable energy and other advanced energy facilities (DSIRE, 2019). The DOE Loan Program Office manages a portfolio of approximately USD 13 billion of loan guarantees covering 17 renewable projects (DOE, 2019c). In January 2018, President Trump approved a declining 30% four-year tariff on almost all imported silicon solar cells and modules, in addition to the existing tariffs on PV cells from China and Chinese Taipei (EIA, 2018a).

Many state and local governments have established financial measures that complement federal incentives for renewable investment. State legislation has provided significant indirect incentives for renewable development through the establishment of policy frameworks such as renewable portfolio standards (RPS), which mandate that a certain share of electricity sales be sourced from renewable energy. As of 2019, 29 states and the District of Columbia (DC) had enacted the RPS legislation with varying degrees of stringency. DC has the most ambitious goal: 100% renewable generation by 2032, and 11 states have RPS targets of at least 50% (LBNL, 2019). Other measures to support renewable development are net metering, generation disclosure rules, mandatory utility green power options, green power purchasing policies and the use of public benefit funds (DSIRE, 2019).

Biofuels have received strong policy support in the transportation sector. In 2007, the EISA mandated a five-fold increase from previous biofuel use targets, requiring fuel producers to use a minimum of 136 billion litres (36 billion gallons) of biofuel by 2022. This included the increase

in advanced biofuels usage (other than that derived from corn) to 79 billion litres (21 billion gallons) by 2022 (US Congress, 2007). Since this law was passed, US consumption of gasoline has flattened, causing the biofuel blend ratio in gasoline to rise unexpectedly (EIA, 2020a).

Biofuel production is tracking below the 2007 targets, even though nearly all US gasoline contains 10% ethanol. In 2019 the EPA mandated that just over 20 billion gallons of biofuels should be blended into the fuel supply for 2020, which is short of the 30 billion gallons envisioned by Congress in 2007 (EPA, 2019b).

The federal government has taken steps recently to increase biofuels production. In 2019, at the president's initiative, the EPA issued a final rule allowing gasoline with 15% ethanol (E15) to be sold year around. However, less than 2% of retail fuelling stations offer E15 (White House, 2018; EIA, 2019o). The EPA previously restricted E15 sales because of their potential to aggravate summertime smog problems (EPA, 2010). In December 2019 Congress renewed a USD 1 per gallon tax credit for biodiesel producers through 2022. This provision provided a USD 2.1 billion subsidy to producers in Fiscal Year 2019. Congress also renewed a USD 50-cent per gallon credit for cellulosic alcohol producers through 2020 (OMB, 2020). In February 2020 the US Department of Agriculture announced a new goal of 15% biofuels in transportation fuels by 2030 and 30% by 2050 (USDA, 2020).

ELECTRICITY AND GAS

The FERC regulates the interstate transmission of electricity and gas, as well as wholesale sales of electricity. The FERC's mandate is to 'ensure supplies of energy at just, reasonable and not unduly discriminatory or preferential rates'. In regulating wholesale electric power markets, the FERC has implemented a policy of fostering competition (FERC, 2008). This has meant granting open access to transmission lines, thereby allowing wholesale customers to meet their needs with purchases from multiple wholesale suppliers connected across a regional grid. Competitive wholesale electricity markets use distinct models in different regions. Regional transmission organisations and independent system operators administer transmission networks and operate wholesale markets across large parts of the US and Canada. In other regions, bilateral contracting between consumers and suppliers, with separate contracting for transmission, remains the norm (DOJ, et al., 2007).

Retail electricity markets are regulated by the states. Thousands of retail electricity providers operate under a variety of regulations. In 2017, 72% of retail customers were served by regulated, investor-owned utilities, 16% by public power systems and 13% by cooperatives (EIA, 2019r). State regulators ensure that these providers serve their customers at rates that are 'fair, reasonable and non-discriminatory' (NARUC, 2017).

In the 1990s, many states began to explore options for restructuring retail electricity markets to create competition among electricity providers, while continuing to regulate distribution networks as natural monopolies. Restructuring gave some consumers the option of buying only electricity generated by renewables. In 2018, 20 states and DC offered consumers a choice of electricity service provider. In general, residential customers pay more per kWh through competitive suppliers than non-competitive suppliers. Commercial and industrial customers are typically able to negotiate discounts and pay less than residential consumers (EIA, 2019p; 2019q). In 2017, 8% of electricity customers were served by energy-only providers (EIA, 2019b).

Natural gas markets are similar to electricity markets. Competitive wholesale markets supply federally regulated transmission pipelines that deliver natural gas to state-regulated distribution networks. The FERC sets natural gas pipeline rates. The DOE regulates the import and export of natural gas. The DOT's PHMSA regulates gas transmission pipelines to ensure that they are operating safely. The pricing and safety of natural gas distribution networks are regulated by state agencies (FERC, 2016b; EIA, 2009; DOE, 2016b).

The US natural gas pipeline transmission network was greater than 485 000 km in 2018 (PHMSA, 2019a). An additional 1 100 km was approved by the FERC in 2018, across 30 major projects

(FERC, 2019). To complement the pipelines, there were 385 active underground storage fields in the US with a working gas capacity of 135 bcm. On 11 November 2016, gas in storage peaked at a record 115 bcm (EIA, 2019i, 2019a). The Department of Health and Human Services subsidises primarily natural gas bills of low-income families through the Low Income Home Energy Assistance Program. This subsidy was USD 3.7 billion in 2019–20 (calculated from HHS, 2019). An additional \$900 million for this program over two years was included in the 2020 corona virus relief bill (US Congress, 2020).

ENERGY EFFICIENCY

Energy efficiency incentives exist at the federal, state and local levels. Federal grants and loans support residential efficiency improvements. The Weatherisation Assistance Program grants funds to states to pay for a variety of energy efficiency measures for low-income homes, including improvements to the building envelope, heating and cooling systems, electrical systems, and electricity consuming appliances. Homeowners can also obtain loans from the federal government to finance energy efficiency measures in new or existing homes (DSIRE, 2019). The US DOE sets minimum energy conservation standards for more than 60 categories of appliances and equipment, including washing machines, dishwashers, refrigerators/freezers, dehumidifiers, ceiling fans, water heaters, lighting, furnaces, boilers, heat pumps, air conditioners and motors (DOE, 2017a).

In December 2019 the DOE decided not to issue new standards for light bulbs, because they were not economically justified (DOE, 2019d). A few months earlier, in September 2019 the DOE rejected its previous 2017 definition change that would have included specialty bulbs in the new standards (DOE, 2019a). Efficiency advocates believe that the 2007 Energy Independence and Security act required a new standard of 45 lumens per Watt to come into effect on Jan. 1, 2020 (US Congress, 2007). Both 2019 rules are being challenged in court (USCA2nd, 2019; 2020.)

Many utilities administer demand-side management programs that provide incentives and technical assistance to reduce demand for electricity and natural gas (DSIRE, 2019). In 2017, 33 states and DC had efficiency targets that require electric and/or gas utilities to meet energy reduction targets over time (EIA, 2019s). At the local level, cities often use building codes to mandate building efficiency improvements (DSIRE, 2019).

CLIMATE CHANGE

In 2018, US energy-related carbon dioxide (CO₂) emissions were 5.3 billion metric tonnes. Energy-related CO₂ emissions declined in 6 of the 10 years since 2009. Petroleum was the largest source of CO₂ emissions, followed by natural gas and coal. Transportation was the largest emitting sector, followed by electric power, industry and buildings (EIA, 2019g). Emissions from fossil fuels produced on federal lands represented, on average, 24% of national CO₂ emissions from 2005 to 2014 (USGS, 2018). From 2005 to 2018, the carbon intensity of the US economy (CO₂/GDP) was down 29% (EIA, 2019t).

On November 4, 2019, the US submitted formal notification of its withdrawal from the Paris Agreement on Climate Change to the United Nations. The withdrawal will take effect on November 4, 2020 (State, 2019b). This follows the announcement that the US would withdraw from the Paris Agreement in 2017 (White House, 2017d). The US had previously submitted its Intended Nationally Determined Contributions to reduce economy-wide emissions by 26–28% below the 2005 levels by 2025 (UNFCCC, 2016). This previous commitment was part of the United Nations Framework Convention on Climate Change (UNFCCC). Congress has not passed legislation to control greenhouse gases. State and local governments have developed their own goals and action plans for greenhouse gas (GHG) emissions mitigation.

FEDERAL REGULATION

In 2019, the EPA issued the Affordable Clean Energy (ACE) Rule with new standards for reducing CO₂ emissions at existing coal-fired electric utility generating units. ACE replaces the more stringent 2015 Clean Power Plan (CPP) (EPA, 2019c). The Energy Information Administration

(EIA) assumes that to comply with ACE, coal-fired plants must either invest in heat rate improvement by 2025 or retire; 87 GW are expected to retire in 2020-2025. In 2050 CO₂ emissions from the power sector are projected to be 2% lower than without ACE (EIA, 2020c). In late 2018, the EPA proposed to loosen CO₂ emission standards for future fossil fuel-fired power plants from 1,400 pounds of CO₂ per MWh on a gross output basis for new large generators to 1,900 pounds per MWh. Supercritical steam technology was proposed as the best option for reducing emissions in large units (EPA, 2018a).

Despite the repeal of the CPP, Congress roughly doubled the 45Q coal tax credits to support CCS technology in coal plants and other facilities in the February 2018 Budget Act. Any new or existing fossil fuel power plant that commences construction before 2024 and captures more than 500,000 tonnes of CO₂ per year for EOR or secure geologic storage, or 25,000 tonnes per year of other utilization is eligible for tax credits for up to 12 years. For EOR the credit is \$20.21 in 2020, increasing linearly to \$35 in 2026; for secure geologic storage, the credit is \$31.77 in 2020, increasing to \$50 in 2026. (US Congress, 2018a). The tax credit is expected to benefit ethanol producers and natural gas processors, in addition to oil and gas drillers. The IEA estimated that the tax credits will add 10-30 million tonnes of CO₂ capture capacity (IEA, 2018). The Energy Futures Initiative, led by former US Energy Secretary Ernest Moniz, estimates that up to 100 million tonnes of CO₂ capture capacity could be added (EFI, 2018). The EIA believes that the enhanced tax credit will have no effect (EIA, 2019d).

The EPA sets limits on sulphur dioxide and nitrogen oxide emissions through the Cross-State Air Pollution Rule (CSAPR) and on mercury and toxic pollutants through the Mercury Air Toxics Standard (MATS). Under CSAPR, in the summertime power plants in 22 states in the Eastern US must limit sulphur dioxide and nitrogen oxides, which are precursors of fine particulates (soot) and ozone (smog), respectively. Implementation of the regulations began in 2015, with further modifications starting in 2017 (EPA, 2017). The MATS regulates acid gases and mercury from coal-fired plants of 25 MW or greater. Under the MATS, mercury emissions must be 88% below their uncontrolled levels (EPA, 2012). In 2018, the EPA proposed that the costs of the rule outweigh the benefits and that regulation of hazardous air pollutants is no longer 'appropriate and necessary' but did not propose a repeal of the rule (EPA, 2018c). EPA sets limits on particulate emissions under the authority of the Clean Air Act. Set in 2013 and proposed for retention in 2020, the daily PM₁₀ standard is 150 micrograms per cubic meter, while the annual PM_{2.5} standard is 12 micrograms per cubic meter and the daily standard is 35 micrograms per cubic meter (EPA, 2013 and 2020).

In 2018, the BLM repealed some of the key requirements of its 2016 Methane Waste Prevention Rule. The original rule aimed to reduce waste of methane from all oil and natural gas production activities on federal and tribal land. (Methane is the key constituent of natural gas and has a global warming potential more than 25 times greater than that of CO₂. (EPA, 2019d)). The BLM rescinded requirements for waste minimisation plans, gas-capture percentages, well drilling, well completion and related operations, pneumatic controllers, pneumatic diaphragm pumps, storage vessels and leak detection and repair. The BLM found that the 2016 rule would have imposed costs exceeding its benefits and might conflict with the EPA regulations (BLM, 2018c). California, New Mexico, and environmental advocates are challenging the repeal (CADOJ, 2018).

In 2016, the EPA issued a similar final standard to cut methane emissions from new, reconstructed and modified processes and equipment, including hydraulically fractured oil wells. In 2018, the EPA proposed to make it easier for drillers to meet the requirements by reducing the frequency of leak inspections and by giving operators more time to make repairs after a leak is detected (EPA, 2018b). The EPA also issued a final rule that requires new and existing municipal solid waste landfills to reduce methane emissions by one-third from the current requirement in 2016 (EPA, 2016c). About half of landfill gas is methane and half is carbon dioxide (EPA, 2019d).

STATE- AND CITY-LEVEL CLIMATE CHANGE INITIATIVES

In addition to federal actions to reduce GHG emissions, regions, states and cities have undertaken their own initiatives. Ten states in the north-east and mid-Atlantic US are members of the Regional Greenhouse Gas Initiative (RGGI), which focuses on reducing CO₂ emissions from fossil fuel power plants over 25 megawatts by 60% compared with the 2005 levels by 2020. Using a cap-and-trade system, the states sell emission allowances through auctions and spend the proceeds on energy efficiency, renewable energy, and other consumer benefit programs.

The RGGI has conducted 46 auctions thus far and plans an additional 30% regional cap reduction between 2020 and 2030 (RGGI, 2020). The six New England states are also party to the New England Governors/Eastern Canadian Premiers Climate Change Action Plan, whose 11 members resolved in 2015 to reduce the region's GHG emissions to 35–45% below the 1990 levels by 2030 and reaffirmed that goal in 2019 (NEG/ECP, 2019).

In 2018, then California Gov. Jerry Brown issued an executive order setting a state-wide goal of achieving carbon neutrality by 2045 and maintaining net negative emissions thereafter (CAGov, 2018). Brown signed into law a bill requiring that California end-use customers get all their electricity from renewable and zero-carbon sources by 2045, and requiring the state to increase the renewable portfolio standard to 60% by 2030 (CALeg, 2018).

In 2017, California extended its five-year-old cap-and-trade program, which applies to both utilities and non-utilities, to 2030 (EIA, 2018b). In 2016, the state legislature passed a bill to set a target of reducing GHG emissions to at least 40% below the 1990 levels by 2030 in legislation (EIA, 2019u). The California Air Resources Board (CARB) has developed an implementation plan to reach the 2030 goal by adding 4.2 million zero-emission vehicles by 2030, and aiming for a 40% reduction in methane emissions below the 2013 levels by 2030, among other goals (CARB, 2017). In 2020 the California Public Utilities Commission adopted planning targets for electricity providers to bring online nearly 25 GW of additional renewable and storage resources by 2030 (CPUC, 2020).

California leads a global effort by cities, states and economies to limit GHG emissions to two tonnes per capita or 80–95% below the 1990 levels by 2050. The Under 2 Coalition was formed in 2015 by the states of California and Baden-Wurtemberg, Germany. The coalition represents 220 governments with more than 1.3 billion people and 43% of the global GDP (including 12 US states) (Under2, 2020).

In reaction to the US withdrawal from the Paris Agreement, 20 state governors representing 47% of the US population and more than half of US GDP have joined the bipartisan United States Climate Alliance. They have pledged to implement policies that advance the goals of the Paris Agreement and aim to reduce GHG emissions by at least 26–28% below the 2005 levels by 2025. The group has reduced emissions more rapidly than the rest of the economy, while growing per capita GDP three times faster (USCA, 2019).

Municipal governments have undertaken other GHG initiatives. The Climate Mayors network was formed in 2014 by the mayors of Los Angeles, Houston and Philadelphia, with each of the more than 438 cities in the coalition setting GHG reduction targets (CM, 2020). The earlier Climate Protection Agreement, launched in 2005 through the US Conference of Mayors, had 1 066 signatories by 2019. The goal of these mayors is to reduce CO₂ emissions below the 1990 levels (USCM, 2019).

VEHICLE EMISSION STANDARDS

In 2020, the EPA and DOT's National Highway Transportation Safety Administration (NHTSA) set new Corporate Average Fuel Economy and tailpipe carbon dioxide emissions standards for passenger cars and light trucks for model years 2021 through 2026. Fleet fuel standards for 2025 were reduced from 23.2 km per litre (54.5 miles per gallon) to 17.0 km per litre (39.8 miles per gallon). The agencies estimate that the rollback would increase fuel consumption by 1.9-2.0

billion barrels and CO₂ emissions by 867-923 million metric tonnes through model year 2029 (NHTSA, 2020).

In 2016, the EPA and NHTSA released new fuel economy standards for semi-trucks, large pickup trucks and vans and all types of buses and work vehicles for 2018 to 2027. These standards were projected to reduce fuel consumption 8–24% (compared with model year 2017 vehicles), reduce GHG emissions by approximately 1 billion tonnes, and save approximately 1.8 billion barrels of oil (NHTSA, 2016).

In addition to the EPA vehicle standards, California had been the only state with the right to enact its own emission standards for new engines and vehicles, which were often more stringent than the EPA standards. By August 2019, 13 other states, constituting more than a third of the US auto market, adopted CARB's advanced clean car program standards, which retained the 23.2 km per litre federal standard (CARB, 2019).

However, in September 2019, the EPA and NHTSA revoked California's authority to set its own pollution standards, affirming pre-emptive federal authority to set national fuel economy standards under the provisions of the Energy Policy and Conservation Act of 1975 (EPA, 2019e). The next day California and 22 other states challenged the decision in federal court, arguing that California's authority to set its own pollution standards dates back to the Clean Air Act of 1970 (CADOJ, 2019).

In 2012, the CARB issued a rule for its zero-emission vehicle (ZEV) program for model years 2018 and beyond, which subsequently included battery electric and hydrogen fuel cell vehicles. The ZEV sales requirement for large manufacturers was 9.5% in model year 2020 and will increase to 22% by model year 2025 (CARB, 2012).

The number of US electric vehicle charging stations rose to more than 61 000 in 2018, an increase of 21% from 2017. Hybrid vehicle sales declined 5.4% from 2017 to approximately 343 000 in 2018, and down from the 2013 peak. However, plug-in hybrid vehicles sales were up by more than one-third from 2017 and all-electric vehicle sales more than doubled from 2017, both the highest ever. Together, plug-in hybrid and all-electric vehicle sales were approximately 362 000, exceeding hybrid sales. Nevertheless, hybrid, plug-in, and all-electric vehicle sales were only 4.2% of all light duty vehicle sales in 2018 (ORNL, 2019). An ITC of USD 2 500 to 7 500 is available for plug-in electric vehicles depending on the size of the vehicle and its battery capacity (Section 30D). The tax credit is available until 200 000 qualified vehicles have been sold in the US by each manufacturer (IRS, 2019). Phase-out of the Tesla and General Motors tax credits began in 2019 (IRS, 2020). The fiscal year 2019 tax expenditure on this provision was estimated at USD 940 million (OMB, 2020).

NOTABLE ENERGY DEVELOPMENTS

US BECOMES NET MONTHLY OIL EXPORTER

In September 2019, the US became a net oil exporter for the first time since monthly records began in 1973. The trend continued even more strongly in October 2019. About 10 years earlier at the beginning of 2009, the US imported 11 million barrels of crude oil and petroleum products more than it exported (EIA, 2019v). Factors contributing to this shift are the rapid growth of US shale oil production, the end of a ban on crude oil exports, and vehicle fuel economy improvements. The EIA predicts that the economy will become a net petroleum exporter on an annual basis in 2020 (EIA, 2019g, 2019w). Despite this status, the US remains a large importer of crude oil. Large exports of diesel fuel, gasoline, propane and other petroleum products are driving the net exports position.

US AND CHINA SIGN PHASE ONE TRADE AGREEMENT

In January 2020, trade tensions eased between the US and China with the signing of a phase one trade agreement. China has agreed to buy energy products above the 2017 baseline totalling

USD 18.5 billion in 2020 and USD 33.9 billion in 2021. (USTR, 2020). In February 2020 China began implementing the trade agreement by cutting tariffs on ethanol, liquefied natural gas, propane, crude oil, metallurgical coal and sub-bituminous coal (CEC, 2020). In the past few years these tariffs had led to a reduction in US energy trade with China, with crude oil exports to China dropping to zero at one point (EIA, 2019c).

NATIONAL COMMUNITY SOLAR PARTNERSHIP REINVIGORATED

In September 2019, the DOE announced the reinvigoration of the National Community Solar Partnership, a coalition of community solar stakeholders working to expand access to affordable community solar to every American household by 2025. The DOE found that nearly 50% of households and businesses are unable to host rooftop solar systems. Providing access to community solar options, such as shared photovoltaic projects, helps connect more people with clean energy. The program aims to make solar accessible and affordable to every US household, allowing more people to offset monthly energy bills, while increasing their community's resiliency, enhancing workforce opportunities, and spurring economic development (DOE, 2019e).

COAL FIRST INITIATIVE FUNDING ANNOUNCED

In April 2019, the DOE announced USD 100 million in planned investments in the Coal FIRST (Flexible, Innovative, Resilient, Small, and Transformative) initiative. Coal FIRST aims to develop coal plants of the future to provide secure, stable, reliable power with near zero emissions. The DOE is supporting R&D projects that will help develop plants that: are capable of *flexible* operations to meet the needs of the grid; use *innovative* and cutting-edge components that enable improved efficiency and have near zero emissions with CO₂ capture; provide *resilient* power; are *small* compared with conventional utility-scale coal plants; and *transform* how coal power plant technologies are designed and manufactured (DOE, 2019f). Funding has been devoted to carbon capture techniques and to the repurposing of waste carbon dioxide (NETL, 2019).

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California Air Resources Board-- www.arb.ca.gov

Database of State Incentives for Renewables and Efficiency— www.dsireusa.org

Department of Energy— www.energy.gov

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Energy Information Administration— www.eia.gov

Environmental Protection Agency— www.epa.gov

Federal Energy Regulatory Commission— www.ferc.gov

Fuel economy— www.fueleconomy.gov

Nuclear Regulatory Commission— www.nrc.gov

Pipeline and Hazardous Materials Safety Administration-- www.phmsa.dot.gov

US Congress-- www.congress.gov

The White House-- www.whitehouse.gov

VIET NAM

INTRODUCTION

Viet Nam is an S-shaped economy located at the centre of Southeast Asia. It is bordered by China to the north, Laos and Cambodia to the west, and the East Sea (Bien Dong) and Pacific Ocean to the east and south, respectively. Viet Nam has a land area of 331 236 square kilometres (km²), with diverse geography and an exclusive economic zone stretching 365 km from its 3 260 km coastline (excluding islands). As it is in a tropical monsoon zone and profoundly affected by the East Sea, Viet Nam has warm weather in most of the territory, abundant solar radiation, high humidity and generous seasonal rainfall. Viet Nam was part of the final batch of economies to join APEC in 1998.

Viet Nam is a dynamic emerging economy with a population of 95 million (36% live in cities and 66% in rural areas [GSO, 2019]) and a gross domestic product (GDP) of USD 590 billion (2011 USD purchasing power parity [PPP]) in 2017 (Table 1). Since Doi Moi (comprehensive economic reforms in 1986), Viet Nam has transformed from a self-isolated, centrally planned economy to its current open, socialist-oriented market economy, with active international integration. Viet Nam's GDP grew at an average of 5.3% per year in the period of 2000-17. GDP growth was 7.1% in 2018, which was the highest growth rate in 10 years.

Viet Nam's economic structure has gradually shifted from agriculture in recent decades. The industry and service sectors expanded from 62% of the economy in the early 1990s to 75% in 2018. Major exports include electronics, machinery textiles, garments and footwear.

In 2019, Viet Nam ranked 70th in the world for its business environment. Accessing electricity is the most progressive sub-indicator (27th in the world) (World Bank, 2019). Electrification in rural areas and remote islands is 99%. The government has promoted 'green growth' since 2012 for Viet Nam's ongoing industrialisation and modernisation (PMVN, 2012a).

Table 1: Key data and economic profile, 2017

Key data ^{a, b}		Energy reserves ^{c, d}	
Area (km ²)	331 236	Oil (billion barrels)	4.4
Population (million)	95	Gas (billion cubic metres)	646
GDP (2011 USD billion PPP)	590	Coal (million tonnes)	3 360
GDP (2011 USD PPP per capita)	6 233	Uranium (kilotonnes U)	-

Sources: ^a GSO (2019); ^b EGEDA (2019); ^c BP (2019); ^d NEA-IAEA (2019).

Viet Nam is endowed with diverse energy resources, such as oil, gas, coal and renewables. Thorough resource assessments have yet to be carried out across the entire territory, especially in deep layers and deep-sea areas. Even so, Viet Nam's proven fossil energy reserves are substantial at 4.4 billion barrels of oil, 646 billion cubic metres (bcm) of gas and 3 360 million tonnes (Mt) of coal in 2019 (Table 1). The OECD estimates the identified recoverable resources of uranium at approximately 3 900 tonnes, though this remains to be proven (NEA-IAEA, 2019).

Assessments and surveys have been undertaken on Viet Nam's renewable energy potential, especially for large hydropower (APEREC, 2016). The technical potential of large hydro facilities is estimated at 123 terawatt-hours (TWh)/year or 31 gigawatts (GW) by the Institute of Energy (2017). The potential of small hydropower facilities (less than 30 megawatts [MW]) is estimated to be 7 GW. Potential capacity for biomass is 53 Mt, while onshore wind is 27 GW, and solar is 340 GW. The energy sector more broadly has been important in attracting foreign investment,

boosting industry growth, increasing export earnings, and promoting scientific and technological development.

ENERGY SUPPLY AND CONSUMPTION

PRIMARY ENERGY SUPPLY

Viet Nam's total primary energy supply (TPES) in 2017 was 78 893 kilotonnes of oil equivalent (ktoe), a 1.6% increase from the 2016 level (Table 2). By energy source, 36% of the supply came from coal, 27% from oil, 27% from renewables, 9.9% from natural gas and a small proportion from other sources (mostly biomass).

COAL

The sub-bituminous-rich Red River Delta coal basin accounts for a large proportion of Viet Nam's coal reserves. Development of this basin is still in the preliminary stages due to complex geological conditions and environmental and economic considerations. Domestic coal is largely produced and supplied through opencast and underground mines in the Quang Ninh province.

Viet Nam's decreasing coal production reflects changes in government policy to prioritise coal conservation for long-term domestic uses rather than for boosting exports. Viet Nam produced 38 Mt of coal in 2017, equivalent to 82% of peak production in 2011. Increasing domestic demand for coal meant that Viet Nam became a net coal importer in 2015. Import volumes have continued to increase, but a small proportion of domestic production is exported (5.8% of the economy's production in 2017). Coal imports are predicted to increase to meet fuel requirements for over 41 GW of new coal-fired power capacity that the government is building, and plans to build, in central and southern parts of Viet Nam (PMVN, 2016b).

OIL

Oil reserves are mainly offshore and in the southern part of Viet Nam. Similar to 2016, crude oil production continued to decrease by 10% in 2017 to nearly 14 Mt, with 47% exported. Based on current proven reserves, oil production will decline to as low as 5 Mt/year by 2035 (MOIT and DEA, 2017) since major fields in the Cuu Long Basin will have matured.

Viet Nam is a net crude oil exporter but a net importer of petroleum products. Total indigenous production reached 15 Mt in 2017. Net imports were 8.3 Mt. Viet Nam's first refinery, Dung Quat (148 000 barrel per day capacity), tempered the need for imports to meet Viet Nam's domestic demand in the early 2010s. Since 2013, petroleum product net imports have kept pace with economic growth. A second refinery, Nghi Son, began operating in late 2018 with the capacity of 200 000 barrel per day capacity. Crude oil imports will rise sharply to meet this new refinery demand (PVOil, 2019). Crude oil is mostly exported to China, Australia, Japan, South Korea and ASEAN while Viet Nam's largest source of crude oil imports is Kuwait.

NATURAL GAS

Viet Nam is self-sufficient in terms of natural gas supply. There are four offshore gas pipeline systems built to deliver gas from Viet Nam's oil and gas fields in the petroleum basins of Cuu Long, Nam Con Son, PM3 – Ca Mau and Red River Delta, to shores in the south-east and south-west regions of Viet Nam.

Viet Nam's natural gas supply in 2017 was approximately 7.8 Mtoe, an 8.3% decrease compared with the 2016 level. Under the government's direction. The Viet Nam Oil and Gas Group, PetroVietnam (PVN) and PVGas, a major member of PVN, are developing two major gas projects to deliver 5 - 7 bcm of additional gas supply per year from Block B, Ca Voi Xanh field to southern and central markets (PMVN, 2016b). Viet Nam has developed new infrastructure for importing LNG to diversify gas supply sources and ensure national energy supply security beyond 2021 (PMVN, 2017a; MOIT, 2015a).

POWER GENERATION

Vietnam Electricity (or EVN) is a state-owned company that has significant control over national power transmission and distribution, contributing 58% of power generation (EVN, 2019a). Total power generation in 2017 was 195 749 GWh, an increase of 8.7% from 2016. Hydro contributed 44% to total generation; 56% was from thermal energy sources (Table 2). Only a very small proportion of generation is from other renewable sources, but its share increased sharply (56%) from 2016.

Since 2004, Viet Nam has relied on biomass and electricity imports from neighbouring economies such as China and Laos to optimise electricity supply and electricity cost-effectiveness. These sources were relatively minor in the economy's power system during 2008–17 (approximately 2.5 TWh in 2017).

Table 2: Energy supply and consumption, 2017

Total primary energy supply (ktoe)		Total final consumption (ktoe)		Power generation (GWh)	
Indigenous production	65 152	Industry sector	34 788	Total power generation	195 749
Net imports and others	15 277	Transport sector	15 038	Thermal	109 278
Total primary energy supply	78 893	Commercial sector	2 244	Hydro	85 940
Coal	28 710	Residential sector	11 396	Nuclear	0
Oil	21 394	AFF and other NEC	1 147	Others	531
Gas	7 811	Non-energy	628		
Renewables	20 925	Final energy consumption*	64 614		
Others	53	Coal	15 192		
		Oil	20 306		
		Gas	1 043		
		Renewables	13 214		
		Electricity and others	14 859		

Source: EGEDA (2019) (data collected in December 2019).

* Final energy consumption and the corresponding breakdown by fuel types do not include non-energy uses. Total final consumption includes non-energy uses. Half of the municipal solid waste used in power plants is assumed to comprise renewables.

FINAL ENERGY CONSUMPTION

In 2017, Viet Nam's final energy consumption (excluding non-energy uses) was 64 614 ktoe, an increase of 3.9% from 2016 (Table 2). By fuel source, oil consumption contributed the largest share (31%), followed by coal (24%), electricity (23%) and renewable energy (20%).

Industry is an important sector for Viet Nam's economic output and accounts for the largest segment of final energy consumption at 53%. The industry sector consumed coal (almost half) and electricity as the main fuels. The transport sector is also a large energy-consuming sector, accounting for 23% of total final consumption. Transport remained the main consumer of petroleum products at two-thirds of the economy's total. Seventy percent of biomass is used in the industry sector, with most of the remainder used for cooking by households.

ENERGY INTENSITY ANALYSIS

In 2017, Viet Nam's energy intensity in terms of primary energy supply was approximately 134 tonnes of oil equivalent per million USD of GDP (toe/million USD), a 4.9% improvement from

2016. Total final energy consumption intensity improved by 2.7%, to 110 toe/million USD in 2017 (Table 3).

Table 3: Energy intensity analysis, 2017

Energy	Energy intensity (toe/million USD PPP)		Change (%)
	2016	2017	2017 vs 2016
Total primary energy supply	141	134	-4.9
Total final consumption	114	111	-2.8
Total final energy consumption excl. non-energy	113	110	-2.7

Source: EGEDA (2019).

RENEWABLE ENERGY SHARE ANALYSIS

Table 4 shows the share of modern renewable energy in final energy consumption increasing from 23% in 2016 to 25% in 2017. Final consumption of modern renewables increased by 10%, while energy consumption from traditional biomass remained almost unchanged.

For electricity, installed hydropower capacity quadrupled from 4.2 GW in 2005 to 17 GW in 2018, reflecting a compound annual growth rate of 13%. The total share of renewables increased from 38% in 2005 to 42% in 2018 on the back of hydro growth. Large hydropower will not continue its recent growth, which is likely to mean that the share of renewables will decrease.

Viet Nam has abundant solar, wind, and biomass energy potential, as well as additional small and medium hydro potential. The economy can significantly contribute to the APEC doubling of renewables goal if these potential resources are utilised.

Table 4: Renewable energy share analysis, 2017

Energy	2016	2017	Change (%) 2016 vs 2017
Final energy consumption (ktoe)	62 165	64 614	3.9
Non-renewables (Fossil fuels and others)	47 766	48 752	2.3
Traditional biomass*	3 920	3 915	-0.1
Modern renewables*	14 398	15 862	10
Proportion of modern renewables in final energy consumption (%)	23%	25%	6.0%

Source: EGEDA (2019).

* Biomass used in the residential and commercial sectors is assumed to be traditional biomass because solid biofuels are typically used in these sectors for heating (residential) and cooking (residential and commercial), with inefficient technologies that often have adverse effects on human health. This definition is applied to all APEC member economies, including those that are members of the Organisation for Economic Cooperation and Development (OECD) and those that are not (Non-OECD). All other renewables (hydro, geothermal and so on.) including biogas and wood pellets are considered modern renewables, although data on wood pellets are limited.

POLICY OVERVIEW

ENERGY POLICY FRAMEWORK

The Ministry of Industry and Trade (MOIT) oversees all industries, including energy. Within the MOIT, two departments (the Department of Energy Efficiency and Sustainable Development

and the Department of Oil, Gas and Coal) and two agencies (the Electricity Regulatory Authority of Viet Nam, ERAV and the Electricity and Renewable Energy Authority, EREA) are the key advisory and executive units assisting the MOIT's Minister with the management of the energy sectors. Most energy research and projection activities are carried out by the Institute of Energy.

PVN, the Vietnam National Petroleum Group (Petrolimex), Vietnam Electricity (EVN) and The Vietnam National Coal - Mineral Industries Group (Vinacomin) are the leading state-owned enterprises (SOEs) in the energy industries in Viet Nam. They actively contribute to formulating and implementing government-issued energy sector development strategies and plans.

The latest umbrella policy document is the 'National Energy Development Strategy to 2020, with a Vision to 2050' (PMVN, 2007a). The strategy addresses the Vietnamese Government's energy development views, objectives, policies and measures to achieve the 2050 vision. An updated strategic document is being prepared following Resolution 55 of the Politburo that called for energy development pathways to 2030 with an outlook to 2045 (Politburo, 2020).

Sectoral targets and policies for each five-year planning period are adjusted to updated assessments. During 2015–18, the prime minister approved strategies and master plans for the development of the oil and gas, renewable energy, coal and electricity sectors. Revised and new plans include the oil and gas strategy to 2025/2035¹ (PMVN, 2015b); the renewable energy strategy to 2030/2050 (PMVN, 2015c); the revised coal plan to 2020/2030 (PMVN, 2016a); the revised power plan for 2010–20/2030, also known as PDP7 (PMVN, 2016b), and the gas plan 2025/2035 (PMVN, 2017a).

Some of the main targets for energy development in Viet Nam to 2030 are:

- Meet domestic energy demand, to achieve the objectives of the 10-year Socio-Economic Development Strategy 2021–2030. Primary energy will reach 175-195 Mtoe by 2030, and 320-350 Mtoe by 2045; the total capacity of power sources will reach 125-130 GW by 2030 and the output power will reach 550-600 TWh.
- The proportion of renewable energy sources in the total primary energy supply will reach 15-20% by 2030, and 25-30% by 2045
- Total final energy consumption reaches 105-115 Mtoe by 2030, and reaching 160-190 Mtoe by 2045. Primary energy intensity will be 420-460 kgOE / 1,000 USD GDP in 2030, and 375 - 410 kgOE / 1,000 USD GDP in 2045.
- Building a smart, efficient grid system capable of connecting the regions; ensuring safe power supply, meeting N-1 criteria for important load areas and N-2 for especially important load areas. By 2030, the reliability of electricity supply will be among the top 4 in ASEAN, the power access index will be among the top 3 ASEAN.
- Oil refineries meet at least 70% of the domestic demand, and ensuring a strategic petroleum reserve of at least 90 days of net imports. Being capable of importing 8 bcm of LNG by 2030 and about 15 bcm LNG by 2045.
- The ratio of energy saving over the total final energy consumption compared to the normal development scenario will be around 7% in 2030 and about 14% in 2045.
- Reduce greenhouse gas emissions from energy activities compared to the normal development scenario by 15% in 2030, and 20% in 2045.

The MOIT is now working on the first ever draft of the National Energy Master Plan for 2021–2030 through 2050. There will be updated energy supply and demand projections and revision to the PDP8.

¹ Not open to public

ENERGY MARKETS

ELECTRICITY MARKET

Viet Nam's electricity market is characterised by the active participation of SOEs and private players involved in power generation and distribution on build-operate-transfer (BOT) and independent power producer bases. EVN is entrusted to manage the development and operation of the national power transmission system. In 2018, the total installed capacity of the power system was 48.8 GW. EVN owned 61% of capacity with remaining contributions from PVN (9%), BOT, Vinacomin and others (30%) (EVN, 2019a). EVN is still the sole provider of electricity transmission and distribution.

Since 2004, the Government of Viet Nam has set out a vision for a competitive power market as part of a long-term development strategy for the electricity sector. The Electricity Law of December (amended 2012), detailed in the Road Map (PMVN, 2013a, b) cements this vision. Competitive market development was planned to comprise three pilot phases, each of which has a pilot (usually in two years) and a full operation stage:

- Phase 1 (2006-14): Competitive Generation Power Market, VCGM
- Phase 2 (2015–21): Competitive Wholesale Electricity Market, VWEM
- Phase 3 (2021 forward): Competitive Retail Electricity Market, VREM

VCGM launched its pilot operation on 1 July 2011 and commenced full operation on 1 July 2012. A single buyer, the Electricity Power Trading Corporation, purchased power from all generators. There were 76 power plants with a capacity of 21 GW selling electricity in the spot market by the end of 2016. The first pilot year of the VWEM was 2016. Official operation of the VWEM began in January 2019.

Resolution 55 of the Political Bureau emphasises removing subsidies and breaking monopolies in the energy market (Politburo, 2020).

TARIFFS

Electricity prices are regulated by the government under market conditions (Provision 29 of Electricity Law 2004 and amendments in 2012). The average retail electricity tariff is defined in Decision 24 (PMVN, 2017c) and is based on the generation, transmission and distribution costs of the sector, while accommodating reasonable profits, and accounting for the costs of regulating, managing and supporting services in the electricity system. EVN calculates the tariff annually. For annual increases greater than 5%, EVN must seek government approval. The average retail tariff (exclusive of value-added tax [VAT]) was set to VND 1864.44/kWh in 2019 (USD 0.08/kWh), an 8.4% increase from the 2017 level and almost double the 2009 level. According to Global Petrol Prices, Viet Nam's electricity price (USD 0.08/kWh) is currently much lower than the world average (USD 0.14/kWh).

CRUDE OIL MARKET

Players in the upstream oil sector in Viet Nam are PVN (and its subsidiary PVEP), international oil companies and other foreign enterprises. According to the Petroleum Law 1993 and amendments in 2000 and 2008, the government reserves the right to be a priority buyer of oil production from contractors. In such cases, foreign contractors have the right to sell their oil at international prices.

Dung Quat in Quang Ngai province is Viet Nam's first refinery, and has 6.5 Mt capacity of crude oil per year (or 140 000 barrels per day). It has been operated by the Binh Son Refining and Petrochemical Company Limited (BSR) since 2009. BSR, PVOil and PVPower were PVN subsidiaries until they were fully equitised in 2018. The sweet crude oil supply to the Dung Quat refinery is mainly from domestic sources, including 60% from the Bach Ho field and 40% from offshore production. Imports remain a negligible contribution.

Viet Nam's crude oil market and imports are anticipated to increase alongside plans for expansion of refining capacity towards 2030. A 10 Mt refinery and petrochemical complex—PVN's Nghi Son project (in Thanh Hoa province, central Viet Nam)—began commercial operation in late 2018 after five years of construction. It is expected to meet approximately 40% of domestic petrol demand. A 16 Mt project, Long Son, is currently under construction, and is expected to begin operating 2022.

OIL PRODUCT MARKET

Refined fuels, including gasoline, diesel, jet fuel, kerosene, fuel oil, biofuels (E5 and E10) and other engine fuels (excluding liquefied petroleum gas (LPG) and natural gas products) are referred to as one product group in Viet Nam.

The government regulates the wholesale prices of these products based on a baseline selling price for the suppliers. The base price takes account of price elements including cost, insurance, freight; government taxes and levies (import tax, excise tax, VAT, environment tax); business expense norms; deductions for the Petroleum Price Stabilisation Fund; and profit norms. Exchange rates also affect the base price.

The E5, E10 base price also accounts for the monthly average price of fuel ethanol (E100). The Ministry of Finance takes a leading role in the calculation of each price element in the regulated base price. Starting from January 2018, E5 has been officially sold economy-wide to replace unleaded gasoline RON 92 after five years of compulsory pilot sales in several cities/provinces.

NATURAL GAS AND LPG MARKET

The government reserves the right to be the priority buyer of natural gases exploited and produced in Viet Nam. PVN and PVGas are the authorised buyers of natural gas from oil and gas contractors, and are the sellers to consumers in the Vietnamese market. According to the price law, natural gas prices are not subject to government regulation; all upstream sellers and downstream buyers are free to negotiate the price and other terms in the Gas Purchase and Supply Agreement (GPSA) with PVN and PVGas.

PVN submits any GPSA, including a price formula and level, to authorised organisations and the prime minister for approval before the GPSA goes into effect. PVGas is responsible for planning, developing and operating infrastructure projects to ensure a safe and reliable natural gas supply. PVN also supports natural gas exploration and production in Viet Nam.

Trading and distribution of LPG, and natural gas products are open to competition among all domestic and foreign investors. Such business activities are regulated under government decree No. 87 (GOV, 2018). The LPG market is partly supplied by the Dung Quat and Dinh Co Gas processing plant, and the rest is imported from China, Qatar, Saudi Arabia and other economies (PVGas, 2018). LNG is also a promising business in Viet Nam, backed up by the government's plan on importing LNG for power (PMVN, 2017a).

Construction on the first of six planned LNG terminals began in October 2019. The first plant is located to the southeast of Ho Chi Minh City, Thi Vai, and is expected to begin operating in 2022. Imported LNG will be used for gas fired Nhon Trach number 3 and 4 power plants. The annual one-million-ton capacity is expected to triple in Thi Vai's second phase by 2023. Construction of the Son My terminal in Binh Thuan province is planned to commence in 2021.

COAL MARKET

Vinacomin's production and sales account for 85% of the total coal market in Viet Nam (Hung and Son, 2018). The North-East Coal Corporation (originally owned by Vinacomin, now under the Ministry of Defence) is the only other coal producer that can supply the domestic market, while Vietmindo (an Indonesian-owned company) can only produce coal for export. PV Power Coal (owned by PVN) oversees coal imports and trading, and ensures the coal supply for their five new coal power plants, namely Vung Ang 1, Thai Binh 2, Long Phu 1, Song Hau 1 and Quang Trach 1. The forecast for total coal demand for these power plants is 16 Mt in 2020 and

20 Mt in 2030. Viet Nam exports coal to Japan, Korea, India and other ASEAN economies, while the sources of coal to Viet Nam are Indonesia, Australia and Russia.

Since 2009, the price of coal for local customers has been set at prevailing world prices. The exception is for power generators. Power generators pay only 60%–70% of the market price. The government has been preparing a strategy to deregulate the price of coal used for power generation.

ENERGY EFFICIENCY

National energy efficiency and conservation programs, often referred to as VNEEP (Viet Nam National Energy Efficiency Program), are approved by the prime minister and were implemented in the following periods: 2006–2010, 2011–2015 and 2019–2030 (PMVN, 2006, 2012b, 2019).

The 2006-2015 program objectives cover community stimulation, motivation and advocacy, science and technology, and mandatory management measures for carrying out coordinated activities related to the economical and efficient use of energy. Phase one of VNEEP for 2006–10 led to 4 900 ktoe in total energy consumption savings in the period, equivalent to 3.4 % of the total energy consumption. By the end of 2014, the regulation and guidelines of measures for enhancing energy savings and efficiency covered the transport (2011), agricultural (2013) and industrial sectors (2014). In 2013, the National Technical Regulation on Energy Efficiency Buildings was revised in line with the updated international trends of minimum standards for energy-efficient building exteriors and interior equipment.

Phase two (2011–15) results were discussed at the National Target Program's meeting on Energy Efficiency of 2011–15 (VNEEP, 2015). MOIT reported the level of energy savings at 5.7% of Viet Nam's total energy consumption during 2011–15. More information can be found in the Compendium of Energy Efficiency Policies of APEC Economies 2017 (APEREC, 2017).

Under VNEEP in 2012–17, Cleaner Production and Energy Efficiency (funded by the GEF/World Bank), brought legal frameworks and energy consumption plans for some industries. A USD 158 million project, mostly funded by the World Bank, is continuing to support industry with energy efficiency technology and practices.

Phase three (approved in 2019) targets energy intensive industries that harm the environment, transport, and construction. The vision extends to 2030. Total national energy consumption reduction targets are 5%–7% for 2019–25 and 8%–10% for 2019–30. The budget is larger (VND 4 400 billion from the state fund and other credit funds) and the goals are more ambitious and comprehensive than in phases one and two. Objectives include the establishment of a national energy data centre and training centres for energy efficiency by 2025.

On March 8, 2018, the Prime Minister issued Decision No. 279 / QD-TTg approving the National Program on Demand Side Management (DSM) for the period 2018-2020, with orientation to 2030. The overall goals of the DSM Program are to contribute to ensuring electricity supply, improving the quality of electricity and reliability of electricity supply, reducing the need for investment capital for new construction, expanding the electricity system, contributing to reducing the pressure on electricity price, environment protection and socio-economic development, raising economic efficiency of the electricity system in association with the sustainable development of the electricity and energy sectors.

DSM programs, especially the Demand Response Program, strive to reduce the peak load capacity of the national electricity system (compared to the forecast of load demand in national electricity development planning) by 300 MW in 2020, 1 000 MW in 2025 and 2 000 MW in 2030.

The Ministry of Industry and Trade is completing the legal framework, especially the policy mechanism, incentive mechanism for electricity units and customers to use electricity to participate in DSM programs in a proactive, positive and effective manner.

RENEWABLE ENERGY

In November 2015, the government first issued the national strategy of renewable energy for the period through 2030, with a vision extending to 2050 (PMVN, 2015c). Renewable energy development in Viet Nam continues to be integrated with the implementation of broader objectives of general socioeconomic development and industrial and sectoral deployment. For instance, modernisation and new rural development fuel diversification and the implementation of Viet Nam's pledge to mitigate the increase in greenhouse gas (GHG) emissions.

Ambitious targets are for commercial renewable energy to reach 37 Mtoe (31% of TPES) by 2020 and 62 Mtoe (over 32%) by 2030; renewable power (including large hydropower) to account for 38% of the total generation by 2020 and 32% by 2030; and biofuels to increase to approximately 5% of total transport fuel demand in 2020 (approximately 800 ktoe) and 13% (3.7 Mtoe) in 2030.

The government expects that accelerated renewable energy growth will contribute to mitigation of GHG emissions in energy activities of around 5% by 2020 and 25% by 2030, compared with business as usual (BAU). In March 2016, the prime minister approved the revised PDP7 to update and detail new targets and policy measures for renewable power developments in Viet Nam to 2030. Renewable energy needs to take an even more important role because of the absence of the halted nuclear power plant project in late 2016.

Support mechanisms and policies for renewable energy development include fiscal incentives (via import taxes, corporate income taxes and land taxes and fees), as well as credit incentives, as specified in legislation. For instance:

- approved electricity prices (avoided-cost tariffs, feed-in tariff [FiT]) for on-grid renewable energy
- standardised power purchase and sale contracts (20 years) within an obligation for EVN (or regional electricity utilities) to prioritise renewable energy in grid connection, the dispatch and purchase of electricity at approved tariffs
- a renewable portfolio standard obligation for major electricity generators and traders
- net metering for electricity consumers with simplified connection arrangements
- environmental fees for organisations using fossil fuels for energy production

In 2017, the prime minister circulated the first solar power development plan (PMVN, 2017b) and renewed in 2020 (PMVN, 2020). The MOIT issued a circular on project development and power purchase agreements for solar power projects to complement the prime minister's plan (MOIT, 2017). The FiT legislation for wind was also updated to attract more investors (PMVN, 2018).

Table 5: FiT for some renewable energies in Viet Nam

Renewable Energy	Tariff level	
	VND/kWh	US cents/kWh*
Wind onshore	1 928	8.5
Wind offshore	2 223	9.8
Biomass power	1 220	5.8

Solid waste power	2 114	10.05
Solar energy (ground-mounted)	1 644	7.09

Estimated at time of decision and subject to exchange rate fluctuations.

Source: PMVN (2014a, b, 2018, 2020)*

The FiT for solar, which was renewed in 2020, reduced the selling price from US cents 9.35/kWh (PMVN, 2017b) to three different levels: 7.09 for ground-mounted projects, 7.69 for floating projects and 8.38 for rooftop project. Besides, it is only applicable to projects coming into commercial operation before year 2021. The revised regulation for wind, with additional separation for offshore power compared with 2011 regulation, is available until 30 June 2020. Both solar and wind power contracts are valid for 20 years from the commercial operation date.

NUCLEAR

The government halted the Ninh Thuan nuclear power plant project in late 2016. There has been no mention of the possibility of a future restart.

CLIMATE CHANGE

A climate action plan was developed through Viet Nam's Intended Nationally Determined Contributions (INDC) in 2015. These intended contributions were converted into Nationally Determined Contributions (NDCs) in 2016 and incorporate mitigation and adaptation components. Viet Nam accounts for 0.5% global CO₂ emissions (GOV, 2015). Despite its relatively small contribution to emissions, Viet Nam is vulnerable to the most severe impacts of climate change and rising sea levels. This has been established by national and international analyses of climate change scenarios to 2100.

Viet Nam has set a target to reduce its GHG emission intensity by 8%–10% from 2010 levels by 2020, and after 2020, to reduce GHG emission intensity by 1.5%–2% per year on average (or 20% by 2030). These targets are Viet Nam's voluntary reduction. Additional international support is required for higher targets of 20% by 2020 and 30% by 2030 (PMVN, 2012a; GOV, 2015). Viet Nam's BAU scenario for GHG emissions was developed based on the assumption of economic growth in the absence of climate change policies. BAU began from 2010 (the latest year of the national GHG inventory). It includes energy, agriculture, waste, land use, land use change and forestry sectors. Emissions baselines and projections are:

- GHG emissions in 2010: 246.8 million tons carbon dioxide equivalent (tCO₂-e)
- Projections for 2020 and 2030 (not including industrial processes):
 - 2020: 474.1 million tCO₂-e
 - 2030: 787.4 million tCO₂-e

Viet Nam signed the United Nations Framework Convention on Climate Change in 1992 and ratified it in 1994. Viet Nam subsequently signed the Kyoto Protocol in 1998 and ratified it in 2002. Viet Nam has fulfilled all requirements to be considered an Annex II economy for developing clean development mechanisms under the protocol.

A National Strategy on Climate Change (Decision 2139/QD-TTg) was issued in 2011. It involves a century-long vision and is the foundation for all ministerial, sectoral and local strategies, plans and programs.

NOTABLE ENERGY DEVELOPMENTS

ENERGY DEMAND AND GROWTH IN 2019

Growth in electricity production and distribution was 9% in 2019 (10% in 2018 and 9% in 2017) according to the General Statistics Office. Even with a large increase in generation capacity,

Viet Nam still faces a risk of power outages (especially in the warmer south). This is because electricity demand will continue apace, accompanying high economic growth that is forecast to be 6.5-7% per year to 2030.

Coal is the cheapest source of energy supply for a developing economy like Viet Nam. Historically, Viet Nam has been a net exporter of coal, but sustained increases in domestic consumption meant that Viet Nam became a net importer of coal in 2016. In the *APEC Energy Demand and Supply Outlook* (7th edition, 2019), the economy is projected to rely on imported fuel (at least 51% of fuel import dependency in 2030), particularly coal. Despite the increasing prominence of coal, LNG is likely to become the energy of choice. Viet Nam has been constructing infrastructure to import about one bcm of LNG per year from 2022. PVGas invested in the second phase of the Nam Con Son 2 pipeline project so that it could receive natural gas from the Su Tu Trang (White Lion) field in conjunction with the first phase of Nam Con son 2.

Hydropower has been a clean, stable and reliable source of energy in Viet Nam, but reservoir capacity constraints mean that it is unable to meet growing demand. Improving energy efficiency, reducing energy losses and implementing conservation measures are important to strengthen energy security. Viet Nam is likely to accelerate its energy efficiency programs, which have gained notoriety in the economy (MOIT and DEA, 2019).

RENEWABLE ELECTRICITY AND NEW CHALLENGES

The total installed capacity of Viet Nam's power system was 55 GW in 2019, which is the second-largest capacity in the ASEAN economies, after Indonesia. Total generation, including imports, increased 8.9% from its 2018 level (EVN, 2020). Hydropower's contribution has begun to shrink (now at 31% in 2019) due to saturation. Fossil fuels (coal, gas and oil) contribute about half of the generation mix. Other types of renewables, including small hydropower, solar, wind and biomass account for as much as 16% of generation.

The decision to halt construction of the nuclear power plant in late 2016 interrupted long-term energy supply plans. The Government of Viet Nam strongly supports the growth of renewable energy, especially wind and solar, in the absence of nuclear power. Dozens of solar projects rushed to integrate to the grid before June 2019 to benefit from the favourable FiTs (PMVN, 2017b). Almost 4.5 GW of renewable energy power went online by late June 2019. Viet Nam is now the leader in renewables in the ASEAN region.

Grid overload and safety have meant that new projects in Ninh Thuan and Binh Thuan have had to restrict their capacity (EVN, 2019b). Local transmission systems have not been able to cope with large increases in electricity demand. The new 2020 FiT also means there is reduced incentive for solar development. Distributed energy sources like household solar rooftop are receiving greater policy attention.

RESOLUTION 55 FOR A NEW ENERGY STRATEGY

The Viet Nam energy regulatory system is still influenced by the 2007 strategy (PMVN, 2007a). In the rapidly changing domestic and international energy situation, the Politburo issued a resolution (No. 55) in early 2020 to orientate Viet Nam's new energy strategy to 2030, with a vision extending to 2045.

The strategy seeks to:

1. Ensure energy security for sustainable socioeconomic development
2. Align the socialism market-based economy with international trends
3. Develop different types of energy, especially clean and renewable energy
4. Take advantage of the industrial revolution 4.0 and digitalise the energy sector
5. Focus on energy efficiency and environmental protection

The objectives are for the renewable share in TPES to be 15–20% in 2030 and 25–30% in 2045; petroleum production to meet at least 70% of domestic demand; and GHG emissions from the energy sector to reduce by 15% in 2030 and 20% in 2045 compared with BAU. A new energy strategy based on resolution 55 is likely to be issued during 2020–2021.

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ABBREVIATIONS AND TERMS

<i>Abbreviation</i>	<i>Term</i>
B/D	barrels per day
Bcf	billion cubic feet
bcm	billion cubic metres
Btu	British thermal units
GW	gigawatt
GWh	gigawatt-hour
kL	kilolitre
km	kilometre
km/L	kilometres per litre
ktoe	kilotonne of oil equivalent
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
Mbbl/D	thousand barrels per day
ML	million litres (megalitre)
Mloe	Million litres of oil equivalent
MMbbl	million barrels
MMbbl/D	million barrels per day
MMBFOE	million barrels of fuel oil equivalent
MMBtu	million British thermal units
MMcf/D	million cubic feet per day
MMscf/D	million standard cubic feet per day
mpg	miles per gallon
Mt	million tonnes
Mtce	million tonnes of coal equivalent
Mtoe	million tonnes of oil equivalent
MW	megawatt
PJ	petajoules
Tbbl/D	trillion barrels per day
tce	tonnes of coal equivalent
Tcf	trillion cubic feet
toe	tonnes of oil equivalent
tU	tonnes of uranium metal
TWh	terawatt-hours
W	watt

ACRONYMS

AAGR	average annual growth rate
ACCC	Australian Competition and Consumer Commission
ACE	Affordable Clean Energy
ADB	Asian Development Bank
AEDP	Alternative Energy Development Plan
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AEP	Atomenergoprom
AER	Australian Energy Regulator
AESO	Alberta Electricity System Operator
APEC	Asia-Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
APG	ASEAN Power Grid
ARENA	Australian Renewable Energy Agency
ASEA	Agency of Security, Energy and Environment
ASEAN	Association of Southeast Asian Nations
ASEP	Access to Sustainable Energy Programme
ASTRID	Advanced Sodium Technological Reactor for Industrial Demonstration
BATAN	Badan Tenaga Nuklir Nasional
BAU	business-as-usual
BCA	Building and Construction Authority
BDPKS	Badan Pemeriksa Keuangan Republik Indonesia
BEC	Building Energy Code
BGC	Brunei Gas Carriers Sdn Bhd
BKPM	Badan Koordinasi Penanaman Modal
BLM	Bureau of Land Management
BNERI	Brunei National Energy Research Institute
BOE	Bureau of Energy
BOEM	Bureau of Ocean Energy Management
BOT	Build-Operate-Transfer
BP	British Petroleum
BPMC	Berakas Power Management Company Sdn Bhd

BRESL	Barrier Removal to the Cost-Effective Development and Implementation of Energy Efficiency Standards and Labelling
BSP	Brunei Shell Petroleum Company Sdn Bhd
BSR	Binh Son Refining and Petrochemical Company
BUMD	Badan Usaha Milik Daerah
CAGR	compound annual growth rate
CAIT	Climate Analysis Indicators Tool
CARB	California Air Resources Board
CCGT	Combined-Cycle Gas Turbine
CCHEN	Comisión Chilena de Energía Nuclear
CCIR	Carbon Competitiveness Incentive Regulation
CCS	Carbon Capture and Storage
CDM	Clean Development Mechanism
CEFC	Clean Energy Finance Corporation
CEN	Coordinador Eléctrico Nacional
CEPA	Closer Economic Partnership Arrangement
CERA	Cambridge Energy Research Associates
CFE	Committee on the Future Economy
CFL	Compact Fluorescent Lamp
CHP	combined heat and power
CIF	cost, insurance and freight
CIT	corporate income tax
CLP	Climate Leadership Plan
CLP	CLP Power Hong Kong Limited
CNE	Comisión Nacional de Energía
CNESA	China Energy Storage Alliance
CNG	compressed natural gas
CNPC	China National Petroleum Corporation
CNSOPB	Canada-Nova Scotia Offshore Petroleum Board
COAG	Council of Australian Governments
COGOA	Canada Oil and Gas Operations Act
COP	Conference of the Parties
COS	Cost of Service
COW	Contracts of Work
CPC	Chinese Petroleum Corporation

CPP	Clean Power Plan
CPRA	Canada Petroleum Resources Act
CSAPR	Cross State Air Pollution Rule
CSG	coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSP	concentrated solar power
CSP	Competitive Selection Process
DASAP	Demand Aggregation And Supply Auctioning Policy
DCS	District Cooling Systems
DEEP	Debottlenecking Project Financing for Small-scale Renewable Energy
DES	Department of Electrical Services
DfE	Design for Efficiency
DGEE	Directorate for Energy Efficiency
DGNREEC	Directorate General of New Renewable Energy and Energy Conservation
DMF	Department of Mineral Fuels
DOE	Department of Energy
DOI	Department of the Interior
DOT	Department of Transportation
DPE	Department of Petroleum and Energy
DPR	Dewan Perwakilan Rakyat
DR	demand response
DSM	Demand-Side Management
DSP	Development Strategic Plan
E&P	Exploration and Production
EAC	Energy Audit Code
EAS	East Asia Summit
EC	Energy Commission
ECA	Energy Conservation Act
ECCC	Environment and Climate Change Canada
EDB	Economic Development Board
EDGE	Enhancing Development and Growth through Energy
EDI	Exploration Development Incentive
EDPMO	Energy Department, Prime Minister's Office
EE	energy efficiency

EEAP	Energy Efficiency Action Plan
EEC	energy efficiency and conservation
EECA	Energy Efficiency and Conservation Authority
EEDP	Energy Efficiency Development Plan
EENP	Energy Efficiency National Partnership
EERS	Energy Efficiency Resource Standards
EGAT	Electricity Generating Authority of Thailand
EGEDA	Expert Group Energy Data Analysis
EI	energy intensity
EIPO	Energy Innovation Programme Office
EIRP	Energy Innovation Research Programme
EISA	Energy Independence and Security Act
EMA	Energy Market Authority
EMS	energy management systems
ENAP	Empresa Nacional de Petroleo
ENERCOM	Energy Regulatory Commission
EOR	enhanced oil recovery
EP	Exploration and Production
EPA	Environmental Protection Agency
EPC	Engineering Performance Contracting
EPIRA	Electric Power Industry Reform Act
EPNS	Energy Projects of National Significance
EPPO	Energy Policy and Planning Office
ERAV	Electricity Regulatory Authority of Viet
ERC	Energy Regulatory Commission
ERF	Emissions Reduction Fund
ERIA	Economic Research Institute for ASEAN and East Asia
ERP	Electronic Road Pricing
ESB	Energy Security Board
ESCO	Energy Service Company
ESPO	Eastern Siberia Pacific Ocean
ESS	energy storage system
ESSD	Energy Sector Strategic Directions
ETS	emission trading systems

ETS	emissions trading scheme
EV	electric vehicle
EVN	Vietnam Electricity
EVTF	EV Taskforce
EWP	Energy White Paper
FED	final energy demand
FERC	Federal Energy Regulatory Commission
FID	Final Investment Decision
FiT	feed-in-tariff
FOB	free-on-board
FOREM	Federal Wholesale Electricity Market
FPT	freehold production tax
FPV	floating photovoltaic
FRT	first registration tax
FTP	first tranche petroleum
GBI	Green Building Index
GDP	Gross Domestic Product
GFA	Gross Floor Area
GGA	Global Geothermal Alliance
GGP	Government Green Procurement
GHG	greenhouse gas
GIS	Geographic Information System
GNC	Gas Network Code
GNWT	Government of Northwest Territories
GOC	Government of Canada
GOM	Government of Manitoba
GOO	Government of Ontario
GOQ	Government of Québec
GPSA	Gas Purchase and Supply Agreement
GR	Government Regulations
GSO	Grid System Operator
GSO	General Statistics Office of Viet Nam
GTFS	Green Technology Financing Scheme
GTMP	Green Technology Master Plan

GWA	Geothermal Working Areas
HDB	Housing & Development Board
HDV	heavy-duty vehicles
HEPS	High Energy Performance Standards
HFC	hydrofluorocarbons
HKE	Hong Kong Electric Company Limited
HQ	Hydro-Québec
IBR	Incentive-Based Regulation
ICCC	Independent Consumer and Competition Commission
IEA	International Energy Agency
IIP	Index of Industrial Products
IMCSD	Inter-Ministerial Committee on Sustainable Development
IMO	Independent Market Operator
INDC	Intended Nationally Determined Contribution
IPCC	Intergovernmental Panel on Climate Change
IPL	International Power Line
IPM	Intermittency Pricing Mechanism
IPP	Independent Power Producers
IRENA	International Renewable Energy Agency
ISP	Integrated System Plan
ITC	Input Tax Credits
ITC	Investment tax credit
IUPTL	Izin Usaha Penyediaan Tenaga Listrik
IWMF	Integrated Waste Management Facility
JBIC	Japan Bank for International Cooperation
JICA	Japan International Cooperation Agency
JODI	Joint Organizations Oil Data Transparency
JOGMEC	Japan Oil, Gas and Metals National Corporation
JPDA	Joint Petroleum Development Area
KCH	Kumul Consolidated Holdings
KEEI	Korea Energy Economics Institute
KEN	Kebijakan Energi Nasional
KEPCO	Korea Electric Power Corporation
KMC	Kinder Morgan Canada

KNOC	Korea National Oil Corporation
KOGAS	Korea Gas Corporation
KPPA	Konebada Petroleum Park Authority
LCOE	Levelized Cost of Electricity
LDV	Light- and Heavy-Duty Vehicles
LED	Light Emitting Diode
LEED	Leadership in Energy and Environmental Design
LGSE	Ley General de Servicios Eléctricos
LNG	liquefied natural gas
LoA	letter of approval
LPG	liquefied petroleum gas
LRET	Large-scale Renewable Energy Target
LSS	Large-Scale Solar
LTA	Land Transport Authority
LTBR	the long-term Government of Canada bond rate
LTEP	long-term energy planning
LULUCF	Land Use, Land-Use Change, and Forestry
MATS	Mercury and Air Toxics Standard
MBIE	Ministry of Business, Innovation and Employment
MCC	China Metallurgical Construction Corporation
MEA	Ministry of Economic Affairs
MEE	Ministry of Ecology and Environment
MEELS	Mandatory Energy Efficiency Labelling Scheme
MELS	Mandatory Energy Labelling Scheme
MEM	Ministry of Energy and Mines
MEMI	Ministry of Energy, Manpower and Industry
MEMR	Ministry of Energy and Mineral Resources
MEPS	Minimum Energy Performance Standards
METI	Ministry of Economy, Trade and Industry
MIR	Minimum Inventory Requirement
MKE	Ministry of Knowledge Economy
MOA	Memorandum of Agreement
MOCA	Ministerial for Climate Action
MOE	Ministry of the Environment

MOEA	Ministry of Economic Affairs
MOIT	Ministry of Industry and Trade
MOTIE	Ministry of Trade, Industry and Energy
MOU	memorandum of understanding
MRA	Mineral Resources Authority
MRRT	Minerals Resource Rent Tax
MSW	Municipal Solid Waste
MTDP	Medium-Term Development Plan
MVA	mega-volt-ampere
NAMA	Nationally Appropriate Mitigation Actions
NCCP	National Climate Change Policy
NCRE	Non-Conventional Renewable Energy
NDC	Nationally Determined Contribution
NDRC	National Development and Reform Commission
NEA	National Energy Administration
NEA	Nuclear Energy Agency
NEA	National Energy Authority of Papua New Guinea
NEA	National Electrification Administration
NEA	National Environment Agency
NEB	National Energy Board
NEG	National Energy Guarantee
NEM	National Electricity Market
NEM	Net Energy Metering
NEMS	National Electricity Market of Singapore
NEP	National Energy Policy
NEPIO	Nuclear Energy Programme Implementing Organisation
NEPP	National Energy Productivity Plan
NEROP	National Electrification Rollout Plan
NESA	National Energy Security Assessments
NEV	Neighbourhood Electric Vehicle
NGL	natural gas liquids
NGTP	National Green Technology Policy
NGV	natural gas vehicle
NGVPPT	Natural Gas Vehicle Programme for Public Transportation

NHTSA	National Highway Transportation Safety Administration
NPC	National Power Corporation
NRA	Nuclear Regulation Authority
NRC	National Research Council
NRC	Nuclear Regulatory Commission
NRE	New and Renewable Energy
NREP	National Renewable Energy Programme
NREPAP	New and Renewable Energy Policy and Action Plan
NRF	National Research Foundation
NSCC	National Strategy on Climate Change
NTI	National Technology Initiative
NTNDP	National Transmission Network Development Plan
NUS	National University of Singapore
NWT	Northwest Territories
NZEECS	New Zealand energy Efficiency and Conservation Strategy
NZP&M	New Zealand Petroleum & Minerals
OECD	Organisation for Economic Cooperation and Development
OEM	Open Electricity Market
ORRC	Organic Resources Recovery Centre
PCECP	Philippine Conventional Energy Contracting Program
PDNGR	Philippine Downstream Natural Gas Regulation
PDP	Power Development Plan
PEP	Philippines Energy Plan
PESLP	Philippine Energy Standards and Labelling Programme
PGU	Peninsular Gas Utilisation
PHMSA	Pipeline Safety and Hazardous Materials Administration
PI	Participating Interest
PIDPT	Pengerang Independent Deepwater Petroleum Terminal
PIPC	Pengerang Integrated Petroleum Complex
PKUK	Pemegang Kuasa Usaha Ketenagalistrikan
PLN	Perusahaan Listrik Negara
PMB	Pulau Muara Besar
PMR	Partnership of Market Readiness
PNAA	The National Environmental Action Plan

PNG	Papua New Guinea
PNG	piped natural gas
PNOC	Philippine National Oil Company
POM	Port Moresby System
PPL	PNG Power Limited
PPP	Purchasing Power Parity
PPP	Public-Private Partnership
PPPC	Public-Private Partnership Center
PPS	Power Producers and Suppliers
PRLCE	Peer Review on Low Carbon Energy
PRRT	Petroleum Resource Rent Tax
PSALM	Power Sector Assets and Liabilities Management
PSC	Production Sharing Contract
PTC	Production Tax Credit
PTT	Public Company Limited
PTTEP	PTT Exploration and Production Plc
PUB	Public Utilities Board
PUP	Perjanjian Usaha Pertambangan
PV	photovoltaic
PVEP	PetroVietnam Exploration Production Corporation
PVN	PetroVietnam
QTP	Qualified Third Party
R&D	research and development
RAPG	Renewable and Alternative Power Generation
RAPID	PETRONAS Refinery and Petrochemical Integrated Development
RD&D	research, development and demonstration
RE	renewable energy
REC	renewable energy certificates
REDD	Reducing Emissions from Deforestation and forest Degradation
RET	Renewable Energy Target
RFP	Request-for-Proposal
RGGI	Regional Greenhouse Gas Initiative
RGT	Regasification Terminal
RMA	Resource Management Act

RPS	renewable portfolio standards
RRR	Reserve Replacement Ratio
RTS	Rapid Transit System
RUEN	Rencana Umum Energi Nasional
SB	Single Buyer
SCA	Scheme of Control Agreements
SCOD	Scheduled Commercial Operation Date
SEB	Sarawak Energy Berhad
SEC	Superintendencia de Electricidad y Combustibles
SEDA	Sustainable Energy Development Authority
SEN	National Electricity System
SERC	State Electricity Regulatory Commission
SERIS	Solar Energy Research Institute of Singapore
SESB	Sabah Electricity Sendirian Berhad
SIRIM	Standard and Industrial Research Institute of Malaysia
SIT	Special Industrial Tariff
SLNG	Singapore LNG Corporation
SME	Small and Medium Enterprise
SNI	Standar Nasional Indonesia
SOE	State-Owned Enterprises
SOE	State-Owned Energy Enterprises
SPARK	Sungai Liang Industrial Park
SPP	Small Power Producers
SPR	Strategic Petroleum Reserve
SRES	Scale Renewable Energy Scheme
SSLI	Smart Street Lighting Initiative
STF	Sludge Treatment Facility
TAC	Technical Assistance Contracts
TAGP	Trans-ASEAN Gas Pipeline
TFC	total final consumption
TFEC	total final energy consumption
TIEB	Thailand Integrated Energy Blueprint
TMX	Trans Mountain Pipeline
TNB	Tenaga Nasional Berhad

TPA	Third-Party Access
TPAS	Tiwai Point Aluminium Smelter
TPC	Taiwan Power Company
TPES	total primary energy supply
TREES	Thailand's Rating of Energy and Environmental Sustainability
UNFCCC	United Nations Framework Convention on Climate Change
URE	Unconventional, Renewable Energy
USACEP	US–Asia Pacific Comprehensive Energy Partnership
USGS	United States Geological Survey
USSR	Union of Soviet Socialist Republics
VAT	value-added tax
VNEEP	Viet Nam National Energy Efficiency Program
VPM	Venta de Primera Mano
VSP	Very Small Power Producers
VVER	Water–water Energetic Reactors
VWEM	Vietnam Wholesale Electricity Market
WACS	Water-cooled air-Conditioning systems
WCI	Western Climate Initiative
WCSB	Western Canadian Sedimentary Basin
WESA	WtE Services Agreement
WESM	Wholesale Electricity Spot Market
WNA	World Nuclear Association
WtE	Waste-to-Energy
WTO	World Trade Organization
ZEV	zero-emission vehicle

CURRENCY CODES

Code	Currency	Economy
AUD	Australian dollar	Australia
BND	Brunei dollar	Brunei Darussalam
CAD	Canadian dollar	Canada
CLP	Chilean peso	Chile
CNY	yuan renminbi	China
TWD	New Taiwan dollar	Chinese Taipei
HKD	Hong Kong dollar	Hong Kong, China
IDR	rupiah	Indonesia
JPY	yen	Japan
KRW	won	Korea
MYR	Malaysian ringgit	Malaysia
MXN	Mexican peso	Mexico
NZD	New Zealand dollar	New Zealand
PGK	kina	Papua New Guinea
PEN	nuevo sol	Peru
PHP	Philippine peso	Philippines
RUB	Russian ruble	Russia
SGD	Singapore dollar	Singapore
THB	baht	Thailand
USD	US dollar	United States
VND	dong	Viet Nam