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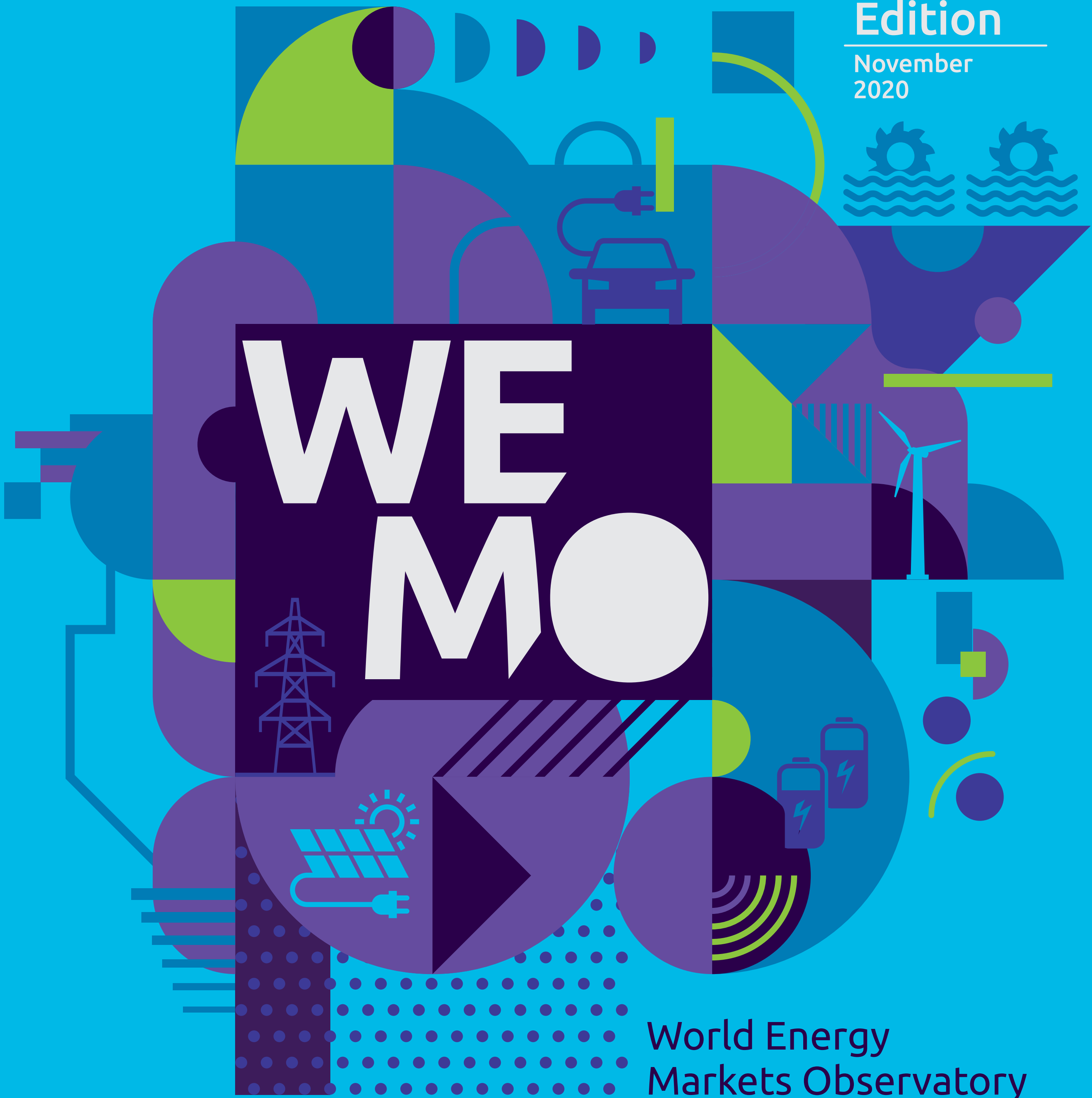

World Energy Markets Observatory

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WEMO 2020 Global Editorial

Colette Lewiner

This WEMO edition reviews an exceptional period with two distinctive phases:

- In 2019 worldwide economic slowdown combined with energy transition measures resulted in some improvements regarding climate change objectives. However, the world was not on track to meet the 2015 Paris agreement objectives.
- In 2020 our planet suffered from the COVID-19 pandemic and the economic crisis that followed, plunging our world into a long period of uncertainty.

In 2019, small progress in climate change objectives

In 2019, the worldwide economy slowed down. Average GDP for G20 countries increased by +2.9%, a 0.8 point decrease compared to 2018[1]. This resulted in a slower energy consumption increase: lower than expected oil consumption growth as a consequence of new vehicle efficiency standards, continuation of the coal to gas shift in power plants, and renewables development – all helping to decrease GHG[2] emissions. A contrasted evolution is observed between developed countries mastering energy and fossil fuel consumption and developing countries, notably China, where fossil fuel (notably coal) consumption and emissions growth continued.

Electricity is widely recognized as the best decarbonization vector, however its consumption growth across the G20 countries slowed down in 2019 (+0.7% vs +3.6% in 2018). China, which accounts for a third of G20 electricity consumption, posted a 4.5% growth, but this was much lower than the average growth observed since 2007 (7.5%per year).

Energy consumption increased less than in previous years: +0.7%[3] (compared to +2.2% in 2018). It decreased in OECD countries but increased in non-OECD ones. The reduction in energy intensity[4] is regular at around -1.5 to -2 points per year which reflects energy effectiveness progress.

Oil consumption grew by 0.9 million barrels per day (b/d) (or 0.9%) slightly lower than the 10-year average of 1.3%. The growth was weaker than expected as new vehicle efficiency measures have started to weigh on transport fuel consumption.

Growth was led by China, where demand rose by 680,000 b/d, the largest increase in the country's demand since 2015. In most developing countries the growth was below average. OECD demand fell by 290,000 b/d, the first decline since 2014.

Oil production fell slightly by 60,000 b/d in 2019 as strong non-OPEC production growth, led by the US (10% growth year on year), was offset by a sharp decline in OPEC production. Nevertheless, the market was well supplied, and oil prices decreased slightly, with Brent averaging $64.21/b, $7/b lower than in 2018. Compared with recent years, oil prices were relatively stable during the year. An exception was on Monday, September 16, 2019: After an attack on key energy installations in Saudi Arabia, the Brent oil price increased by $9/b. The price increase was relatively short, and prices returned to pre-attack levels by the end of the month as Saudi Arabia was successful in bringing production back online rapidly.

1 https://www.enerdata.net/publications/reports-presentations/world-energy-trends.html
2 GHG: Green House Gases
3 https://www.enerdata.net/publications/reports-presentations/world-energy-trends.html
4 Energy Intensity is measured by the quantity of energy required per unit output or activity.

Concerns about demand growth led OPEC+[5] countries to agree on December 7, 2019, to deepen the production cuts originally announced in December 2018.

Natural gas consumption increased by 2% in 2019 , below its 10-year average and down sharply from the exceptional growth seen in 2018 (5.3%). In volume terms, demand increase was led by the US and China.

Gas production grew by 3.4% outpacing growth in consumption. US natural gas production increased by 10% after strong growth in 2018. It accounted for almost two-thirds of net global growth. Australia and China also contributed to this supply growth.

Much of 2019's increase in gas production was used to feed additional exports of liquefied natural gas (LNG). LNG exports grew by 12.7%, the strongest import growth since 2010, driven by record increases from the US, where five terminals are now operational, and from Russia, which increased by 60% its LNG exports.

Nearly all incremental LNG supplies headed to Europe, which accounted for 36% of US LNG exportation.

The European Union is importing more and more LNG from the US to diversify its supplies and make them less dependent on pipeline imports from Russia.

US Henry Hub prices dropped almost 20% to average $2.53/Mbtu[6], while European and Asian prices fell by more than 40% (averaging $4.47/ Mbtu and $5.49/Mbtu respectively). Prices in Europe, the region most affected by LNG oversupply, fell to their lowest levels since 2004.

As international gas trade is still limited, prices differ from one region to another. While there is still a significant spread between US and European prices, thanks to LNG development the spread between Asia and European prices was only $1/ Mbtu.

Coal consumption decreased overall by 0.6%. It continued to increase in some emerging economies, particularly in China, Indonesia and Vietnam. These increases were more than offset by decreases in demand in the developed world (-10% in OECD countries) as a result of policies in place in Europe (notably in Germany) to close coal-fired plants. In the US cheap gas continued to replace coal in the power sector. As a result of gas consumption increase and renewables growth, coal's share in the energy mix fell to 27%, its lowest level in 16 years. Thermal coal prices fell by 30% over the year.

Nuclear energy:

In 2019, nuclear energy provided about 10% of the world's electricity from 450 power reactors and is the second lowest carbon source of electricity after hydropower[7].

The nuclear situation varies. In Europe and North America, construction of new plants is difficult and projects such as the two EPRs at Olkiluoto in Finland and Flamanville in France are experiencing huge delays and budget overruns[8]. At the Flamanville reactor (which should start operations in 2023) the cost of electricity produced is estimated at € 120/MWh, nearly triple EDF's price for its new offshore wind project at Dunkirk (€44/MWh).

In contrast Russia, China and other Asian countries are successfully building new plants. In China two EPRs built by CGN with EDF support successfully started operations in 2018 and 2019 after "only" five years' delay.

Early September 2020, nuclear fuel loading into the No. 5 unit of China's Fuqing Nuclear Power Plant under China National Nuclear Corporation started, marking an important step towards its operation that is scheduled to start by end 2020. The No. 5 unit is the world's first pilot project using China's indigenous third-generation nuclear power technology Hualong One.

In 2019[9], 5.5 GW of additional nuclear capacity were connected to the grid in Russia (including "Akademic Lomonosov", a 70 MW floating nuclear reactor[10]), China and South Korea and 9.4 GW were permanently shut down in US, Japan and Taiwan-China, bringing global capacity to 443 GW. New projects were launched (about 5.2 GW), and refurbishments are under way in many countries to ensure the lifetime extension of the existing fleets.

On August 1, 2020[11], the United Arab Emirates (UAE) successfully opened a nuclear power plant, becoming the first Arab country to produce nuclear energy and the first new country to launch a nuclear power plant in three decades, the last being China in 1990. The $24.2 billion (€19 billion) Barakah plant is being developed

5 OPEC + includes OPEC-Organization of Petroleum Exporting Countries- members at its allies notably Russia.

6 Mbtu: Million British Thermal Unit

7 https://www.iaea.org/newscenter/news/preliminary-nuclear-power-facts-and-figures-for-2019

8 According to the July 2020 "Cour des Comptes "report, Flamanville EPR budget was multiplied by 3 (total amount €12.4 bn) and construction time by 3.5. Delays for Olkiluoto EPR have reached 12 years with cost overruns similar to Flamanville's

9 https://www.iea.org/reports/nuclear-power

10 https://time.com/5659769/russia-floating-nuclear-power/

11 https://www.cnbc.com/2020/08/03/uae-becomes-first-arab-country-to-launch-local-nuclear-energy-program.html

by a consortium led by the Korea Electric Power Corporation. The aim is to operate four nuclear power plants (in total 5,600 MW capacity) that will provide a quarter of the country's energy needs in an emissions-free way.

New nuclear constructions in the Western world face many hurdles among which are: public opinion, green parties' opposition, increasing complexity of reactors linked to more stringent safety requirements, and Utilities' lack of efficient construction management. Construction of Small Modular Reactors should be easier.

SMRs: Global interest in small and medium sized or modular reactors (SMRs)[12] is increasing due to their ability to meet the need for flexible power generation[13]. They also have an enhanced safety performance through passive safety features, necessitate less upfront capital investment, and are easier to build as they are deployable either as a single or multi-module plant and as they include large components designed to be built in factories. However, they occupy significantly more land per unit of electricity generated.

There are about 50 SMR designs and concepts globally. Most of them are in various developmental stages and some are claimed as being near-term deployable.

Among these the most advanced is probably the US firm NuScale Power SMR. End August 2020 the American Nuclear Regulatory Commission (NRC) had approved the safety aspects of this reactor design. It is the first SMR to receive such NRC approval. According to the Company's announcements its first plant should be operational by 2027[14].

In Canada, in 2018, NuScale signed partnership agreements with the two Canadian nuclear operators OPG and Bruce Power and is proceeding with submissions to the Canadian Nuclear Safety Commission for licensing approvals.

According to IEA, new nuclear construction is not on track with its Sustainable Development Scenario[15] as nuclear capacity in 2040 will amount to 455 GW – well below this scenario level of 601 GW. Additional lifetime extensions and a doubling of the annual rate of capacity additions are therefore required. With the present trends, this target seems extremely difficult to meet.

Renewables:

In 2019 capital spending in wind and solar PV accounted for almost half of total power plant investment.

Onshore wind-generated electricity increased by an estimated 12% in 2019[16], remaining the largest non-hydro renewable technology and generating almost as much as wind offshore and solar together.

China's onshore wind capacity expanded from 19.0 GW in 2018 to 23.8 GW in 2019 as the government lifted development bans in certain regions in response to the decrease of electricity curtailment levels reflecting better grid balancing conditions.

In the European Union, onshore wind capacity growth accelerated in 2019 with 9.1 GW becoming operational, 17% higher than growth in 2018. In the US, onshore additions rebounded from 6.9 GW in 2018 to 9.1 GW in 2019 as developers wanted to benefit from full production tax credits before they end in 2020. In India,

12 SMR produce electricity of up to 300 MW per module

13 https://www.iaea.org/topics/small-modular-reactors/smr-regulators-forum

14 https://www.neimagazine.com/news/newsnuscales-first-smr-plant-should-be-completed-by-2027-7254981

15 In this scenario, the Paris Agreement on climate change objectives are met

16 https://www.iea.org/reports/onshore-wind

deployment levels in 2019 remained at the low level observed in 2018, reaching only 2.4 GW due to policy and market uncertainties.

Grid-connected *offshore wind* additional capacity amounted to 5.9 GW in 2019, 40% higher than in 2018. Expansion is accelerating in China, and in the European Union additional capacity grew again after a slowdown in 2018, with record installations in 2019[17]. In France after several years of delay due to legal procedures, the first French offshore farm construction was launched in Saint-Nazaire in June 2019. This 480 MW capacity project will be built by EDF and Enbridge.

China is strengthening its position as a leader in offshore capacity additions with around 2 GW of new installations in 2019, followed by the UK (1.6 GW) and Germany (1.1 GW). In the US, developers have proposed multiple projects in four different states (Maryland, New York, New Jersey, and North Carolina). According to a Wood Mackenzie study[18], in the next decade US investment in offshore wind projects is predicted to rise from virtually nothing 10 years ago to $78 bn which is comparable with the $82 bn planned for US offshore oil development.

Solar: In 2019 additional capacities and production grew respectively by 18% and 22%, however at a slower pace than in 2018 due to China's slowdown.

After months of uncertainty, on April 10, 2019, China's National Energy Administration (NEA) released a consultation paper that defined how China intends to move forward in the remaining period of the 13th "Five Year Plan"[19,20], a period in which the Chinese market will evolve from a subsidy-driven market to both grid-parity and FIT (Feed In Tariff) supported projects. It is expected that the market will eventually enter a subsidy-free era starting from 2021 or slightly later.

These policy uncertainties have led to a 32% decline in annual capacity additions for solar PV that amounted to 30 GW compared with 44 GW in 2018[21]. Lower installation figures in China pushed Chinese manufacturers to export. PV module exports increased by 45% in 2019 compared to the previous year, meaning lower PV prices across the globe and decreasing installation costs.

One could expect a rush for renewables permits and constructions before the end of FITs in 2021; however, this rush could be slowed down by pandemic-related construction delays

In certain Chinese regions, and elsewhere with a high renewables share in the electricity mix, variable renewable plants (solar and wind) cannot operate at full capacity because of oversupply or an insufficiently robust transmission grid. During certain periods, electricity generation must be curtailed.

In 2019 in China, the curtailment rates for those energies dropped compared to the previous two years and reached "only" 4% (of annual generation) for wind and 2% for solar.

During the COVID-19 pandemic renewables developers have experienced supply chain disruptions, and lockdown measures have slowed construction and permitting activity resulting in a reduction of short-term capacity additions mainly in 2020 but also the following year.

A second consequence is that delayed projects may run the risk of not reaping the benefit of incentives ending in 2020. It is reasonable to assume that most projects missing incentive deadlines may be further delayed or cancelled. In order to address these concerns, several countries have introduced policy changes[22].

Renewables technology and costs improvements: The ongoing increase in wind turbine size[23] for onshore applications should continue, from an average of 2.6 MW in 2018 to 4-5 MW for turbines commissioned by 2025. For offshore applications, the largest turbine size of around 9.5 MW in 2019 will be surpassed; projects to be commissioned in 2025 should comprise turbines with 12 MW capacity.

The combination of improved wind turbine technologies, deployment of higher hub heights, and longer blades with larger swept areas together, with digitization and better generation forecasting software, leads to increased capacity factors for a given wind resource. For onshore wind plants, the global weighted average capacity factor should increase from 34% in 2018 to more than 40% in 2030.

For offshore wind farms, more progress should be achieved, with capacity factors in the range of 36% to 58% in 2030, compared to an average of 43% in 2018.

17 https://www.iea.org/reports/offshore-wind

18 Financial times July 2020

19 https://www.apricum-group.com/towards-a-subsidy-free-era-for-chinas-solar-pv-market/

20 13th five-year plan: 2016-2020

21 https://www.power-technology.com/comment/solar-pv-capacity-additions-china-2019/#:~:text=Annual%20capacity%20additions%20for%20solar,was%20installe

22 https://www.iea.org/reports/renewable-energy-market-update/covid-19-impact-on-renewable-energy-growth

23 https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Oct/IRENA_Future_of_wind_2019.pdf

Over the past 10 years, the LCOE[24] of onshore wind has fallen by 8% each year since 2010 to reach a range of $45 to $65 /MWh worldwide.

In addition to capacity factor increases and economy of scale, offshore turbine foundations are improving with floating platforms adapted from the oil and gas industry. The average worldwide offshore wind LCOE has also decreased to reach a range $79 to $118 /MWh. Further decreases are expected as illustrated by the September 2019 UK auction where the strike price for a planned commissioning in 2025 was in the range of $49-52 /MWh.

Solar Photovoltaic (PV) panel efficiencies are improving as well as their spectral responses to solar light impact.

There are three dominant technologies: multi-crystalline silicon, mono-crystalline silicon, and thin film cadmium telluride. The latter technology, which currently has the smallest market share, surpasses the crystalline silicon PV module technologies in terms of sustainability and yield performance. It is expected to increase its market share in the future.

In addition to improved solar cells, better Balance Of Plant design and smart sensor additions led to even more spectacular decreases in the generation cost for photovoltaic solar than for wind. It decreased by 18% per year to reach the range of $34-67/MWh.

In certain regions this cost can be even lower as illustrated by the Al Dhafra solar project in Abu Dhabi. On July 27, 2020, the bidder consortium, formed by French EDF Group subsidiary, EDF Renewables, and the Chinese Jinko Power Technology Co. Ltd, was awarded this solar photovoltaic project, which will be the largest solar plant in the world with a capacity of 2 GW. It will also be the first one on such a scale to deploy bifacial module technology (meaning that both sides of the PV modules capture light to yield higher generation). The bid was awarded at $13.5/MWh[25] on an LCOE basis.

As wind and solar are intermittent sources of electricity, they have negative effect on grid balancing systems.
In certain Chinese regions where there is a high share of wind generation, regulators have introduced grid penalties, or they do not authorize projects that are not contributing to system balancing. This promotes combined renewables with storage and hybrid farms linking wind, solar and storage.

If one does not consider the additional costs incurred for grid operators (grid design revision and balancing extra costs), onshore wind and solar are competitive with other sources of electricity generation such as the existing nuclear reactors.

Batteries: It is essential to add energy storage to intermittent renewables generation.

The cost of battery storage has fallen sharply (by 19% per year over the past 10 years) to reach a market average at $156/kWh[26] range of $175-234/kWh. According to BNEF's forecast, prices are projected to fall to around $100/kWh by 2023 increasing electrification of the economy[27].

Tesla is getting ready to introduce lower-cost, longer-lasting batteries for its electric vehicles in China in late 2020. This battery is being co-developed with Chinese battery giant Contemporary Amperex

24 LCOE: Levelized Cost Of Energy

25 https://www.power-technology.com/projects/al-dhafra-solar-project-abu-dhabi/

26 https://about.bnef.com/blog/battery-pack-prices-fall-as-market-ramps-up-with-market-average-at-156-kwh-in-2019/

27 For example, commercial electric vehicles, like delivery vans, would become increasingly attractive

Technology Co. Ltd (CATL). Its cost should be as low as \$100/kWh, which would allow Tesla and other automotive manufacturers to make EVs[28] far more accessible. General Motors[29] is also trying to match Telsa performances by mid-2020.

Mega-factories are expanding: As of December 2019, the number of lithium ion battery mega-factories in the pipeline has reached 115 plants, (88 of which are planned in China) amounting to 564 GWh capacity addition to a global total of 2,068.3 GWh or the equivalent of 40 million EVs by 2028.

The market is dominated by Asian players: in 2019, the largest Li-ion battery manufacturers were LG Chem from Korea (production capacity over 50 GWh), CATL (production capacity over 40 GWh) and Panasonic from Japan (production capacity 35 GWh).

Li-ion batteries have by far the largest market share. In the last decade, adjusting the chemical composition of the cathode, as well as mastering the manufacture and packing of battery cells, allowed increased energy density and significantly lowered the cost of production.

Batteries' improvements: Research and development efforts are now focusing on improving energy density, increasing charging speeds, and lowering cost.

Safety improvement by reducing Li-ion batteries' inflammability is a key issue. In April 2019 a very damaging explosion took place at a 2 MW Li-ion battery storage facility near Phoenix (Arizona). In a report released in July 2020, its root causes are debated, and the report concludes that safety standards need to be revised. Arizona Public Service had installed those batteries to help manage generation fluctuations due to clouds or the setting sun in areas with many rooftop solar panels. While APS has pledged to build 850 MW of battery energy storage by 2025, this accident has put all plans in Arizona on hold. Across the US, battery storage is projected to take off as states mandate a growing renewable power capacity share. The country was on track to install 2,500 MW of battery storage by 2023[30].

Other research and development efforts are focusing on new electrolytic couples such as Aluminum-air and Zinc -air. In the US, researchers[31] have developed a low-cost Sodium-ion battery that could compete with Lithium-ion chemistries for energy density and reliability.

BMS (battery management systems) are also getting more sophisticated in order to adapt to different battery usages.

Second-life battery re-use (for example as stationary storage improving grid balancing) and end-life recycling are issues that are starting to be addressed.

Also, battery producers are trying to limit the use of heavy metals such as cobalt: More than 50 percent of the world's supply is produced in the Democratic Republic of Congo in questionable humanitarian conditions. Thus, in early 2020, General Motors announced that its new generation of batteries will use 70 percent less cobalt.

Hydrogen: The most common way to produce hydrogen is from fossil fuels; however, this process releases a lot of greenhouse gases.

In 2019, green hydrogen produced from electricity was around three times more expensive than that produced with natural gas but as the cost of electricity generated with solar and wind continues to decrease, green hydrogen production and usages should develop.

Presently hydrogen is used in industry processes and is starting to be used in transportation (trains , buses, ships).

In the future, it could provide flexibility services on the grid becoming a good complement for important renewable intermittent generation by participating in demand response and in electricity storage. Hydraulic storage and hydrogen are the main inter-seasonal storage solutions as stationary batteries can only provide daily electricity storage. Unfortunately, in western countries nearly all suitable sites are already equipped with dams.

With the increasing share of renewables (thus a decreasing share of schedulable electricity), green competitive hydrogen could enable storage of large amounts of electricity needed to stabilize the grid.

GHG emissions: *Energy-related* global GHG emissions have decreased year on year by 0.4%[32] for the first time since 2009 with contrasting situations between non-OECD countries where GHG emissions have increased by 1.3% and OECD countries where they decreased by 2.8%.

From 2014 to 2017, *total worldwide annual GHG emissions* had stabilized, but they started to grow again by 2.7% and 0.6% in 2018 and 2019,

28 EV: electric vehicle

29 https://edition.cnn.com/2020/03/04/business/gm-electric-car-battery-400-miles-of-range/index.htm

30 According to data from the US Department of Energy's Energy Information Administration

31 Washington State University (WSU) and the Pacific Northwest National Laboratory (PNNL)

32 They represent 58% of total G20 emissions

respectively. In 2019, global emissions reached another record high.

At the end of 2019, according to IEA, the world was not on track to meet its agreed target of limiting warming to 2°C. Under current policies, expected warming will be in the range 3.1-3.7°C.

What decisions need to be made to get on track to meet climate change objectives?

Investment decisions:

Hydropower is the largest source of low-carbon electricity worldwide and nuclear power the second. Together, they represent 70% of low carbon electricity generation. In advanced economies nuclear power is the largest low carbon source of electricity but in those countries its future role will decrease as governments trying to get green parties' support are prematurely phasing out nuclear plants. A good example of these political decisions that have no technical or environmental grounds is the closure of the two French Fessenheim reactors in H1 2020: If renovation work had been carried out, they could have continued for 10 more years. Moreover, the French Energy Transition law did not request such closure as the new Flamanville reactor will not start before 2023. An indemnification protocol was signed between the government and the reactor's owner, EDF, amounting to a fixed part of around €400 million and a variable part corresponding to EDF lost production revenue until 2041.

The extension of hydropower and nuclear generation installations are sound investment decisions. This is also the case for energy efficiency measures in industry, buildings and transportation. With buildings accounting for more than 30% of global energy consumption and 30% of energy related GHG emissions, investment in retrofitting existing buildings[33] needs to accelerate. However, as a result of COVID-19 lockdown, investment in buildings energy efficiency is likely to drop by nearly 15% in 2020 from around $150 billion in 2019.

Most post-COVID stimulus plans include incentives for building efficiency improvements. In addition to increased funds, simplified administrative approaches addressing shortages of skilled providers, and increasing decision makers' confidence, are crucial.

In contrast, measures such as switching to biofuels, or adding CCUS[34] to a coal-fired power plant, would reduce emissions but would also generate significant additional cost over their lifetimes.

Regulatory decisions:

- *In China,* the emphasis of the 13th plan on environmental development was impressive with measures related to the electric power development and sustainable energy supply. Emissions reductions goals were partially achieved by 2018 as carbon intensity decrease reached more than 45% of the 2020 goal, while the use of non-fossil energy has almost hit its 15% goal. However, after a dramatic decline in 2016-2018, 2019 saw an increase of 5% in coal utilization. Let's not forget that coal is a domestic Chinese resource and the new countries' nationalistic approach could explain this trend change.

33 Existing buildings are expected to account for up to 80% of the stock in 2030 in certain countries

34 CCUS: Carbon Capture Usage and Storage

- *Carbon Dioxide* (CO_2)
  Two main regulatory schemes exist to limit CO_2 emissions: The Emissions Trading Scheme and the carbon tax. Of the 34 OECD members (out of 37) who have implemented one or other scheme, 45% have an ETS system, 39% combine this with a carbon tax, and 8% impose the carbon tax alone.

  - *ETS scheme in Europe:* Carbon prices increased in 2019 up to €25/t thanks to the Market Stability Reserve (MSR) implementation that absorbed excess allowances off the market. In March 2020 during the COVID-19 pandemic lockdown, carbon prices decreased to €15 /t accelerating the electricity spot price decrease. At these low levels it has little effect on CO_2 emissions decrease. On September 14, 2020 it increased again to €30/t[35].

    One important issue is to clean coal fired plants, which are numerous and still growing, by installing a CCUS system. A minimum carbon price of €50 /t is needed to make this happen.

  - In 'The Value of International Electricity Trading'[36] report, researchers from UCL and the University of Cambridge show that the *tax on carbon dioxide emissions* in Great Britain, introduced in 2013, has contributed to the decrease of the coal-fired share in the electricity mix, from 40% to 3% over six years, replaced by less emissions-heavy sources of generation such as gas and renewables as well as increased imports from the continent. The Carbon Price Support tax increased to £18/t in 2015 and researchers measured the positive impact of this in reducing coal-fired generation.

    This tax translated to an average £39 additional cost on British households' electricity bills. If EU countries adopted a high carbon tax, significant carbon emission reductions would happen throughout the Continent. However, this point has been debated for years, with some countries such as Poland opposing this measure.

    Upon her arrival, the new European Commission President, Ursula von der Leyen, announced her intention to install a carbon tax including imported products, which makes sense. Otherwise, with carbon leakage, production of goods would become more delocalized to less environmentally cautious countries and transportation would add to overall CO_2 emissions.

    However, with the post COVID-19 crisis, some countries such as France[37] are cautious as taxes are unpopular. Adding expenses to household budgets when unemployment resulting from the COVID-19 crisis is growing, could trigger a social crisis.

- **Global methane emissions have risen nearly 10%** over the past two decades[38], resulting in record-high atmospheric concentrations of this powerful greenhouse gas.
  Methane is an important contributor to global warming because it traps heat in the atmosphere. Its atmospheric lifetime – around 12 years – is much shorter than that of carbon dioxide, which stays for more than a century, but methane is, per unit, more than 20 times as potent as CO_2 as a greenhouse gas. This means that over a 20-year period, the global-warming potential of one ton of atmospheric methane is like 85 tons of CO_2[39].

  While the European Green Deal identifies energy-related methane emissions as an important issue requiring an accelerated initiative from the European Commission, the American administration, through its Environmental Protection Agency, announced in mid 2019 plans to loosen regulations on methane!

  According to a recent IEA study[40], it is crucial for the oil and gas industry to be proactive in limiting, in all ways possible, their environmental impact and for policy makers to recognize methane curbing is a pivotal element of global energy transition.

2020 COVID-19 pandemic and its consequences

To combat the COVID-19 pandemic, many governments decided to lockdown their populations for several weeks, in January in China, from March to May in Europe, later in America. In August, some countries imposed new focused population containments to try to avoid a second pandemic wave.
Those decisions led to an economic crisis with dramatic drops in GDP, rising unemployment, and social unrest. According to OECD[41] scenarios, with one worldwide pandemic wave GDP would contract by 6% in 2020 while this contraction would reach 7.6% in the case of a second wave.

35 https://ember-climate.org/carbon-price-viewer/
36 https://phys.org/news/2020-01-british-carbon-tax-coal-fired-electricity.html
37 Emmanuel Macron interview on July 3, 2020, « Aujourd'hui en France »
38 https://www.nature.com/articles/d41586-020-02116-8
39 According to the Intergovernmental Panel on Climate Change. When looking at its impact over 100 years, one ton of methane is still equivalent to about 28 tons of CO_2
40 https://www.iea.org/reports/methane-tracker-2020
41 OECD June 10, 2020

The COVID-19 crisis has severely impacted on the transportation sector with a strong decrease in all travel activities. Some of them are recovering post lockdown, others such as aviation are affected in the long term. Work was also transformed by the implementation of social distancing rules and by the need to operate teams at a distance. All industrial and tertiary activities were negatively affected during the period.

Consequently, all types of energy consumption dropped significantly.

Energy companies enforced their business continuity plans and their collaborators were very dedicated, insuring notably electricity security of supply. This was of utmost importance as electricity and telecommunications were vital for companies managing a significant part of their activities virtually.

Oil crisis:

The oil crisis started before the coronavirus spread to the Western world. It was worsened by the crisis.

On March 8, 2020, in response to Russia's refusal to reduce its oil production to push up prices, Saudi Arabia initiated a price war that resulted in an oil price drop of around 30% (in addition to a 30% drop since the beginning of 2020). Shortly after, oil consumption went from around 100mb/d in early 2020 to 75-80 mb/d during the midst of the pandemic lockdown. Oil excess filled storage facilities and oil tankers.

WTI oil prices went from $64/b in early 2020 to negative territory for the first time in history (minus $37.63/b on April 20) as anxiety grew in the US over what to do with excess oil. Finally, on April 12, 2020, OPEC+ members decided to adjust downwards their overall crude oil production by 9.7 mb/d, starting on May 1, 2020, for an initial period of two months that was further extended until the end of July. Consumption recovered at 90 mb/d in June 2020 and prices increased to around 40$/b and seem to stabilize at that level.

These OPEC+ cuts should decrease to 7.7 mb/d in the following months until year-end.

Oil production also decreased in the US as the number of rigs went down from 630 in November 2019 to 290 in June 2020, which is the lowest level since 1987. Most of shale oil basins are not profitable at such low oil prices and many shale producers are highly indebted. At the end of June 2020, a shale oil pioneer company, Chesapeake Energy Corp, filed for Chapter 11 bankruptcy protection as it bowed to heavy debts and the impact of the coronavirus outbreak.

In June 2020, forecasts are for a decrease in US oil production by 670 mb/d from its 2019, 12.2 mb/day level.

Electricity markets:

During the lockdown period (March 17 – May 11, 2020) the demand for electricity in France (as elsewhere in Europe) fell by 15-20% depending on the day[42]; renewable production increased by 18%. In contrast, nuclear production fell by 18% and that of fossil fuel power stations by 53%. At the end of lockdown, thanks to the resumption of activity, the drop in electricity consumption was only 9% and by the end of June 2020 it had almost reached its normal level.

This new supply-demand balance as well as the significant drop in commodity prices resulted in a sharp

42 Decryptage 63

drop in prices on the spot markets. The average price in France was €15.3/MWh during the confinement period against €37.8/MWh over the same period in 2019. The excess of renewable production associated with low demand pushed prices into negative territory for 38 hours during the two lockdown months, while the entire year 2019 totaled only 27 hours of negative prices.

The coronavirus crisis has also affected electricity futures markets. At the beginning of the crisis, the prospect of a global economic slowdown and falling commodity prices led to a decline in electricity futures markets across Europe: in France, the price of the 2021 annual product fell from€ 45.70 / MWh on January 2, 2020 to € 37.4 / MWh on March 17.

Prices then went up to reach € 46.9 / MWh on May 26, 2020, following EDF's announcements regarding the nuclear fleet reduced availability the during winter 2020-2021 and the year 2021.

During the lockdown period carbon prices decreased to €16.6/t on March 23 and increased again to more than € 29/t on June 30, 2020 recovering their 2019 level.

There is a lot of uncertainty around the world economy recovery, and the total energy consumption for 2020 should be significantly below that of 2019.

Electricity grid flexibility must be enhanced

Renewables growth impacts on grid management

- The lockdown period foreshadowed future grid management issues.

  During lockdown, electricity consumption decreases combined in Europe with sunny and windy weather resulted in high shares of renewable electricity on the grid. Near blackouts[43] happened in Germany and in the UK, demonstrating that grids and regulations are not adapted to deal with the high renewables share planned for the end of the decade[44].

  Outside Europe, Mexico has taken radical measures to preserve its national energy security during the COVID-19 pandemic. In May and June 2020, the Mexican government significantly increased grid connection fees for renewable power plants (up to nine-fold) and introduced restrictions on grid connections for new wind and solar power projects.

  Such measures have already existed for a few years in China where renewables operators face grid penalties and electricity curtailment. They are strongly incentivized to be equipped with their own balancing systems (hybrid farms with battery storage for example) and precise weather and generation forecasts.

- With traditional schedulable generation (fossil fuels, nuclear and to a certain extent hydropower) grid balancing was well mastered and managers procured ancillary services (such as frequency control) for slow adjustment in case of unavailability of a plant for example.
  With the increasing share of intermittent renewables generation (wind and solar power), grid balancing is more difficult, and security of supply can be endangered.

  This issue was illustrated by mid-August 2020 with rolling blackouts in California. Officials at the California Independent System Operator described a "perfect storm" of conditions that caused demand to exceed available supply: scorching temperatures, diminished output from renewable sources, and fossil-fueled power plants affected by the weather, and in some cases plants going offline. In addition, as neighboring states were hit by the same heatwave, they could not provide electricity to California as they usually do for 30% of its needs.

  California's electricity supply relies on 33% from renewables with a large share of solar energy. This is challenging on hot summer evenings, when electricity from solar generation drops to zero but demand for air conditioning remains high. This challenge will intensify as California adds more solar panels and wind turbines to meet its targets of 60% renewable electricity by 2030 while phasing out fossil fuel and nuclear plants schedulable generation.

  For many officials, there is a need for more generation redundancy, battery storage, and efficient demand response systems to incentivize customers to reduce their consumption (e.g. for air conditioning) when requested.

  The grid system needs to become more flexible and its regulation has to change in order to accommodate energy transition to low-carbon electricity.

- **Copper investments:** Intermittent renewables generation necessitates additional line constructions as these new energy sources injections must be connected to the overall grid.
  The majority of solar or wind farms are connected to distribution lines. However, more and more countries have voted for energy transition plans in which the renewable generation output

43 See Europe Editorial for more details

44 By 2030, according to IEA reports, renewables (including hydropower) will represent 53% of the total installed capacity in Europe.

increase coincides with closure of schedulable electricity plants such as coal-fired plants or nuclear plants. In this situation a grid overhaul is needed.

Germany has closed half of its nuclear plants (and will close all of them by 2022) that were in the south of Germany near the industrial consumption centers. At the same time large investments were dedicated to offshore wind farms in the North Sea. Because of administrative procedures and local public opposition, construction of new transmission overhead lines[45] to transport electricity from the north to the south of the country were rejected, and wind farms that were ready to operate were not connected to the grid.

To overcome these oppositions, German TSOs decided to build underground lines which are roughly 10 times more costly in CAPEX investments[46] and more difficult to maintain generating additional OPEX. In early 2020, all four of them (TenneT, TransnetBW, 50Hertz Transmission, and Amprion) launched the German Link project to build HVDC[47] underground cables in three corridors of 700 km each. Completion of these corridors should be in 2026 and the cost will be at least €10 bn.

When built, the new lines will enable solutions to congestion point issues.

In Europe new interconnection lines, by leveraging different consumption times in different countries and aggregating more generation sources, are also contributing to security of supply.

- New flexibilities are needed: However, solutions other than building extra lines must be implemented[48].

- *Storage equipment:* Additional electricity storage helps to balance this increasingly intermittent generation. In most Western economies, hydropower sites are saturated and green hydrogen is not yet competitive. The extra storage needs will be provided by stationary batteries that benefit from electric vehicle battery technology and production improvements. Consequently, the global stationary battery storage market size is anticipated to grow at a 17.6% compound annual growth rate (CAGR)[49] and to surpass 74 GW by 2030.

  However, insufficient ROI[50] on storage capacity investments is slowing down their implementation. Better remuneration of ancillary services should be provided by grid operators, for consumption load shedding, and frequency control, etc. A multiple user approach could also enhance attractiveness of those investments such as batteries participating in hybrid farms development (wind, solar and storage) avoiding energy losses and enabling better grid integration.

  In some countries, like China, battery storage can decrease renewable curtailment losses and, in some provinces, it is required for permitting renewables connection to the grid.

- In addition to electricity energy markets, many countries in Europe have established ***capacity markets*** (with different models) in order to ensure security of supply at peak consumption times (in

45 Usually it takes 5 to 10 years to build overhead lines in Western countries and this lead time delays renewable generation grid connection and electricity output.

46 Between 4 and 14 times more costly https://www.power-grid.com/2013/02/01/underground-vs-overhead-power-line-installation-cost-comparison/#gref

47 HVDC: High Voltage Direct Current

48 https://www.thinksmartgrids.fr/wp-content/uploads/2020/07/TSG_Livret_Plan_de_relance_vDEF_1707.pdf

49 https://www.gminsights.com/industry-analysis/stationary-battery-storage-market

50 ROI: Return On Investments

winter usually) if there is no wind and no sun. They remunerate additional available capacity during high-stress days as well as peak shaving. For example, the French capacity market relies on balancing responsibility. For the first time, in 2019, French capacity market auctions selected carbon-free solutions and awards went to battery investment and to demand response operators as industrial or tertiary aggregators able to guarantee peak shifting. Consequently, remuneration was higher than previous years.

- On the consumption side:

  Consumer patterns are also changing with an increasing number of self-consumption customers, microgrids, smart cities, and so on. Grid managers' demand forecast tools must be enhanced and network tariffs adapted. To develop demand response that improves grid balancing and enables customers to take advantage of low prices (when renewable generation is high), dynamic pricing (including time of use tariffs) should be implemented. Smart metering deployment, completed some years ago in North America and nearly complete in Europe, enables these new price implementations. Dynamic tariffs have been effective for many years in the US. Under an EU-level agreement reached in June 2019, energy companies with more than 200,000 clients will be obliged to provide households with at least one offer comprising dynamic price contracts. This agreement must now be implemented in Member States.

- *Electrical vehicles (EVs)* are developing all over the world boosted by battery improvements, environmental concerns, public subsidies, and regulation[51]. Their charging must be managed in order not to saturate DSO grids at certain times of the day (for example at lunch time if many EV owners decide to charge their car in the office car park at the same time). Smart charging must be widely enabled, for example by new pricing signals. In addition, cooperation between DSOs, charging station[52] owners[53], and local public authorities should be instituted in order to position new charging stations according to the networks' ability to accommodate them, hence decreasing extra grid costs.
  Idle vehicle batteries could provide ancillary services to grid managers (such as frequency regulation). Remuneration varies according to networks and regulations and it should be increased in the future.

- *Data usages:* With increasing levels of distributed renewable energy being brought online, power can flow in the reverse direction (towards the transformer).
  This changes the TSO/DSO relationship. They need to coordinate their operations in a way closer to real time. Thus, frequency of data exchanges between them have to be enhanced and data exchange protocols have to be compatible enabling quick analysis and decision making if needed.

  Thanks to smart meter deployment, accurate consumption data is known to within half-hour intervals, for example. Data transparency is a key flexibility enabler. DSOs should continue developing data exchange systems and share relevant data with all stakeholders while ensuring their protection[54] and preventing security breaches.

  Some DSOs, notably Enedis in France, are publicly sharing electricity consumption, profile coefficients[55], and self-consumption for consumer clusters, as well as distribution infrastructure location, quality of electricity supply, and EV charging station locations.

  This data, added to other public data, could enable energy efficiency service companies, renewables providers, and smart charging station developers to build new offers.

  Greater precision and real-time data would enhance these offers, which could avoid grid congestion and improve grid flexibility.

- New regulations
  - *Grid tariffs:* In order to increase grid flexibility, "soft" investments (in software, IT systems, artificial intelligence, modeling, etc.) should be promoted. Presently this is not the case in the grid remuneration tariffs calculation. Only equipment and lines investment are included in the Regulated Asset Base used to establish grid tariffs. This calculation method must evolve in order to also include those "soft" investments.
  - **Market rules:** In Europe, because the "merit order" used to bring generation equipment onto the grid is based on variable costs, renewables such as solar and wind

51 In Europe for example, car makers will have to pay in 2021 and onwards, fines that could reach €34bn if the cars they sell are emitting gases beyond a certain threshold

52 3 million public charging points should be installed in Europe by 2030

53 More and more Utilities and Oil and Gas companies are investing in charging stations or buying charging station companies

54 For example, in Europe by complying with GDPR (General Data Protection Rules)

55 The coefficient used to generate an estimate of consumption https://www.elexon.co.uk/operations-settlement/profiling/

that have very few variable costs (no fuel costs) are called first. As they are not schedulable, when their share becomes important (more than 50%) grid stability is difficult to maintain as was demonstrated by the British near blackout in April 2020.

New regulations allowing curtailment of renewables injection in the grid if needed should be adopted as it seems to be the case in Portugal[56]. In addition, incentives for renewables generation developers to add storage and provide accurate generation forecast (based on local, timely meteorological forecast, for example) could be introduced. This is already done in many Chinese provinces where grid penalties are applied if renewables are not matched with equipment making them more schedulable.

Companies organizations:

Digitization: The pandemic crisis was a catalyst for digitization as expressed by Satya Nadella (Microsoft CEO): "We saw two years of digital transformation in two months".

Post lockdown, companies will not go back to previous practices.

According to a study published in July 2020 by BCG and ANDRH[57] on the organization of work in the new reality, 85% of human resources managers wish to develop telework practice within their company in a sustainable way even if it will not apply to all the company's functions. They are in favor of a hybrid model combining face-to-face and telework (usually 2 to 3 telework days a week), even if managing virtual and face-to-face working together is complex. Among HR managers, 88% are aware of the risks that this practice can pose for the company culture empowerment, cohesion between employees, and creativity.

These wishes meet those of their employees that are happy to reduce commuting time but wish to have face-to-face meetings with their colleagues.

Productivity gains are expected from these new working methods combined with accelerated digitization and reduction of office space and travel expenses.

Western world industry changes: On the one hand, the crisis has seriously endangered certain sectors, such as aeronautics for example. In addition, the post COVID-19 crisis will speed up closures of fragile industrial plants that were hardly profitable before.

On the other hand, there is a political desire for reshoring, notably supply chain regionalization and for subcontracting relocation near consumption sites.

During the last year Saudi Aramco has had to react quickly to many crises. They had to restore production after the September 2019 attacks, to increase production after the OPEC Saudi decision on 20 March, and to operate during the pandemic when many of their subcontractors' plants were closed. They decided to relocate production of their equipment to reach 70% of their suppliers located in the Saudi Kingdom compared to 56% before the crisis.

Unless national policies are in place with increased import taxes on certain products (as in the US), relocating imported products can only be wishful thinking. Manufacturing labor costs for spare pieces or equipment are

56 Enerpresse n°12644 du vendredi 28 août 2020, p4

57 Boston Consulting Group and Association Nationale des Directeurs de Ressources Humaines, June 2020

much lower in developing countries and with the economic crisis the population is not ready to buy more expensive goods.

Electricity and oil products' consumption patterns will be different in future, whether those relocations happen or not. In case of failure, tertiarization of developed economies will increase with positive local effects on GHG emissions but with increased global emissions.

Energy players must revisit their strategy:

All energy players are implementing savings plans and, up to June 2020, total expenses cuts of $400 bn were announced.

Utilities: Low electricity prices and decreased consumption have significant impacts on their

financial situation, pushing them to seek productivity gains. In addition to traditional OPEX and CAPEX expenses cuts, digitization and telework offer cost reduction opportunities provided they have their employees' support. Some Utilities, such as EDF in France, have also suffered from maintenance work delays due to the lockdown and afterwards from the slower pace of work due to social distancing measures. This has strongly impacted on nuclear reactors' yearly shut-down planning resulting in lower nuclear generation. EDF has launched a new cost-cutting plan called Mimosa and is resuming assets divestments with a new €3 bn plan.

Oil and gas companies have even tougher strategic choices to make as they are suffering from larger consumption drops. According to EIA estimates in July 2020[58], oil production will fall in 2020 to

94.6 mb/d compared to 106.6 mb/d in 2019, and consumption in 2021 (98.8 mb/d) will still be lower than in 2019. Production could be even lower if a second pandemic wave pushes governments to impose new widespread lockdowns.

- **Increased flexibility in operations:** Oil and gas companies had to be very flexible in operations and trading as consumption and prices became more volatile. Consumption was 17.8 mb/d lower in Q2 2020[59] compared to the same period in 2019, and Brent crude oil spot prices fell from a monthly average of $64/bl in January to a minimum of $18/bl and grew to around $40/b in June 2020.
  Oil refineries are struggling as demand for oil products has crashed and refinery margins are squeezed. Europe is considered the most at risk because facilities are generally old, and governments are planning to reduce oil product usage from transportation. Analysts at UBS have forecast that almost 3m barrels a day of refining capacity equivalent (about twice as much as the UK consumes) need to be removed from the markets by 2021[60].
- **Heavy expenses cuts:** To protect their financial situation OPEX and CAPEX expenses were severely cut by around €200 bn globally. Cuts were especially important in exploration areas and impacted on oil service companies such as Schlumberger, which announced a plan to reduce its workforce by 20,000 people (a third of its total headcount).

  As operators need between five and seven years to bring projects to life, one could fear an oil shock in the medium term if consumption grows again.
  Many oil majors are depreciating their assets[61] as they predict that the impact of the COVID-19 crisis on oil demand and prices will last for a few years.
  All these factors add to the complexity of managing oil and gas companies and must be considered in their new strategic plans.
- **M&As:** Financially robust companies will take advantage of other, weaker players to acquire them. At the end of July 2020, Chevron announced that it had agreed to buy Noble Energy for $13 bn in the first big oil and gas industry deal of 2020. This acquisition could trigger other deals in the oil sector as flourishing companies such as Chevron or Exxon may spot potential acquisitions among indebted US shale operators. Chevron's decision not to acquire Anadarko in 2019 was wise as today the acquirer, Occidental Petroleum, is struggling with its debt increase from the $55 bn deal.
  This purchase fits with Chevron's strategy to focus on the international natural gas business and US shale production[62].
- **Longer term strategy:** For a few years, major oil companies' shareholders have pushed them to decrease their greenhouse gas emissions for scope 1, 2 and 3[63] activities. In some cases, they include in scope 3 the companies' customers: this is the "well to wheel" concept.

58 https://www.eia.gov/outlooks/steo/report/global_oil.php

59 https://www.cnbc.com/2020/06/16/oil-prices-iea-sees-largest-drop-of-demand-in-history-this-year.html

60 Financial Times, July 8, 2020

61 At the end of June 2020, Shell announced $22 bn asset depreciations. Financial Times, July 1, 2020

62 Financial Times, July 21, 2020

63 Scope 1 covers direct GHG emissions from owned or controlled sources. Scope 2 covers indirect emissions from the generation of purchased electricity, steam, heating and cooling consumed by the reporting company. Scope 3 includes all other indirect emissions that occur in a company's value chain.

Oil companies (mainly European ones but also Saudi Aramco) are committing to reduce methane emissions, to invest in CCUS in order to sequestrate their GHG, and to become significant players in renewables and in electric vehicle charging stations.

Major European oil companies are committing to become carbon neutral. In February 2020, BP set the goal of becoming a net zero company by 2050 (or sooner) by:

- reducing its operation's GHG emissions,
- cutting 50% of the carbon intensity of products they sell,
- installing methane measurement at all their major oil and gas processing sites by 2023 and reducing methane intensity of operations by 50%, and
- increasing the proportion of investment into non-oil and gas businesses.

Smaller European players have accomplished this turnaround, such as the Norwegian oil company Statoil (that became Equinor) or the former Danish oil company Dong. The latter changed its name to Oersted and is operating successfully in offshore wind. Its market cap increased spectacularly from less than $20 bn in November 2017 to more than $50 bn in July 2020.

It will be interesting to observe the strategies of American oil and gas majors (Exxon, Chevron) regarding GHG emissions.

In the longer term, the question is: Who will be the new players? One can speculate that they will come from developing countries such as China and India.

A greener post COVID-19 society?

By early April 2020, daily global carbon dioxide emissions had fallen by 17% compared with 2019 levels[64] demonstrating that a radical and forced change in lifestyle could reverse the trend.

This was done at the cost of many human lives and cannot be envisaged as a lasting solution.

The 2020 annual emissions drop will depend on the pandemic development with a low estimate of -4% and a high estimate of -7%.

When the virus is contained, the world will probably return slowly to pre-pandemic conditions and if no measures are implemented, the daily rate of GHG emissions will increase again to 2019 levels or more.

In many countries, politicians have announced that the post COVID-19 world will be "greener". This is also their citizens' aspirations even if after the crisis, worries about health, employment and individual revenues are stronger and viewed as first priorities. In many countries and regions, huge stimulus plans are being adopted.

- *Stimulus plans:* Around $9,000 bn worldwide of emergency packages were pledged to mitigate the effects of this unprecedented economic crisis. In G20 countries, the GDP share of those packages is very dispersed, the largest being Japan with 21% of GDP. In absolute terms, the US has the largest finance package (nearly $3,000 bn). Priority is given to economic recovery, job salvage, and health questions (including research and education). A study published in May 2020 by Oxford University[65] surveyed the relative performance of 25 major fiscal recovery plans in G20 countries, including significant

64 https://www.nature.com/articles/s41558-020-0797

65 https://www.smithschool.ox.ac.uk/publications/wpapers/workingpaper20-02.pdf

worker and business compensation schemes which protect livelihoods. Their assessment is that out of $7,300 bn fiscal rescue measures, 4% of policies are 'green', with potential to reduce long-term GHG emissions, 4% are 'brown' and likely to increase net GHG emissions beyond the base case, and 92% are 'colorless', meaning that they maintain the status quo.

Many of those packages acknowledge the central role for electricity which is a vital need in developing countries with plans to extend electrification and reinforce electricity grids but also in developed countries as electricity is also The vector for decarbonization.

Many packages include sustainability components with short- or longer-term views. For example, the European €750 bn stimulus plan adopted in June 2020 provides that 30% of these funds will be dedicated to climate change issues[66].
Several Member State packages are going in the same direction.

In early July 2020 the European Union commission unveiled a plan to invest between €180-470 bn by 2050 to reach a share of 12-14% in 2050 for green hydrogen in the European energy mix, boosting its two industrial champions Air Liquide and Linde. Germany and France stimulus plan will allocate respectively €9bn and €7bn for hydrogen development. Europe would thus regain some sovereignty on electricity storage as battery production is presently mainly located in Asia (China, Japan and South Korea) and in the US.

In July 2020, in a move that marks a partial shift from its strong support of coal, the Japanese government said it will tighten state-backed financing criteria for overseas coal-fired power plants[67].

In China, announcements during the National People's Congress in May 2020 included additional investments in electric and fuel cell vehicles, as well as in new EV charging stations and investments in ultra-high voltage electricity transmission[68].

A very ambitious and well documented global three-year stimulus recovery plan proposal was published in June 2020 by IEA[69] with a $1 trillion investment per year (70% of spending would come from private sources). It aims at boosting economic growth, creating jobs, and building more resilient and cleaner energy systems.

According to their modelling, globally, annual energy-related CO_2 emissions would be nearly 3.5 Gt lower than they would have been otherwise, and methane emissions would be cut by 0.8 Gt CO_2-eq.

In addition, around 420 million people would gain access to clean cooking solutions in low-income countries, and nearly 270 million people would gain access to electricity.

This plan is a framework to be reflected on for the future. However, there are many obstacles to its implementation as it asks for a huge amount of financing (including private funds), quick and agile changes in regulations, real cooperation between players, and genuine international coordination.

In conclusion, the right balance must be found between climate change related expenses and those needed to combat the pandemic and boost employment after the crisis. This could be even more true if, as is probable, a second pandemic wave hits the world.

- *Private initiatives:* In July 2020, nine multinationals came together at the initiative of Microsoft to share their research and strategies in order to enable them to achieve a carbon neutral footprint by 2050. Called Transform to Net Zero, this initiative currently brings together the Danish carrier AP, Moller-Maersk, the American Starbucks, the French Danone, the Anglo-Dutch Unilever, the German Mercedes-Benz, the Brazilian Natura & Co, the American Nike as well as the Indian IT services group Wipro.
Since the 2015 Paris Agreement on climate change, more and more companies are committing to become carbon neutral by 2050 at the latest. Cumulatively, they represent an annual turnover of more than 4.7 trillion dollars.

Although very positive, these declarations arouse a certain suspicion in many experts, including the UN environmental agency. In order to achieve this neutrality, companies mainly rely on carbon offsets, which allow carbon to be captured, for example in deforestation projects. "The most effective way today to eliminate carbon, for less than 10 dollars a ton, is reforestation", confirmed the CEO of Total, in July 2019.
However, certain precautions must be taken ensuring that the project would not have existed without this funding, the permanence of the CO_2 storage for forest projects (it could disappear in case of fire destruction, for example), and the consent of indigenous peoples. In addition, the probability that these carbon offset actions achieve what is announced is low.

The risk is indeed that the companies' carbon credits purchasing policies can lead to a significant delay in the fight against climate change if they are not accompanied by an ambitious reduction of their own emissions.

On the financing side, developed countries committed to mobilize jointly $100 bn a year in climate

66 See Europe editorial

67 https://www.reuters.com/article/us-coal-japan-finance/japan-tightens-rules-on-support-for-overseas-coal-fired-plants-idUSKBN24A0CH

68 China super grids are at very high voltage – 1.1 million volts – in order to reduce electricity losses in this huge country.

69 IEA Sustainable recovery June 2020

finance by 2020 to address the needs of developing countries to mitigate climate change consequences. Several countries and multilateral development banks pledged in 2019 and 2020 to scale up the climate finance they would provide in future. Significant progress has occurred: According to a 2020 OECD study, countries should increase the levels of public climate finance – bilateral and multilateral – to $67 bn by 2020 compared to $44 bn in 2014. In addition, if every dollar of projected public finance would mobilize private finance in the same proportion as during the 2013-2014 period, the projected private finance amount would be an additional $24.2 bn.

- *Individual behaviors:* During lockdown, there was a significant reduction in energy consumption notably linked to telework, the absence of commuting and international travel, and plant closures or slowdown. Countries in full lockdown experienced an average 25% decline in energy demand per week and countries in partial lockdown an average 18% decline[70]. The relaxation of lockdown has of course reduced these savings.

  In June 2020, an "energy-post.eu" global study[71] revealed that if everybody able to work from home were to do so for just one day a week, it would save per year around 1% of global oil consumption for road passenger transport. Considering the increase this would bring in energy use by households, the overall impact on global CO_2 emissions would be an annual decline of 24 million tons – equivalent to the bulk of Greater London's annual CO_2 emissions. This is a notable decline but small compared to the reductions that would be necessary to put the world on a path towards meeting long-term climate goals. If everyone who can work from home were to do so more frequently than one day a week, the reduction in emissions would most likely be proportionally larger. It is probable that some of these saving will be sustained for a couple of years thanks to new HR policies and restrictions in company travel policies.

  It is thus important to change behaviors, particularly those of households. According to various studies[72] there is no one single motivating factor that can drive individuals to adopt energy-saving attitudes. Multiple factors such as financial considerations, environmental concerns, competitiveness, cooperation, conformity and altruism come into play. There are also barriers that prevent or limit changes in behavior (e.g. comfort, aesthetics and the physical layout of homes). Behavior change programs based on routine reporting of comparative consumption information and energy efficiency advice have led to small (around 3%) but consistent reductions in energy use in the home.

Geopolitical impacts on energy

Awareness by Western nations and particularly the US of the increasing power of China heightened tensions in 2019 between this country and the US (and its traditional allies). The COVID-19 crisis exacerbated these tensions.

The complex situation in the Middle East, which is the scene of several conflicts, but which remains the major oil-producing region, has given rise to potentially explosive situations with Iran.

Thanks to its shale oil production, the US is in a stronger position toward such oil producing countries compared to previous decades.

70 https://www.iea.org/reports/global-energy-review-2020

71 https://energypost.eu/calculating-the-energy-saved-if-home-working-becomes-the-norm-globally/

72 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/69797/6921-what-works-in-changing-energyusing-behaviours-in-.pdf

US-China tensions consequences:

During 2019, trade tensions between the US and China increased with periods of crisis and periods of appeasement.

In the energy sector, US dependence on Chinese technologies has been contained by US tariffs on Chinese solar panels prompting companies like SunPower (a Total subsidiary) to repatriate their production to the US, however at an increased cost. Elsewhere, dependency has increased in line with PV installed capacity mainly procured by Chinese manufacturers. Moreover, the domestic slowdown in China's PV installations has pushed manufacturers to export more. In 2019, PV module exports increased by 60% hitting 66[73] GW.

Asia has a dominant position in the batteries market and the increased sales of EV and stationary storage batteries has also increased dependency on Asian manufacturers, especially Chinese ones. Finally, wind turbines and batteries use rare earths and metals that predominantly come from China.

With the COVID-19 crisis, American nationalist and isolationist politics intensified. This notably resulted in the ban on the use of telecommunications equipment manufactured by Huawei[74], based on accusations of spying on information exchanges. The US has pushed its European partners to take similar action.

Tensions between China and the European Union have increased. For example, in mid-July 2020 the UK announced that it would ban Huawei equipment from the country's high-speed wireless 5G network, a victory for the American administration. In addition, the British Prime Minister has offered to host up to 3 million Hong Kong residents and seeks (like other European countries) to strengthen the control of foreign investment on its soil.

The construction of new nuclear reactors in the UK could suffer from potential Chinese retaliatory measures. Indeed, the Chinese company CGN[75] could question its partnership with EDF for the construction of several reactors in the UK. This is unlikely to happen with the two Hinkley Point C reactors under construction because 33.5% partner CGN has invested around £3.5 bn (in mid-June 2020). The financing of Sizewell project, for which an authorization request was filed in June 2020, could be affected; and new financing schemes would be needed

Probably the longer term Bradwell project is the most vulnerable. In this project CGN is a 66.5% shareholder and plans to build an HPR 1000 reactor using Chinese technology adapted to British safety standards.

Oil and gas related tensions

- *On the oil side,* increased shale oil production enabled the US to become the first oil-producing country strengthening its position, notably toward Iran and Venezuela on which it has imposed sanctions.

  In 2019 and early 2020, heightened tension between Iran and the US was linked to the US withdrawal from the JCPOA (also known as the Iran Nuclear Deal) and imposition of new sanctions on Iran by the US. This tension was illustrated by many incidents in the Strait Of Hormuz (SOH) in May and June 2019.

  Also, in retaliation for the Gibraltar government seizing a tanker carrying Iranian oil, supposedly bound for Syria, a British-flagged bulk carrier was seized in July 2019 by the Iranians while transiting the SOH.

73 https://www.infolink-group.com/en/solar/feature-china-exports/analysis-of-2019-china-module-exports

74 Huawei equipment is recognized as being of good quality, reliable and competitive)

75 CGN : China Guangdong Nuclear

On January 3, 2020, the American drone that killed Maj. Gen. Qasem Soleimani, the powerful Iranian commander, drastically increased tension between Washington and Tehran.

These various incidents did not have a sustained impact on oil prices.

Later in 2020, the COVID-19 crisis led to a sharp drop in oil prices endangering several shale producers, such as Chesapeake which was one of the pioneers of hydraulic fractionation. In an election year, the President of the US is satisfied with cheap gasoline. However, as American shale oil production decreases, his country's strategic position in the Middle East could be weakened.

- *On the gas side,* in 2019 the increase in the number of American liquefaction terminals in operation boosted liquified shale gas exports to Europe, reducing this region's dependence on Russia.

  In order to sell more of its LNG and to weaken Russia's position in Europe, the American Administration entered a harsh battle against Nord Stream 2 – the new pipeline that should transport directly gas from Russia to Germany bypassing Ukraine – with the objective of derailing this near-completed infrastructure. By mid-July 2020, the US Secretary of State had threatened to impose sanctions on any company helping to build this pipeline and particularly the foreign shareholders that have provided half of the funding (Shell, Engie, Uniper, OMV, Wintershall).

  The political impact of Russian dissident Alexei Navalny poisoning in August 2020 may force Germany to disassociate itself from this project, it has supported so far, casting doubt on its completion in the near future.

  Thanks to the giant 3,000 km Power of Siberia gas pipeline between Russia and China inaugurated on December 2, 2019, Gazprom was able to decrease its dependence on Europe by increasing its sales to Asia.

Conclusion:

The period studied by this 2020 edition of WEMO is exceptional. It had two distinct phases.

During 2019, lower economic growth and the implementation of certain energy transition measures led to only minor progress towards achieving climate objectives. Despite the decline in emissions from the energy sector, global emissions reached an all-time high. The good news is that the costs of renewable energies and electricity storage by batteries continued to drop dramatically and this should continue. However, our planet remains far from reaching global climate objectives: Extension of the 2019 trajectory would have led by 2050 to a global temperature increase of 3.1-3.7° C – well above the 1.5-2° C desired by international agreements.

In early 2020, the COVID-19 pandemic, and the lockdown that a very large number of countries adopted to combat the spread of the virus, led to a very significant change in this trajectory. During this confinement period, electricity consumption fell by 15-25% and the share of renewables in certain electricity grids, in Europe in particular, exceeded 50%, posing grid stability problems. GHG emissions decreased by 17% during this period and over the year are expected to drop by 4-7%.

Analysis of this period demonstrates, as I pointed out in the WEMO 2019 editorial, that by changing lifestyles and consumption patterns, GHG emissions drop dramatically. Of course, lockdown is not a solution to fighting climate change. By way of illustration, it would take a similar confinement every year for the next 10 years to get on the right environmental trajectory, which is of course totally unthinkable.

To get on the right trajectory to meet the Paris Agreement objectives these measures should be adopted:

- Master GHG emissions:
  - Strengthen carbon-related regulatory measures to reach a higher carbon price
  - Apply carbon tax to imported products in order to avoid overall emissions growth by offshoring product manufacturing
  - Alternatively impose carbon taxes
  - Better control methane emissions (as methane is a potent GHG)
- Incentivize carbon-free generation plant construction (renewables but also safe nuclear plants) to generate “green” electricity
- Consequently, incentivize electrification of uses (notably for transportation) allowing decarbonization of the whole economy.
- Ensure safe grid management with a high, intermittent renewables share by:
  - Grid upgrading with increase digitization
  - Imposing dynamic tariffs to increase demand side response
  - Changing grid tariff calculation methodology to also remunerate “soft” investments
  - Modifying the European “merit order” to allow renewables curtailment if needed
  - Revising DSO missions.
- Encourage green hydrogen as, along with hydropower, it’s the only way to store electricity for weeks or months
- Ensure that the “green” share of stimulus plans becomes a reality:
  - Track these funds’ sustainability in relation to other urgent needs, particularly health and social
  - Strengthen those plans’ “green” conditionality.

Finally, energy players must adapt to a more volatile environment and become more agile and forward-looking. Increasing digitization and innovation will be key levers.

Enjoy reading this new and enriched WEMO edition.

Colette Lewiner

Senior Energy Advisor to Capgemini Chairman
Paris, September 18, 2020

1-COVID-19

The COVID-19 crisis led to significant energy demand decreases across oil and gas and electricity and had a strong negative impact on electricity wholesale prices.

Lockdown

-10 to -20%

Overall -10% to -20% consumption due to fall in client activity

During lockdown

- +3 to 5% in residential consumption due to working from home
- -40 to 90% in certain sectors (plant closures)

Post-Lockdown

-5 to -10%

3 weeks post lockdown compared to normal

- There is a direct correlation between GDP and energy consumption, with energy efficiency making slight progress year on year. In the countries that will manage to be almost virus free and have launched their recovery plans, consumption may get back to pre-crisis levels by End 2021 – 2022.

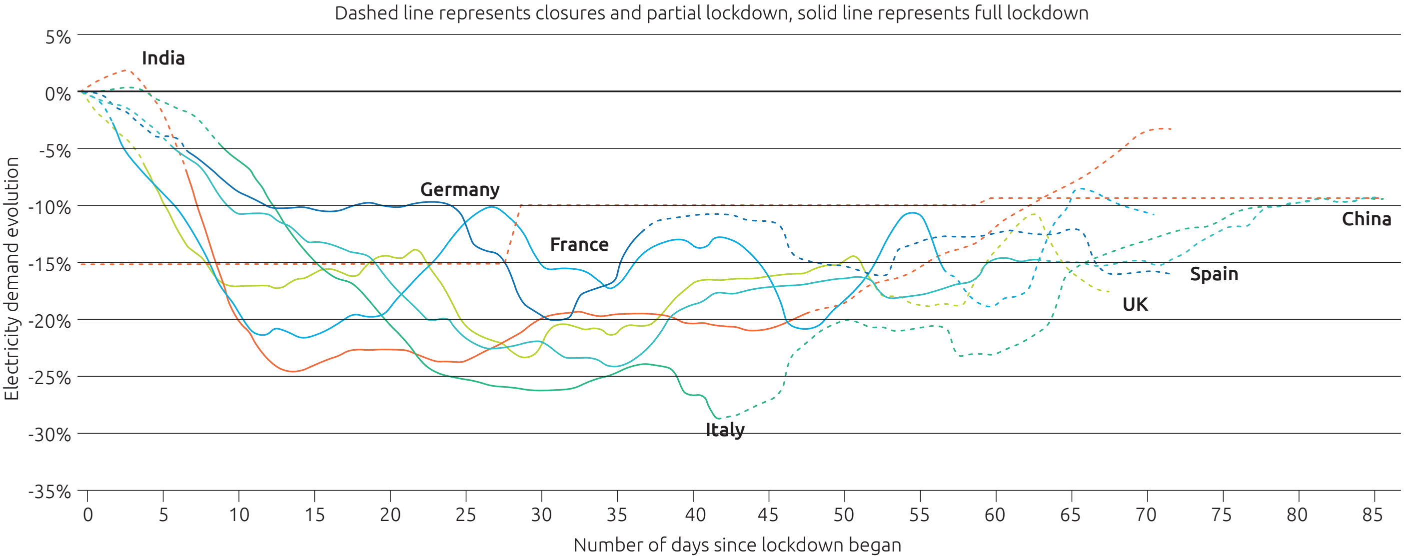
Wholesale electricity prices have been hit

Wholesale electricity prices fell in mid-April 2020 to about €20/MWh in Europe, down from €50/MWh in 2019, with multiple negative price episodes, due to market overcapacity and unavoidable intermittent renewable sources.

After the lockdown, prices restored to €30-35/MWh in Europe and are expected to get back to €40/MWh in 2021 (markets futures). European security of supply could be endangered for winter 2020/21 due to the low availability of French nuclear power. This low availability will result from social distancing requirements having significantly slowed nuclear maintenance and refuelling programs generally happening during the spring.

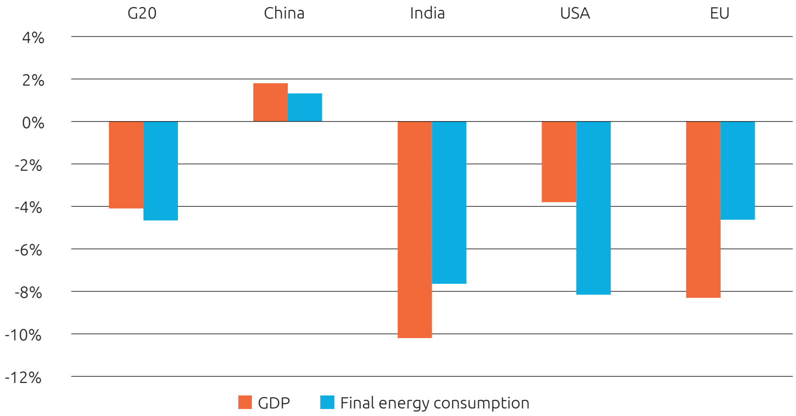
Refer please to the WEMO Financial chapters to learn about the financial impacts of the crisis.

Figure 1.1. Reductions in electricity demand after implementing lockdown measures in selected countries, weather corrected, 0 to 86 days



Source: IEA 2020

Figure 1.2. Year-on-year evolution of final energy consumption and GDP, 2020 estimates/2019



Source: Enerdata estimates, October 2020, Global Energy Trends - 2020 edition

COVID-19 led to the largest reduction of GHG emissions since World War II. Levels returned to the 2010 equivalent.

A drop of 8.6%[1] in CO_2 emissions for 2020?

Mobility restrictions and the sharp industrial slowdown have had a conversely favorable impact on real-time CO_2 emissions, leading to an unexpected forecast of an 8.6%[1] reduction in emissions over the full year.

This decrease being circumstantial and nonstructural, emissions will likely start to rise again as the crisis subsides. Before the crisis, GHG emissions were not on the Paris agreement trajectory, which aims to limit global warming to 2°C.

Shift up a gear with green recovery packages

Governments from OECD and non-OECD countries should seize the opportunity for recovery packages (Green Deal for Europe, Green Act in the US) to accelerate energy transition and sustainability, using a wide range of measures, such as:

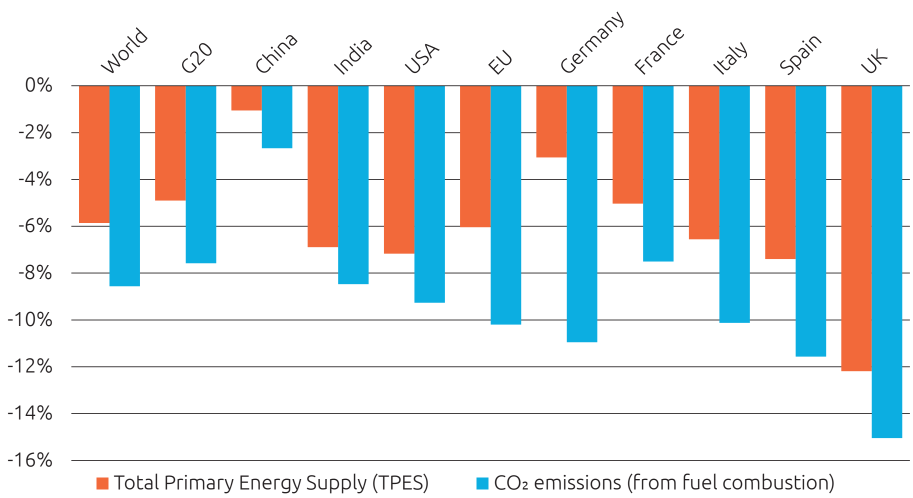
- Growing renewables and green hydrogen, to push electrification (green mobility);
- Insulating and refurbishing buildings, to take energy efficiency to the next level;
- Growing smart grids at scale to enable transformation as well as convergence of commodities and networks;
- Reduce travel and change individual behaviors.

Methane emissions are rising dramatically

- Methane is a greenhouse gas 28 times more powerful than carbon dioxide. While being especially emitted by fossil fuel combustion, agriculture and garbage decomposition, this gas is today responsible for roughly 20% of climate change.
- After remaining steady between 1999 and 2007, methane emissions have been dramatically increasing since 2007 and since 2014 they have been at record-breaking levels.
- In 2017, methane concentration in the air was already significantly higher than the 2020 2°C scenario forecast.

CO_2 emissions are estimated to drop by 10% in the EU, 9% in the US, and by 8.6% globally[1]

Figure 1.3. Change in CO_2 emissions and primary energy consumption, forecasts 2020/2019



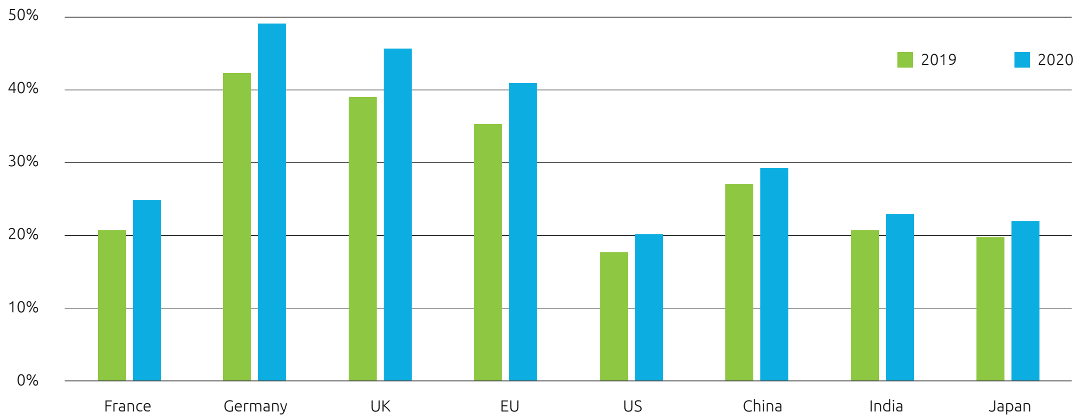
Source: Enerdata estimates, October 2020, Global Energy Trends - 2020 edition

During lockdown, reduced electricity consumption and favorable weather provoked an unexpected jump in the renewables share of the energy mix, at a level that could have been expected by 2025-2028

Renewables held a larger share of the electricity mix during the COVID-19 outbreak

- During the COVID-19 pandemic, lower electricity demand due to lockdowns, combined with favorable weather conditions, enabled shares of renewable electricity to increase significantly.
- Non-schedulable renewable electricity with no storage solution has to be consumed as soon as it is produced. Thus, the combination of reduced demand, favorable weather, and prioritizing renewables led to reduced production from schedulable sources. In the EU, the renewables share in the electricity mix was above 40%[2] for several weeks. This higher than usual share enabled the UK to stop using coal power plants for more than two months, giving a glimpse of the future as the country plans to close all its coal plants by 2024.
- In India, the same circumstances of reduced demand and favorable weather enabled a significant reduction in the share of coal-based electricity production from 75% to 60% while the US saw renewable sources become the second biggest electricity producers after gas power plants[3].

Figure 1.4. Share of renewables in electricity generation, forecast 2020 compared to 2019



Source: Enerdata estimates, May 2020, Global Energy Trends - 2020 edition

This level of renewables demonstrates, if needed, the requirement for smart grids and flexibility

- Such large shares from intermittent power sources caused blackout fears in the UK.
- The UK's National Grid asked energy regulators to make urgent changes in order to permit solar and wind farms to be turned off, to avoid overloading the grid on the May 8 public holiday[4].

> ***The impact of COVID-19 led to a massive increase in the renewables share which, combined with the drop in CO_2, could be considered positive. But other solutions have to be found to make lasting CO_2 reductions and they will be structural, not circumstantial.***

1 Enerdata Global Energy Trends - 2020 edition - October update, October 2020
2 Enerdata Global Energy Trends - 2020 edition, May 2020
3 IEA, COVID-19 impact on electricity, August 2020
4 Bloomberg Law, National Grid Asks for Emergency Powers to Avoid U.K. Blackouts, May 2020

Operating in the new normal

Acceleration of digitization

Business leaders must re-evaluate their digitization transformation plans and increase efforts to leverage faster OPEX cost savings.

Office working may no longer be full-time

Companies have to establish teleworking policies that address the needs and preferences of their employees while maintaining high standards for productivity, efficiency and quality. Social boundaries will be more and more supported by digital.

Industrial assets

There will be factory and plant closures and a tendency to relocate production of critical components within the supply chain to be closer to the customer.

Utilities must be attentive to the magnitude and the consumption impacts of these two opposite transformation triggers.

Financial recovery

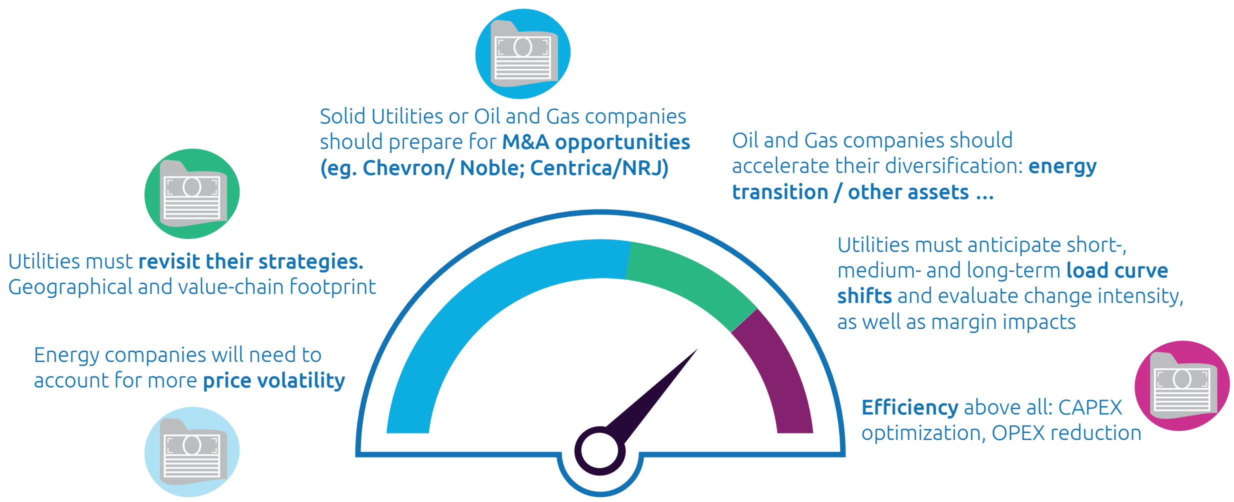
Oil and Gas companies as well as Utilities generally, will see long-lasting cuts in revenue and margins during 2020-2021. A new wave of OPEX and CAPEX programs will create additional unrecoverable debts. As they resume their current performance, Utilities have been revising their financial plans to enhance operational profitability, and depreciating some assets.

Client churn

Demand from residential and B2B clients has decreased, and action needs to be taken to protect revenues.

Post-crisis, the situation could change if customers impacted by reduced working hours or unemployment experience financial worries. Meanwhile, a drop in wholesale prices could offer opportunities to new entrants to propose cheaper tariffs, fueling a switching wave.

Companies should anticipate higher customer churn and adapt their services and prices accordingly.



Topic Box 1.1: Overview of the impact of economic recovery plans for the energy sector

The IEA has designed a recovery plan for the energy sector focused on sustainable development

The coronavirus pandemic significantly reduced carbon emissions from most industrialized countries with many borders closed and people confined to their homes, which reduced transport and changed consumption habits. However, this reduction was temporary and, helped by economic recovery plans, carbon emissions began to grow again.

In response, the International Energy Agency (IEA) and the International Monetary Fund (IMF) designed a global sustainable recovery plan proposing measures to increase global GDP by 1.1% per year, save or create 9 million jobs per year, and save 4.5 billion tonnes of carbon dioxide by 2023. The plan requires investment of US$1 trillion per year over three years, less than 10% of fiscal expenditure in recovery plans already announced, for expenditure in six sectors: electricity, buildings, transport, industry, fuels and innovation.

At a virtual summit in July 2020, stakeholders welcomed the plan and agreed to meet again in 2021 to assess its implementation.

The EU plan for economic recovery after COVID-19 will apply the Green Deal principles

On July 6, 2020, EU member states signed an open letter to the European Commission (EC) to use the European Green Deal, the roadmap of policies and measures agreed in December 2019, as a framework to draft the EU plan for recovery.

The overarching aim of the Green Deal is to achieve climate neutrality by 2050. The first stage, to achieve by 2030, is to reduce GHG emissions by at least 50% and preferably closer to 55% compared with 1990 levels. The two main financial pillars of the Green Deal, included in the EC budget, are the Just Transition Fund (to benefit specific territories) and the Invest EU fund (to promote new facilities in strategic sectors such as hydrogen, batteries or CCUS).

On July 21, 2020, EU leaders agreed to a €1.8 trillion recovery package that combines €1 billion from the EU budget for 2021-2027 and €750 billion from the Next Generation EU recovery instrument. It was also decided that a climate target of 30% will apply to expenditure from the EU budget and the recovery plan. In other words, all member states' recovery plans will include measures compatible with the European Green Deal and climate change.

The following table provides the main measures of plans drafted or passed by 11 of the IEA Summit's participants (including EU member states) dedicated to the six sectors of the IEA sustainable recovery plan.

	Status / Budget	Buildings	Electricity / Renewable energy	Fuels	Transport and industry	Innovations
Canada	Adopted / US$82 billion	Measures announced to reduce greenhouse gas emissions.	Measures announced to develop the offshore sector (US$75 million).	Measures announced to reduce oil and gas sector with a focus on methane (US$750 million); cleaning program for orphan and inactive oil and gas wells ($1.72 billion)	N/A	N/A
Finland	Proposed / €500 million	Subsidies to phase out oil heating in households and public buildings (€45 million).	Subsidies for energy pilot projects (€20 million)	Subsidies for digitalization and low-carbon operations in manufacturing industries (€300 million)	Subsidies for cycles (€18 million)	N/A
France	Announced /€30 billion (of the €100 billion plan)	Measures announced for buildings' thermal renovation.	N/A	N/A	Measures announced to cut carbon emissions	Measures announced concerning batteries and hydrogen.
Germany	Implemented / €50 billion (of the €130 billion plan)	N/A	Tax rebate on electricity consumption to 6.5 cents/kWh in 2021 and to 6.0 cents/ kWh in 2022; support to ENR capacities as offshore wind (to 5 GW in 2030 and to 10 GW before 2040).	N/A	Support the purchase of electric vehicles; investments in charging infrastructure for electric vehicles (€2.5 billion); support program for modern shipping (€1 billion) and for modern aviation solutions (€1 billion).	Measures to support research and development of hydrogen (€9 billion); support program in in clean technologies in the automotive industry (€2 billion).
Ireland	Announced / €6 billion	Energy efficiency (€135 million).	Subsidies for on-farm renewable energy projects (€10 million).	N/A	Subsidies to decarbonize private travels, to improve public transportation and infrastructures (€115 million).	N/A
Italy	Adopted / €55 billion	Tax rebates for buildings renovation projects; tax rebates for solar plants and storage systems associated with buildings renovation projects.	N/A	N/A	N/A	N/A

Japan	Adopted / US$102,8 million (of the US$ 927 billion plan)	N/A	Subsidies for the installation of energy-efficient ventilation systems in public spaces (US$74 million)	Creation of a platform for governments to exchange views on the recovery.	Construction of factories powered by ENR	N/A
Luxembourg	Announced / €700-800 million	Tax rebates for building thermal efficiency projects; subsidies for consumers switching to renewable energies for heating.	Subsidies for solar plants over 30kW.	N/A	Subsidies for buying bicycles, e-bikes, quads, motorcycles, mopeds, and electric cars; and for the installation of electric charging stations.	Fiscal measures for companies to carry out economic development, digitalization or environmental protection projects.
South Korea	Discussed / US$94 billions	N/A	Large-scale investment in renewable energy and in smart grids (£16 billion).	Implementation of a phase out of coal operations and a carbon tax.	Conversion of 4,000 of Seoul's public buses to electric or to hydrogen; subsidies for the purchase of electric vehicles and hydrogen cars.	Financial measures announced to develop digital technologies.
Spain	Announced / €3.75 billion (recovery for automotive sector)	N/A	N/A	N/A	Fund to support the electrification of public transport, adjustment of rail routes, the development of charging infrastructure for electric vehicles, and the e-bike sharing (€1.125 billion)	Measures to support research and development of hydrogen technology for transportation.
UK	Announced / £3 billion (energy efficiency plan)	"Green homes grant" program for energy efficiency in domestic buildings (£2 billion).	N/A	Measures for the decarbonization of heavy industry and construction (£350 million budget)	Measures for the decarbonization of transportation and aviation sectors (same budget)	N/A

Apart from member states of the EU that had not yet announced their economic recovery plan (such as France), most participants at the IEA Clean Energy Transitions Summit in July 2020 did not include any green measures in their economic recovery plans for the energy sector.

In reality, economic recovery plans for the most populated and industrialized countries cannot be considered as "green" (such as the US, China, Indonesia, Thailand, and Taiwan). For example, India's economic recovery plan is mainly focused on commitments to support coal mining (with an investment of US$6 billion in coal transportation).

Only a few participants included green measures specifically for the energy sector in their economic recovery plans.

- All plans contained green measures to an extent, but some were not globally focused on a climate change target and could be considered insufficient from that perspective (e.g. Italy, Spain, Ireland and Canada). This is also the case for Japan, which plans to allocate only US$102.8 million of its US$927 billion plan to promote energy-efficient ventilation.
- Only a few recovery plans contained strong measures compatible with climate change (such as Finland, Germany, Ireland, Luxembourg, South Korea, and the UK). In this group, most set ambitious goals for buildings, electricity, renewable energy, or transportation. However, in the fuel and innovation sectors, only a few countries announced measures to reduce emissions and develop new technologies, such as hydrogen or batteries.

At the same time, some countries that did not attend the IEA summit also included green measures in their economic recovery plans, such as Nigeria (investment of €552 million in the solar energy sector) and Malaysia (investment of US$2.9 billion for green policies).

2-Commodities

The crude price war in March-April between Russia and Saudi Arabia together with the COVID-19 lockdown caused a crisis in O&G markets

8.1m
barrels/day

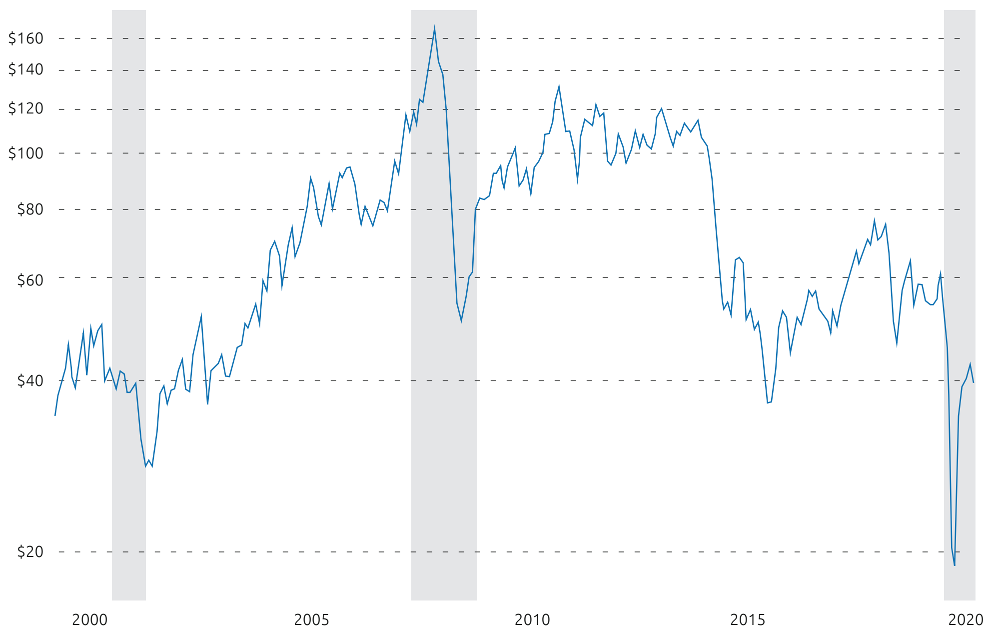
The expected daily demand fall for oil in 2020, the largest in history, before recovering by 5.7 mb/d in 2021

There may be strong long-term impacts on global oil demand and transportation; reduced jet and kerosene deliveries will impact on total oil demand until at least 2022. Peak oil levels may have been reached in some regions.

- The worst crisis ever experienced by the O&G industry has collapsed profits for majors and led smaller or shale players to question their survival.
- After the $20/bl mark for Brent and negative prices on WTI (-$37/bl), with previous overcapacity and reserves fully loaded, prices bounced back up to $40/bl in June 2020. At that level, Oil majors have renewed profitability (breakeven price around $25-30). This is not the case for shale oil producers.
- The situation could lead to various reactions on the market: upstream investments cuts (-30%), lower profitability, diversification acceleration for the majors, and a series of failures or consolidations for shale players. For example, Chesapeake Energy has filed for bankruptcy protection. The diversification trajectories vary. European majors have clearly laid out their intention to become broad energy companies (renewables, storage, hydrogen, energy retail & services), whereas US Oil majors and NOCs are looking at different options (e.g. managing other large assets, moving elsewhere in the value chain).

- Negative prices were due to fully loaded tanks. Prices dipped further before bouncing back in May at around $30 ($35 in June); they are expected to remain volatile.
- Oil majors are under increasing pressure from stakeholders to reduce their carbon footprint.
- European players are extending their activities by acquiring CO_2 carbon sequestration certificates.

Figure 2.1. Crude oil prices (Brent)



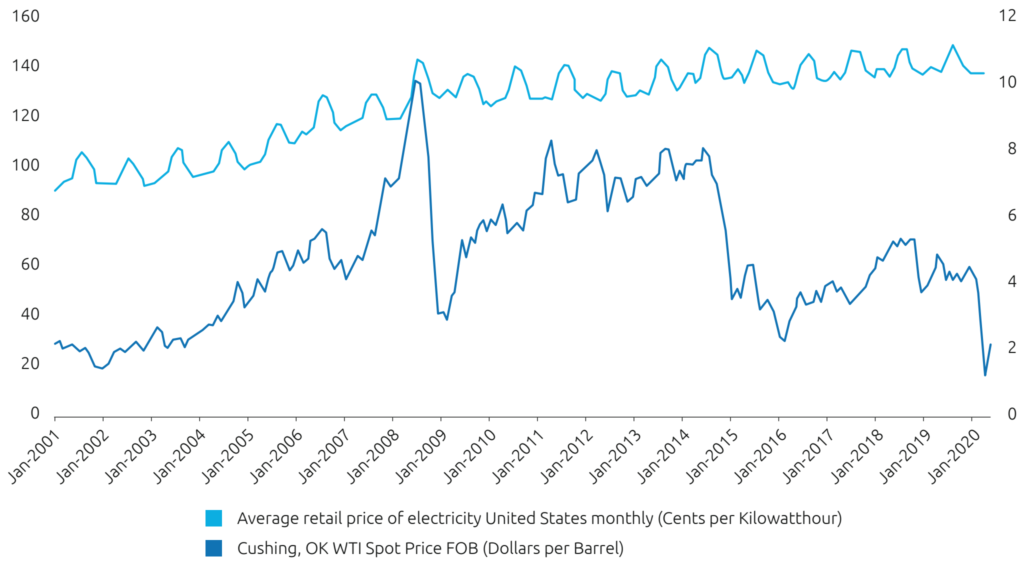
Source: Macrotrends

Price volatility has become the norm, for Oil more than for Electricity

- Energy & Utilities should expect more price volatility.
- Crude oil prices have been more volatile than electricity wholesale markets at least since the early 2000s.
- The gradual rise in demand post-crisis should lead to an increase in spot electricity prices (forward prices for next year are at 40 €/MWh). However, these are expected to remain lower than before the crisis.
- For oil prices, the lasting drop in demand, the current overproduction and the lack of storage capacity could keep prices low. It is difficult, however, to predict production restrictions on the part of OPEC or American shale oil producers. It is also necessary to take into account possible geopolitical tensions, which could drive up prices. Therefore, analysts remain cautious with their middle and long-term oil prices predictions.

Players must operate at the lowest possible costs and develop their agility to deal with market variable levels.

Figure 2.2. Commodities markets volatility



Source: Energy Information Administration

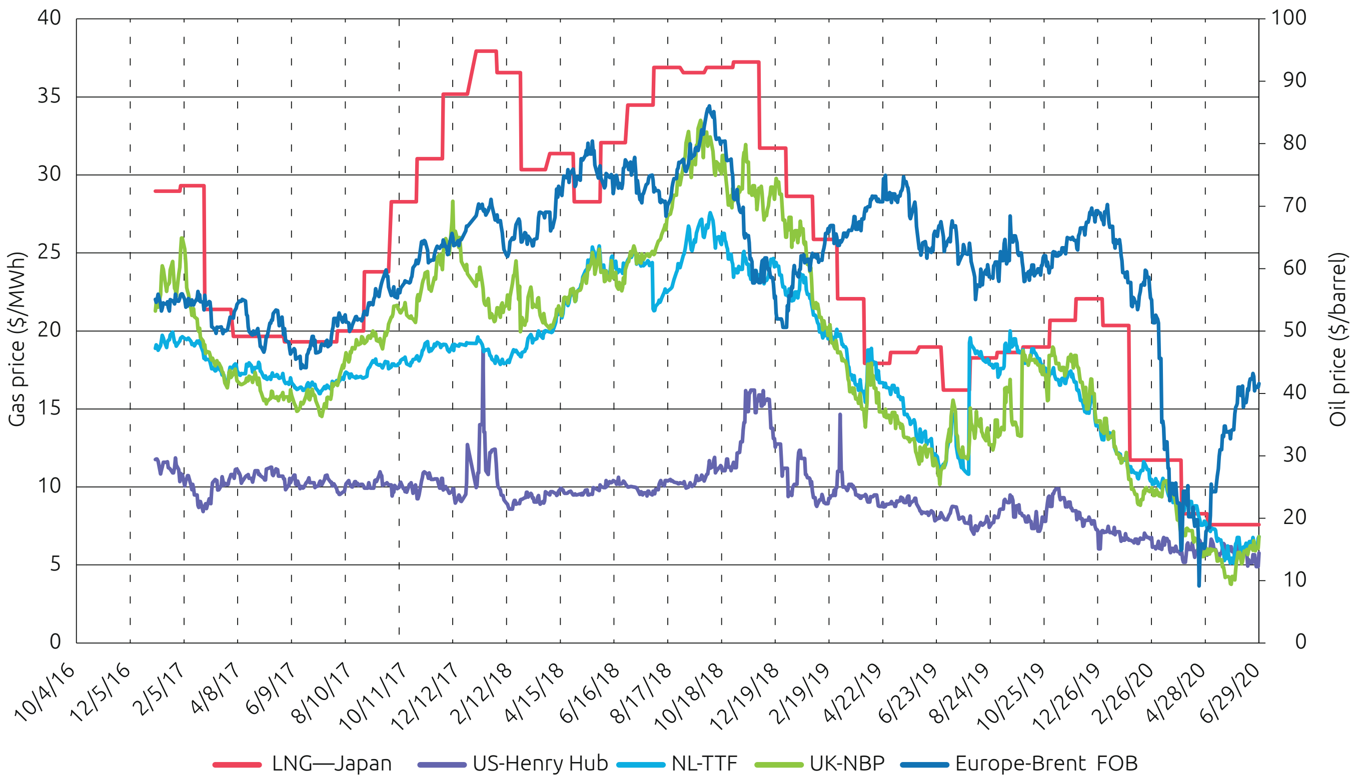
COVID-19 has accelerated convergence of gas prices

COVID-19 has accelerated convergence and falling gas prices due to historical decreases in demand.

The LNG glut in Asia (and subsequent price drop) led to lower prices in Europe

- Global gas demand should decrease by 4% in 2020 according to BNEF report. This would be the first time ever that global demand would experience such a hit (-2% in 2019).
- Gas prices started to fall in 2019 triggered by large LNG supplies and competition with piped gas. LNG imports have been growing, with new terminals being commissioned and benefiting from less exposure to geopolitics.
- Gas prices in the EU were affected by increasing LNG imports; intensive storage gas consumption in the EU complements renewable energy generation and is consequently volatile.
- In gas-dependent countries like Japan, most factories can't run at full capacity unless the entire supply chain is backed up by strong production exports.
- Weak demand from the industrial, manufacturing and hospitality sectors, and high inventory levels during the COVID-19 crisis, also contributed to a drop in LNG prices.
- US gas prices, which were already low, did better than other countries during COVID-19 although Henry Hub prices fell globally. The impact of coronavirus on US LNG exports is likely to be small because prior to the outbreak the country hadn't been exporting any LNG to China due to China's 25% tariffs on US LNG.

Figure 2.3. Gas spot prices (2019 and H1 2020)



Source: Refinitiv

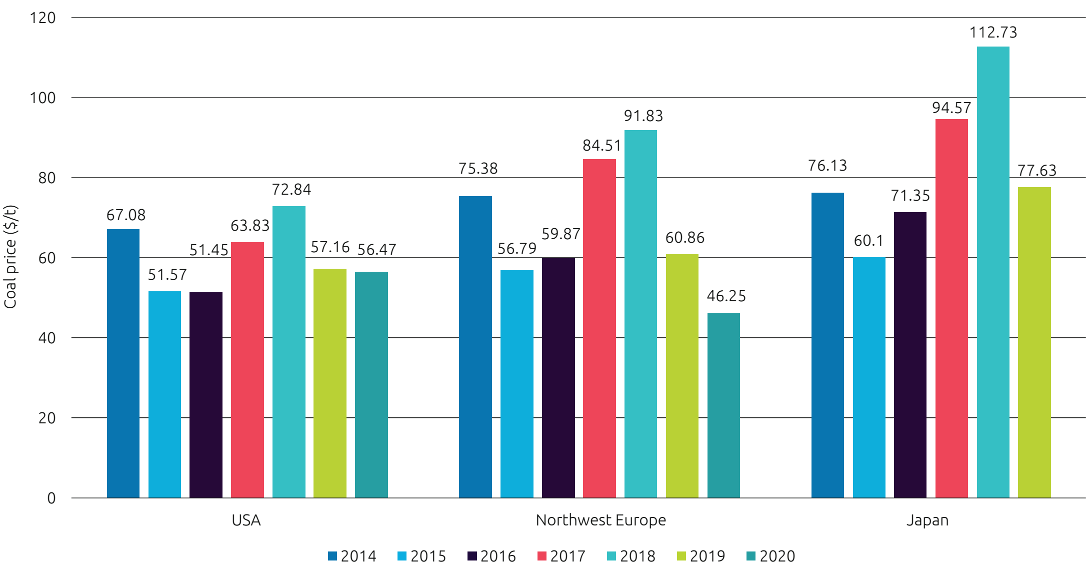
Coal prices globally decreased in all regions, becoming less competitive than gas

In China and India consumption is still high as coal power plants are opening

Europe reduced its coal consumption by 12% in 2019 compared to the previous year and this trend continues in 2020.

- Global coal consumption decreased by 0.6% in 2019, mainly due to overcapacities in electricity generation and the European coal phase-out policy.
- Despite the US and Europe shuttering coal-fired power plants, coal remains a major fuel in global energy systems.
- China remains the world's largest coal consumer, accounting for more than 50% of global consumption.
- Despite energy consumption slightly increasing in 2019, coal saw consumption remain flat from 2018 to 2019.
- The IEA expects global coal demand to fall by 8% in Q1 2020 relative to Q1 2019.
- Coal prices have been under heavy pressure amid oversupply concerns in the face of weaker demand from China and India.
- During the coronavirus in April 2020, Indonesia's coal exports hit their lowest level since October 2010. However, exports had already dropped below average in February and March 2020, before declining further in April 2020.

Figure 2.4. 2014-2020 coal prices evolution



Sources: BP Statistical Review, Refinitiv

CO_2 prices fell during the crisis (to €15 in Europe) before rising again; while gas became more competitive than coal

With an unprecedented 40% price increase, uranium appears to be the winner energy commodities during the COVID-19 pandemic

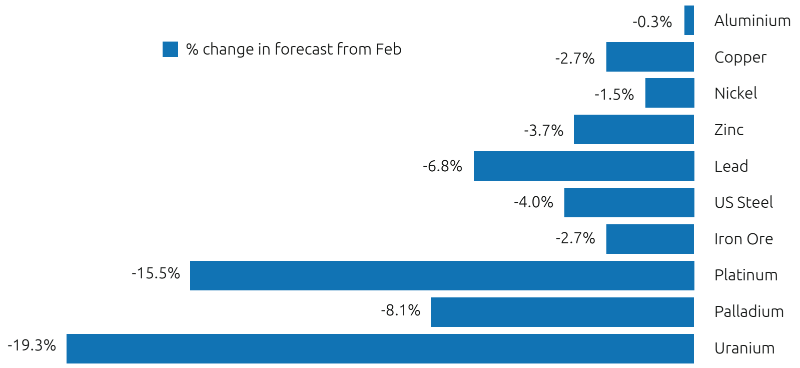
Unlike commodities affected by lack of demand, uranium experienced a renewed price surge, unseen since the 2011 Fukushima disaster, from $24 per pound in mid-March 2020 to $34 in May.

While nuclear energy demands remained stable, uranium supply has been disrupted.

Two factors explain the rise in uranium's price:

- There has been no enforced shutdown of nuclear power reactors – unlike coal and gas plants which are more flexible to demand – and protection of workers in response to the pandemic slowed down processes in mines and facilities.
- Production was interrupted in Canada, Kazakhstan and South Africa:
  - Canada's Cameco suspended production at its Cigar Lake mine, responsible for 13% of total uranium production.
  - In April 2020, Kazakhstan's state-owned production company Kazatomprom announced staff reductions for three months in all facilities. This could lead to a drop in annual production of up to 4,000 tU
  - 20% down on their expected turnover. The Kazakh giant, which produced 40% of the world's uranium in 2019, announced it would draw from its current stock to meet contractual obligations.
  - All mining, including uranium, was suspended in South Africa.

Figure 2.5. Drop in metal production expectations for 2020



Source: Bloomberg, May 2020

A supply risk could arise in an extended pandemic scenario.

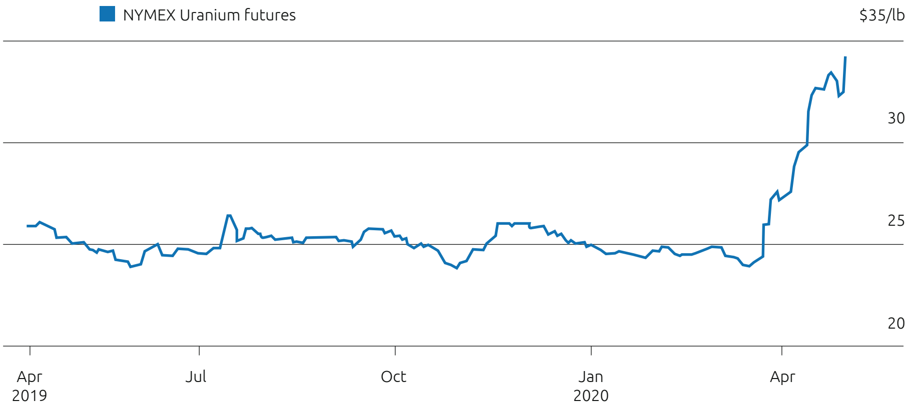
- Even though nuclear plants have several months' worth of uranium stock, uranium supply needs to be reserved for 2 years before being used as fuel.
- In 2019, mines supplied 80% of the utilities' annual requirements. The balance was met from secondary sources including stockpiled uranium held by utilities.
- However, quoted uranium spot prices represent only a quarter of supply. Most trade is fulfilled through long-term contracts of 3-15 years, with producers selling to utilities at a higher price than the spot market, which shows the security of supply.

Therefore a steady supply is needed even during tough economic times. A long-term pandemic could have further potential impact on the initial fuel supply chain, but this should be contained if the crisis does not extend beyond long-term contracts and utilities' available stock.

Prices are still far from what they were pre-2011.

- Prices were boosted up to 80$ per pound before the Fukushima accident, with Chinese starting to invest in nuclear energy.

Figure 2.6. Uranium prices per pound



Source: Bloomberg, May 2020

3-Oil & Gas

Context: How rising uncertainty is accelerating strategic divergence

Framed by increasing uncertainty, the O&G industry is rethinking its future

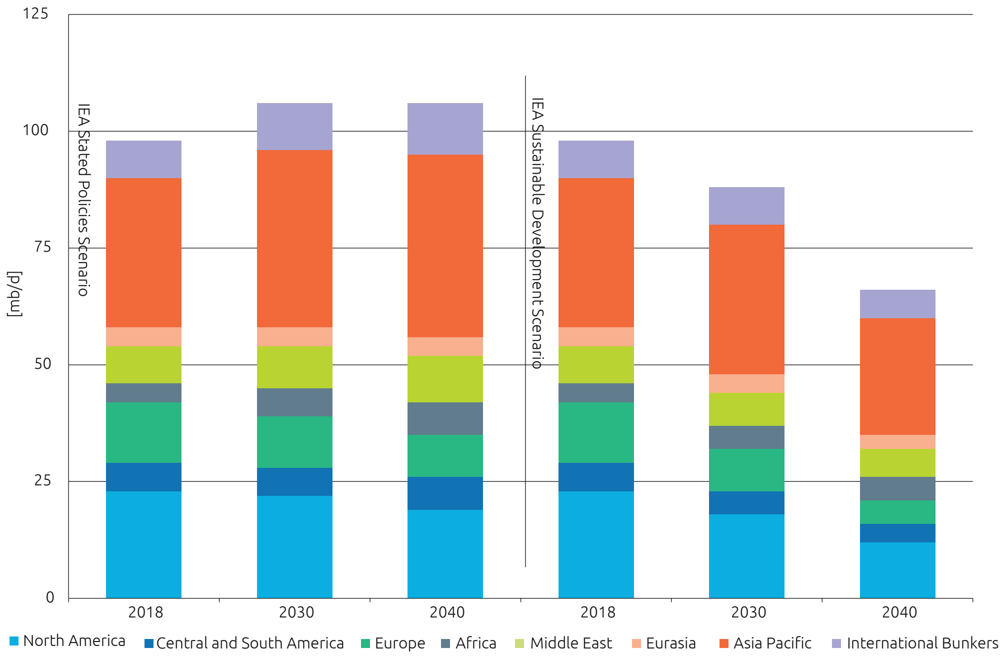
O&G players are facing an unprecedented context with shrinking margins

- Price volatility has long been the norm in the oil and gas industry. This volatility has followed a macrocyclical pattern supported by steadily growing demand. It has acted to benefit many incumbents as they have been more able to thrive through the cycles.
- Today there is increasing uncertainty around future demand for oil and gas – and long-term price assumptions are consequently being questioned. In the IEA's Sustainable Development Scenario, demand could be reduced by a third by 2040 compared to 2019 figures.
- With accelerating adoption of electric vehicles and electrification in the electricity and industrial heating sectors, competition from other forms of energy is increasing.
- Lower demand might put additional pressure on oil prices and eventually prevent high, sustained "peaks" in prices as electrification increases and oil and gas become increasingly able to be substituted with other forms of energy, decreasing price elasticity.
- In recent years, oil and gas companies have also been under pressure to reduce emissions from both operations and use of petroleum products, impacting on both their profitability and license to operate.

The transition to other energies or business models will require in-depth changes

- Lower returns within oil and gas means that renewable investments can be comparatively more attractive and can receive better investment prioritization within the O&G sector. Companies are being pressured to make material investments in creating new options.
- Responding to this requires adapting business models. As cashflow tightens and uncertainty and volatility increase, operating models, organizations, and decision processes will have to adapt to compete.

Figure 3.1. Oil demand by region and scenario, 2018-2040



Source: IEA

Despite prolific communication, investments from the oil and gas industry within "new energy" remains low, with diverging approaches across industry players

Today, O&G industry investments are still focused within the core oil and gas business. The main difference between actors can be seen on their commitment outside of this core

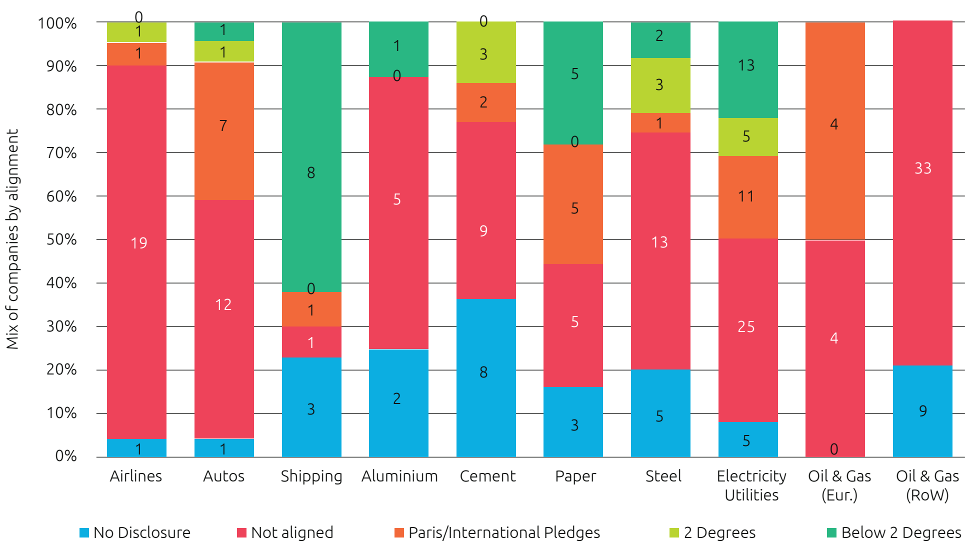
- The industry is still largely rallying around the core business, with only ~0.8% of the overall industry investment focused outside the core (though this number is rising fast).
- There are a few notable European International Oil Companies (EU IOCs) that have begun to make large, material pivots outside of their core, with larger investment forecast – but even this ambition is relatively low compared to investments in the core business.
- This marks one of the strongest divergencies in the industry, strengthened by the diverging environmental focus of US and EU governments and investors.

European majors have set ambitions that include emissions from the end use of their products on an absolute basis but are still behind other industries, meeting neither the Paris nor the 2-degree roadmap targets

- Emissions targets have been getting gradually more ambitious, with the major milestones of discussion Scope 3 emissions and targets such as "net zero" emerging. Repsol was the first large International Oil Company (IOC) to set a net zero ambition for 2050, with BP following.
- Some of the highest level of ambition has been when BP announced in July that it is targeting 40% lower production by 2030 and stopping exploration in new countries. Shell, Total, and Equinor have so far communicated more limited ambitions but are expected to adjust their communications and strategies through 2020. Repsol has paralleled BP's approach in narrowing exploration focus to nearfield and Eni's ambitions also appear to move the company away from O&G growth and towards a managed decline of O&G.

- US IOCs, most NOCs, and unconventional players have not had the same ambition, in line with less pressure from shareholders and stakeholders. As of summer 2020 the US IOCs did not report scope 3 emissions nor communicate long-term oil price assumptions.

Figure 3.2. Carbon performance alignment by sector



Source: TPI 2020

5 main groups emerge based on the need and ability to respond to change

- **EU IOCs** such as Shell, Total, BP, Eni, Equinor, and Repsol
  - Moving towards defining themselves as «energy-first» rather than O&G.
  - Exploring and committing to commercial options outside O&G, such as Total's acquisition of Direct Energie and BP's acquisition of Chargemaster (both in 2018). Other moves have been in areas such as biofuels, hydrogen, electricity storage, and EV charging.
- **US IOCs** such as ExxonMobil, Chevron, and ConocoPhillips
  - Aiming to be the last producers in a world of shrinking demand, focus on commercial options within O&G. Both Chevron and ExxonMobil investments in renewables have been relatively scarce so far, with no targets in place for a move to cleaner energy.
- **National champions and NOCs** such as Saudi Aramco, Petrobras, CNPC, Rosneft, Gazprom, Petronas
  - Prioritizing development of national resources, ensuring national supply and revenue.
- **Unconventional players** such as Occidental, Apache, EOG, Marathon, Pioneer.
  - Prioritizing survival, facing fewer options and a higher cost structure.
  - Facing the bankruptcy of their peers, Whiting Petroleum and Chesapeake Energy.
- **Others** which includes independent local players and smaller IOCs
  - Prioritizing survival, focusing on most commercial assets and playing where they win.
  - Examples include AkerBP, Suncor, and Woodside.

- **O&G actors are facing an unprecedented context of shrinking margins combined with uncertainty on future demand for oil and gas, impacting on both their profitability and license to operate.**
- **Lower returns within oil and gas means that renewable investments can be more attractive, but a transition to other businesses will require in-depth changes.**
- **Different factors influence the ability and necessity to act for each company. The industry is still rallying on the core business with less than 1% of overall industry investments focused outside of the core.**
- **EU IOC's emissions targets have gradually become more ambitious, have included scope 3 emissions in their reporting, and set "net zero" emission targets. US IOCs, most NOCs, and unconventional players have not had the same ambition, in line with less pressure from shareholders and stakeholders.**

Strengthen the Core Business to maintain short-term Profitability

In line with oil price evolution since 2010, companies have been reducing their CAPEX, but reserve replacement needs make this CAPEX reduction unsustainable

Since the 2014 oil price crash, industry CAPEX has followed a similar trend to the oil price, declining sharply then remaining relatively flat

- Cashflow constraints due to the low oil price have forced companies to shrink or slow their investment pipeline and focus on short-term liquidity, resulting in near-universal CAPEX cuts for 2020. These cuts range from around 20% on average for the IOCs to over 45% on average for US unconventional players. The industry saw its peak with US $779 billion globally in 2014 but since then has decreased significantly across all groups. Following 2016, investment has remained relatively flat.
- Reducing CAPEX in the development portfolio is achieved by improving concept development via simplification, standardization, and negotiations with suppliers (particularly at times of low investment activity in 2014 and 2020). Among offshore drilling contractors Noble, Diamond Offshore, and Valaris filed for bankruptcy while Transocean scrapped more than 50 of its rigs and others are fighting to maintain liquidity. Illustrating this trend, deepwater semisubmersible drill rig utilization has plummeted from nearly 100% in 2014 to well under 50% in 2020 while day rates followed an even steeper decrease.
- The combination of the COVID-19 demand contraction and the supply glut caused an unprecedented crash in prices in 2020 - particularly challenging for those with higher leverage and higher cost structures, such as unconventional players still recovering from the 2014 crash.

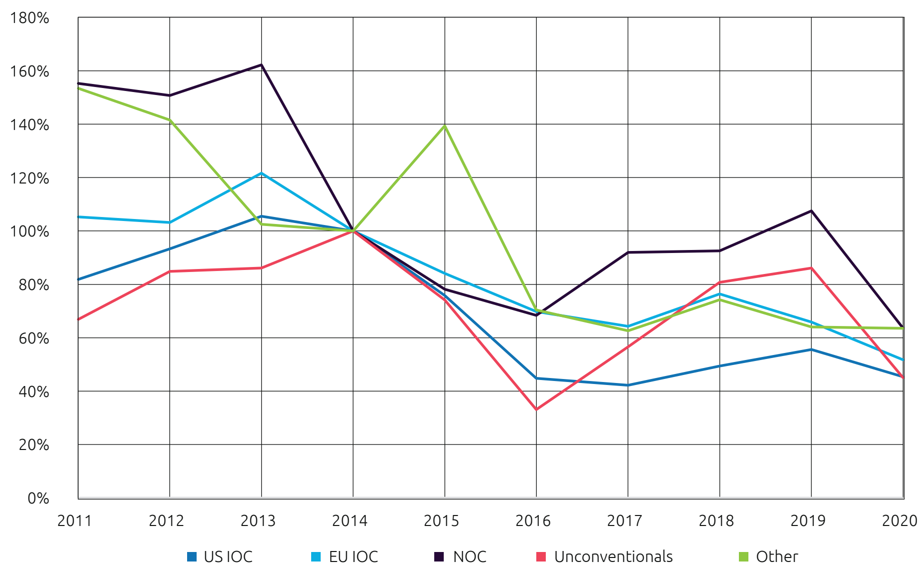
A combination of short-term liquidity requirements and changes in long-term price assumptions will guide CAPEX decisions going forwards

- In US onshore, drilling has slowed, with Occidental moving from having 22 Permian drilling rigs in 2019 to only 1 in 2020 – a decline of more than 95%. Drilled-but-uncompleted (DUC) wells have continued to rise, implying that companies are also postponing production start as a way of conserving cash and hoping for higher prices in the future.

CAPEX reduction is putting reserves replacement at risk

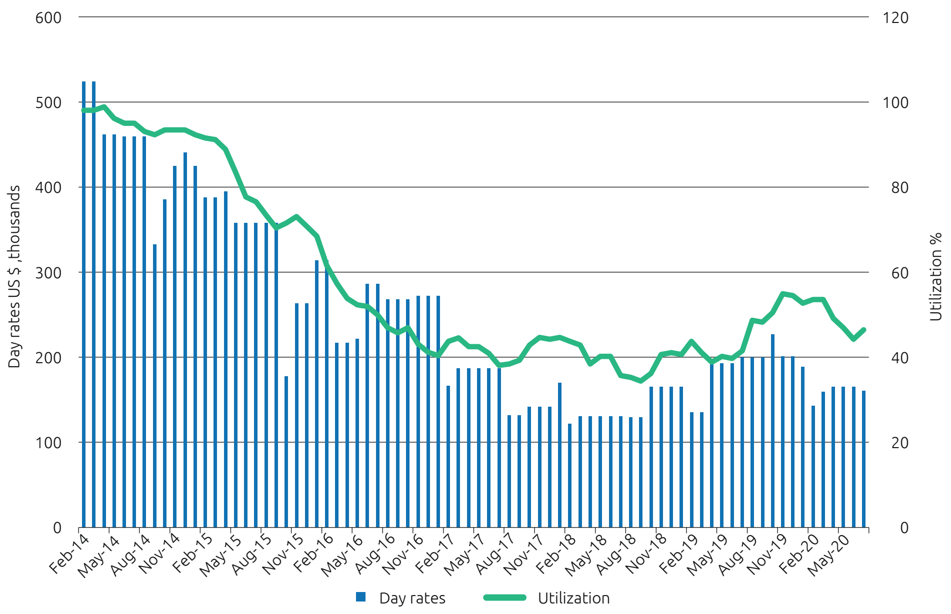
- Reducing CAPEX investment focus can optimize profitability (prioritizing value over volume). For example: Occidental requires US $2.9 billion of annual investment to sustain production but has limited its 2020 budget to US $2.5 billion. By cutting CAPEX and impairing reserves, companies are communicating a tighter, less profitable path going forward and the industry is shrinking to survive.

Figure 3.3. O&G nominal CAPEX by group, rebased to 2014



Source: Company reports, Capgemini analysis

Figure 3.4. Worldwide Semisubmersibles >7,500 ft Average day rates V Total contracted utilization



Source: IHS Markit 2020, Capgemini analysis

In the meantime, companies are trying to reduce their operating costs to maintain short-term liquidity and cashflow

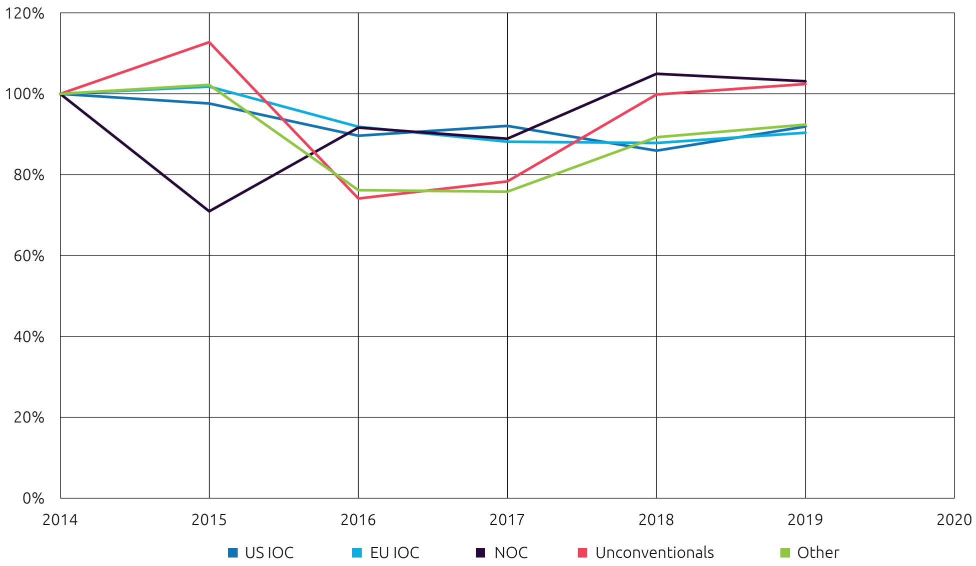
Efficiency improvements have been widespread, building on years of lean focus since the 2014 contraction, but further improvements may cannibalize value

- Since 2014, companies have been focused on optimizing operations and reducing operating costs. This means that much of the progress that can be done via organizational means has been already put in place – the quick wins or low hanging fruit have long since been implemented. This is reflected in the decrease between 2015 and 2016-2017. The work that companies postponed during the worst of the crash – and the increase in activity as prices rebounded – contributed to the rise in OPEX in 2018-2019.
- Further changes in OPEX efficiency will have to come from structural changes, improved economies of scale (such as sharing an operations base) or technology or digitalization improvements (such as automation and predictive maintenance). Beyond this, OPEX reductions can continue, but it will be difficult to do so in a manner that improves efficiency without harming the ability to operate long-term. Postponing non-essential maintenance, reducing crewing, and shutting production are not sustainable.

Digitalization is a key enabler for improving economics in a way that avoids consuming value

- Rystad Energy estimated that automation and digital transformation has the potential to reduce upstream spending by up to 10% globally – up to US $100 billion annually. Digitalization can be a powerful tool for cost reduction and business stabilization, allowing for remote working, automation, and outsourcing basic capabilities to reduce cost. Digitalization can also be leveraged to improve decision making, such as predictive maintenance and production optimization, reducing breakdowns, costs, and capital investment.
- For example, Total has allocated US $700 million for its Digital Factory and aims for US $1.5 billion in annual savings. In 2019, Eni invested €105 million in digital transformation, against which economic benefits of €173 million were generated. Digitalization is also a central part of Equinor's strategy, where part of the ambition is to increase value from onshore operations in the US by US $ 0.5 billion through integrated remote operations, and increase value from the Norwegian Continental Shelf (NCS) fields by US $2 billion before 2025 through integrated operations centers. ExxonMobil plans to leverage digitalization and other activities to double earnings by 2025.
- As foundational competencies such as data management and data science are often stronger outside of the O&G industry, companies have forged new partnerships and outsourced digital competence at scale.

Figure 3.5. Nominal OPEX by group, rebased to 2014



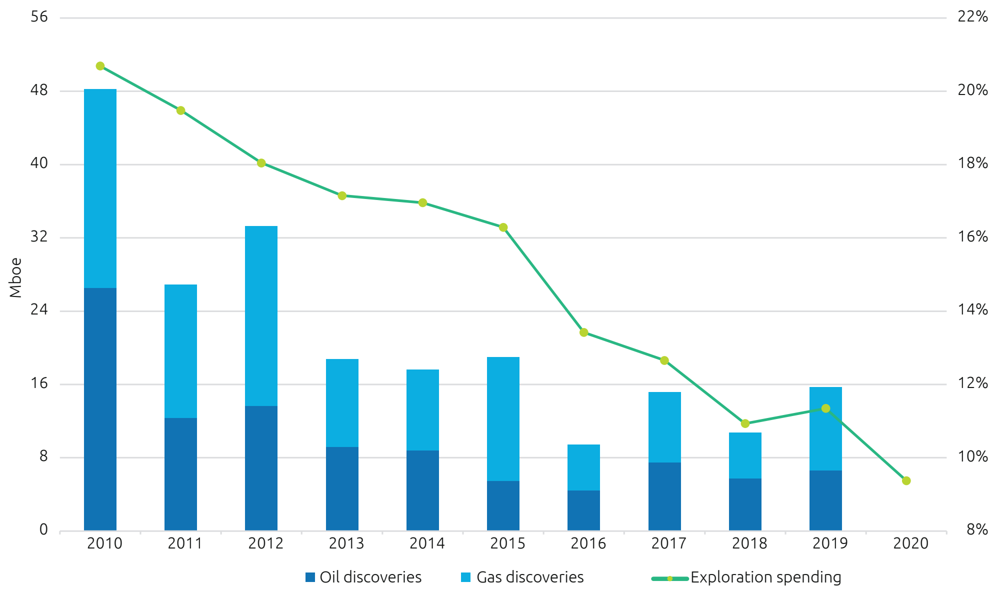
Sources: Company reports, Capgemini analysis

As part of their resilience strategy, many companies are adjusting their approach to risk as well

Reducing capital exposure by reducing exploration efforts

- Exploration investment has largely shifted towards a lower risk appetite, with exploration as a percentage of total investments consistently declining since 2010 and the corresponding reserve additions declining across both oil and gas.
- This change in prioritization boosts modification and tie-in projects over greenfield, onshore over offshore, and proven basins over frontier projects.
  - BP has acknowledged that complex, long-lead-time projects will be more difficult to sanction than simpler, faster projects. BP also announced in July that they were ceasing exploration investment in new countries. This is the strongest message yet from an oil major that puts a limit on their long-term production and signals a move towards a "harvest" mindset in their O&G business.
  - Equinor had planned on and received approval for drilling the high-impact Stromlo-1 exploration well in the Great Australian Bight but cancelled this due to what they said was a lack of commerciality.
  - In contrast, ExxonMobil has continued exploration and their focus on high-impact wells. Their 18 wells in the giant Stabroek block in Guyana added 3 Bboe recoverable resources in 2019.

Figure 3.6. Global conventional resources discoveries and exploration spending as % of total upstream investment, 2010-2020



Source: IEA 2020

Ensuring robust balance sheets and cash reserves helps companies prepare for an uncertain future

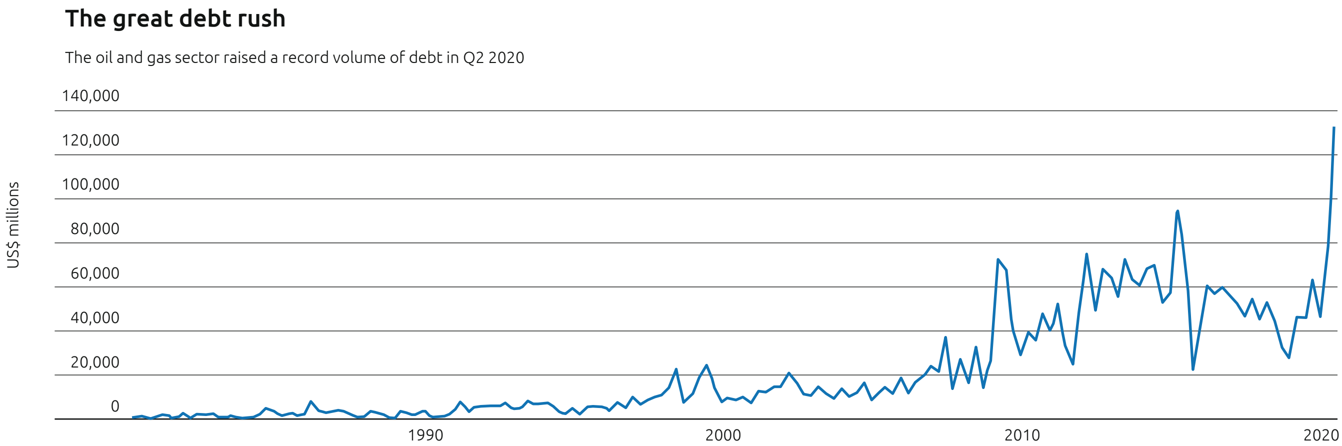
Companies have taken advantage of low interest rates to raise massive levels of debt

- The low interest environment has opened the door for companies to raise or refinance debt at relatively cheap rates, strengthening the balance sheet and enhancing opportunity for M&As. As of May 2020, the O&G sector raised over US $171 billion in debt, with the O&G majors comprising nearly half of the total Q2 numbers.
- Raising cash has the added benefit of helping build a war chest for potential M&As and countercyclical investment. As many companies have struggled to maintain their reserve pipeline, distressed companies struggling to maintain liquidity may lead to a wave of consolidation.
- Financially-constrained players with higher existing debt loads may find it difficult to raise additional debt at attractive rates. This is evident among unconventional players, where Pioneer and EOG Resources increased their long-term debt but Occidental, Marathon, and Apache did not.

European IOCs and unconventional players have reduced their dividends as a means of shoring up the balance sheet and avoiding bankruptcy respectively, but US IOCs have preferred to focus on capital discipline

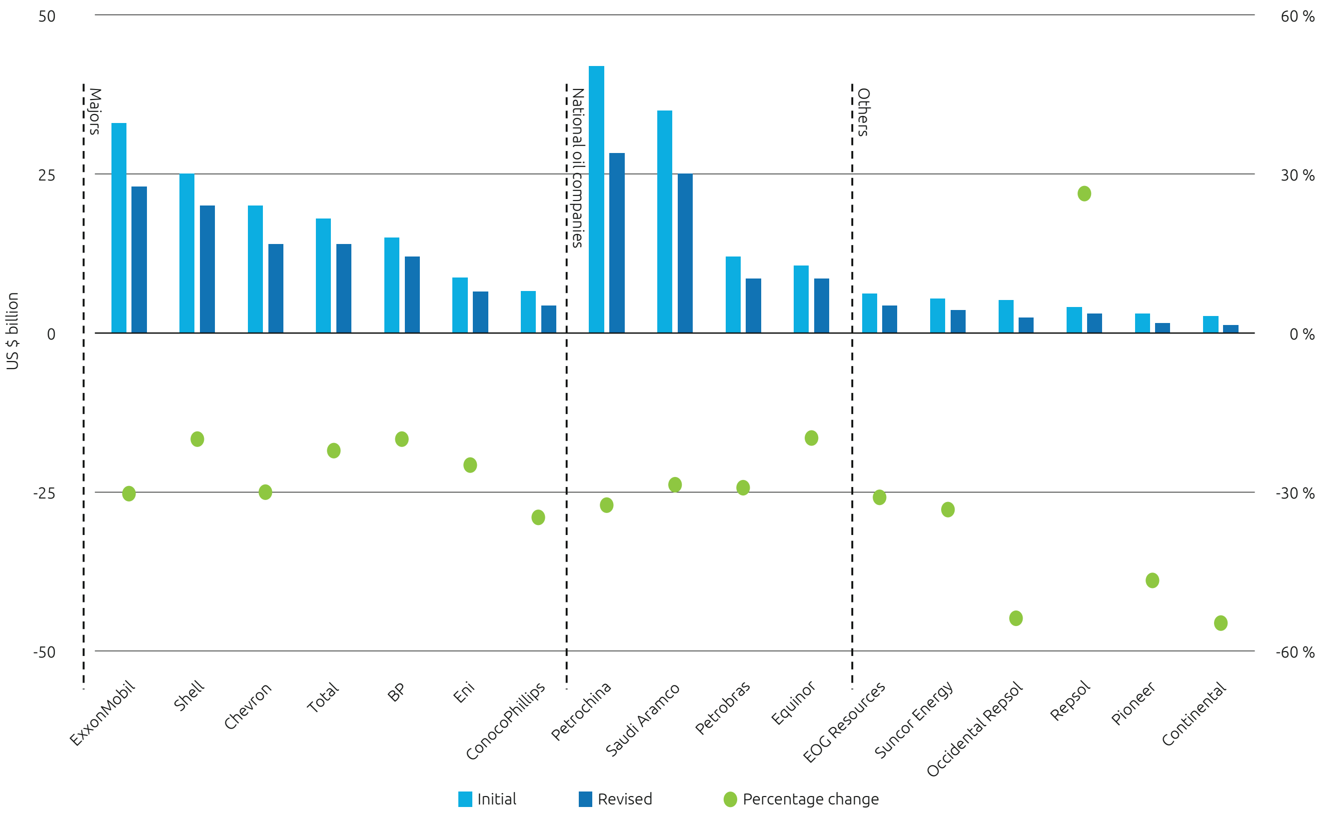
- Companies have responded to these unprecedented conditions by reducing or postponing dividend payments or by reducing the future capital intensity of their businesses.
- Equinor and Shell both communicated a 67% dividend reduction. BP committed to a 50% reduction while announcing at the same time a 10-fold increase in renewable investments and a pivot of their O&G business away from "growth" and towards "harvest". The market responded with an 8% share price increase, showing the importance of coupling the dividend story with a credible growth story.
- Unconventional players have cut their dividends by up to 98% (Occidental).
- US majors have kept their dividends steady but reduced their CAPEX by a larger amount than the EU IOCs instead.
- Most NOCs have continued their dividends, particularly where their capital distribution is necessary for the ongoing economic support of their owners. An exception would be Petrobras, which postponed their dividend payment instead.
- Suppliers have also drastically cut their dividends, with Schlumberger and Halliburton cutting 75% and 50% respectively.

Figure 3.7. O&G sector's volume of debt



Source: Reuters 2020

Figure 3.8. Change in announced upstream spending for 2020 versus initial guidance for the year for selected oil and gas companies



Source: IEA 2020

Despite lower breakeven prices, tight market conditions are forcing companies to reexamine their assumptions and to begin planning for stranded assets

Since 2014 companies have been vocal about the competitiveness of their breakeven prices. This focus on breakeven has become increasingly relevant in a period of extremely low prices

- During the 2014 crash, progress on the portfolio breakeven became an important signal to investors of progress towards profitability and resilience in the face of low prices. This marked the transition from an industry-wide focus on volumes to a more pragmatic focus on value.
- US unconventional players lowered their breakeven at the same time as many of companies were going bankrupt. This was accomplished by falling upstream costs, focusing on the "sweet spots": These improvements helped drive the 33% increase in US reserves from 2015 to 2018.

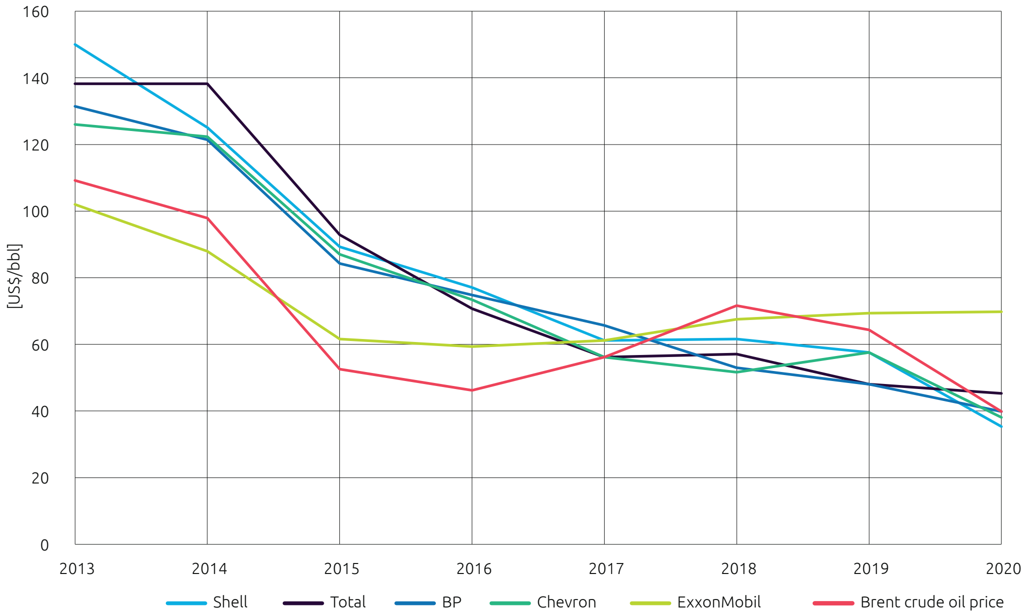
The drop in breakevens from 2014-2016 will be difficult to replicate – instead, deeper structural changes are needed to ensure continued value creation

- CAPEX improvement led to lower breakevens in the development portfolio as only the most profitable projects were sanctioned.
- Even with structural changes, the opportunity to extract long-term economic rents will be unpredictable in times of uncertain and decreasing demand. Restructuring the operating model and fully embracing digital transformation as a core competence is needed to materially move the cost curve in the long-term.

Decreasing long-term price assumptions have driven several IOCs to substantially write-down their reserve base – but this varies between players

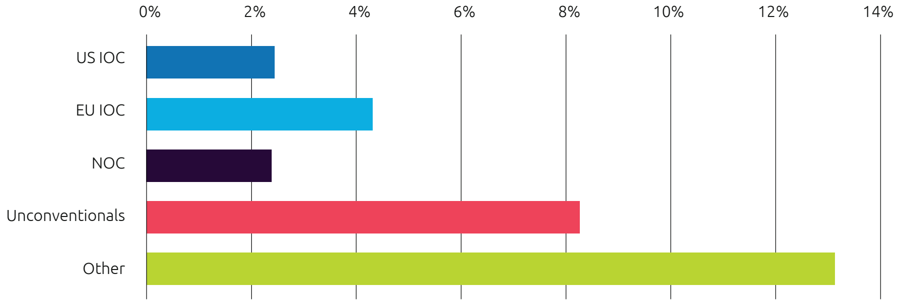
- Several EU IOCs have announced revisions in their long-term price assumptions. In Q2 2020 Total took US $8.1 billion in impairment charges. Shell wrote down up to US $15-22 billion assets in the same period across their portfolio due to lowered long-term price assumptions and BP wrote down US $13-17.5 billion. Repsol booked US $6.6 billion in impairments in 2019 and US $1.5 billion by Q2 2020.
- US unconventional players also revised their assumptions, with Occidental booking a US $6-9 billion impairment following their US $35 billion acquisition of Anadarko in Q3 2019. Among suppliers, Baker Hughes wrote down US $15 billion – or 28.1% of their 2019 assets.
- US IOCs were more conservative in their writedowns. Chevron booked an impairment of US $1.8 billion, but ExxonMobil and ConocoPhillips refrained from any major Q2 impairments. However, ExxonMobil did announce that if market conditions persisted it would have to write down up to 4.5 Bboe (or 20%) of its proven reserves. ExxonMobil, like its US IOC peers, does not publicly disclose its long-term oil price assumptions.

Figure 3.9. Oil majors' breakeven prices US$/bbl



Sources: The Economist & Goldman Sachs, 2020

Figure 3.10. 2020 writedown as % of 2019 assets as of July 2020



Source: Company announcements, Company reports, Capgemini analysis

CAPEX

- Since 2014, cashflow constraints have forced companies to shrink or slow down investments and focus on short-term liquidity. Investments remained relatively flat following 2016, however in 2020 the combination of the COVID-19 demand contraction and the supply glut caused an unprecedented crash in prices
- CAPEX reduction is putting reserves at risk and suppliers are forced to reduce workforce leading to an exodus of talent.

OPEX

- Efficiency improvements have been widespread, building on years of lean focus since the 2014 contraction. Further changes in OPEX efficiency, without pushing the activity to unreasonable risks, will come from structural changes (improved economies of scale) and technology/digitalization.

RISK

- Exploration investments have decreased and shifted towards lower risk areas. Risk from capital exposure is also a focus, with preference for modifications and tie-in projects over greenfield, onshore over offshore, and proven basins over frontier projects.

Balance sheet & cash reserves

- Companies have taken advantage of low interest rates to raise or refinance debt at relatively cheap rates where possible, strengthening the balance sheet and enhancing opportunity for M&As.
- European IOCs and unconventional players have reduced their dividends as a means of shoring up the balance sheet and avoiding bankruptcy respectively, but US IOCs have preferred to focus on capital discipline.

Breakeven prices & stranded assets

- Since 2014 companies have been vocal about the competitiveness of their breakeven prices, signaling to investors of progress towards profitability and resilience in the face of low prices. CAPEX improvement leads to lower breakeven in the development portfolio as only the most profitable projects are sanctioned.
- Further drop in breakeven will be difficult and will require restructuring the operating model and embracing digital transformation.
- Decreasing long-term price assumptions has driven several IOCs to write-down parts of their reserve base, but this varies between players. Several EU IOCs, US unconventional players, and suppliers took significant impairments while US IOCs so far have been more conservative, potentially due to more-cautious long-term price assumptions.

Reduce scope 1 & 2 emissions to secure the License to Operate

Many O&G companies are increasingly discussing climate but, while EU IOCs are pushing ahead with changes, the industry overall is lagging

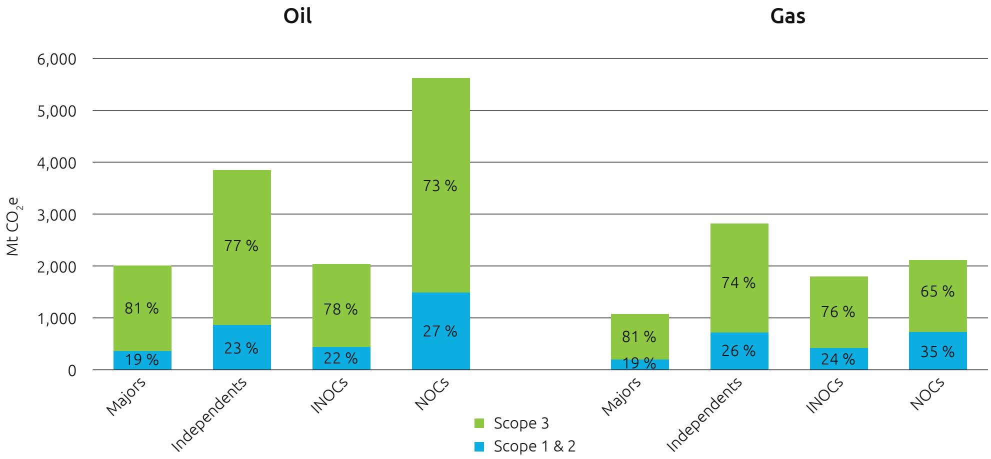
Reaching net-zero emissions will require tackling both upstream and downstream emissions at the same time

- Scopes 1 & 2 account for a quarter of global GHG emissions. The split between scope 3 and companies' own emissions is relatively constant between oil and gas but varies between the different actors. By focusing on scope 1 and 2 emissions, companies can concentrate on the emissions which they have control over and where legal accountability is clearer. Almost all majors have similar targets ranging from a 15% reduction by 2030 to a 40% reduction by 2040.
- Most upstream emissions come from NOCs and independents. As these players also have the lowest level of sustainability ambitions, there will likely be little change from within this part of the industry. US and EU IOCs have comparatively lower scope 1 emissions, driven by their focus on commercially optimal assets globally. These companies also comprise a majority of the Oil and Gas Climate Initiative (OGCI), reflecting their focus on (and potentially vulnerability to) climate risk.

Maintaining the long-term dividend and share price while reaching a target of absolute net-zero in 2050 will require radical transformation over the next 30 years

- Shell has the explicit ambition of being the world's largest electricity company – an ambition that requires significant changes in capabilities and operating model vs. the historical integrated O&G major in order to deliver profitability.
- BP has also announced a 10-fold increase in its renewable energy investments by 2030 – a drastic transformation from BP today. BP communicated that their Return On Average Capital Employed (ROACE) of 8.9% today would become 12-14% as they transformed – somewhat of a surprise compared to existing O&G preconceptions but supported by the performance of companies like Ørsted which forecasts a ROACE of 10.6% for the next 5 years.

Figure 3.11. Estimated annual scope 1, 2 and 3 GHG emissions from the full oil and gas supply chain according to company type, 2018 (INOC = International NOC)



Source: IEA 2020

Defending licenses to operate starts with companies improving their own (scope 1 and 2) emissions

Scope 1 emissions are the emissions from a company's own operations

Methane leakage is overwhelmingly the largest source of scope 1 emissions, but this varies between geographies and assets

- Methane leakage that is able to be mitigated by 2030 comprised 31% of overall upstream scope 1 emissions in 2018. Leakage in the US has particularly been a source of attention in recent years, with companies like SeekOps emerging to leverage drone technology and methane detection to trace and quantify leaks. Over 60% of methane leakage in the US comes from production and gathering of produced O&G.
- Transparency has vastly increased with local goals (Oil and Gas Climate Initiative - OGCI) and international efforts leveraging technology such as the Canadian GHGSat satellite and European TROPOMI tool.

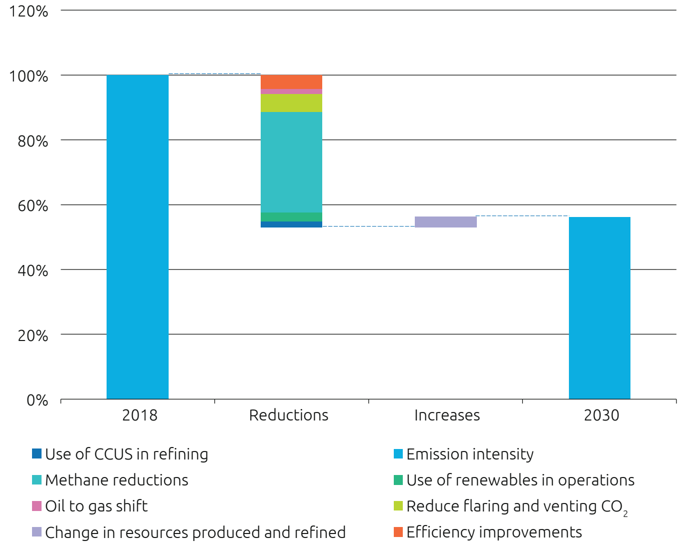
Scope 1 emissions vary strongly by region and by asset

- In contrast to the world average of 18 kgCO_2e/boe, companies' targets can be as low as 1 kgCO_2e/bbl and are often dependent on their existing portfolios. LNG, oil sands, and heavy crude from older facilities can have high scope 1 emissions whereas modern, large-scale, light oil fields such as Johan Sverdup in Norway and Saudi Arabian onshore production have emissions well below 1 kgCO_2e/bbl.

For upstream O&G, scope 2 is primarily emissions from tankers

- Mitigation would involve optimizing trading routes to reduce shipping needs and use of alternative fuels and scrubbers to reduce shipping emissions.

Figure 3.12. Breakdown of potential upstream scope 1 emission reductions by 2030



Source: IEA 2020

Methane leakage and flaring represent most of the industry's upstream emissions – but this can be addressed

Methane leakages have a massive impact on climate

- Methane is a potent greenhouse gas, with an impact from 28-84 times larger than CO_2 depending on the time scale used. This means that reducing methane leakage has a much larger impact than CO_2 reductions of the same volume. Methane leakage and flaring are the largest source of upstream emissions intensity.
- According to the IEA, the largest sources of methane emissions are from conventional oil production in the Middle East, conventional gas production in Russia and the Caspian, conventional oil production in Africa, and North American unconventional gas production. Most of this is from deliberate venting, followed by fugitive emissions (unintended leaks).

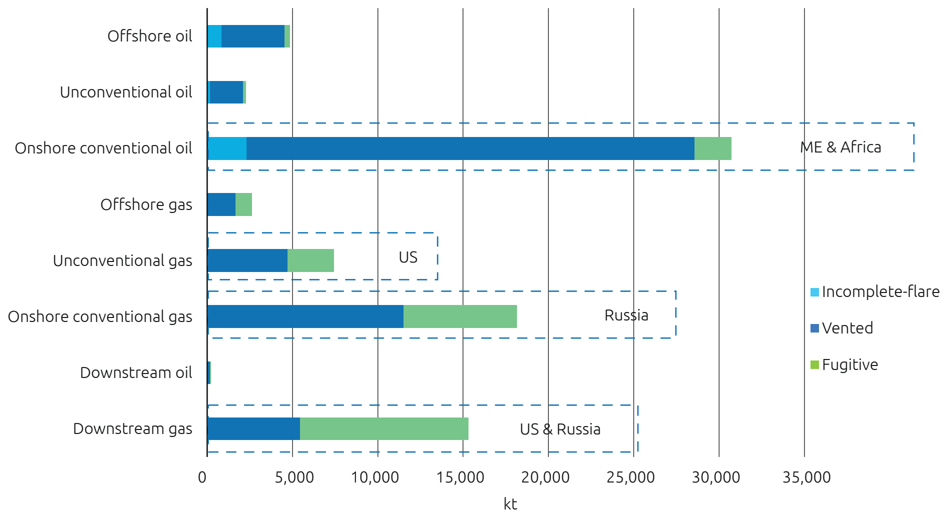
OGCI has established a global target on methane reduction

- The OGCI (Oil and Gas Climate Initiative) has set a collective methane target for its members for a 20% reduction in upstream methane intensity by 2025 and elimination of routine flaring by 2030. The OGCI consists of members from across the industry groups, including Saudi Aramco, Chevron, ExxonMobil, Shell, BP, Eni, Equinor, Total, Repsol, Petrobras, Pemex, CNPC, and Occidental.

Many abatement opportunities have positive business cases, but awareness and investment prioritization is lacking

- The cause of these methane emissions varies from gas-driven pumps and motors to aging infrastructure. This means that the solution requires several simultaneous approaches. Many of these measures are commercial today but implementing them has been slow as companies lack information around the problem and potential cost-effective solutions, lack infrastructure to export the abated gas, and lack the investment focus and capital prioritization (IEA). In the Middle East, the IEA estimates that 52% of methane leakage can be abated at zero or negative cost. In contrast, in the US, where gas prices are low and there has been regulation to reduce methane leakage, only 16% of the remaining abatement measures are at no net cost to the operator.
- The OGCI has recognized that the lack of capital has been a major barrier for many of these abatement projects and has launched a global investment call to solicit abatement plans that will demonstrate the commercial viability of these projects.
- In 2019 and 2020 this problem has been exacerbated by low gas prices, limiting the abatement business case. The lack of regulation and financial incentives will limit this in the near future as well.

Figure 3.13. World emissions sources, IEA estimate. Major contributors highlighted.



Source: IEA 2020

However, some companies are choosing to increase their focus on gas production to reduce the total climate impact of production and products

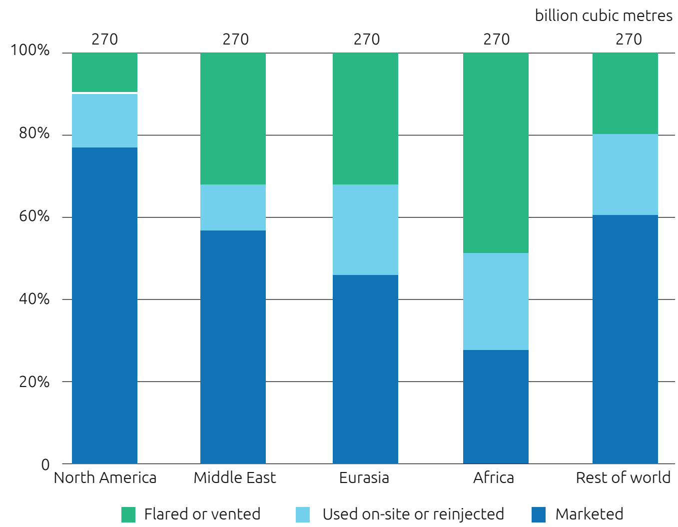
Valorization of associated gas provides revenue and reduces emissions

- Valorization is a major lever in reducing emissions from O&G production. Where commercially possible, valorization is increasingly used as an outlet for gas rather than flaring, venting, or reinjecting. This depends on a local market for gas and infrastructure to transport the gas to market, and the business case improves significantly when the external costs of venting or flaring are taken into account. Regulation has helped drive the US to be the leader in valorizing associated gas, but measuring progress is difficult as measurement quality has historically been very poor, missing up to 60% of leakages.
- Further growth on valorization depends on the individual business cases. Gas prices, limited infrastructure growth, and slow regulation of venting/flaring will likely limit this trend in the future, particularly in Eurasia and Africa where flaring and venting levels are the highest.

Investment in LNG helps bring a lower carbon fuel to a global market

- LNG production significantly increases its own emissions for most O&G players but allows for an international market for gas production and asset backed trading. LNG as a product can emit lower carbon overall and is a way for O&G companies to improve the overall emissions intensity of their portfolio while avoiding reliance on pipeline infrastructure. Additionally, LNG production allows for market access where resources might not be available to IOCs (such as China or Japan).
- 2019 was a record year for LNG project announcements, but in 2020 LNG capacity additions declined by ~40%. During this same time period demand growth declined by 90%. If this trend continues it will result in an oversupply of liquefaction capacity, limiting the economics of these projects.
- LNG might offer a hedge against declining demand for liquids, but it has an upstream emissions intensity comparable to that of Canadian oil sands.

Figure 3.14. Use of associated gas by region in 2018



Source: IEA 2019

Electrification of O&G operations is continuing to move forward but progress is limited by the business case

Onshore micro-scale electrification has been most prominent onshore in the US

- Small photovoltaic (PV) arrays can be used to power everything from wellhead control panels, data acquisition and control systems, and small chemical injection pumps. These have become commonplace across the US as the well pads are remote and distributed.
- Electric-powered hydraulic fracturing is being tested by EOG Resources and other unconventional players. Driven by natural gas (that would otherwise be flared) rather than diesel, electric fracking represents a lower emissions and lower cost fracking solution.

Onshore captive solar continues to be implemented at larger scales by a variety of O&G players

- Algeria's state-run oil company Sonatrach has collaborated with Eni to build a 10 MW solar PV plant to power production at the Bir Rebaa North oil field.
- Occidental has signed a power purchase agreement (PPA) for 109 MW solar to power some of their Permian operations and ExxonMobil has signed an agreement with Ørsted for 500 MW of wind and solar for their Permian operations. Shell also powers their Permian operations partially with solar energy.

Norway has encouraged powering offshore production facilities via subsea cables connected to the onshore grid

- Equinor's giant Johan Sverdrup development was built with 100 MW of renewable power from shore and this development will soon be expanded to include several neighboring fields in the Utsira High area with an additional 35 MW of capacity. This installation replaces some of the offshore generation which today is done via natural gas turbines. Offshore turbines burning natural gas represent 80% of the O&G industry's emissions in Norway, which in turn are 27% of Norwegian emissions overall.

Home to significant potential offshore wind resources, Norway has also moved forward with utilizing offshore wind to supplement natural gas generation offshore

- The Hywind Tampen project is one of the largest floating wind projects on the planet and the first to offer captive renewable electricity to offshore oil platforms. Consisting of 11 8MW floating wind turbines, Hywind Tampen is set to deliver power to the Snorre and Gullfaks fields by 2022.
- This same solution can be applied anywhere where water depths and wind conditions make the solution practical and the commercial terms make the business case attractive enough – which potentially includes Brazil and Canada.

Electrification of O&G operations is continuing to move forward but progress is limited by the business case

Heavy oil and oil sands are highly emissions intensive

- The process used for in-situ extraction in oil sands is highly energy intensive and the limited options for low-cost, low-carbon energy results in production that is significantly higher than most IOCs' average emissions intensity and breakeven price.
- High energy intensity is exacerbated by increased complexity, with significant technologies and infrastructure required to bring the product to market such as new pipelines for oil sands, heated subsea pipelines for heavy oil, and production facilities that must be equipped for high levels of hydrogen sulfide (for sour crude), produced water, complex reservoirs, or impurities such as mercury content.
- In addition, these products are often sold at a significant discount, particularly if the receiving refinery isn't optimized for this product and lighter crudes need to be blended.

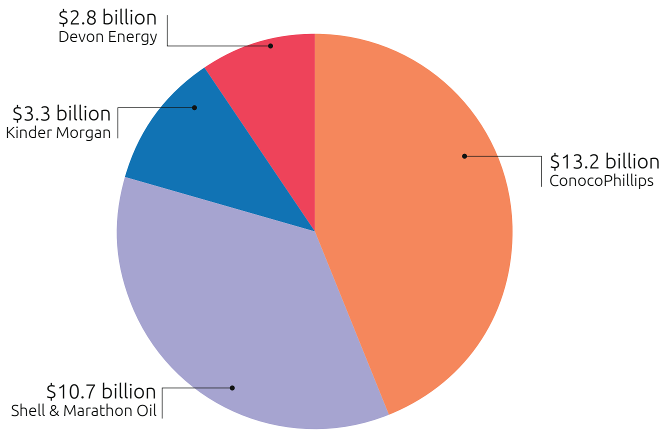
Many IOCs have exited or written down their oil sands investments with domestic Canadian players moving in instead

- Shell exited in 2017 and ConocoPhillips, Equinor, and CNOOC have all worked to reduce their stakes in various oil sands assets.
- Total has been the most recent IOC to exit. Total announced in late July 2020 that they were taking US $8.1 billion in writedowns, US $7 billion of which was in Canadian oil sands including the assets Fort Hills and Surmont.
- The buyers of these Canadian assets have been domestic firms such as Suncor, Cenovus, Pembina Pipeline Corp. and Canadian Natural Resources.

Certain companies have pivoted to gas to better position themselves as the world's energy systems change

- Shell's acquisition of BG Group solidified its position as a global gas leader and its leadership in LNG enables it to build on that competence globally. Shell's LNG business is managed separately from its upstream O&G business, reflecting the different operating model needed to maximize value generation.

Figure 3.15. Foreign energy companies' sales in oil-sands assets



Source: Bloomberg, 2019

Introduction

- Reaching the net-zero emissions will require tackling both upstream and downstream emissions at the same time
- Scope 1 & 2 represent a significant part of total emissions

Scope 1 & 2

- Methane leakage and flaring are the largest source of upstream emissions intensity. It varies significantly between geographies and assets
- For upstream O&G, scope 2 is primarily emissions from tankers

Methane leakage & flaring

- Most methane emission is from deliberate venting, followed by unintended leaks.
- Many abatement opportunities have positive business cases, but awareness and investment prioritization is lacking. Valorization of associated gas can also be drastically improved (reinjection, LNG production or on-site electricity generation)
- OGCI has established a global target on methane reduction and flaring elimination for its members. Further, OGCI has launched a global investment call to solicit plans that will demonstrate the commercial viability of abatement projects.
- Investing in gas generation enables companies to decarbonize via a future carbon capture, utilization, and storage (CCUS) value chain.

Electrification

- Onshore micro-scale electrification has been most prominent onshore in the US, in electric-hydraulic fracking.
- Onshore captive solar continues to be implemented at larger scales by a variety of O&G players, including Eni, Occidental, ExxonMobil and Shell.
- Norway has encouraged powering offshore production facilities via subsea cables connected to the onshore grid. Norway has also moved forward with utilizing offshore wind to supplement natural gas generation offshore.

Portfolio adjustment

- Many IOCs have exited or written down their oil sands investments with domestic Canadian players moving in instead
- LNG development has accelerated, but moving from oil to LNG is not improving the emissions intensity

Creating New Options to preserve the long-term Profitability

European IOCs are beginning to commit to a leading role in energy transition but the rest of the industry is focusing on the current core activities

Capital expenditure by the oil and gas industry in renewables has picked up gradually over time

- The largest outlay has been in solar PV, with some EU IOCs (e.g. Eni, Equinor) developing projects directly or in partnerships and others (e.g. BP, Total, Shell) owning major (~40%) stakes in large solar companies (Lightsource, Sunpower, and Silicon Ranch, respectively).
- Offshore wind is another growth area (e.g. Equinor, Shell, CNOOC) – 40% of the full lifetime costs of a standard offshore wind project have significant synergies with the offshore oil and gas sector (IEA, 2020).

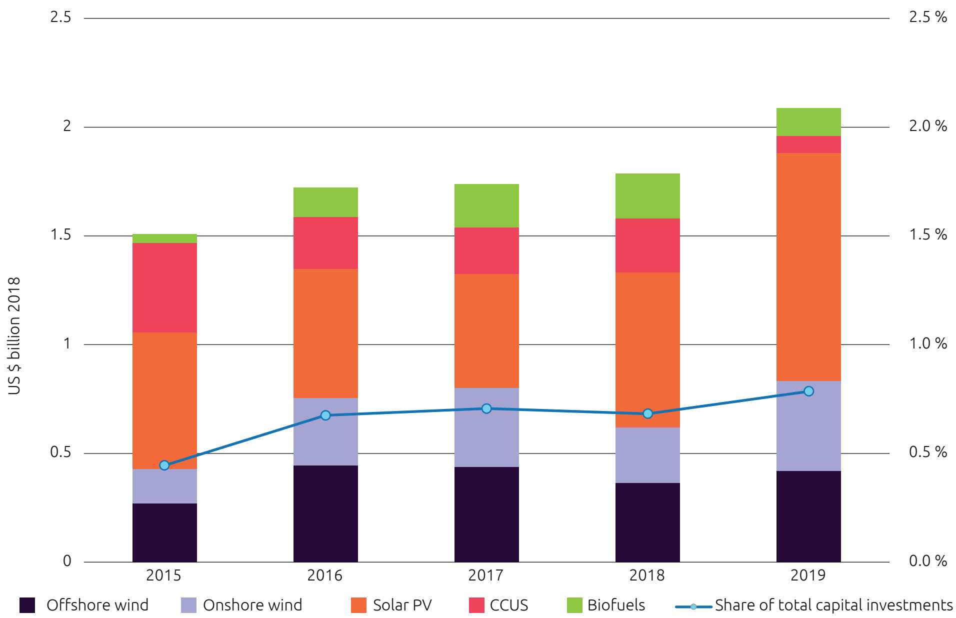
However, overall less than 1% of CAPEX is invested outside oil and gas

- Some European majors are leading the way with 5-7% of CAPEX invested outside core oil and gas supply. Ambitions have been accelerating though, in part due to the growing appetite from shareholders, increasing pressure from society, fewer O&G opportunities, and better understanding of the value drivers and operating model in renewables.
- According to Rystad Energy almost all of the renewable investments by oil and gas players through 2025 will come from only 10 oil majors, which are collectively poised to spend just over $18 billion on specific renewable energy projects through 2025. BP's new ambition might increase this amount by up to US $7 billion. This has to be compared to the $166 billion forecast to be spent on greenfield oil and gas projects during the same period.

The rise of the broad energy company is emerging in Europe

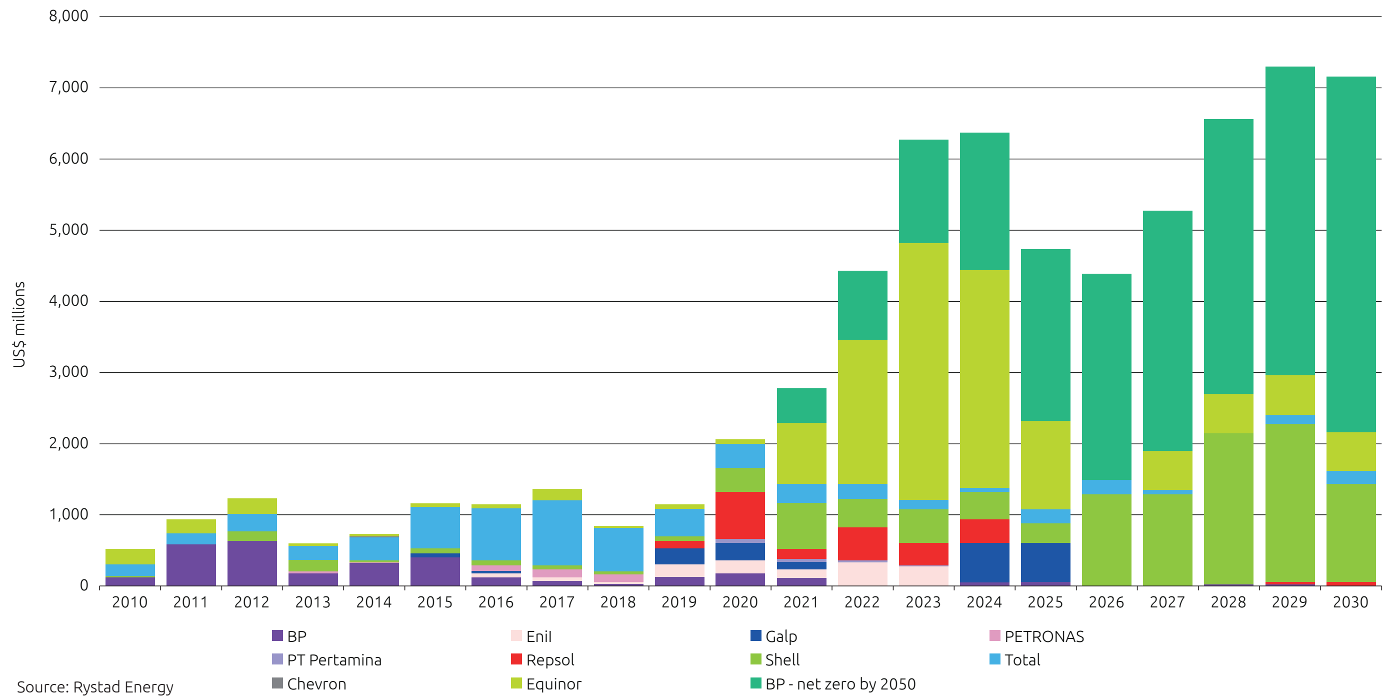
- Repsol and BP have stated their ambition to be "net zero" by 2050 or earlier. Total and Equinor have both begun defining themselves as "broad energy" companies – active across the energy value chain, and an important shift in terms of defining their future core business as opposed to traditional international O&G companies. Shell has the additional ambition to be the world's largest electricity company and is moving with conviction into the non-O&G space.
- These companies are making material moves not only in upstream electricity generation but also in electricity storage (Total buying SAFT), EV charging (Shell purchasing Greenlots), and hydrogen (Equinor and H21).
- US IOCs, unconventional players and NOCs have remained steady with their O&G identity and necessary role in the energy mix. As an example, ExxonMobil's new energy focus remains on biofuels and carbon capture and storage (CCS).
- The companies in the "other" category have more varied responses depending on their specific circumstances. One notable company that would have fallen into this category was DONG – previously a smaller, local IOC and now the world's largest offshore wind company (Ørsted).

Figure 3.16. Capital expenditure on new projects outside core oil and gas supply by large companies, absolute and as share of total CAPEX, 2015-2019



Source: The oil and gas industry in energy transition, IEA, 2020

Figure 3.17. Project-specific near-term future investments among oil majors including BP's net zero by 2050 ambition



Source: Rystad Energy

Companies have invested further downstream to help secure future demand

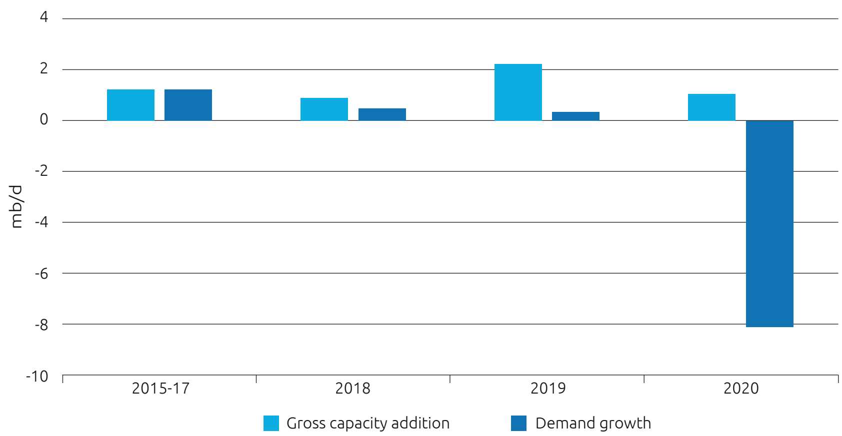
Preserving demand for liquids has often involved petrochemicals and refining

- In 2020, Saudi Aramco completed its US $69 billion acquisition of 70% of SABIC, the world's fourth-largest petrochemicals company. This enables cashflow independent of oil prices and helps guarantee a customer for at least part of Saudi Aramco's production.
- Refining and chemicals have been shown to be key strategic assets for NOCs looking to guarantee a buyer of their production. PDVSA and Citgo are an example of this – export of Venezuelan heavy crude has benefitted from guaranteed access to refineries set up for their heavier blends. This can come with geopolitical risks, however, as in April US refiners and service companies were told to wind down their business with Venezuelan companies and PDVSA creditors have continued to work towards takeover of Citgo.
- In contrast, others have moved to reduce the scale of their refining operations, with Eni accelerating their exit from conventional refining in 2020 in response to COVID-19.

However, these investments may not be the safe havens they once were

- Historically, downstream investments have performed countercyclically – when oil prices were high, returns were modest, but when oil prices were low the margins in midstream and downstream were more robust. This has been supported by the supply-side nature of the previous commodity supercycles.
- During 2020, the price crash has been driven by a significant drop in demand for liquids, primarily for gasoline and kerosene. This low demand has squeezed margins across the value chain.
- From 2015-2017, refining demand and refining capacity investments were roughly equal but from 2018 onwards, investment growth has exceeded demand growth, potentially leading to future overcapacity and further pressure on midstream returns.

Figure 3.18. Annual capacity/demand growth for refined products, 2015-2020



Source: IEA 2020

As for now, US and Asia-Pacific are focusing on CCUS for enhanced oil recovery (EOR), while EU majors are exploring various business models for industrial capture

Despite the potential of CCUS it still hasn't really taken off

- O&G are expected to be a part of the energy mix for the next decades (99% of investments are still in core O&G). CCUS is therefore central to most majors' ambitious strategies of reducing CO_2 emissions until energy consumption is fully decarbonized.
- So far, few large-scale facilities have been developed globally. According to Wood Mackenzie 68 projects have started and terminated so far, primarily due to cost challenges (no projects are the same, so it is difficult to scale) and proprietary technology. As for now, installed capacity is only capable of capturing 1% of annual global emissions. If the world is to get onto a 2-degree pathway, we could need up to 100 times the capacity installed today according to IEA.

In early 2020, around 22 large-scale CCUS projects were in operation, while 20 were under development worldwide

- North America is leading the way with 14 CCUS projects in operation (out of 22) and 9 under development (out of 20). However, the highest growth is expected in Asia Pacific with 2 operational projects and 9 under development.
- Most of the large-scale CCUS projects outside Europe are used for EOR.
- Europe currently only has 3 projects in operation (2 of them are located in the North Sea) and no mature developments. However, with 13 ongoing studies Europe is heavily involved in R&D, pilot projects and partnerships to explore viable business models.

The O&G industry will be critical for CCUS to reach maturity…

- Despite low overall investment, O&G companies still account for a major share of total investment. 75% of the CO_2 captured in large-scale facilities is from O&G operations, and the industry accounts for over 35% of overall spending on CCUS projects. In 2019, Total increased R&D investment in CCUS to up to 10% of the total R&D budget, while Eni announced in 2020 that they will increase investment in CCUS by 30% from 2020 to 2024 compared to previous plans.

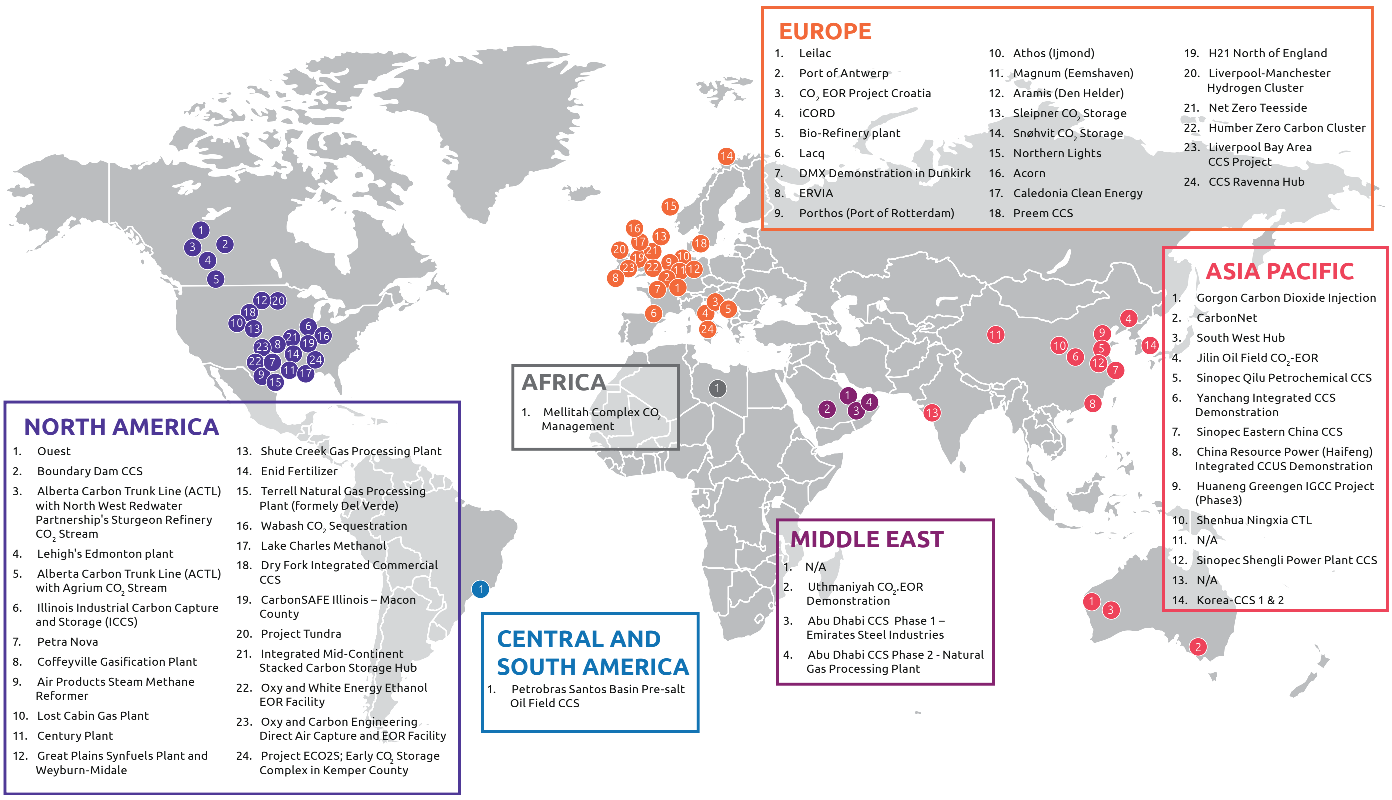
…but to further boost deployment the industry needs to create viable business models in partnership with governments

- Policy support: governments will have to take on a significant proportion of the risks of early commercial projects and provide signals that they will be supported in the future. Many countries are increasing their support for CCUS development. For example, the US government launched a performance-based tax credit for CCUS projects in 2018, while the UK confirmed its pledge to invest £800 million in CCUS infrastructure.
- Higher carbon prices: Wood Mackenzie have estimated that a minimum carbon price of US$90/tonne is needed for most applications, around three times today's traded price in Europe.
- Lower cost: a modular, standardized approach is needed.

How is Big Oil investing in CCUS?

- Storing carbon extracted from high CO_2 gas fields – Petrobras (Santos Basin Pre-salt Oil Field), Chevron/ExxonMobil/Shell (Gorgon, Australia) and Equinor (Sleipner and Snohvit, Norway) have projects already in operation.
- Injecting post-combustion CO_2 to enhance oil recovery – could be a cost-effective way to develop CCUS since the oil revenues generated reduce project costs and expand the amount of CO_2 stored per unit of investment. CCUS for oil recovery are most common in North America, China, and the Middle East.
- Partner in high-emitting, but hard-to-decarbonize sectors – Total has teamed up with Lafarge and Svante in Canada to pilot CO_2 capture and reuse of Lafarge's Richmond cement plant in British Colombia. Shell, Equinor and Total have launched the "Northern Lights" project in Norway, where the plan is to capture CO_2 from onshore industrial facilities, transport it by ship and pipelines, and store it east of the Troll field in the North Sea. Eni have started a study to evaluate the feasibility of CCUS in the Ravenna area, with the combination of depleted offshore gas fields with infrastructure still in operation, together with onshore power plants and other industrial sites nearby.

Figure 3.19. Overview of existing and planned CCUS facilities



Source: IOGP data, 2020

Renewable energy represents the most attractive new business area outside of the typical O&G core, but companies are also growing elsewhere in the new energy space

O&G companies have several advantages when exploring renewable energy businesses

- Competence synergies: Project development, stakeholder management, portfolio management, investment de-risking, operations, long-lifetime marine engineering… all can be applied to the renewable and offshore wind sectors.
- Market synergies: Gas can balance the intermittent generation from renewables. Also, O&G production is highly energy intensive and producing renewable energy for one's own consumption can provide a captive market for building and testing these capabilities.
- Climate synergies: Positioning away from "enemy of the climate" to "part of the solution" is a powerful lever with society and talent and enables O&G companies to remain relevant with a broader range of stakeholders.

However, several obstacles must be addressed when exploring building a renewable energy business

- Relatively high embedded cost of capital, investment prioritization & competing for capital with the O&G opportunity set, the embedded O&G operating model, and a culture, mindset, and strategic inertia based in O&G make committing to competing at scale in renewables difficult.

EU majors diverge from the rest of the world in their scale and messaging around their role in energy transition

- Many European majors have spent the last decade deepening their new energy toolbox both organically and inorganically. Examples include BP buying 40% of Lightsource, Shell buying 40% of Silicon Ranch, Total buying Sunpower and Saft, and Equinor buying Danske Commodities.
- On a smaller scale, companies are building understanding, capabilities, and options via venture capital funds and entrepreneurship initiatives such as Equinor's collaboration with Techstars Energy (in which Capgemini is also a partner) or various majors using their venture funds to invest in startups specializing in hydrogen, grid edge technology, CCUS, EV charging, battery storage and demand management.
- The most prominent transformation story has been that of DONG, now Ørsted, transforming from a medium size O&G company to the world's largest offshore wind company.

Some NOCs are using their muscle to help drive the development of a domestic renewable energy industry, but US majors remain focused closer to their core business

- Saudi Aramco has established a US$ 500 million fund to support its investments in renewable energy and energy efficiency, complementing the US$ 500 million it invested in 2012. However, the scale of these investments is very small compared to their overall CAPEX budget. Another NOC, Petrobras, sold its onshore wind assets in 2020.
- US majors have kept their focus much closer to their existing core business - on biofuels and CCUS.

- **O&G companies have several advantages when exploring renewable energy businesses such as competence synergies, market synergies and climate synergies**
- **However, several obstacles must be addressed when exploring building a renewable energy business, e.g. cost of capital, investment prioritization, operating model, culture, mindset and strategic inertia**
- **EU majors diverge from the rest of the world in their commitment and messaging around their role in energy transition**
- **Some NOCs are investing in renewables to help drive the development of a domestic renewable energy industry, but US majors remain focused closer to their core business**

In this time of structural flux, where the value is created is also changing

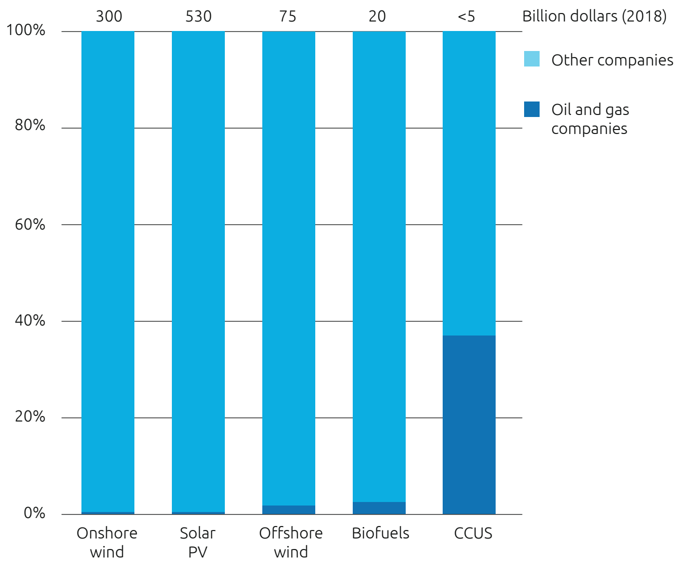
Upstream exploration and production (E&P) companies will no longer be able to capture the same economic rents in an era of decreasing demand

- Companies can add reserves in three ways – exploration, acquisition, and technological innovation. As nations dependent on oil and gas revenues tighten commercial terms and competition for the top exploration prospect intensifies, the cost of reserve replacement via exploration increases. At the same time, acquisition is often viewed as "paying a dollar for a dollar" – sellers often focus on valuations at higher long-term prices than buyers. Finally, technological innovation may have unlocked significant reserves via fracking and driven the rise of US unconventional production, but relying on future innovation to replace reserves is highly unpredictable. Because of this, many companies are under pressure to ensure the future growth of their value creation in O&G.
- Tightening commercial terms, more competition for the best subsurface assets, declining investments in supplier capacity, declining attractiveness to talent and capital, and the potential for declining demand make maintaining margins increasingly difficult.

Value capture in renewables comes from elsewhere in the value chain and by leveraging alternative business models, such as the build-sell-operate modelseen in onshore solar

- Equity production is no longer the core value-driver it used to be in O&G. Because of the low risk of operating assets and steady cashflow from electricity prices (particularly with PPAs), equity ownership is capital intensive and offers low returns relative to the typical O&G company's cost of capital. By participating as a developer – when project risks are highest – and farming down as the project begins production, companies can optimize use of their capital and maximize returns. This can be referred to as capital recycling and efficacy can vary with geography, market, and regulatory environment.
- Alternatively, a pure upstream renewables player must accept the market price or PPA price, whatever it may be. Upside must be generated through reducing OPEX, increasing uptime, or innovating value delivery to customers. This can be done via guarantees of origin for renewable electricity, specific production profiles, or by offering services such as delivery management. Building these capabilities requires a highly opportunistic mindset and deep skill set in stakeholder management and market design.
- Moving closer to the customer is a key strategic position to be able to capture value through aligning energy supply with demand, but this competence is very far from the traditional upstream O&G mindset.

Figure 3.20. Total investment in renewable energy and CCUS by O&G companies vs. others



Note: CCUS only includes large-scale facilities.
Source: IEA, 2020

- **Upstream E&P may no longer be able to capture the same economic rents in an era of decreasing demand.**
- **Tightening commercial terms, more competition for the best subsurface assets, declining investments in supplier capacity, declining attractiveness to talent and capital, and the potential for declining demand make maintaining margins increasingly difficult.**
- **Value capture in renewables comes from elsewhere in the value chain and via alternative business models.**
- **Capital recycling (e.g. "build-sell-operate") is one way to maintain attractive returns, while for an operator operational excellence and/or innovation can generate upside. Moving closer to the customer can also capture value by enabling better demand and supply management and value-added services.**

Moving within O&G value chains and to other businesses changes who the competitors are and what it takes to compete

Moving downstream and strengthening the refining and chemicals business means customers can often become competitors

- Often moving downstream involves purchasing a major customer. In this way the demand of this customer is also guaranteed. The largest example of this is Saudi Aramco's purchase of SABIC.

Renewable energy and electricity value chains are quite distinct from upstream oil and gas, with major equity partners often being low-involvement, low-risk-tolerance pension funds more interested in guaranteed returns

- Competing for steady, low-risk returns means that the cost of capital has significantly more influence on profit. O&G players growing in the renewables space are finding themselves competing and partnering with pure-play renewable companies and even pension funds – both of which have a significantly lower cost of capital due to lower technical, commercial, and geopolitical risk.
- Development concept maturity and technical maturity are quite different: Companies must make an investment decision at the time of bid submission – an earlier stage of concept maturity than typical O&G projects, where the investment decision will come much later. Additionally, a competitive bid typically requires use of the latest generation of wind turbine – which often will be at a much lower technology readiness level (TRL) than needed for O&G sanction. This requires different approaches to project de-risking and collaboration with major suppliers and can even mean that a company can bid against a coalition that includes one of its key suppliers in other bids.

The shift from subsidized PPAs to merchant pricing may give O&G companies a future advantage

- Losing the guaranteed cashflows from PPAs may increase the commercial risk of the positions renewable players and pension funds hold. This increased risk can raise the cost of capital for these players, but O&G companies have this risk already embedded as well as deep competence in trading and portfolio management that helps manage long-term cashflow in the face of uncertain prices.

- **Moving downstream and strengthening the refining and chemicals business means customers can often become competitors. Moving downstream can even involve purchasing a major customer which also has the benefit of ensuring demand**
- **Renewable energy and electricity value chains are quite distinct from upstream oil and gas, with major equity partners often being low-involvement, low-risk-tolerance pension funds more interested in stable, low-risk returns**
- **The shift from subsidized PPAs to merchant pricing may give O&G companies a future advantage due to their ability to manage pricing risk and generate value via competence in trading and portfolio management**

Introduction

- Capital expenditure by the oil and gas industry in renewables has increased gradually over time. However, in 2019, less than 1% of oil and gas companies' CAPEX was invested outside core oil and gas.
- In Europe, some majors have begun to shift their identities from "integrated O&G" to "broad energy companies". US IOCs, unconventional players and NOCs have remained steady with their O&G identity and necessary role in the energy mix. Almost all of the renewable investments by oil and gas players through 2025 will come from only 10 oil majors (most of them European).
- Building competencies and investing outside of the core, like downstream and CCUS, will contribute to a future market. Companies are also pivoting towards new businesses, changing who they compete with and building new competencies to compete.

Downstream

- These investments may not be the safe havens they once were. During 2020, there has been a drop in demand for liquids squeezing demand across the value chain and trends show that for recent midstream investment, supply growth has exceeded demand growth.

CCUS

- CCUS will be central to most majors' strategies to ensure their place as an energy provider.
- However, few large-scale facilities have been developed yet: In early 2020 around 22 large-scale CCUS projects were in operation, while 20 were under development. To further boost deployment of CCUS the industry needs to create viable business models in partnership with government.
- The oil and gas industry will be critical for CCUS technology to reach maturity. Most of the CCUS projects in operation and under development are in North America and Asia Pacific and are mainly used for EOR. Europe is investing mostly in R&D projects (13 ongoing studies) with focus on industrial capture from high-emitting industries and re-use of existing infrastructure to reduce costs.

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WEMO North America Editorial

Randall Cozzens

In 2020, the United States was at the very bottom of the Climate Change Performance Index (CCPI) for the first time after withdrawing from the Paris Agreement and lowering its GHG and CO_2 emissions targets. While current year energy-related carbon dioxide (CO_2) emissions are projected to fall by 11%, this drop can be attributed to the industrial slowdown and travel restrictions related to COVID-19. Thus, these changes are non-sustainable.

Even with present day GHG emissions 14% below 2005 levels, the U.S. is at serious risk of missing its Copenhagen Accord target of a 17% reduction in total emissions by the end of 2020.

Canada, on the other hand, accelerated its targets by developing a plan to achieve net-zero emissions by 2050 and setting five-year emissions reduction milestones.

Energy mix – coal remains major contributor though the share of renewables is growing

Coal remains dominant in the U.S. electricity generation mix. However, 5% of existing coal-fired plants are being retired with the total reaching 13% by the end of 2020. This shift has been driven primarily by a surge in natural gas consumption.

Nuclear generation capacity is also being retired due to high operational costs. That said, small modular reactor (SMR) demonstration units are planned through 2030.

According to the Nuclear Energy Leadership Act (NELA) bill of 2019, the DOE will develop next-generation nuclear and legalized demonstration of two designs by 2025 and up to five additional designs by 2035.

Solar excelled in 2019, accounting for 40% of all new electricity generation capacity added in the U.S. In 2021, the total installed U.S. PV capacity is expected to double in size, with annual installations expected to reach 20.4 GW. Solar and wind energy have seen major cost-efficiency gains. Within a decade, they will come close to outcompeting operational coal and nuclear plants. However, COVID-19 has had a negative impact on installations in 2020 due to disruptions in global supply chains and imports from China.

2019 and 2020 also saw an uptick in new power purchase agreement (PPAs) among corporate players. In 2019, companies procured a record-breaking 13.6 GW of clean energy capacity, led by Google, AT&T and Walmart.

Energy consumption hit a low in 2020

U.S. energy consumption reached a 16-year low in Q1, 2020. Residential solar consumption increased due to stay-at-home orders related to the pandemic, which undermined the stability of power stations. As a result, the California "duck curve" was recast as the solar curve.

Asset finance of solar and wind projects increased in 2019. However, the uncertainty of tax credits and the non-passage of the Growing Renewable Energy and Efficiency (GREEN) Act, as well as the lasting economic effects of the pandemic, have delayed many renewable projects. According to the American Wind Energy Association (AWEA), an estimated 25 GW of wind projects are at risk of being delayed, scaled back, or scrapped altogether due to the COVID-19 economic slowdown.

The U.S. has raised thresholds for the procurement of renewables such as solar, wind and energy storage through carbon-free goals and mandates, as opposed to renewables-only targets.

In Canada, provincial governments have budgeted millions of dollars for the transition of coal. In addition, many power plants have switched to natural gas.

High oil production

The U.S. registered its highest-ever oil production levels, with shale gas being the top contributor. However, it is likely that the sector may experience zero growth in shale gas production by 2021 or that production will be negative if the coronavirus continues.

According to EIA, the U.S. is expected to account for 85% of the increase in global oil production as per the current policies scenario, and for 30% of the increase in gas. Thus, U.S. stands strong to become a net exporter of both fuels. In 2019, the U.S. became a net exporter of natural gas with net natural gas exports averaging 5.2 billion cubic feet per day (Bcf/d)—a trend that is expected to continue since the Federal Energy Regulatory Commission (FERC) authorized the siting, construction, and operation of gas export projects to countries without free trade agreements with the U.S.

Financial performance

Greater regulatory rates management, as well as smoothly operating generation, transmission, and distribution facilities, allowed utility companies such as Exelon and Hydro-Quebec to achieve higher revenues in 2019.

Meanwhile, outstanding control of operating and financial expenses and managerial costs have allowed utilities such as NextEra Energy and Hydro-Quebec to score better EBITDA margins and dividends per share. PG&E, having established a US$34 billion debt financing plan, has reported high stock performance and was able to maintain the lowest P/E ratio.

2019 saw a record-high US$124.1 billion in capital expenditures, which, in turn, bolstered regulated assets in the U.S. Retail sales are down by 6.5% in industrial and commercial sectors and 1.3% in the residential sector.

In 2019, the annual average price of electricity in the U.S. was about 10.60¢ per KWh. Between 2009–2019, retail residential electricity prices nationwide increased by 13%—significantly more than other sectors.

COVID-19 recovery plans

COVID-19 has severely impacted the energy sector during the first half of 2020. A large number of Assistance Programs from Public Utility Commissions have been created in North America to mitigate the economic effects of COVID-19. Utility companies are cutting their capital projects and costs related to operations and maintenance expenses. They have also applied billing mechanisms like deferrals, rider recovery and bill mitigation.

Increased Cyberattack

In 2019, 17 U.S. utilities, mostly small organizations, were the targets of cyberattacks. Canada aims to play a leadership role in establishing globally accepted standards and certification programs to significantly reduce the risk and severity of cyber threats through IIoT devices.

Given the gravity of cybersecurity in the utilities sector, Congress passed several bills, including the Securing Energy Infrastructure Act and the Enhancing Grid Security Through Public-Private Partnerships Act. The Department of Energy pledged to take necessary actions and is currently developing a national cybersecurity implementation plan. Meanwhile, the Energy and Commerce Committee earmarked US$157 million for Cybersecurity, Energy Security, and Emergency Response, (CESER) in its FY2020 budget.

Conclusion

U.S. climate policy faces extreme challenges on all fronts. On the national level, there is no target or policy for lowering the country's very high GHG emissions. However, on a positive note, Lazard's Levelized Cost of Energy Analysis predicts a further decline in the cost of renewable technologies, which would make renewables more cost-efficient as an energy source. However, regional disparities and dispatch hurdles remain a challenge.

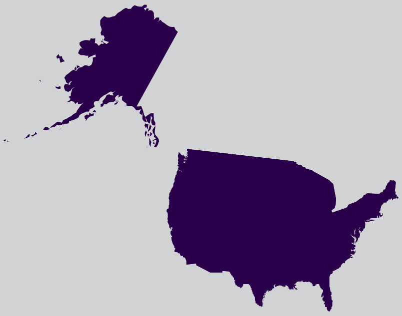
The race to qualify for federal tax credits propelled the U.S. clean energy capacity investment by 28% in 2019 but the chances of being scaled back later are high.

Randall Cozzens

Executive Vice President,
Head of North America Energy,
Utilities, Chemicals Market Unit

Region description (U.S.)

Quick introduction



Region: U.S.
Population: 328,239,523 (Jul 2019)
GDP: US$ 21,427,700 million

Electricity

- Total electricity generation (2019) : 4401.3 TWh
- Average electricity price: 13.04 US¢/KWh (residential price)
- Electrification share (average): 100%

Gas

- Total Natural gas production : 920.88 bcm
- Total Natural gas consumption : 846.65 bcm
- U.S. Henry Hub: 2.53 US$/Tcf

Energy players

Revenue for each main player:

- Exelon : US$ 34.4 billion
- Duke Energy: US$ 25.1 billion
- Southern Company: US$ 21.4 billion
- Pacific Gas & Electric: US$ 17.1billion
- NextEra Energy: US$ 19.2 billion
- American Electric: US$ 15.6 billion
- Edison International: US$ 12.3 billion
- Consolidated Edison: US$ 12.6 billion
- Sempra Energy: US$ 10.8 billion
- FirstEnergy: US$ 11.0 billion
- The AES Corp: US$ 10.2 billion
- NRG Energy: US$ 9.8 billion

Renewable energy

- Renewables share of primary energy: 6.2%
- Renewable power in United States: 489.80 TWh

Environment

- Total CO_2 emissions: 5117.77 million tonnes of CO_2 equivalent
- CO_2 per EJ: 52.45 t/EJ

Country highlights

- Due to COVID-19, CO_2 emissions are projected to fall by 11% in 2020—the largest decline since 1949.
- Old nuclear generation plants are being retired due to high operational costs, but the design of new, smaller prototypes are under innovation.
- As part of COVID-19 recovery efforts, regulatory jurisdictions are supporting utilities with different billing and pricing schemes to mitigate the effects of the economic downturn associated with the pandemic.
- As a result of a recent wave of cyberattacks on utilities, new legislation including the Securing Energy Infrastructure Act & Enhancing Grid Security Through Public-Private Partnerships Act were approved by the U.S. government to boost the rights of the DOE.
- U.S. continued to export more natural gas than it imported in 2019. Gas exports averaged 5.2 Bcf/d.

Region description (Canada)

Quick introduction

Region: Canada
Population: 37,971,020 (April 2020)
GDP: US$ 1,736,430 million

Electricity

- Total electricity generation (2018): 660.4 TWh
- Electrification share (average): 100%

Gas

- Total Natural gas production: 173.10 bcm
- Total Natural gas consumption: 120.31 bcm
- Canada Alberta: 1.27 US$/ Tcf

Energy players

Revenue for each main player:

- Hydro-Québec: US$ 10.6 billion
- BC Hydro: US$ 5.0 billion
- Hydro One: US$ 4.9 billion
- Ontario Power Generation: US$ 4.5 billion
- ENMAX: US$ 1.9 billion
- TransAlta: US$ 1.8 billion

Renewable energy

- Renewables share of primary energy: 4.0%
- Renewable power in United States: 49.30 TWh

Environment

- Total CO_2 emissions: 588 million tonnes of CO_2 equivalent
- CO_2 per EJ: 39.13 t/EJ

Country highlights

- In 2019, Canada's anticipated emissions for 2030 were projected to be 227 million tonnes below the rates projected in 2015 – an unprecedented level of emissions reduction.
- A considerable gap between electricity rates in the NWT and the Canadian national average has been observed. With many Northwest Territories Power Corporation's (NTPC) generation and transmission assets nearing end of life and no major funding available, electricity rates are likely to increase.
- Canada aims to play a leadership role in future in creating globally accepted standards and certification programs to significantly reduce the risk and severity of cyber threats through IIoT devices.

1-Climate Change & Energy Transition

U.S. ~ Energy-related emissions: CO_2 emissions are projected to fall 11% in 2020 (the largest decline since 1949) due to the effects of decreasing economic growth resulting from COVID-19

According to EIA, in May 2020, U.S. energy-related carbon dioxide (CO_2) emissions decreased by 2.8% in 2019 compared to 2018

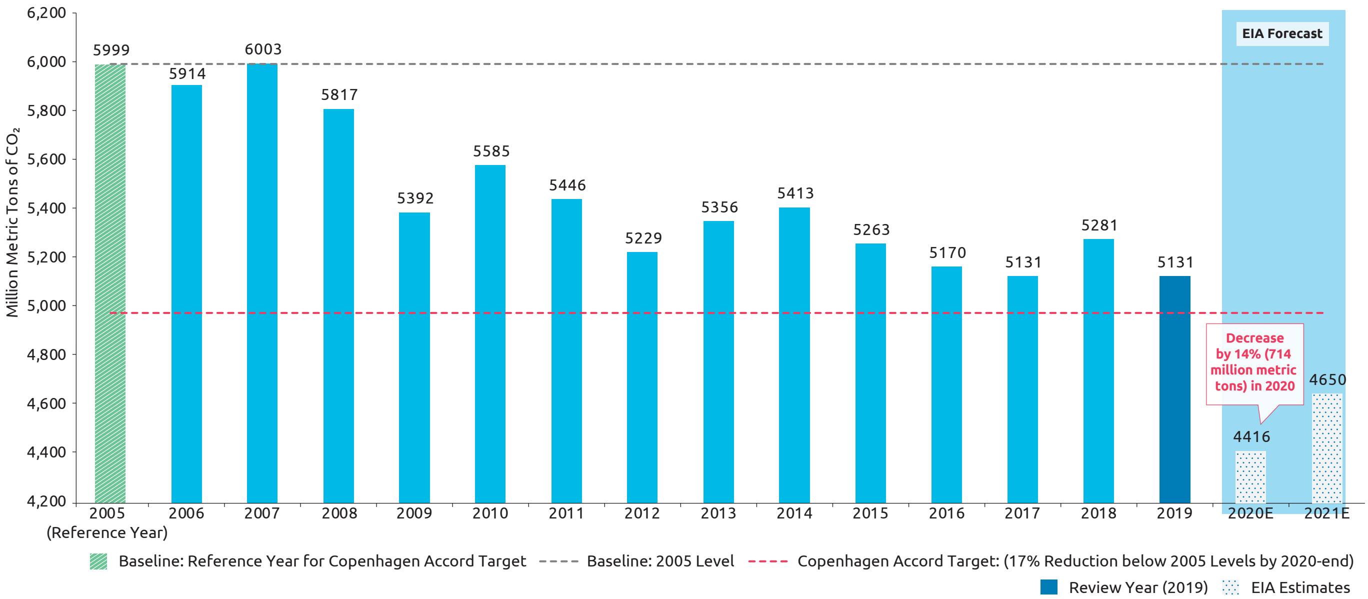
- EIA forecasted that CO_2 emissions will decrease by 11% (572 million metric tons) in 2020 as compared to 2019. If realized, this decrease would signify the largest decline in absolute terms since 1949. This record drop is the result of travel restrictions and a decline in industrial activity related to the pandemic.
- Even before the effects of COVID-19 became obvious in mid-March, EIA anticipated a decline in 2020 energy-related emissions. This is generally consistent with the trend of lower CO_2 emissions since peaking in 2007.
- EIA also forecasted that energy-related CO_2 emissions will increase by almost 5% in 2021 as compared to 2020 due to economy revival and the easing of business and travel restrictions.
- This change in emissions is proportionally less than the expected change in the economy (6% increase in GDP) as businesses, industries, and institutions resume normal operation. Apart from revival of the economy, energy-related CO_2 emissions in 2021 will also be affected by changes in weather, energy prices, and fuel mix.

U.S. CO_2 Emissions throughout 2020

- As of September 2020, CAMS data indicates that the west coast wildfires have emitted 79.6 million metric tons of carbon dioxide in California, 26.8 million metric tons in Oregon and 5.1 million metric tons in Washington.
- The U.S. reduced its carbon emissions by one-third in the first week of April 2020, with overall emissions falling to 307 million metric tons (MMmt) in the same month.

The U.S. is at a serious risk of missing its Copenhagen Accord target of a 17% reduction in emissions by the end of 2020. The country is even further away from its 2025 goal of a 26-28% reduction in emissions set in the Paris Agreement.

Figure 1.1. U.S. ~ Energy-related CO_2 Emissions: Evolution since 2000; Outlook through 2021E (million metric tons CO_2)



Source: U.S. EIA, Monthly Energy Review, May 2020; US EIA Short-Term Energy Outlook, Jun 2020

U.S. ~ Energy-related emissions: Natural gas-related CO_2 emissions fell at a lower rate than petroleum and coal in 2020

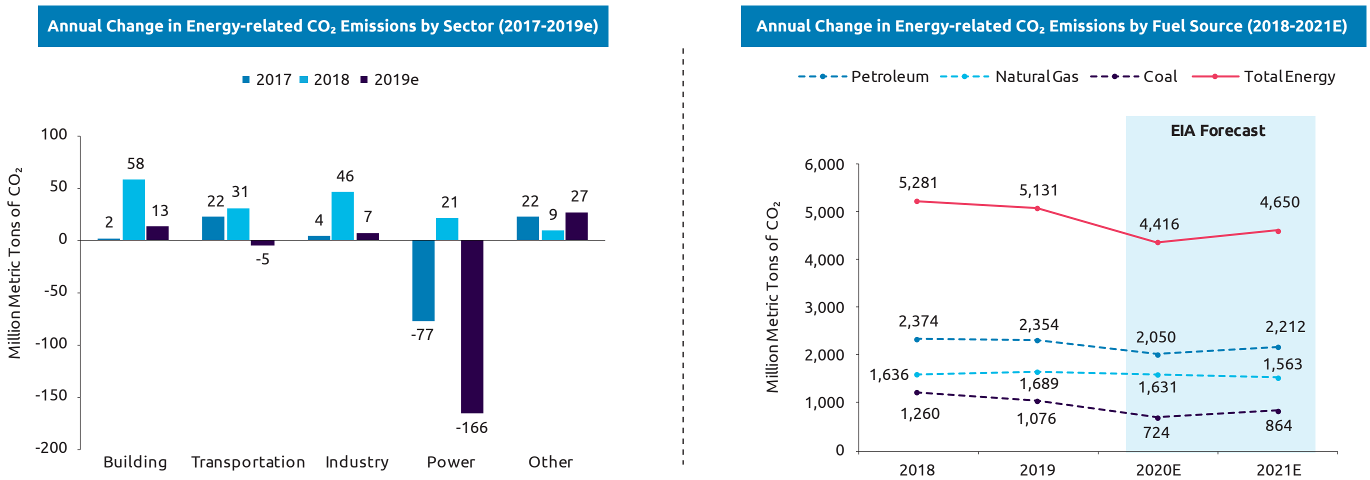
Transportation-related CO_2 emissions remained relatively flat in 2019. Emissions from buildings, industry and other sectors rose, though at a lower rate than in 2018

- According to preliminary U.S. Emissions Estimates for 2019 offered by the Rhodium Group, industrial emissions (both energy and process) increased by 0.6%. Direct emissions from buildings rose by 2.2% and emissions from other sectors (agriculture, waste, land use, oil and gas methane, etc.) increased by 4.4%.
- This was a considerable improvement from the relatively sharp rise in building, transportation, and industrial emissions recorded in 2018.

Petroleum was the greatest single source of energy-related CO_2 emissions in the U.S. in 2019

- Petroleum accounted for 46% of total emissions in 2019. According to EIA, petroleum-related CO_2 emissions are estimated to decline by nearly 11% in 2020.
- Natural gas accounted for 33% of the 2019 total, the second-largest share of energy-related CO_2 emissions in the U.S. Energy-related CO_2 emissions from natural gas consumption decreased by 17% in March and April 2020.
- EIA expects a smaller decline in natural gas-related CO_2 emissions in 2020 as compared to petroleum and coal. The terminating or reduced operation of many nonessential businesses, combined with generally hotter weather in 2020, has led to a decline in commercial sector natural gas consumption.
- CO_2 emissions from coal have fallen over the past few years, accounting for 21% of total CO_2 emissions in 2019. According to EIA forecast, coal-related CO_2 emissions will fall 23% in 2020 to 832 million metric tons.
- In April 2020, the U.S. electric power sector CO_2 emissions declined to the lowest levels on record. Total electricity generation decreased by 7%, while energy-related CO_2 emissions fell by 16%.

Figure 1.2. U.S. ~ Energy-related CO_2 Emissions: Annual Change by Sector, 2017-2019e (million metric tons CO_2); Annual Change by Fuel Source, 2018-2021E (million metric tons CO_2)



Source: U.S. EIA, Monthly Energy Review, May 2020; U.S. EIA Short-Term Energy Outlook, June 2020; Rhodium Group Estimates, Jan 2020

Some U.S. states have taken a leadership role in reducing emissions by enhancing their annual target thresholds for the procurement of wind, solar, and energy storage and establishing carbon-free goals and mandates, as opposed to setting renewables-only targets.

U.S. ~ Energy-related emissions: An increase in transportation and industrial activities is expected to offset the carbon emissions target. However, an increase in investment in renewable energy will enhance the chances of further reduction in carbon emissions by 2050

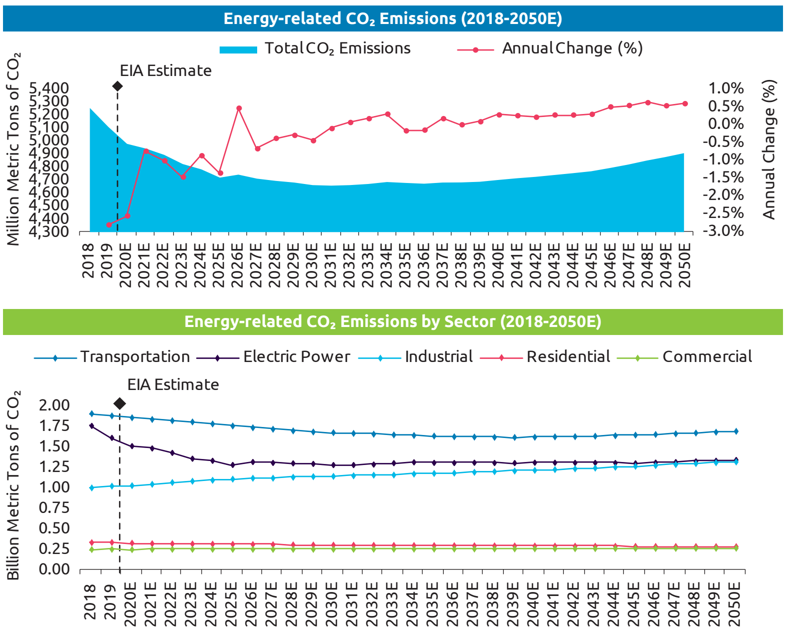
Energy-related CO_2 emissions in almost all sectors are forecast to decrease through 2022. However, emissions are expected to increase between 2023 and 2050 as economic growth and increasing energy demand outweigh improvements in efficiency

- Total U.S. energy-related carbon dioxide emissions will experience modest growth through the 2030s, driven largely by an increase in energy demand, particularly in the transportation and industrial sectors.
- Energy-related carbon dioxide emissions are projected to increase in the industrial sector from 2019 to 2050 but remain relatively flat in other sectors and fuels through 2050.
- Energy-related CO_2 emissions are expected to decrease until the mid-2020s as a result of changes in the fuel mix consumed by the electric power sector.

Energy related CO_2 emissions from March – April 2020

- CO_2 emissions in the transportation sector have observed the largest decline due to pandemic-related travel restrictions.
- CO_2 emissions from motor gasoline consumption fell to a record low at 59 MMmt of CO_2. Similar trends were witnessed in CO_2 emissions from jet fuel.

Figure 1.3. U.S. ~ Energy-related CO_2 Emissions: Outlook through 2050E, 2018-2050 (million metric tons CO_2); Energy-related CO_2 Emissions by Sector, 2018-2050E (billion metric tons CO_2)



Source: U.S. EIA Annual Energy Outlook, 2020

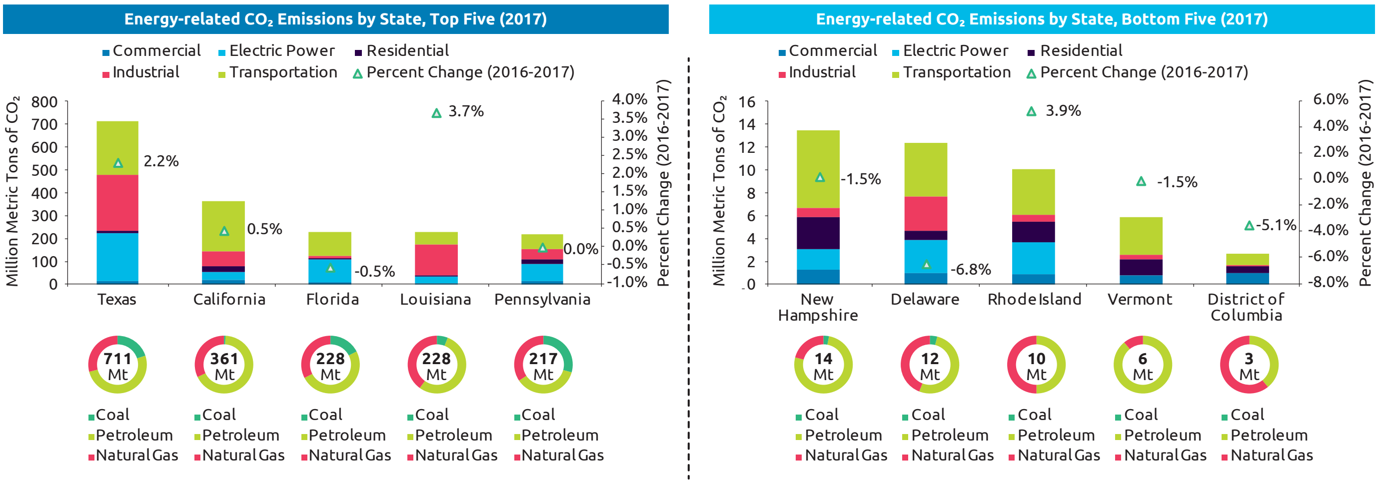
U.S. energy-related carbon dioxide (CO_2) emissions are expected to contract by 11% in 2020 due to the disruption of COVID-19. Despite this decrease, the U.S. is at a serious risk of missing its Copenhagen Accord target of a 17% reduction by the end of 2020. Meanwhile, Texas recorded a massive carbon footprint dominated by petroleum products and coal in 2019.

U.S. ~ Energy-related emissions: Texas emits more CO_2 than any other state in the U.S.

According to EIA, Vermont and Rhode Island, as well as the District of Columbia, emitted no coal-related CO_2 emissions. West Virginia, Wyoming, North Dakota are among the states with the maximum content of coal in their CO_2 emissions

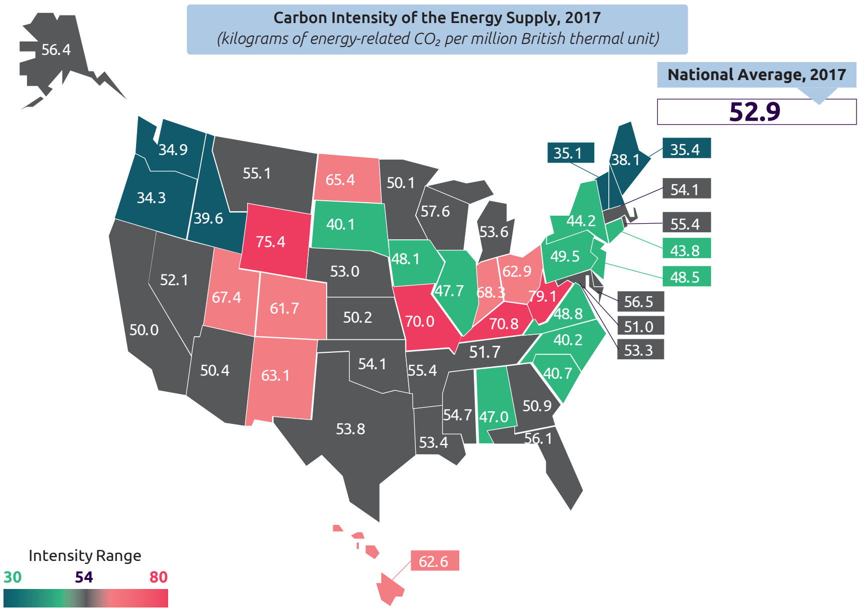
- In the period from 2016 to 2017, energy-related CO_2 emissions rose in 9 states and remained the same or decreased in all other states.
- Texas witnessed the largest absolute increase between 2016 and 2017, with emissions rising 15 Mt (+2.2%). Louisiana followed at 8.1 Mt (+3.7%).
- Missouri (4.7%) and Rhode Island (3.9%) reported a maximum increase of CO_2 emissions in percentage terms between 2016 and 2017.
- The largest percentage decrease between 2016 and 2017 was reported by Maryland (-10%).
- Texas has a massive carbon footprint, with an emissions rate almost double that of California.
  - Texas's CO_2 emissions were dominated by petroleum products in 2017, followed by natural gas and coal.
  - The state's outsized volume of emissions arises in part from the state's disproportionate share of energy-intensive manufacturing, as well as its growing auto-dependent population.

Figure 1.4. U.S. ~ State Profiles: Energy-related CO_2 Emissions: Top Five and Bottom Five States by Sector, 2017 (million metric tons CO_2) and Percent Change, 2016-2017; Share by Fuel Source, 2017



Source: EIA Review, May 2020

Figure 1.5. U.S. ~ State Profiles: Carbon Intensity of Energy Supply, 2017 (kilograms of energy-related CO_2 per million British thermal unit)



Source: EIA Review, May 2020

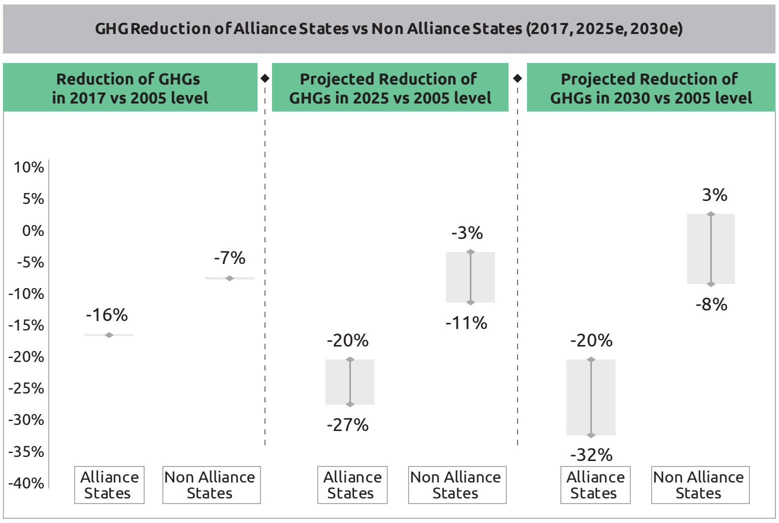
U.S. Climate Alliance: Alliance states are cutting GHG emissions at a faster pace than non-alliance states, driving a nationwide reduction in emissions

With the addition of eight new states in 2019 and continued leadership, the U.S. Climate Alliance is cutting GHG emissions at a faster pace than the rest of the country and helping to drive down national emissions

- Between 2005 and 2017, the U.S. Climate Alliance decreased their collective GHG emissions by 16% as compared to just 7% for the rest of the country—more than double the rate.
- Within that period, the combined per-capita economic output generated by these states grew by 12% in comparison to 4% for the rest of the country, indicating that climate leadership and economic progress can move hand-in-hand.
- Based on current policies, the U.S. Alliance states have a projected GHG emissions reduction of 20-27% below 2005 levels by 2025. By 2030, current policies are projected to reduce GHG emissions by 20%-32% below 2005 levels.
- For non-Alliance states, GHG emissions are projected to fall by about 3-11%, compared to 20-27% for Alliance states.
- By 2030, the differential grows. Alliance states are projected to reduce their emissions by 20-32% below 2005 levels, while the projections for non-Alliance states range from an 8% reduction to a 3% increase.

The Regional Greenhouse Gas Initiative (RGGI) & Transportation and Climate Initiative (TCI) gained momentum with the addition of new states and policies.

Figure 1.6. U.S. ~ GHG Reduction in U.S. Climate Alliance states vs non- alliance states



Aggregate GHG Emissions from Alliance States, million metric tons carbon dioxide equivalent (MMTCO₂e)

Sector	2005	2017	2020	2025	2030
Transportation	1028	929	908	863 to 871	815 to 842
Electricity	854	596	574	463 to 513	408 to 495
Residential	258	215	215	202	191
Commercial	147	147	151	146	143
Industrial	369	324	345	344	337
HFCs	43	98	97 to 110	77 to 120	49 to 125
Agriculture	183	205	210	216	222
Fugitive and Process Emissions from Oil & Gas Operations and Coal Mining	49	58	57 to 58	55 to 60	58 to 64
Other Industrial Processes and Product Use	64	42	40	35	33
Waste	64	51	46	40	35
Total Gross GHG Emissions	3059	2665	2664 - 2657	2441 - 2542	2291-2478
LULUCF Sequestration	-381	-409	-472 to -450	-497 to - 408	-483 to -323
Total Net GHG Emissions	***2678***	***2257***	***2172 to 2207***	***1944 to 2134***	***1808 to 2155***
Change from 2005		***-16%***	***-18% to -19%***	***-20% to -27%***	***-20% to -32%***

Source: U.S. Climate Alliance 2019 Annual Report

Withdrawal from the Paris Agreement in November 2019 has slashed U.S. GHG & CO_2 emissions targets—one of the reasons why the country landed at the very bottom of this year's Climate Change Performance Index (CCPI).

Canada ~ Emissions: In 2019, Canada's projected emissions in 2030 are expected to be 227 million tonnes (Mt) below projections made in 2015 – an unprecedented level of emission reduction

In December 2019, the Canadian Minister of Environment and Climate Change, Jonathan Wilkinson, published the conclusions of Canada's annual greenhouse gas emission projections

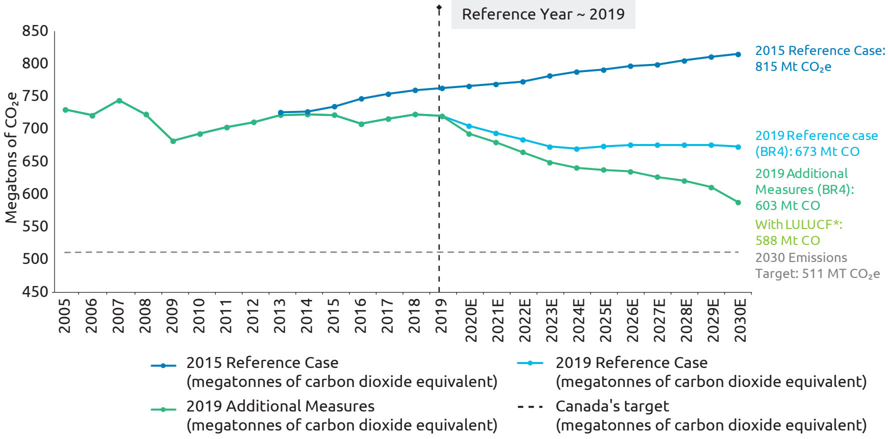
- According to the analysis:
  - In 2019, Canada's 2030 emissions are projected to be 588 million tonnes (Mt).
  - In 2015, Canada's 2030 emissions targets were projected to be 815 million tonnes (Mt).

The underlying policies and measures are projected to achieve a 2030 emissions level that is 28 million tonnes lower than last year's projections

- In December 2019, the Canadian government announced it would strengthen existing measures and implement new greenhouse gas reducing measures that would exceed Canada's current 2030 emissions reduction goal.
- Additionally, Canada is also expected to develop a plan to achieve net-zero emissions by 2050 and will also set five-year emissions reduction milestones.
- The government has dedicated its efforts to increase clean electricity, invest in greener buildings and communities, quicken the electrification of transportation, and adopt nature-based climate solutions.

Canada aims to accelerate its targets by developing a plan to achieve net-zero emissions by 2050.

Figure 1.7. Canada ~ Historical GHG Emissions and Projections, 2005-2030 (megatons of CO_2e)



LULUCF*: Land Use, Land Use Change and Forestry | Note: The 2019 Reference Case scenario includes policies and measures in place as of September 2019. The Additional Measures scenario includes additional measures from Canada's clean growth and climate change plan that have been announced but are still under development

Source: Government of Canada's Emissions Progress Report, January 2020

Topic box 1.1: Chances for federal carbon pricing action remain limited in the U.S.—a stark contrast to the vast carbon pricing actions and increased cooperation on carbon pricing at the state level

At the national level, policymakers presented an assortment of bills in 2019-20 for an emissions trading system (ETS) or carbon tax without success. Each of these bills would give back carbon pricing revenues to citizens. Until now, none of the bills have made any advancement in the legislative process. The Climate Leadership Council issued a bipartisan climate roadmap that includes a carbon dividends plan that would prevent carbon leakage and protect industry competitiveness by implementing a border carbon adjustment system.

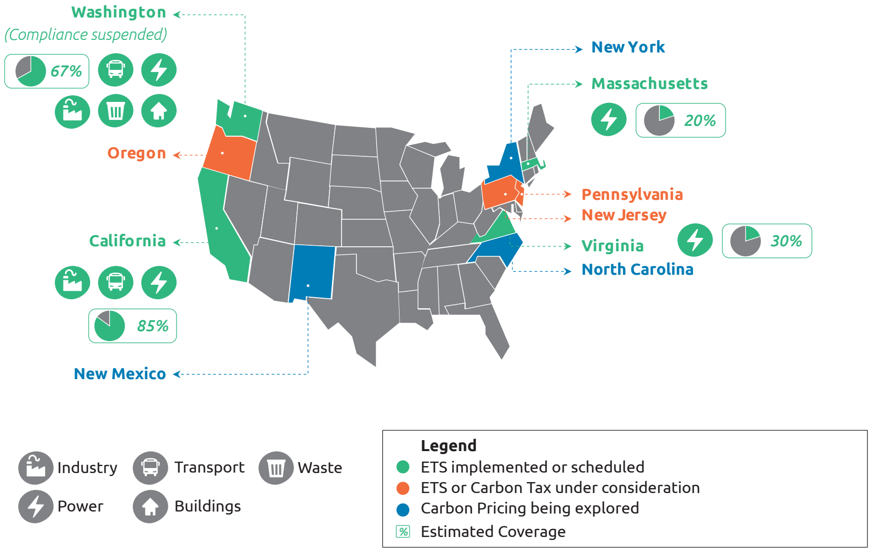
Key Developments in the Regional Greenhouse Gas Initiative (RGGI):

- RGGI, a regional carbon market for the power sector, readmitted New Jersey in January 2020 after its exit from the initiative in 2011. New Jersey's first auction as a rejoined member was in March 2020.
- Two other states—Virginia and Pennsylvania—are also considering admission. The inclusion of Pennsylvania would significantly increase the size of the carbon market and bring a major fossil fuel state into the initiative. Virginia is preparing to join RGGI in early 2021 and Pennsylvania may enter as soon as 2022.

Key Developments in Transportation and Climate Initiative (TCI):

- Maine, New Hampshire and New York joined the TCI process, a cluster of 11 states and Washington DC in considering a carbon pricing mechanism for their transport sector.
- In October 2019, participating TCI jurisdictions released a plan for a regional ETS that would address CO2 emissions from the combustion of gasoline and on-road diesel fuel in the transport sector. The ETS is scheduled to start in 2022.
- In December 2019, the TCI jurisdictions released a draft memorandum of understanding (MOU) with further design elements such as three-year compliance periods, interim compliance obligations and timings for regular program evaluations.

Figure 1.8. U.S. ~ Summary Regional Carbon Pricing Initiatives (ETS and Carbon Tax) ~ (implemented, scheduled for implementation and under consideration) and Sectoral Coverage



Source: State and Trends of Carbon Pricing, 2020; World Bank, May 2020

U.S. ~ Carbon Pricing: Many carbon pricing initiatives are under consideration in several U.S. states, including Pennsylvania, New Mexico, North Carolina and Oregon

Various states continue to develop their own carbon pricing initiative or strengthen existing plans

Summary of recent developments in key carbon pricing initiatives in various states

Jurisdiction	*Type and status*	*Key Developments*
New York City	Carbon pricing being explored	The New York City government is required to examine the possibility of a citywide ETS for the buildings sector as part of a local law that sets emission intensity limits for most large buildings starting in 2024. The findings are expected to be issued by 2021.
New Mexico	Carbon pricing being explored	In November 2019, the New Mexico Climate Change Task Force issued introductory recommendations stating the requirements for New Mexico to implement a state-wide ETS to help reach emission reduction goals.
North Carolina	Carbon pricing being explored	In October 2019, the North Carolina Department of Environmental Quality issued recommendations to begin examining how a market-based program could help the state achieve its GHG emission reduction goals.
Oregon	ETS under consideration	After two bills proposing a cap-and-trade system failed to pass in the Oregon state legislature in 2019 and 2020, an executive order was signed by the Governor in March 2020 for a "Cap and Reduce Program" for large stationary sources of emissions. The cap is consistent with previous legislation requiring a 45% reduction in GHG emissions based on 1990 levels by 2035 and at least an 80% reduction by 2050. The program will begin in 2022.
Pennsylvania	ETS under consideration	In October 2019, the government signed an executive order to develop a proposal for an ETS covering the power sector, with the intention to join or link with RGGI. The earliest start date for Pennsylvania's ETS and its linkage to RGGI is 2022.
Virginia	ETS scheduled	In June 2019, Virginia's ETS Regulation came into force, which set the legal basis for the Virginia CO_2 Budget Trading Program to become operational as of January 1, 2020. This legislation establishes an ETS for its power sector and facilitates participation in RGGI.
Washington State	ETS implemented (compliance suspended)	The compliance prerequisites under the Clean Air Rule (CAR) have been deferred since December 2017, following a county court ruling. In January 2020, the Washington Supreme Court moderately upheld the CAR. This new ruling specified that the compliance requirements could apply to stationary sources of direct emissions but not to fuel suppliers and natural gas distributors that indirectly emit GHGs from combustion occurring further downstream.

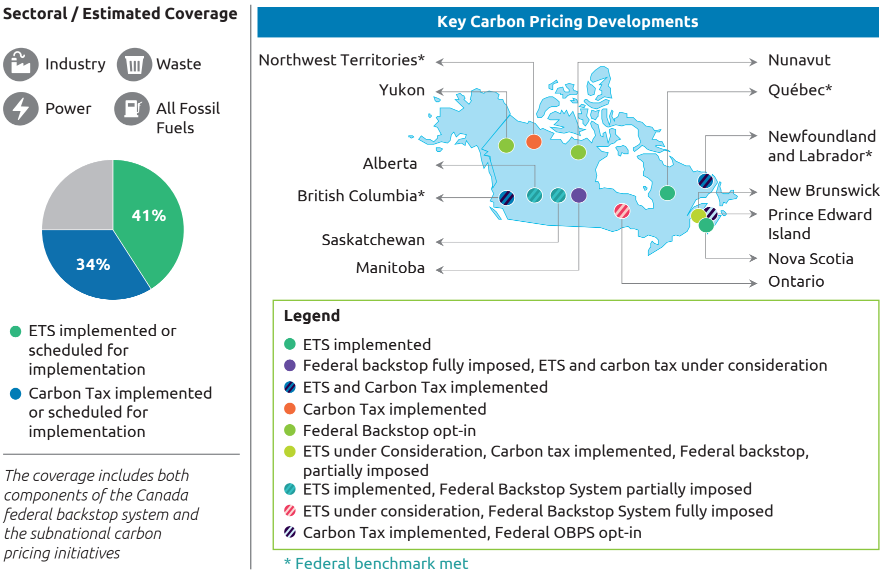
Canada ~ Carbon Pricing: 2019 saw a flurry of subnational initiatives emerge across the provinces and territories driven by Canada's federal carbon pricing approach

According to the World Bank, governments raised nearly US$45 billion in carbon pricing revenues in 2019 globally as a result of newly launched carbon pricing reforms—an increase of US$1 billion since 2019

- The largest contribution to the increase in global revenues is due to the federal fuel charge (i.e. carbon tax backstop component) from Canada.
- Canada's federal backstop system—which includes an ETS and a fuel charge similar to a carbon tax—has been enforced on provinces and territories that do not opt in to the system, or that do not put in place an appropriately ambitious carbon pricing mechanism.
- The federal backstop comprises of two components:
  - A regulatory charge on fossil fuels set at US$14/t$CO_2$e in 2019 that rises by US$7/t$CO_2$e per year to US$35/tCO_2e in 2022.
  - An Output-Based Pricing System (OBPS) that sets emission intensity standards for power generation and a wide range of activities.

The two parts of the federal system can be implemented either together or separately.

Figure 1.9. Canada ~ Summary Regional Carbon Pricing Initiatives (ETS and Carbon Tax) ~ (implemented, scheduled for implementation and under consideration) and Sectoral Coverage



Source: State and Trends of Carbon Pricing, 2020; World Bank, May 2020

Canada ~ Carbon Pricing: Most Canadian provinces and territories introduced new initiatives in response to the federal government's Pan-Canadian Approach to Pricing Carbon Pollution

Summary of recent developments in key carbon pricing initiatives in Canadian provinces and territories

Jurisdiction	***Type and status***	***Key Developments***
Alberta	ETS implemented Federal backstop partially imposed	• Substituted its Carbon Competitiveness Incentive Regulation (CCIR) with the Technology Innovation and Emissions Reduction (TIER) Regulation system—a baseline-and-credit ETS—starting from January, 2020. • Eradicated its carbon tax in May 2019. Starting in January 2020, the federal fuel charge of the backstop was imposed on the province.
British Columbia	ETS and carbon tax implemented Federal benchmark met	• Carbon tax was scheduled to increase from US\$28/tCO_2e to US\$32/tCO_2e in April 2020 and continue to increase annually by US\$4/tCO_2e until the rate is US\$35/tCO_2e in 2021. • Due to COVID-19, the rate was frozen at US\$28/tCO_2e until further notice.
Manitoba	Federal backstop fully imposed ETS and carbon tax under consideration	• Intended to implement a Made-in-Manitoba OBPS and Green Levy as of July 1, 2020 as a substitute to the federal backstop. • In March 2020, the Manitoba Legislative Assembly voted to suspend its sittings due to COVID-19, making it uncertain when these two carbon pricing initiatives could start.
New Brunswick	ETS under consideration Carbon tax implemented Federal backstop partially imposed	• Carbon tax was introduced in April 2020 at a rate of US\$21/tCO_2e. • This replaced the fuel charge component of the federal backstop.
Newfoundland and Labrador	ETS and carbon tax implemented	• Carbon tax and provincial baseline-and-credit ETS have been there since January 2019. • The state government wanted to raise its carbon tax to US\$21/tCO_2e in April 2020, but this has been postponed due to COVID-19.
Northwest Territories	Carbon tax implemented	• Carbon tax came into force in September 2019. • The initial US\$14/tCO_2e 2019 tax rate will increase annually by US\$7/tCO_2e to reach US\$21/tCO_2e in July 2020 and US\$35/tCO_2e in 2022.
Nova Scotia	ETS implemented	• Launched its ETS in January 2019. • The first allocation of allowances took place in April 2019 and auctioning will begin later in 2020.The minimum price for auctions held in 2020 are US\$14/tCO_2e and each subsequent year the minimum price will increase by 5% plus inflation.
Nunavut	Federal backstop opt-in	• As of July 1, 2019, both the federal carbon fuel charge and OBPS are applicable.
Ontario	ETS under consideration Federal backstop fully imposed	• Proposed its own alternative to the federal OBPS for large emitters—called the Emissions Performance Standard (EPS). • Also subject to the federal fuel charge.

Summary of recent developments in key carbon pricing initiatives in the Canadian provinces and territories

Jurisdiction	***Type and status***	***Key Developments***
Prince Edward Island	Carbon tax implemented Federal OBPS only opt-in	• Carbon tax has been in force since April 2019. The carbon tax is consistent with the federal fuel charge and is currently at US\$21/tCO_2e. • At the request of the province, the federal OBPS for large emitters was implemented on January 1, 2019.
Québec	ETS implemented Federal benchmark met	• Has been developing a reform to free allocation for 2024-2030 in consultation with industrial emitters. This proposed reform is expected to be introduced in regulation in 2020.
Saskatchewan	ETS implemented Federal backstop partially imposed	• OBPS was instituted in January 2019. It covers large industrial facilities across 11 sectors that emit over 25 ktCO_2e with a voluntary opt-in for facilities emitting between 10 to 25 ktCO_2e.
Yukon	Federal backstop opt-in	• As of July 1, 2019, the federal backstop applies to Yukon.
Prince Edward Island	Carbon tax implemented Federal OBPS only opt-in	• Carbon tax has been in force since April 2019. The carbon tax is consistent with the federal fuel charge and is currently at US\$21/tCO_2e. • At the request of the province, the federal OBPS for large emitters was implemented on January 1, 2019.

In Canada, the COVID-19 pandemic has led to court hearings on the federal carbon pricing approach being delayed

- States like Saskatchewan and Manitoba have witnessed the postponement of court hearings on federal carbon pricing policies due to COVID-19.

- The pandemic has also affected prices in various carbon taxes.
  - Newfoundland and Labrador had planned to raise its carbon tax in April 2020, but this has been postponed until further notice due to COVID-19.
  - Similarly, British Columbia froze its carbon tax rate at US\$28/tCO_2e, delaying its decision to increase it to US\$40/tCO_2e until further notice. It also increased and expanded the British Columbia climate action tax credit to provide income support for its residents.

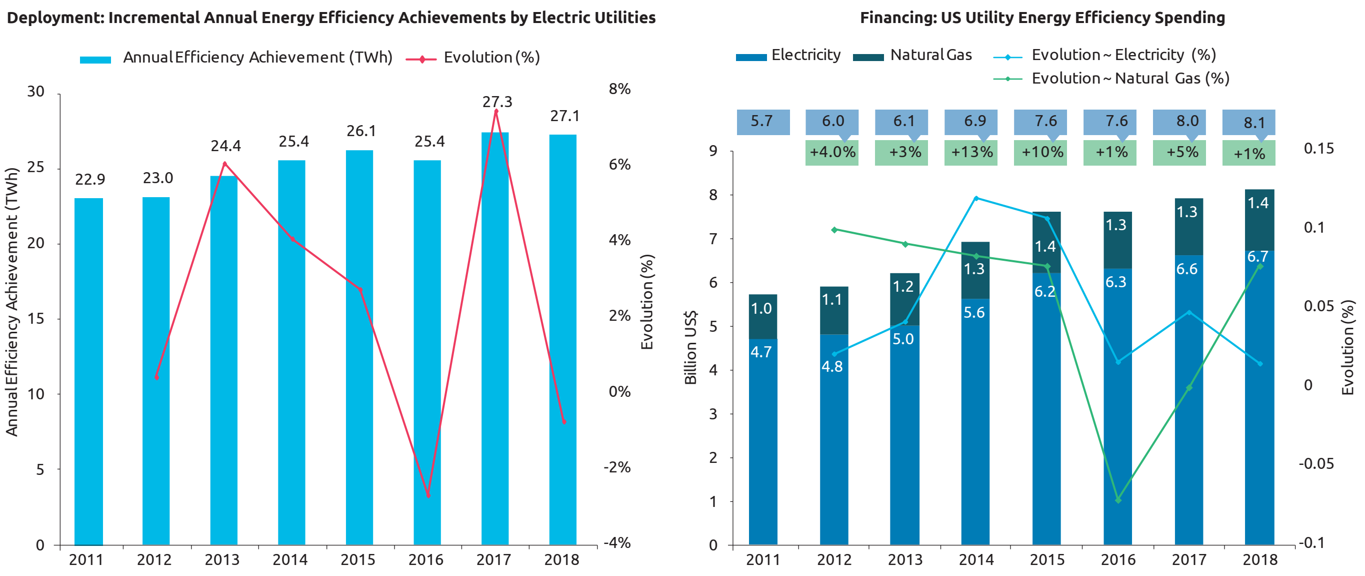
U.S. ~ Energy Efficiency: 2018 Utility energy efficiency savings declined modestly by 1% from the previous year

According to Bloomberg, the years leading up to 2011 saw an increasing number of states introducing Energy Efficiency Resource Standards (EERS), which directed utilities to invest in energy savings among their customer base. As a result, the U.S. saw an increase in investment in utility energy efficiency programs.

Since 2011, the number of states with EERS policies in place has increased modestly, along with investment. With the decrease of funding, utility electricity savings were also decreased.

- In 2018, out of the 28 states that decreased their efficiency program spending, 19 states also saw a decrease in their electricity savings.
- The largest program reduction came from Kentucky, which cut US$60 million from its efficiency spending and had a 224GWh decrease in electricity savings.
- In 2018, utility spending on energy efficiency stood at US$6.65 billion for electricity and US$1.4 billion for natural gas. Total spending was just 1% higher than in the previous year.
- While investment remained stable nationwide, the scenario was more dynamic at the state level.
  - California invested the most in both natural gas, US$380 million, and electricity, US$1.4 billion.
  - New York saw the biggest rise in electric program spending by US$183.4 million (+41%). California saw the biggest rise in gas program spending (US$75.9 million / +27%).
  - 11 states cut their efficiency budgets by more than 10% in 2018. Kentucky was the largest, reducing its program by US$25.4 million (-70%).
  - It was followed by Alabama (down US$5.4 million, -68%), Tennessee (down US$24.3 million, -59%), and Mississippi (down US$18.8 million, -37%).

Figure 1.10. U.S. ~ Incremental Annual Energy Efficiency Achievement/Utility Spending, 2011-2018



Source: BNEF ~ Sustainable Energy in America Factbook, 2020

U.S. ~ Levelized Cost of Energy: The cost of renewables is falling but at a slower rate

According to Lazard's Levelized Cost of Energy Analysis (Version 13), the cost of alternative energy continues to decrease, but the rate of decline is slowing

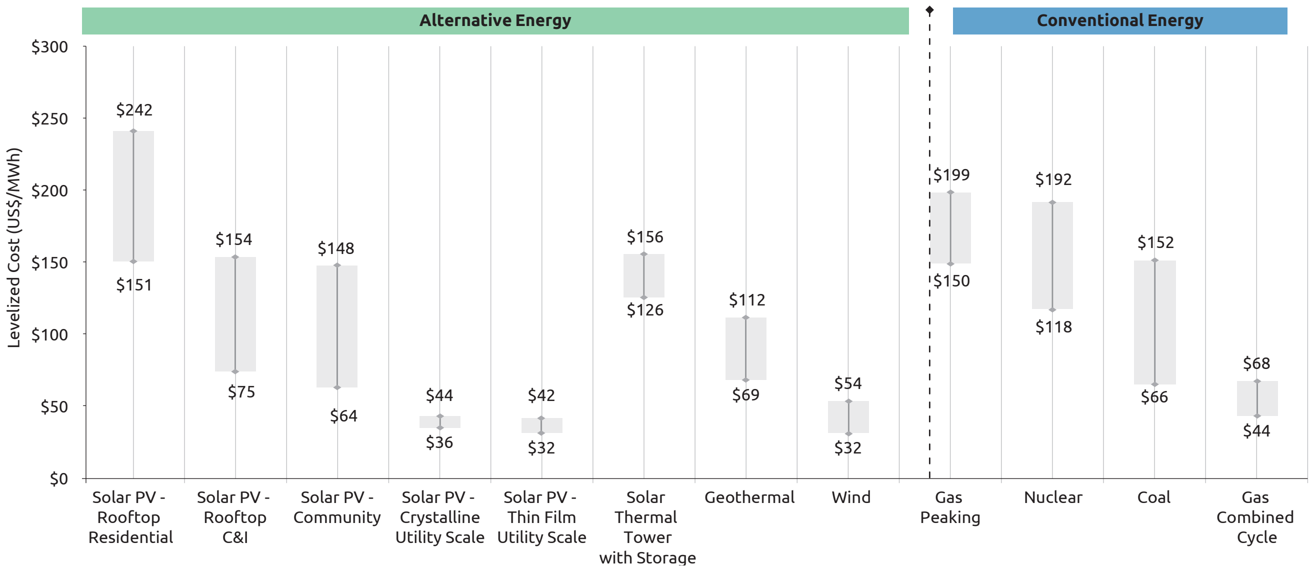
- The continuous decline in the cost of renewable technologies is putting pressure on conventional resources. However, regional disparities and dispatch hurdles for intermittent resources remain a factor in determining the most economical mix.
- According to Lazard, the decline in wind and solar costs include the decreasing price of system components, improvements in efficiency and other factors. But as the industries are maturing, the rates of decline have diminished.

Solar and wind energy have seen major cost-efficiency gains. Within a decade, they will come close to outcompeting operational coal and nuclear plants.

- Unsubsidized utility-scale solar LCOEs have plunged between 2009 (US$323-394) and 2019 (US$36-44).
- For unsubsidized wind, LCOE improvements have ranged from US$101-169 in 2019 to US$28-54 in 2019.
- While existing coal and nuclear plants carry marginal costs of US$26-41 and US$27-31, unsubsidized thin-film utility-scale PV and onshore wind instead carry LCOEs of US$32-42 and US$28-54.

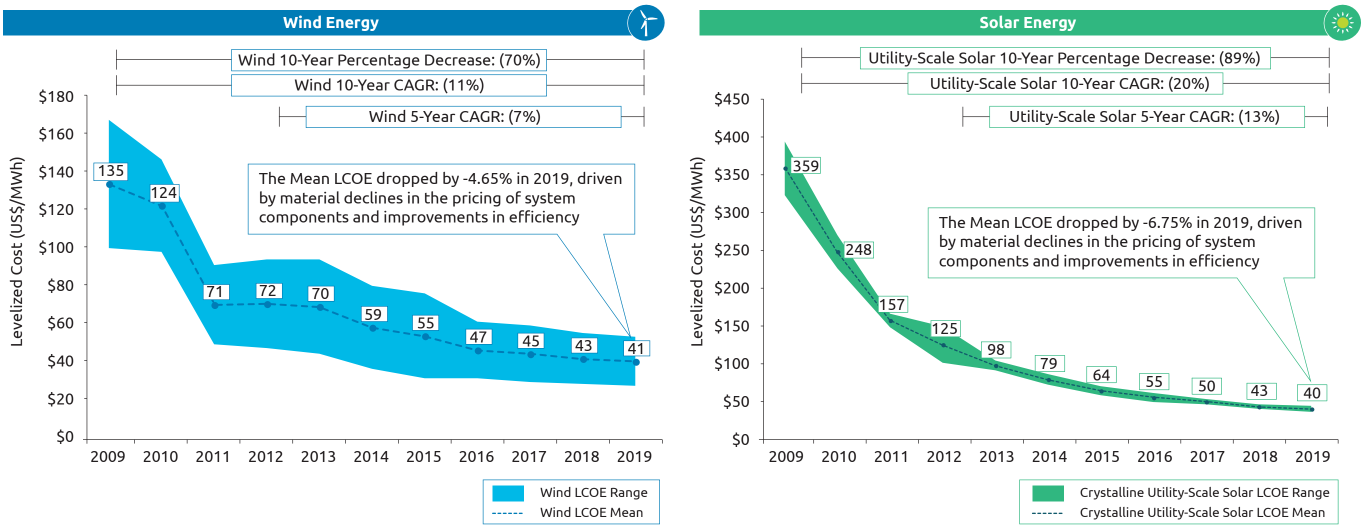
Lazard's Levelized Cost of Energy Analysis predicts a further decline in the cost of renewable technologies, though regional disparities and dispatch hurdles remain a challenge.

Figure 1.11. U.S. ~ Unsubsidized Levelized Cost of Energy (LCOE), 2019 (US$/MWh)



Source: Lazard - Levelized Cost of Energy, Version 13.0, November 2019

Figure 1.12. U.S. ~ Historical Alternative Energy LCOE Declines, 2009-2019 (US$/MWh)



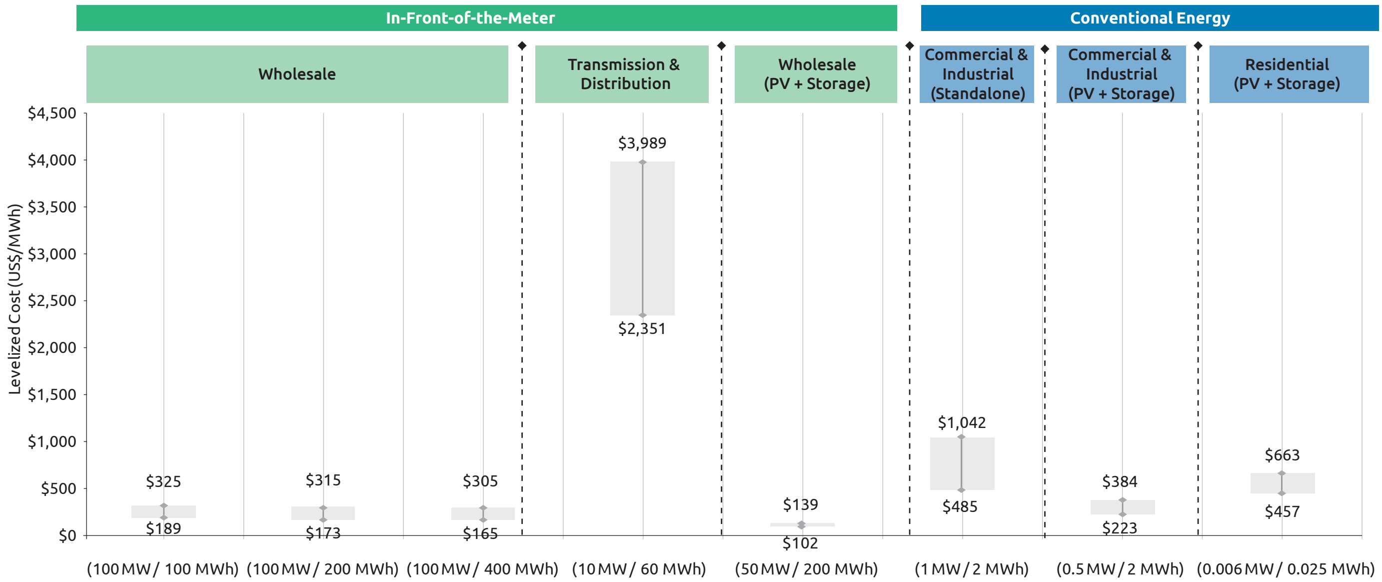
Source: Lazard - Levelized Cost of Energy, Version 13.0, November 2019

U.S. ~ Levelized Cost of Storage: While there is a significant cost decline across most use cases, year-over-year cost declines are less pronounced than those observed a year ago

Solar PV + storage systems are economically lucrative for small-duration wholesale and commercial use cases. However, they remain impractical for residential and longer-duration wholesale use cases.

- According to Lazard in Nov 2019, the unsubsidized Levelized Cost of Storage (LCOS) in terms of energy gives the comparison as follows:
  - 100 MW/200 MWh systems ranged from US$173/MWh to US$315/MWh.
  - Residential systems sized 0.006 MW/0.025 MWh had costs from US$457/MWh to US$663/MWh.
- The Lazard report reveals a considerable cost declines across most use cases. However, industry concerns about increasing costs for future deliveries of Lithium-ion systems due to higher commodity pricing and challenges related to storage module availability remain.
- Cost reductions for storage modules were more marked than for system components or operations and maintenance. Year-over-year cost declines were less significant than what Lazard noted a year ago.

Figure 1.13. U.S. ~ Unsubsidized Levelized Cost of Storage (LCOS), 2019 (US$/MWh)



Note: Lazard's LCOS analysis evaluates storage systems on a levelized basis to derive cost metrics based on annual energy output

Source: Lazard - Levelized Cost of Storage Analysis, Version 5.0, November 2019

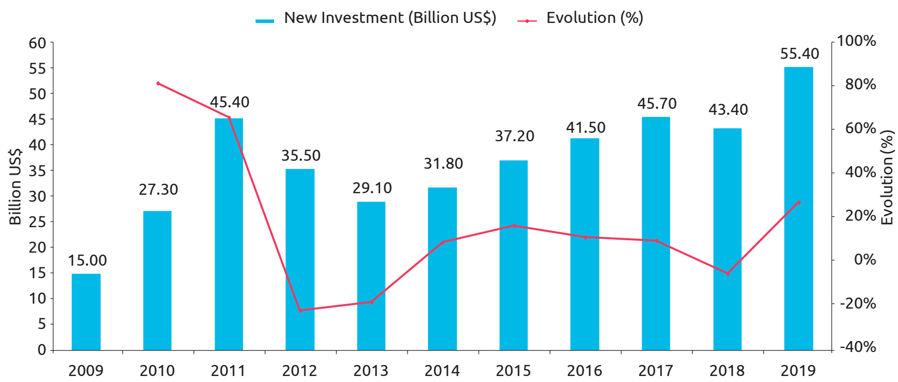
U.S. ~ Renewable Energy Capacity Investment: A surge in clean energy investment in 2019 was prompted by a rush to qualify for federal tax credits set to be scaled-back in 2020

U.S. clean energy capacity investment totaled US$390 billion in 2010-2019

- According to a Bloomberg NEF report, "Late Surge in Offshore Wind Financings Helps 2019 Renewables Investment to Overtake 2018":
  - A total of US$55.5 billion was spent in 2019 on renewable energy capacity, an increase of 28%, second only to China, and beating Europe.
  - "It's notable that in this third year of the Trump presidency, which has not been particularly supportive of renewables, U.S. clean energy investment set a new record by a country mile," quoted by Ethan Zindler, head of Americas for BNEF, noting that the second-highest year for investment (US$45.7 billion) came in Trump's first year, 2017. "These technologies are more cost-competitive than ever, and the fact that there was a tax credit step-down on the horizon made the market particularly busy in 2019."

- Wind and solar investments topped US$ 55 billion—representing almost all of the total 2019 U.S. renewable energy capacity investments in 2019 (US$ 55.5 billion).
- New clean energy investments were buoyed by wind and solar companies accelerating to qualify for federal tax credits being scaled back in 2020.

Figure 1.14. U.S. ~ Renewable energy capacity investment , 2009-2019 (US$ billion)



Source: BNEF ~ Sustainable Energy in America Factbook, 2020

U.S. ~ Renewable Policies: A number of states may change their RPS requirements in 2020

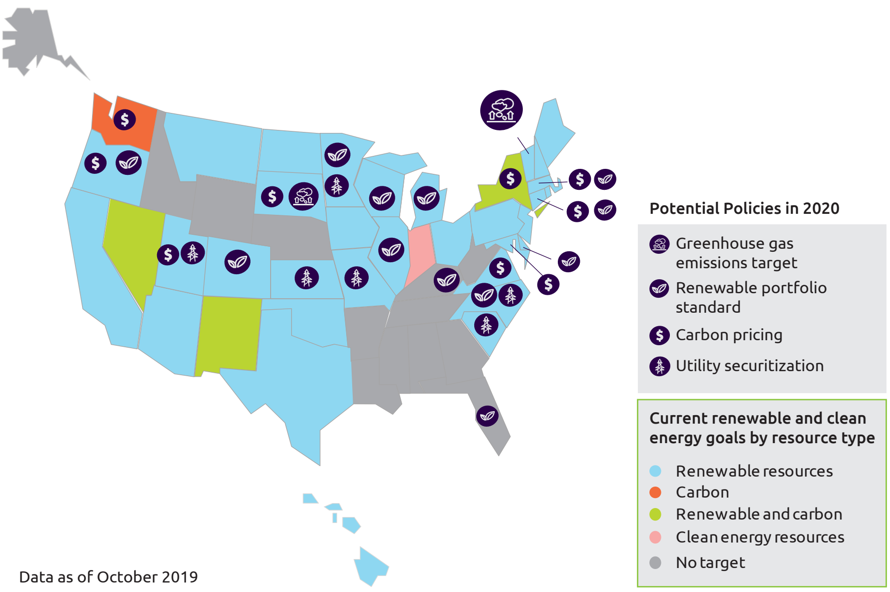
Major steps have been taken in the U.S. to enact advanced renewable energy measures at the state level in recent years. 2020 is likely to bring continued legislative activity

- As federal activity in the sphere of curbing climate change remains inhibited, states are looking to strengthen their renewable portfolio standards (RPS) requirements or increase annual target thresholds for the procurement of wind, solar, and energy storage.
- Additionally, many governors will be on the lookout to endorse legislation that will increase their state's renewable requirements in 2020.
- Several states have started implementing carbon-free goals and mandates, rather than renewables-only targets.
- As states and utilities continue to announce their greenhouse gas emissions-reduction targets, this trend is going to become more apparent in the coming years.
- Many states are looking to introduce legislation to securitize costs associated with the retirement of certain generation facilities, similar to the securitization measures enacted by Colorado and Montana in 2019.

Due to inadequate finance and structural obstacles, the RPS of Illinois will face a funding crunch over the next few years that will restrict additional new project development beyond the end of 2020, if not sooner.

- Policymakers in Illinois were adamant in pushing for such reforms. Illinois could fall short of its current target of securing 25% of eligible retail electricity sales from renewable energy sources by 2025.
- Policymakers were hopeful that changes to Illinois's current policy, the Future Energy Jobs Act, could be addressed during the next legislative session.
- But as the legislature was suspended in March 2020, solar backers are making a last attempt to pass a relatively small change that would allow unspent money collected under the program to be rolled over into future years.

Figure 1.15. U.S. ~ Potential renewables-related policies to be introduced in 2020



Source: S&P Global Market Intelligence, November 2019

2-Infrastructure & Adequacy of Supply

U.S. ~ Electricity Use Growth: The U.S. will experience slow growth through 2050 due to the modernization of the electric system. However, COVID-19 has highlighted the uncertainty and volatility of usage patterns

According the 2020 EIA Outlook, the estimated annual growth in electricity demand will average about 1% through 2050

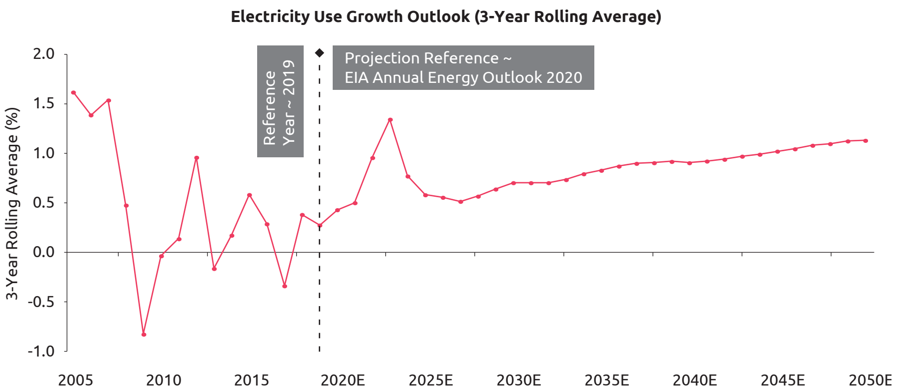
- Currently, electricity usage is favorable to utility players. However, in the future, electricity demand will be limited due to the implementation of efficiency devices and energy saving equipment.
- According to an EIA report in April 2020, demand from the residential sector is expected to fall by 1.3% in 2020 as compared to 2019. Meanwhile, heating and air conditioning reduction will be offset by a rise in household electricity consumption.
- U.S. energy productivity (GDP/energy consumption) increased by 18% between 2010-2019, which benefited residential and commercial sectors. In the past decade, the U.S. economy grew every year; whereas energy usage fell in five of the past ten years.
- However, there is a hike of 65% in energy consumption by the building sector (residential and commercial structures) due to rising income & urbanization.
- U.S. energy consumption is growing at a slower rate than GDP as U.S. energy efficiency continues to increase. Energy intensity is expected to decline until 2050.
- EVs will also significantly contribute to total energy consumption in the near future as adoption continues to grow.
  - The increase in adoption of non-managed home charging, smart charging, workplace charging & vehicle-to-grid applications will impact the overall load on the grid and flow of electricity usage throughout the day.

Energy usage in the U.S. fell to a 16-year low in the first three months of 2020

- Uncertainty of economic conditions in the U.S., caused an 11%-14% decrease in weekday electricity consumption in New York in March and April 2020.

Electricity consumption will continue to rise, but demand will be reduced due to improvements in energy efficiency.

Figure 2.1. U.S. ~ Electricity Use Growth Outlook, 2005-2050E



Source: U.S. EIA Annual Energy Outlook, 2020

U.S. ~ Historical Electricity Generation Mix ~ Total U.S. electric power sector generation witnessed a decline of 1.25% in 2019

A rise in natural gas consumption coupled with new retirements in coal-fired plants has led to the slowest growth rate in natural gas since 2017

- According to EIA, "natural gas consumption increased by 3% in 2019, reaching a new record of 85.0 billion cubic feet per day (Bcf/d)".
- EIA has estimated the growth rate of natural gas in 2020 to be 1.3%, the slowest increase since 2017 due to projected higher natural gas prices in a scenario where Oil and Gas supply will be less.
- In 2019, 12.7 GW of coal-fired capacity, or 5% of existent coal-fired plants, were replaced by new natural gas plants.
  - 5.8 GW is planned to retire by 2020, contributing to a 13% decline in coal-fired-generation.

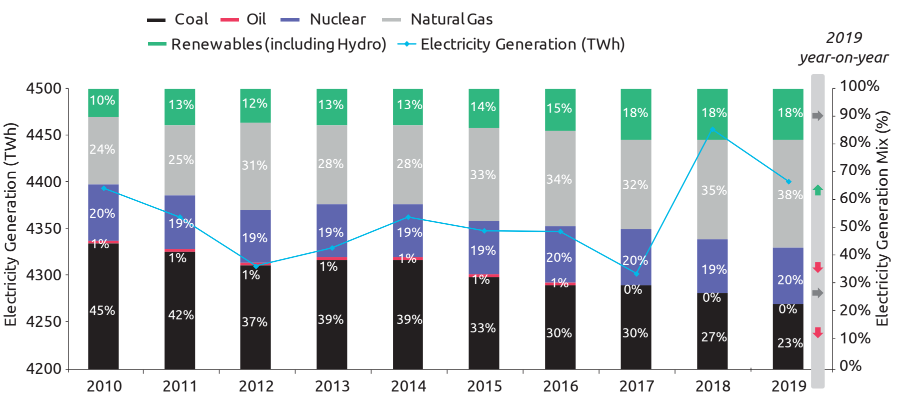
Unexpected increase in nuclear power generation in 2019

- Due to the modification of nuclear power plants, reactors are now able to provide total electricity generation capacity consistently. Even though present capacity generation equals the capacity of 2003, operating nuclear power reactors is less costly than in 2013.
- Illinois State was the highest net producer of nuclear power generation in 2019 at 11,582 MW.
- Nuclear power generation is expected to slow down in the next two years, but its share is predicted to increase to 22% in 2020.
- Two new reactors that are now under construction in Georgia—Vogtle Units 3 and 4—are expected to come online between 2021 and 2022.

Renewable energy generation capacity is expected to increase in 2020

- EIA has estimated that renewable generation in the electric power sector, which comprises a wind capacity of 20.4 GW and 12.7 GW in utility-scale solar capacity, will rise by 11% in 2020.

Figure 2.2. U.S. ~ Historical Electricity Generation Mix ~ Evolution, 2010-2019 (percent)



Note: For the year 2018, 2019 the percentage is not adding up to 100%. The numbers have been sourced as is from BNEF

Source: BNEF ~ Sustainable Energy in America Factbook, 2019 ; BP Statistical Review of World Energy, 2019

U.S. ~ Electricity Generation Mix Outlook ~ Coal & Nuclear will maintain a steady pace of retirement. Meanwhile, renewable energy's reduction in capital cost and the U.S.'s desire to be the leading world LNG exporter will be critical to the growth of these energy sources

According to EIA, the U.S. is planning to retire another 17 GW in coal-fired generation by 2025

- Utility players are either expecting to retire its coal plants or convert them into gas power generation plants.
- Coal's contribution to the energy mix has declined since 2010. As of 2018, plants contributing 13,000 MW of capacity were shut down. In 2019, plants contributing 10,600 MW of capacity were converted into gas-fired plants.
- By 2025, the percentage of plants that could be replaced with new wind or solar generation increased to 86% of the entire existing U.S. generation fleet. In 2018, 211 GW of coal capacity were at risk of being phased out due to high operation costs, as compared to wind or solar. This number is expected to increase to 246 GW in 2025.

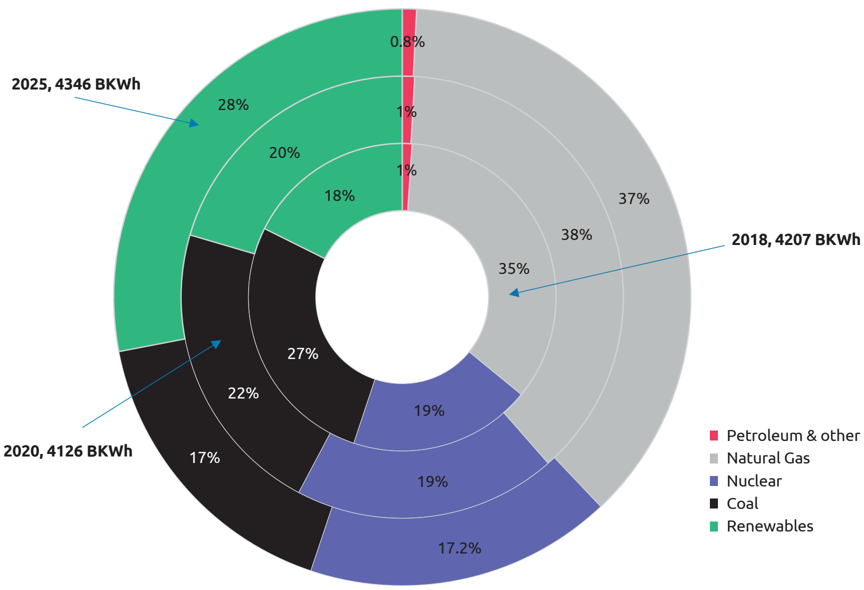
Nuclear plants are increasing their power generation capacity due to shorter refuelling maintenance cycles and reactor upgradation

- A total of 12 reactors—roughly 17% of the nuclear power reactors in the U.S—are expected to close by 2025, decreasing U.S. nuclear capacity by 10.5 GW.
- While Georgia Power's Vogtle 3 and 4 are expected to come online in 2021-22, retirement plans for the rest of the country are expected to remain unchanged for the next seven years.

By 2025, electricity generated from renewable energy sources is expected to surpass the electricity generated from nuclear energy

- Renewable energy generation is expected to surpass nuclear power generation in 2020. The U.S. is also expected to become a net energy exporter due to a substantial domestic production of oil, natural gas and LNG.
- Electricity generation from renewable sources is expected to increase and contribute more to the energy mix as capital costs continue to fall.

Figure 2.3. U.S. ~ Electricity Generation Mix Outlook, 2019-2025 (percent)



Source: U.S. EIA Annual Energy Outlook, 2020

U.S.~Electricity generation: Electricity generation share from coal and nuclear power plants will decrease after 2025

Solar and wind are going to claim majority of the market-share gains in the expanding U.S. power market through 2050. Meanwhile, the market share of natural gas, nuclear and coal is expected to show a corresponding decrease

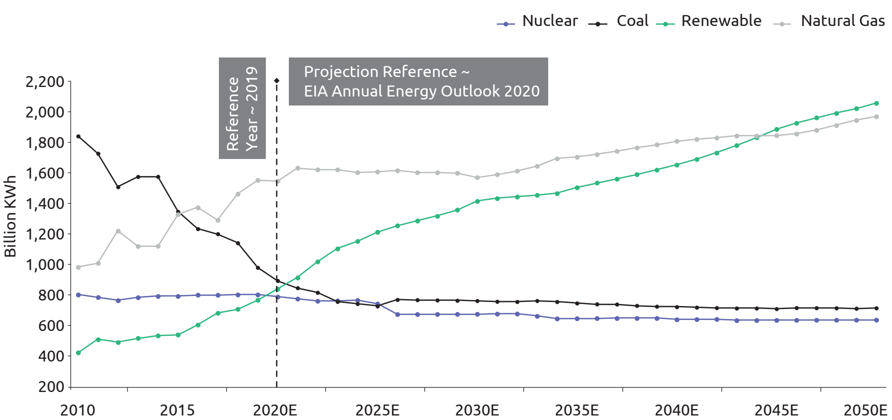
Coal and nuclear power plants will collectively provide more than 25% of generation through 2050.

- The share or electricity generation from coal is expected to decline from 24% in 2019 to 13% by 2050; nuclear power generation is forecasted to slip from 20 percent to 12 percent during the same period.
- Low natural gas prices, state-level clean energy initiatives, renewable energy growth and limited growth in electricity demand are the main factors supporting the decrease in nuclear and coal-fired power generation.
- According to EIA's survey of power plant operators and the companies' retirement announcements in Feb 2020:
  - 33 GW capacity of coal-fired power plants have announced their intention to retire.

Companies' projection of electricity generation:

- In January 2020, Arizona Public Service Co. announced that it will produce all of its electricity from carbon-free sources by 2050 and generate 45% of its power from renewable sources like solar and wind by the end of the decade.
- Duke energy plans to achieve net-zero carbon emissions by 2050 and double generation from renewable energy sources by 2025. However, the company will also continue running coal-fired plants for the next two decades while adding natural gas pipelines in parallel.

Figure 2.4. U.S. ~ Projected Mix of Electricity Generation (Select Fuel Type), 2010-2050E



Source: U.S. EIA Annual Energy Outlook, 2020

U.S. ~ Capacity Change Projections: Elimination of the U.S. production tax credit (PTC) extension at the end of 2020 is driving large wind capacity additions

According to EIA, new capacity additions of 42 GW are set to begin operations in 2020, bringing the share of solar and wind to 76%.11GW of coal-fired capacity are planned for retirement in 2020

Wind Capacity Additions:

- 18.5 GW of wind capacity will come online in 2020, exceeding the record of 13.2 GW in 2012.
- Five states constitute more than 50% of the 2020 planned wind capacity additions. Texas accounts for 32%, followed by Oklahoma at 6% and Wyoming, Colorado and Missouri at 5% each.
- According to the American Wind Energy Association (AWEA), 25 GW worth of wind projects have a chance of being delayed or abandoned due to the pandemic.
- In Sept. 2020, BP and Equinor partnered to develop offshore wind projects in the the U.S. Apollo Funds also made a structured investment in U.S. Wind Inc.
- According to research published by Wood Mackenzie in 2020, the U.S. offshore wind industry is set to surge from near zero to as much as 25 GW by 2029.
  - In New England and New York, 80% of wind capacity will be located offshore by 2026.

Solar Capacity Additions:

- 13.5 GW of solar capacity is expected to come online in 2020, exceeding the record of 8 GW set in 2016. Four states will account for more than 50% solar photovoltaic (PV) capacity additions with Texas leading the way at 22%, followed by California (15%), Florida (11%) and South Carolina (10%).
- Utility-scale and small-scale applications will grow through 2050 as solar PV costs decline in the future.

Nuclear Capacity Retirements:

- Major nuclear capacity retirement plans accounting for 1.6 GW of capacity were announced in 2020. This includes retiring Indian Point Unit 2 in New York and Iowa's only nuclear power plant, Duane Arnold Energy Center.

Coal Capacity Retirements:

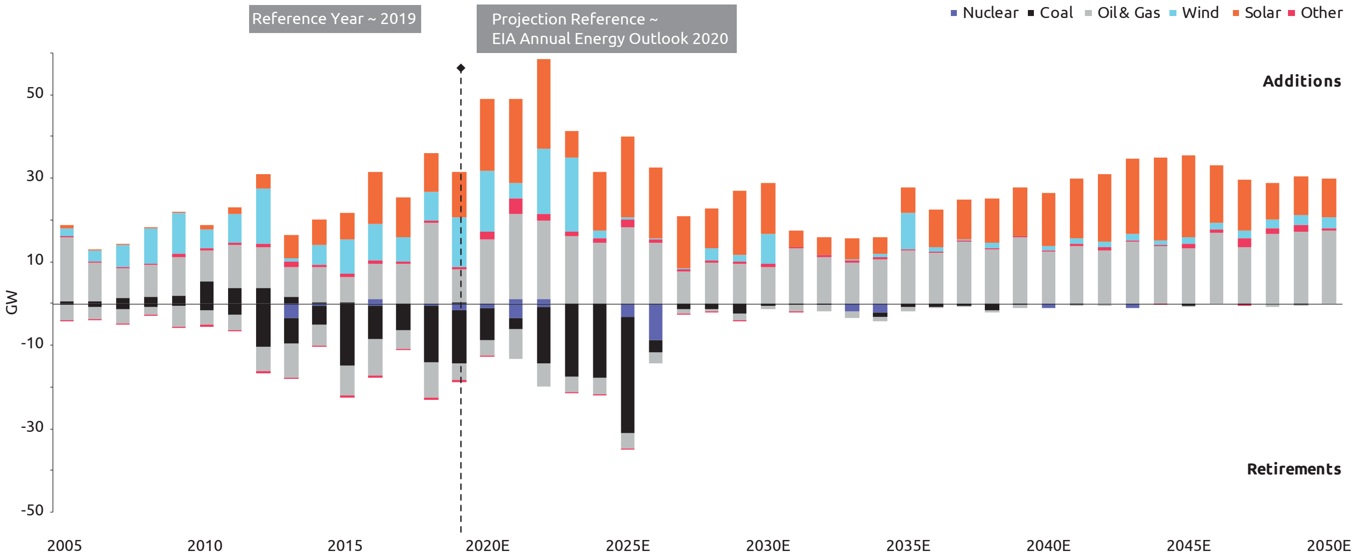
- In 2019, U.S. coal-fired electricity generation hit a 42-year low. Eight U.S. coal companies filed for bankruptcy, including Hartshorne Mining Group, and Foresight Energy.
- Moody's Investor Services anticipates that the U.S. coal industry will observe more closures and bankruptcies as domestic demand is expected to fall in the near term due to the pandemic.

Natural Gas Capacity Additions and Retirements:

- Natural gas capacity additions are expected to reach up to 9.3 GW in 2020. Combined cycle plants will account for 6.7 GW and combustion-turbine plants will account for 2.3 GW.
  - More than 70% of these additions are located in Pennsylvania, Texas, California and Louisiana.
- Steam turbine plant retirements account for 68% of all natural gas plant retirements.
- Alamitos, Huntington Beach and Redondo Beach AES plants in California, which account for a combined to 2.2 GW capacity, are set for retirement.
- The Inland Empire Energy Center, which has been operating below capacity for many years, is also up for retirement.

2019 was a banner year for natural gas electricity generation due to the retirement of coal plants and new additions in natural gas plants. Electricity generation also observed a 1% increase in 2019.

Figure 2.5. U.S. ~ Annual Electricity Generating Capacity Additions and Retirements, 2005-2050E (GW)



Source: U.S. EIA Annual Energy Outlook, 2020

U.S. ~ Capacity Change Projections: Renewable energy generation is expected to surpass coal-generated energy in 2020

As of 2019, the U.S. coal fleet is 20% smaller than it was a decade ago

- In 2019, coal-fired power plant retirements maintained roughly the same pace as the year prior.
- 12 GW of coal capacity was retired in 2019, down from 13 GW in 2018.
- According to numbers complied in Jan 2020, 65 TW hours of electricity was generated by coal, which is a 35% year-over-year decrease. This marks the first year in history where coal generation was below 100 MW.

Planned retirements are increasing each year

- In the beginning of 2020, two coal-fired generators in Montana discontinued their operations.
- Colorado based coal-fired generators committed to closing their New Mexico coal plant by the end of 2020.
- PacifiCorp announced closing one of their three Cholla coal-fired power plants in northern Arizona.

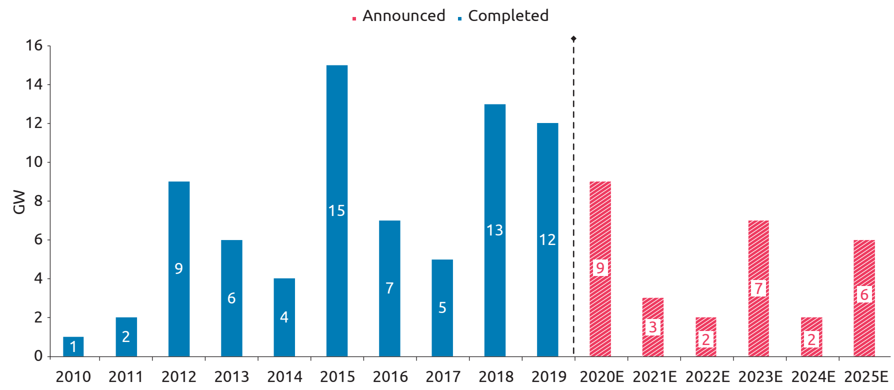
Penetration of alternative sources of energy in several states in the U.S. will lead to a reduction in coal

- Falling gas prices, followed by state-level support for nuclear plants and a slight dip in demand, have compressed coal's margins and future.

According to a report published by the Institute for Energy Economics and Financial Analysis, renewables generated more electricity than coal every day of April in response to COVID-19

- **According to the EIA: "Coal generation will mount 724.2 billion kWh in 2020, as compared to 761 billion kWh of renewables, a considerable difference from 2019 when the coal/renewables breakdown was 959.5 billion kWh to 688 billion kWh."**
- As low-cost natural gas generation increases each year, the profitability of coal-fired plants in deregulated markets is falling, pushing many towards retirement.

Figure 2.6. U.S. ~ Coal-fired Electric Generation Capacity/Retirements, 2010-2025E (GW)



Source: BNEF ~ Sustainable Energy in America Factbook, 2020

Coal is still dominant in the electricity generation mix. However retirement of existing coal-fired plants is expected to accelerate from 5% to 13% in 2020.

U.S. ~ Nuclear electricity generation: U.S. is in the midst of retiring old nuclear plants that carry high operational costs

EIA forecasted a 19% decline in nuclear electric generating capacity from 98 GW in 2019 to 79 GW in 2050. Also, no further plant additions are expected to come online after 2022

- Smaller/Single reactor nuclear plants which possess inflated operating costs are the most affected. The situation is further aggravated by deregulated wholesale power markets and states with no zero-emission credit policy.

Declining prices of electric power in wholesale markets have exponentially increased economic pressures on many nuclear plants in the U.S., leading to their closure.

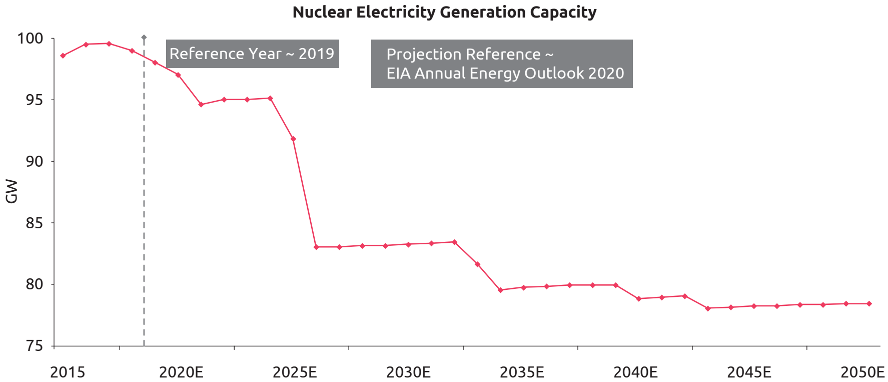
- Entergy aims to withdraw itself from operating reactors in the merchant power market by 2023. The company will terminate Indian Point 2 & 3 in New York, and Palisades in Michigan over the next three years.
- Exelon has also retired its Three Mile Island 1 BWR in Pennsylvania, which generated 873 MW capacity in September 2019.
- NextEra Energy will cease its Dune Arnold operation by 2020 and PG&E intends to shutter its two reactors at Diablo Canyon in California by August 2025.

New nuclear plant build in North America:

- Some small modular reactor (SMR) demonstration units are planned through 2030. NuScale Power's reactor is the world's first SMR to undertake design certification review by the U.S. Nuclear Regulatory Commission.

Nuclear generation capacity functioning through old practices are getting retired due to higher operating cost, but the design of new smaller prototypes are under innovation. These factors are expected to contribute to a surge in nuclear generation capacity.

Figure 2.7. U.S. ~ Nuclear Electricity Generation Capacity Outlook, 2015-2050E (GW)



Source: U.S. EIA Annual Energy Outlook, 2020

North America has a strong focus on nuclear power

According to the 2019 Nuclear Energy Leadership Act (NELA), DOE will direct the development of two next generation nuclear designs and authorities' demonstration by 2025, as well as up to five additional designs by 2035.

U.S. ~ Renewable Capacity Build: U.S. installed ~20.2 GW of renewable capacity in 2019, up 2.3 GW from 2018—the second-highest year on record.

An upswing in wind electricity generation

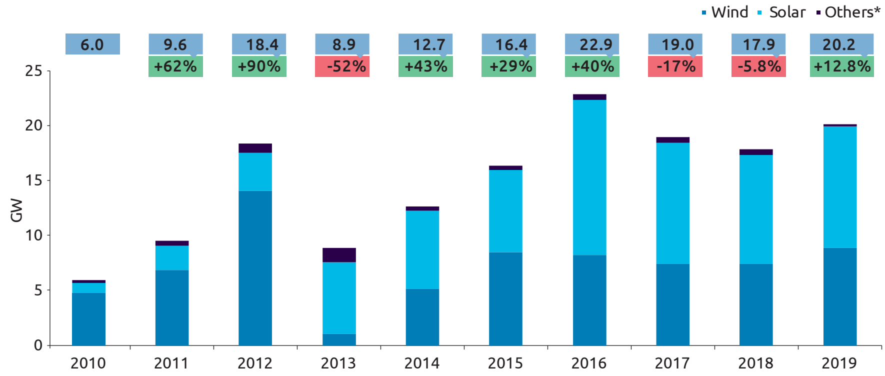
Wind installation received a boost in 2019 as developers geared up to take advantage of the federal Production Tax Credit (PTC) before it expires.

- The new installations are planned in the northeast region of the U.S.
- 9 GW of onshore wind capacity was added in 2019, reaching a new total of 105 GW. This is the third largest installation by volume, following the record of 13 GW in 2012 and 10 GW in 2009.
- According to AEWA, Texas leads with a cumulative capacity of 27 GW. This supply of power supports 32 million homes and 500 factories.

Solar electricity generation

- The U.S. has witnessed record-setting residential solar capacity addition in 2019 with more than 2.8 GW installed capacity. In addition, the contracted utility PV pipeline grew to a record high of 48.1 GW in 2019. The total installed PV capacity is expected to double in the next five years.
- The total installed PV capacity is expected to double in the next five years. By 2021, annual installation of 20.4 GW is expected as the federal solar Investment Tax Credit for residential systems expires
- Texas and Florida emerged as major PV states. Notable growth also occurred in Arizona, Georgia and North Carolina.
- According to the annual report released by Solar Energy Industries Association and Wood Mackenzie, solar markets in Pennsylvania and Colorado are expected to boom. Meanwhile, policy changes in New York, Maryland and Maine will also spur adoption.
- In 2020, solar installations have been impacted severely due to supply chain disruptions and imports from China. Reduction in ITC credit has also been a contributing factor affecting the market.

Figure 2.8. U.S. ~ Renewable Energy Capacity Build by Technology, 2010-2019 (GW))



Note: Others* ~ Hydro, Geothermal, Biomass, Biogas, Waste-to-Energy; All values are shown in AC except Solar, which is included as DC capacity; Numbers include Utility-scale (>1MW) projects of all types, Rooftop Solar, and Small and Medium-sized Wind

Source: BNEF ~ Sustainable Energy in America Factbook, 2020

U.S. ~ Renewable capacity spend: Strong financing of wind projects is generating a strong pipeline for 2020-21

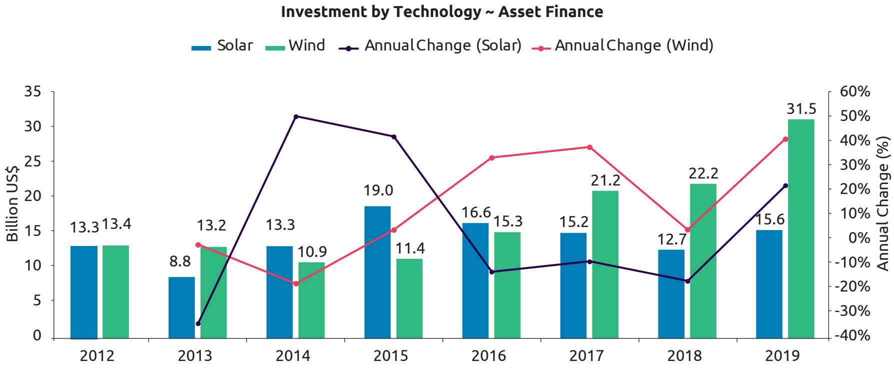
U.S. clean energy asset investment totaled US$390 billion between 2010-2019. This was due to cheaper technology costs and an increase in financial support

Asset finance for solar projects increased to US$15.6 billion in 2019.

- The increase in financing indicates a recovery in capacity additions in 2020, as assets are typically financed a year before commissioning.
- In 2019, private equity and venture capital investment in solar energy were at their lowest rate in the past decade.
- In 2018, investments in wind projects totaled US$22.2 billion; US$31.5 billion projects were financed in 2019. This indicates that the U.S. has a very strong 2020 and 2021 new-build pipeline of wind energy.
- Growth in the number of wind projects receiving financing in 2019 can be attributed to the impending expiration of the production tax credit (PTC). These projects are expected to come online by the end of 2020.
- Projects that started construction after 2016 will receive a phase-down credit. Projects that will start after 2020 (and come online after 2024) will receive no federal support.

Assets finance for solar and wind projects was favourable in 2019. However, due to high uncertainty of tax credit and approval of GREEN Act, many projects which are further delayed by pandemic also. According to the American Wind Energy Association (AWEA), wind projects worth 25 GW are at risk of being delayed, scaled back, or scrapped altogether due to the COVID-19 economic slowdown.

Figure 2.9. U.S. ~ Asset Finance for Large-scale Solar and Wind Projects, 2012-2019 (US$ billion)



Note: Solar ~ Solar Thermal, Utility-scale PV; Wind ~ Large-scale Wind

Source: BNEF ~ Sustainable Energy in America Factbook, 2020

In 2019, solar accounted for 40% of all new electricity generation capacity added in the U.S. Total installed U.S. PV capacity is expected to more than double in 2021, with annual installations reaching 20.4 GW. However, supply chain disruptions and the economic slowdown associated with COVID-19 may disrupt or delay installations.

Canada ~ Coal phase out: Projected future coal retirements present an opportunity for wind and natural gas generation

According to research from Wood Mackenzie, Canada is set to retire 5 GW of coal-fired capacity by 2028, mainly in Alberta and Saskatchewan

Province governments have budgeted millions of dollars for transition.

- Ottawa has budgeted US$185 million for the transition, which includes US$35 million for skills and training and US$150 million for infrastructure and economic development.
- In March 2020, the Saskatchewan government pledged US$10 million to help coal workers transition to new jobs over the next few years.

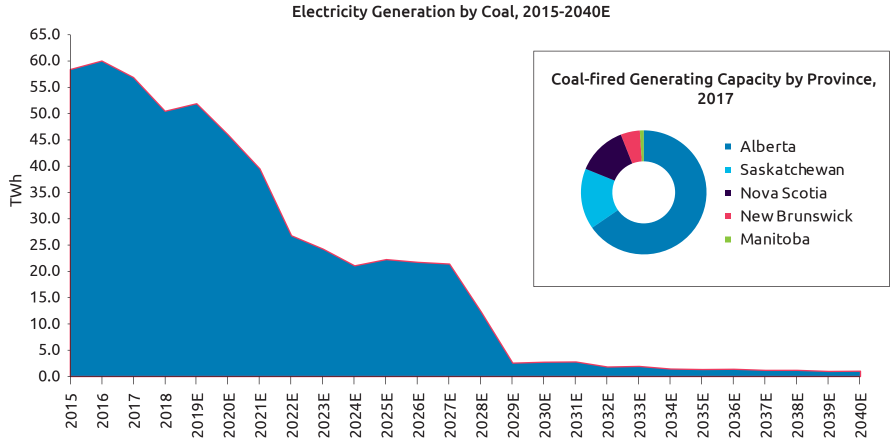
Canadian production of coal remained steady at 62.3 million tonnes in 2018.

- In 2018, Canada exported 34 million tonnes of coal globally and imported 7.6 million tonnes, predominately from the U.S., 97% of which accounts for metallurgical coal.

Switching to other electricity generation sources.

- Chinook Power Station is the latest natural gas fired power plant. It came online in November 2019 and provides 353 MW of baseload power.
- According to reports from the Canada Energy Regulator, Saskatchewan's power mix will showcase wind generation as a significant contributor by 2040.
- In December 2019, the development and deployment of small modular reactors (SMRs) was initiated by the Provinces of Ontario, Saskatchewan and New Brunswick.

Figure 2.10. Canada ~ Coal Phase-out Overview



Source: NEB Canada, October 2019; Government of Canada

In Canada, province governments have budgeted millions of dollars to phase out the use of coal. As part of this process, many power plants have switched to natural gas.

U.S. ~ Dry natural gas production: Tight oil and shale gas production is increasing annually, but frackers & U.S. shale operators are at the verge of bankruptcy

The U.S. broke its 14-year record for oil production in 2019 with shale gas as a major contributor

- According to the EIA, U.S. natural gas production rose 9.8 billion cubic feet (Bcf/d) in 2019, a 10% increase from 2018.
- According to IEA, the U.S. will supply 85% of the new oil and 30% of new gas through 2030.
- According to the OPEC market outlook, it is predicted that by 2025 shale production will rise by 40% from its current level to 17 million bpd, an upward revision of 3.1 million bpd.

In 2019, the U.S. established itself as a net exporter of natural gas

- The U.S. became a net exporter of natural gas in 2019 with net natural gas exports averaging 5.2 billion cubic feet per day (Bcf/d).
- According to EIA, exports for crude and petroleum products will outpace imports as of Q4, 2020. This trend is expected to continue through 2027, after which it is expected to plateau.

Impact of COVID-19 on shale gas production

- According to several analyst firms, the boom in shale gas growth is slowing down, with little or no growth in 2021. The market may shrink due to the economic slowdown associated with the pandemic.
- Gas and utilities market analysts have also predicted that U.S. shale gas production may decline by 1.45 billion cubic feet per day until November 2020.
- Analyst reports indicate that 30% of U.S. shale operators may report insolvency at US$35-a-barrel oil prices. It may take several years for them to recover from the COVID-19 slump.
  - Additional capital budget reductions have also been reported by various U.S. shale gas operators.

The Appalachian region leads the U.S. in natural gas production

- According to the Annual Energy Outlook (AEO2019), total U.S. natural gas production was driven by the continued development of the Marcellus and Utica Shale Gas plants in 2019.
  - Eagle Ford (coproduced with oil) and Haynesville in the Gulf Coast region were the largest contributors to domestic dry natural gas production in 2019.
- According to EIA, tight oil in the Permian Basin in the Southwest region will soar until 2022 before gradually declining through 2050.
- According to EIA estimates issued in March 2020:
  - The Appalachian region is the largest natural gas producing region. The region is home to the Marcellus and Utica/Point Pleasant plants, as well as other facilities in Ohio, West Virginia and Pennsylvania.
  - Development in the Permian Basin and Haynesville shale formations has contributed to Texas' natural gas production.

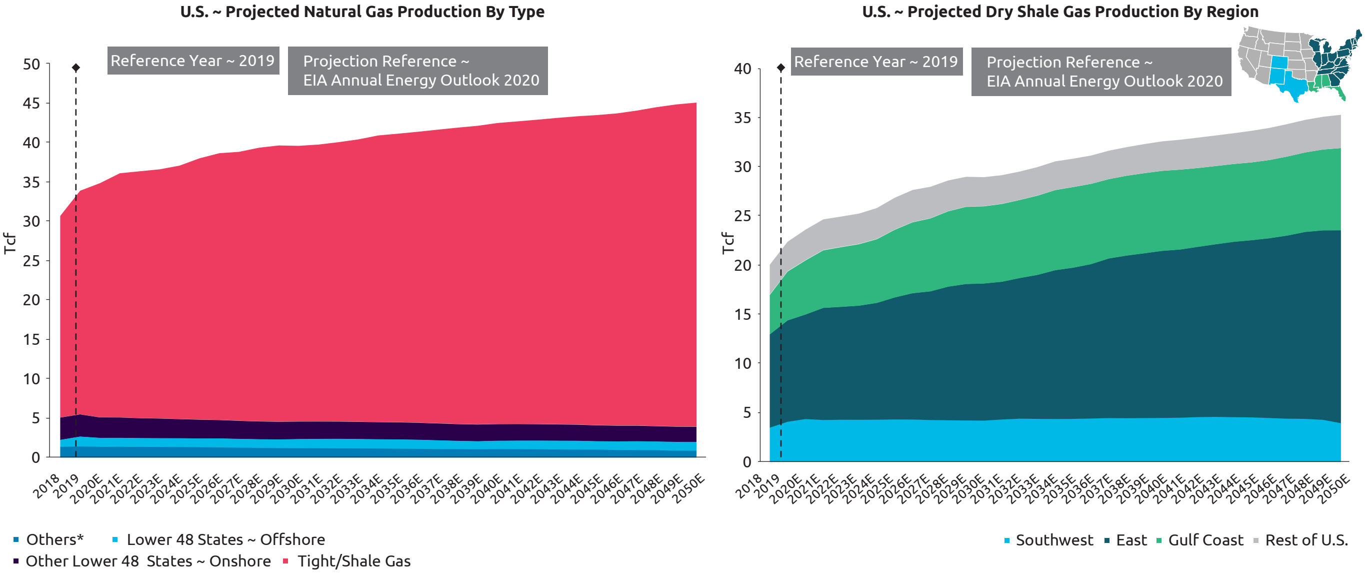
In November 2019, the Federal Energy Regulatory Commission (FERC) authorized the siting, construction, and operation of four liquified natural gas projects to export natural gas. All four LNG project sponsors have applications pending before the U.S. Department of Energy seeking authorization to export gas to countries without Free Trade Agreements with the United States.

- In Feb 2020, FERC approved Texas LNG Brownsville's proposal for a 4 million metric ton/year terminal on the Brownsville Ship Channel in Cameron County, TX.
  - FERC also approved an export terminal—the Rio Grande LNG and the Rio Bravo Pipeline's proposal which is to be built on a 1,000-acre industrial site in Cameron County at the Port of Brownsville.

Chapter 11 Bankruptcy

- Fracking pioneer Chesapeake Energy Corporation has filed bankruptcy protection during COVID-19 and has also skipped the interest payments of US$13.5 million.
- Since 2010, frackers have invested US$300 billion and brought millions of barrels of oil into the market. However, only a third of frackers can break-even at US$35 per barrel.

Figure 2.11. U.S. ~ Projected Natural Gas Production by Type, 2018-2050E (trillion cubic feet); Projected Dry Shale Gas Production by Region, 2018-2050E (trillion cubic feet)



Note: Others* includes Alaska and Coalbed Methane

Source: U.S. EIA Annual Energy Outlook, 2020

According to EIA, the U.S. will supply 85% of the new oil and 30% of the new gas through 2030. In 2019, the U.S. continued to be a net exporter of natural gas production which is taken by 2020 with Federal Energy Regulatory Commission (FERC) authorizing the siting, construction, and operation of the export projects to export gas to countries without free trade agreements

Topic Box 2.1: Hedge Agreements vs. PPAs (including Proxy Revenue Swap (PRS) & pgPPA)

Hedge agreement, PRS and pgPPA are new agreement mechanisms for renewable energy projects.

Hedge agreements have emerged as an alternative offtake structure for renewable energy project developers to obtain financing. It is a contractual device used to lock in predictable per unit prices against commodity price fluctuations. The predictable revenue stream provides assurance of meeting expectations and covers the company's debt obligations. It also gives financial return targets to project lenders.

Power purchase agreements (PPAs) are documents that act as tools for negotiation and review. Agreements are governed by an International Swaps and Derivatives Association (ISDA) or Edison Electric Institute (EEI).

Proxy Revenue Swap (PRS):

- An agreement outlining financial derivatives to yield stable revenues for the project irrespective of power price fluctuations and weather-driven dependencies, hedging the project from risk associated with price and volume.

- **Recent implementation in the U.S. wind market:**
  - In Dec. 2019, Enel Green Power North America initiated operations at its 450MW High Lonesome wind farm in Texas. The US$720 million project is forecast to generate about 1.9 TWh of electricity per year. A 12-year power purchase agreement (PPA) has been signed with Danone North America for 20.6 MW power. This means that projects located in Upton and Crockett Counties will undergo a new 50 MW expansion.
  - The PRS for High Lonesome plant was completed in collaboration with REsurety, Inc. Under the PRS agreement, fixed payments will be received by the plant on the expected value of future energy production.

pgPPA (Proxy Generation Power Purchase Agreement):

- PgPPA are specific suite of risk management tools that allow both buyers and sellers of renewable energy to manage risks associated with weather-driven renewable energy.
- While a PRS guarantees a revenue amount, the pgPPA guarantees a rate per MWh. The pgPPA facilitates cash flow to support financing but does not pay the transfer of risk associated with this project.
- pgPPAs are favored by corporate buyers. Unlike other contracts, pgPPAs settle on a Proxy Generation index rather than the observed or metered generation.

- **Recent Implementation in the U.S. Wind Market:**
  - In Oct. 2019, Nephila Climate, the weather, climate, and ESG-driven specialty division of Nephila Holdings Ltd., has announced plans to use a PgPPA model for the 180MW Heart of Texas (HTX) wind farm situated in McCulloch County, which is being developed by Scout Clean Energy of Boulder, Colorado.
  - Allianz Global & Specialty, Inc.'s Alternative Risk Transfer unit collaborated to create the pgPPA model with Scout, in partnership with Nephila Climate.

Topic Box 2.2: Green Hydrogen

Green Hydrogen has emerged as a new alternative enabling reduction in carbon emissions

Green Hydrogen:

- A product of the renewable energy-powered electrolyser that splits water (H_2O) to make hydrogen (H_2) gas is known as Green Hydrogen. The process makes renewable hydrogen (RH_2) gas more expensive than the source (wind or solar) that is used to create it. However, it generates zero-emissions electricity in turbines or fuel cells, which is later stored in higher densities and lighter weights than batteries and is usable in high-heat industrial processes.

A push by the U.S. Administration:

- The U.S. Department of Energy (DOE) has declared up to US$64 million in funding to encourage the expansion of the country's green Hydrogen (H_2) market.
- Ten million metric tons of Hydrogen is currently being produced in the U.S., 95% of which is via centralized reforming of natural gas. The DOE's Fuel Cell Technology Office has allotted the main part of its funding to the H_2@ Scale concept.
  - The U.S. Department of Energy is determined to energize more activity in the area of distributed wind power to boost the green hydrogen market.
- In June 2020, the Energy Department launched two new lab consortia to support new Hydrogen and fuel cell research.

Latest developments propelling the green Hydrogen market:

- In May 2020, SGH2, a global energy company, announced plans to build a green hydrogen production facility in Lancaster, LA. This plant will feature SHH2's advanced technologies to leverage recycled mixed paper waste for green gas production. The City of Lancaster will supply feedstock of recyclables. It is expected to create savings in the range of US$50-75 per ton in landfilling and landfill space costs.
- In May 2020, Plug Power Inc. announced that it will pursue transactions to acquire United Hydrogen Group Inc. and an electrolyzer technology platform company. These planned acquisitions are in line with the company's strategy to have more than 50% of Hydrogen be green by 2024.
- FirstEnergy Solutions has planned to deploy a two-year project of 1 to 3 MWe low-temperature electrolysis unit to generate commercial quantities of hydrogen. The first site, planned for 2020, is FirstEnergy Solution's Davis-Besse Nuclear Power Station near Toledo, Ohio.

Topic Box 2.3: Benefits of Growing Renewable Energy and Efficiency Now (GREEN) Act

On June 22, 2020, Democratic lawmakers in the U.S. House of Representatives introduced US$1.5 trillion infrastructure package, the Moving Forward Act which includes the Growing Renewable Energy and Efficiency Now Act ("the GREEN Act"). Currently, it awaits Senate's decision.

The GREEN Act proposes to extend several tax credits for clean energy deployment and expand several others.

- **Solar and wind incentives:** Under this legislation, the 30% investment tax credit (ITC) for solar energy projects, which had been reduced to 26% for projects that started operating in 2020, would be extended for 5 additional years until 2025. For wind facilities, the production tax credit (PTC) would also be extended for facilities that begin construction before 2026.
- Under the GREEN Act, the 30% residential energy efficient property credit would also be extended through 2025. The credit would be reduced to 26% for equipment placed in service in 2026 and further reduced to 22 percent for equipment placed in service in 2027.
- To claim the carbon capture, utilization and sequestration (CCUS) credit under section 45Q, construction of a facility must begin by the end of 2023. Under the GREEN Act, the deadline has been stretched until the end of 2025.
- **Credits for other technologies:**
  - The GREEN Act will push the geothermal ITC from 10% to 30% and extend ITC deadlines for fibre-optic solar fuel cell, micro turbine, combined heat, and power system, and small wind projects by 6 years through 2026.
  - Certain waste energy recovery, biogas and linear generator projects will be covered under the 30% ITC bracket and extended until 2025.
  - The PTC extension has been called for biomass, landfill gas, trash facilities, hydropower, and marine and hydrokinetic facilities that begin construction before 2026.
- **Publicly Traded Partnerships:** To keep their MLP status, publicly traded partnerships (commonly called master limited partnerships [MLPs]) must earn income derived from green and renewable energy. Under the proposed legislation, qualifying income will be derived from energy property eligible for the PTC and ITC, renewable fuels, gasification and CCUS projects.

Other aspects of the GREEN Act:

- The GREEN Act can lower U.S. net GHG emissions by up to 100 million tons in 2030 as compared to a scenario with no extension of tax credits.
- Deployment of up to nearly 60 GW of new non-hydro renewable generation by 2030 can be catalyzed, compared to a scenario with no extended tax credits. Market share of these resources will double to 19-26% of total generation, up from 10% in 2019.
- If EV tax credits are extended, it would increase sales by 3.4-5.7 million vehicles. In this scenario, 38% of all light-duty vehicle sales in 2030 would be EVs—a significant jump from 3% in 2018.

Topic Box 2.4: The Duck Curve in 2020 - Impact of COVID-19

Changes in energy-use patterns due to the pandemic will affect grid operations, power purchasing practices and long-term plans. Pecan Street has been a great contributor in supervising electricity use and generation from hundreds of homes to understand consumption patterns between March and May 2020

- During the lockdown period, peak usage comes at 4 p.m. when the average home's energy consumption increases by 425 kWh as compared to 2019 averages. At the time of publication, most "duck curves" have flattened.
- The steep rise in home energy demand occurred between March 10 and 21, which matches with several events related to the country's COVID response.
- According to Sense home data, after March 14, a 35% increase in mid-day demand has driven daily energy consumption up by 22.4% in U.S., though these results vary by state.

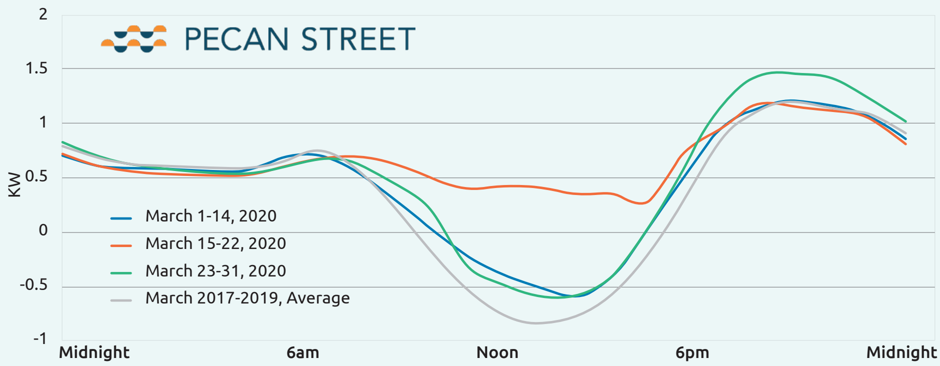
Pecan Street analysis of March 2020:

- Pecan Street measured and analyzed the use of rooftop solar and electric vehicles in Austin, Texas.
- In Austin, March is usually a time of high rooftop solar production and relatively low energy use, but this year has been an anomaly.
- The analysis showed a reduction in "sell back" energy exports due to extensive use of energy in homes during daytime hours.

According to CAISO report of March 2020:

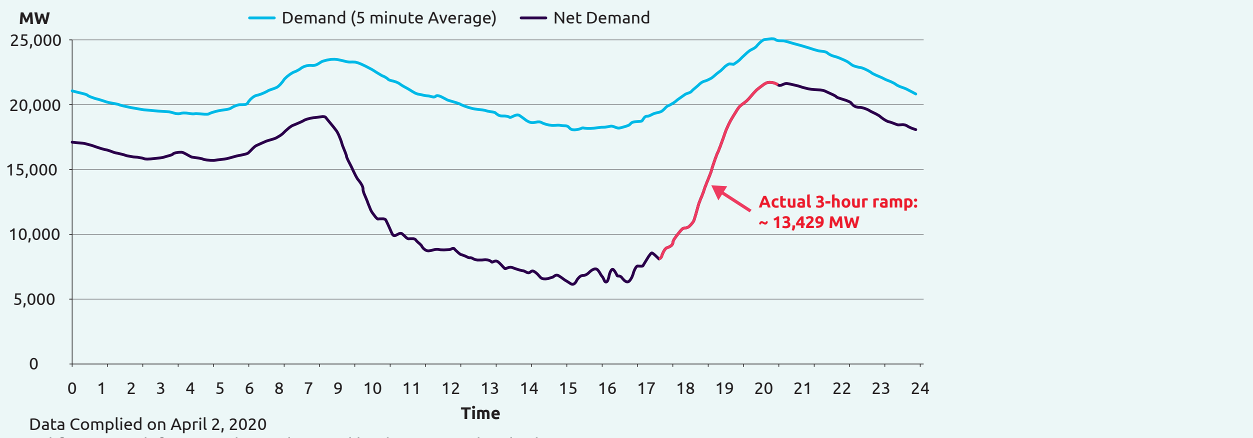
- On March 27 2020, the net load on the CAISO system hit a low of 5,949 MW, the third-lowest mark in history. In the evening on the same day, net demand shot up to nearly 25,000 MW.
- Rooftop solar arrays intensified the effect by offsetting the need for grid power with onsite production. As net demand soars with the setting sun, California's natural gas generation and hydroelectric dams quickly bank before leveling off during evening hours.
- The broaden duck curve showcased the rising need for flexible resources to manage sprouting midday solar-fueled oversupplies and a increasing need for a dispatchable generation, which is largely supplied by natural gas.

A New Duck Curve - March 2020



Source: California ISO

CAISO's 'duck curve' shows the need for a steep ramp-up in generation as solar fades based on actual net demand March 27, 2020



Data Complied on April 2, 2020
California ISO defines net demand as total load minus wind and solar generation

Source: California ISO

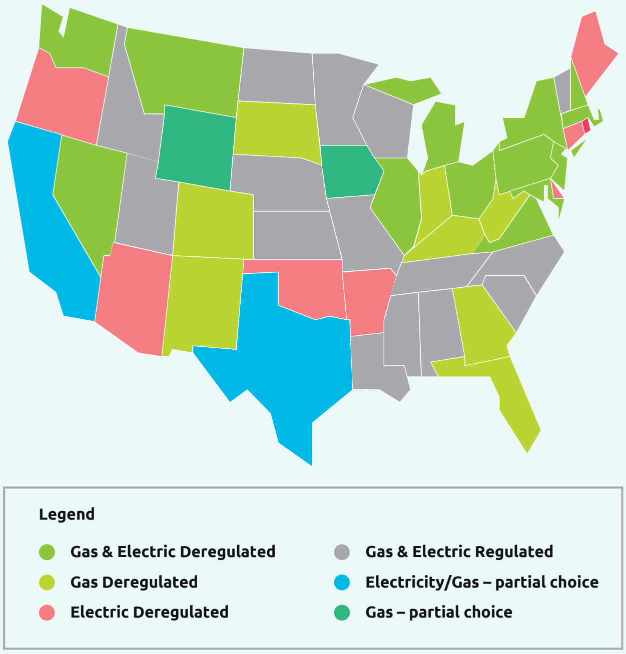
Topic Box 2.5: U.S. ~ State regulations

In the U.S., energy regulation by state can be segregated into six categories – Natural Gas & Electricity Deregulated, Gas Deregulated, Electricity Deregulated, Gas & Electricity Regulated, Electricity/Gas – partial choice and Gas – partial choice.

- **Gas & Electricity Deregulated:** End-user customers in these states are free to choose electricity providers. Players don't indulge in rate caps or other forms of regulatory protections. Investor-owned utilities (IOUs) sell their electric generating facilitates as a part of the implementation of retail choice.
- **Regulation of Gas & Electric:** States are controlled by the Federal Energy Regulatory Commission (FERC) which regulates the interstate transmission of natural gas, oil & electricity. Private utility companies conduct business through the PPA model with a government agency.
- **Electricity or Gas – Partial Choice:** Partial deregulation allows end-user consumers to participate within limits. The amount purchased is restricted by fully regulated markets.

States with Gas & Electricity Regulation

- **States with such regulations include:** Connecticut, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island and Virginia, as well as Washington, D.C.



  – In **New York**, the NY Public Service Commission (PSC) supervises local utilities and approves utility rates for both energy supply and delivery. The PSC also licenses New York alternative electricity suppliers, known as Energy Service Companies, or ESCOs.

  – **Illinois** has a Commerce Commission. Approximately 75% of the state of Illinois is eligible for natural gas choice.

  – **Connecticut and New Hampshire** do not offer natural gas choice to residential customers at this time.

  – In **Virginia state**, both natural gas and electric choice programs are limited for residential consumers.

  – **In Utah**, gas choice is partial and very limited.

  – In **Maine**, gas choice is only available to industrial and commercial customers.

  – In **Maryland**, some residential, commercial and industrial customers in some areas of the state are not eligible for natural gas choice.

- **States with regulated electricity and gas are:** Alabama, Alaska, Arizona, Arkansas, Hawaii, Idaho, Kansas, Louisiana, Minnesota, Mississippi, Missouri, Nevada, North Carolina, North Dakota, Oklahoma, South Carolina, Tennessee, Utah, Vermont, Washington and Wisconsin.
- **States with only deregulated gas are:** Florida, Georgia, Indiana, Kentucky, Montana, Nebraska, New Mexico, South Dakota, West Virginia, Wyoming, Iowa and Colorado.
- **States with only electricity deregulated:** Oregon has deregulated electricity.

  – **Nevada and Arizona** are both campaigning to adopt energy deregulation.

  – **In New Mexico and West Virginia**, natural gas choice is available though participation is very limited.

  – **Wyoming** offers a very limited program with only one utility offering a choice program.

  – In **Indiana**, natural gas choice is only available for NIPSCO customers.

Electricity or gas — partial choice:

- **Texas and California** have partial choice programs.
  – **Texas** is the only deregulated state where a majority of households are registered in a customer choice program. Approximately 85% of the state has access to energy choice.
  – **California's** electric choice works on a very limited lottery system called DirectAccess.
    – In Jan 2020, the California Public Commission launched a new program to regulate natural gas away from state's transition. This created stranded assets and unfair cost shifts among ratepayers.

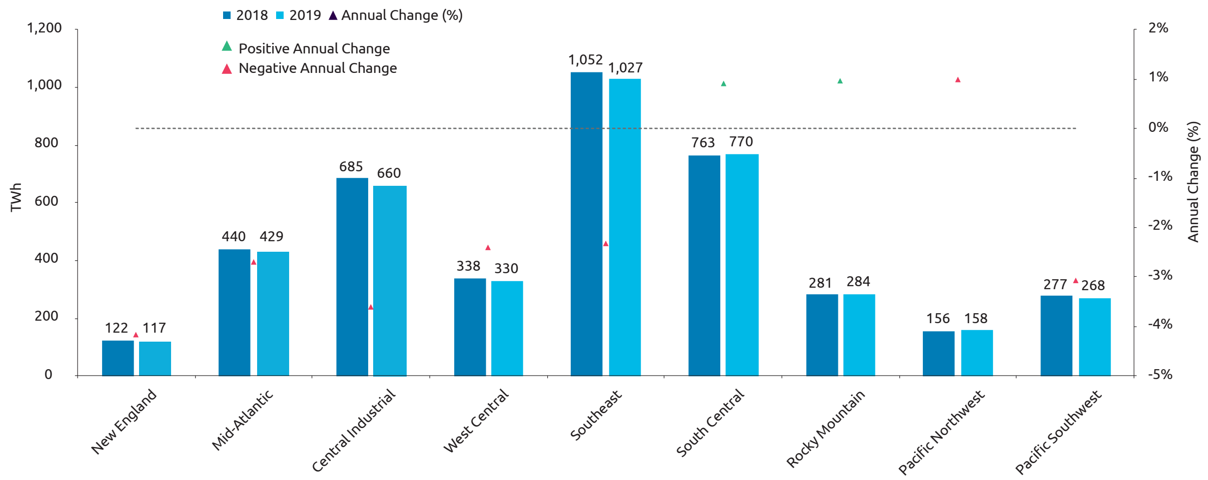
3-Supply & Final Customer

U.S. ~ Electric Output by Region: The Southeast recorded the highest electric output in 2019

Total electric output for the U.S. was 4042 TWh in 2019, as compared to 4113 TWh in 2018

- Annual electric output decreased by 1.7% in 2019 and has risen in only six of the last 12 years. Previously, a year-to-year output decline was a rare event in an industry that typically experienced low-single-digit percent demand growth.
- Energy efficiency initiatives, demand-side management programs, and the off-shoring of U.S.-based manufacturing and heavy industry continue to constrain growth in electricity demand.

Figure 3.1. U.S. ~ Electric Output By Region, 2018-2019 (terawatt hours)



Note: Represents all power placed on grid for distribution to end customers; does not include Alaska or Hawaii

Source: Edison Electric Institute ~ Annual Report of the U.S. Investor-Owned Electric Utility Industry, 2019

Energy efficiency initiatives, demand-side management programs, and the off-shoring of U.S. based manufacturing and heavy industry have obstructed the rise in electric output. As a result, 2019 saw a decline in electric output by 1.7%.

U.S. ~ Electricity sales: In 2019, electricity retail sales declined with transportation being the only sector to experience an increase

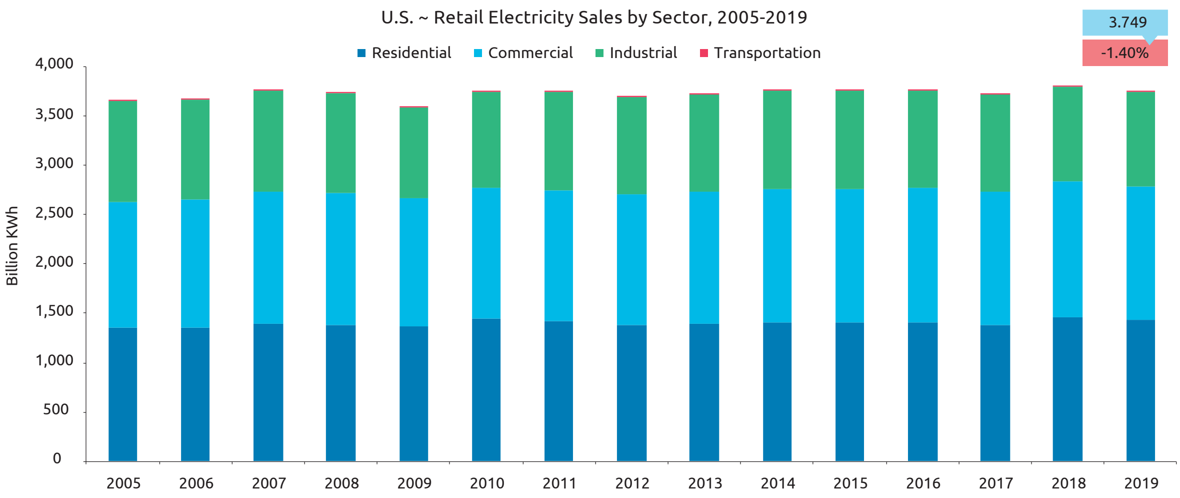
U.S. retail electricity sales added up to about 3,750 billion kWh in 2019, a decrease of about 111 billion kWh from 2018

- Although the economy has grown, electricity demand has slowed down as new, efficient devices and production processes requiring less electricity have replaced older, less-efficient ones.
- The residential sector constituted 38% of electricity sales (1,435 billion kWh), followed by the commercial sector (36%), industrial sector (25%) and transportation sector (0.2%).
- Electric sales from the transportation sector constitute a very small percentage of economy-wide demand because electric vehicles (EVs) have not reached ubiquity.
- The EV market is largely dependent on regulatory policies. Both vehicle sales and utilization need to increase considerably for EVs to raise electricity sales growth rates.

Impact of COVID-19 on future electricity sales:

- The COVID-19 pandemic is expected to impact U.S. electricity consumption.
- In May 2020, EIA has predicted that retail sales of electricity in the commercial sector could fall by 6.5% in 2020 due to the closure of many businesses and people working from home.
- Retail sales of electricity in the industrial sector are also expected to fall by 6.5% in 2020 as many factories cut back production.
- Additionally, U.S. retail sales of electricity in the residential sector are expected to be down 1.3% due to decreased electricity demand caused by milder winter and summer weather, which is balanced slightly by increased household electricity use as the majority of the population spends more time at home.

Figure 3.2. U.S. ~ Retail Electricity Sales By Sector, 2005-2019 (billion KWh)



Source: U.S. EIA, May 2020

Lower electricity retail sales in 2020 due to COVID-19

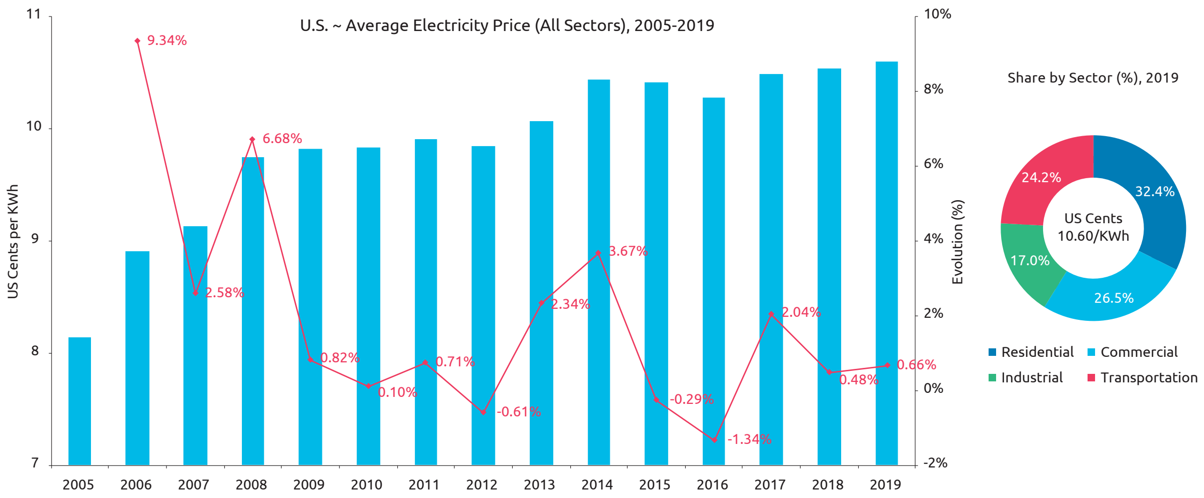
The pandemic has severely impacted retail sales during the first half of 2020, with sales down by 6.5% in the Industrial and commercial sectors, followed by 1.3% in the residential sector. In 2019, the annual average price of electricity in the US was about 10.60¢ per KWh. In the previous decade, retail residential electricity prices nationwide increased by 13%, outpacing many other sectors. Retail electricity prices have not been impacted as utilities are leveraging bill mitigation and deferrals as part of COVID-19 recovery measures.

U.S. ~ Electricity prices: Residential electricity prices increased more than other sectors between 2010 and 2019

In 2019, residential consumers had the highest electricity price increase as compared to other sectors

- In 2019, the annual average price of electricity in the U.S. was about 10.60¢ per KWh. The annual average prices by major types of utility customers were:
  - Residential – 13.04 US¢ per KWh.
  - Commercial – 10.66 US¢ per KWh.
  - Industrial – 6.83 US¢ per KWh.
  - Transportation – 9.73 US¢ per KWh.
- Most residential customers believe they are reasonably well served by the current situation.
- However, for larger commercial and industrial customers who purchase electricity from independent suppliers, costs may increase in the future as a result of increased demand to supply power from renewable sources.
- **From 2010 through 2019, retail residential electricity prices nationwide increased by 13%, notably more than the 4.6% and 0.89% increases for commercial and industrial customers, respectively.**

Figure 3.3. U.S. ~ Average Electricity Price, 2005-2019 (2019 cents per KWh)



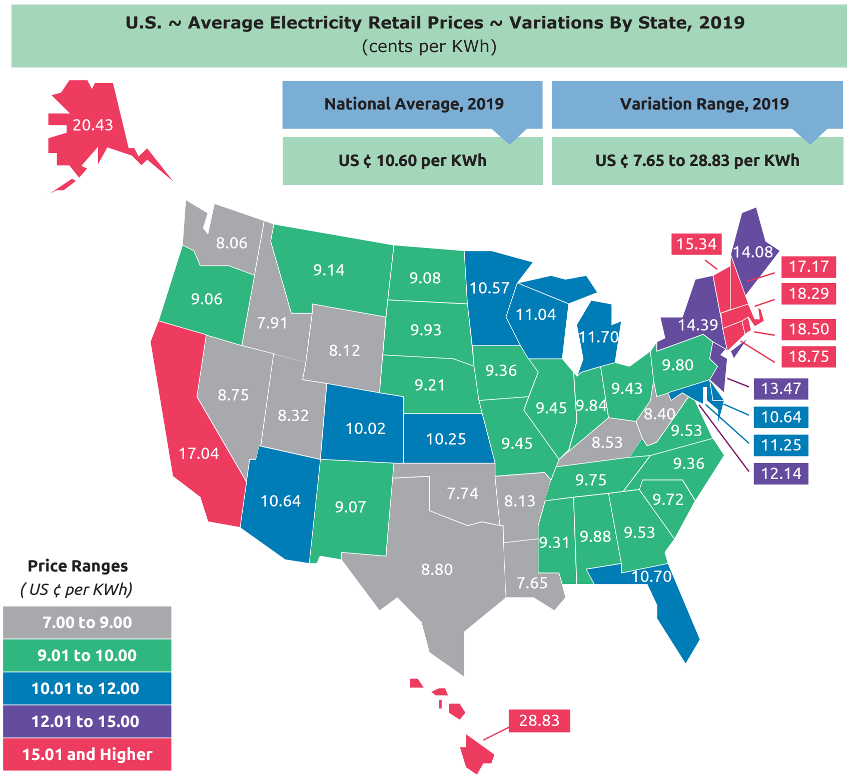
Source: U.S. EIA (May 2020)

U.S. ~Electricity Retail prices : In 2019, annual average electricity retail prices ranged from approximately 28.83 US¢ per KWh in Hawaii to approximately 7.65 US¢ per KWh in Louisiana

Electricity prices in the U.S. rose from 10.58 US ¢ per KWh in 2018 to 10.6 US ¢ per KWh in 2019

- Hawaii is the most expensive state for electricity (28.83 US ¢ per KWh) while Louisiana is the cheapest state (7.65 US ¢ per KWh).
- In Hawaii, electricity is generated from crude oil, which is more expensive than other sources.
- One of the probable reasons for low electricity cost in Louisiana could be that the company that delivers electricity to the entire state, Entergy Louisiana, owns many power plants. This implies that the company creates energy, instead of purchasing it from another entity.
- **Oklahoma and Idaho are the two other states with the lowest electricity prices.**
  - Power providers in Oklahoma are blessed with multiple sources of energy that help keep power prices affordable.
  - Idaho produces a majority of its power through hydroelectric dams, which is a relatively simple process that requires limited machinery.
- **Alaska and Hawaii have higher electricity prices than the rest of the country.**
  - One of the key factors leading to the high electricity price is fuel price.
  - Fuel prices, especially for natural gas and petroleum fuels (mainly in Hawaii and Alaska), may surge during periods of high electricity demand or as a result of fuel supply disruptions.
  - Fuel supply disruptions can be caused by extreme weather events or disruptions in transportation or the delivery infrastructure. Higher fuel prices result in higher costs to generate electricity.
- **States that depend on coal to supply their electricity continue to enjoy the lowest electricity rates in the nation.**
  - Arkansas, Kentucky, Oklahoma, Utah, West Virginia and Wyoming are the among the top ten cheapest states thanks to their reliance on coal to generate electricity.
  - Washington and Idaho enjoy the benefits of low-cost and geographically-dependent hydroelectric power to maintain their positions in the low-cost ten.

Figure 3.4. U.S. ~ Average Electricity Retail Price ~ Variations By State, 2019 (2019 cents per KWh)



Source: Global Energy Institute, 2020

Variations in electricity prices in the U.S.

- **Electricity prices in the U.S. vary depending on each state's accessibility of power plants and fuels, costs of local fuel and pricing regulations.**
- **In some states, utility commissions fully regulate prices, whereas other states have a combination of unregulated prices (for generators) and regulated prices (for transmission and distribution).**
- **Generally, electricity prices are highest for residential and commercial consumers since it costs more to distribute electricity to these customers.**
- **The price of electricity to industrial customers is close to the wholesale price of electricity since supplying electricity to this group is often more efficient and less expensive.**

U.S. ~ Electricity prices ~ There is a decline in electricity prices encouraging more electricity consumption

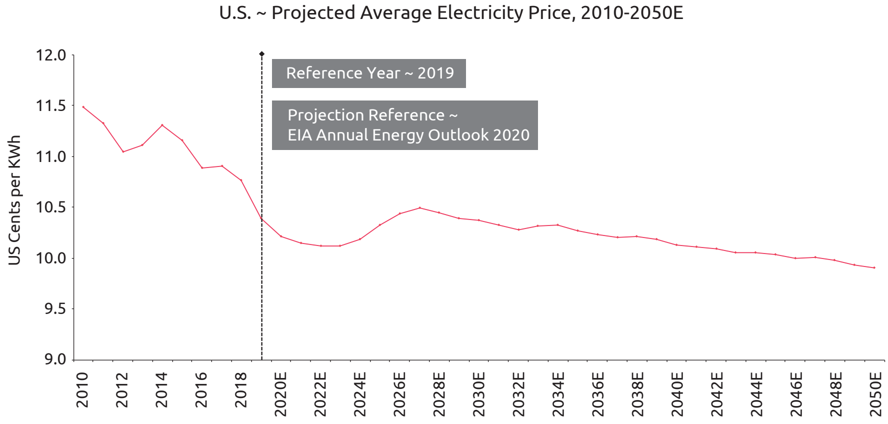
EIA forecasts that by 2050, the U.S. will experience the maximum electricity price decline as compared to 2019

- Electricity prices are falling in the near term, primarily because utilities pass along savings from lower taxes under the Tax Cuts and Jobs Act of 2017.
- Utilities are also substituting more costly power plants with new plants that are less costly to construct and operate.
- Lower prices are encouraging more electricity consumption in the near term. However, near-term efficiency standards and population shifts to warmer areas of the country moderate this trend.

COVID-19 impact on U.S. electricity prices:

- EIA forecasts that there will be a decline in overall electricity demand as a result of the economic slowdown associated with COVID-19 and lower than expected natural gas fuel costs for power generation. This influences EIA's forecast that wholesale electricity prices will be lower in 2020 throughout the U.S.
- Although, the lower costs of electricity supply will most likely not influence retail electricity prices in the near term, it will be reflected in lower retail prices in the future as utilities make adjustments to their electric rates during the coming months.

Figure 3.5. U.S. ~ Projected Average Electricity Price, 2010-2050E (2019 cents per KWh)



Source: U.S. EIA Annual Energy Outlook, 2020

Effect of decline in electricity prices

Despite increased efficiencies in equipment, declining electricity prices encourage greater use of energy-consuming appliances and devices. PV growth is also sensitive to electricity prices. With decline in electricity prices, residential and commercial PV capacity may also increase.

U.S. ~ Electricity prices: Declining generation costs are offset by rising transmission and distribution costs

Generation, the largest component of electricity price, accounted for 58.4% of the total cost in 2019

Other components involved in electricity prices are: transmission and distribution; reliability costs to maintain stable voltage and frequency; maintenance needed to keep the system running; depreciation; and taxes.

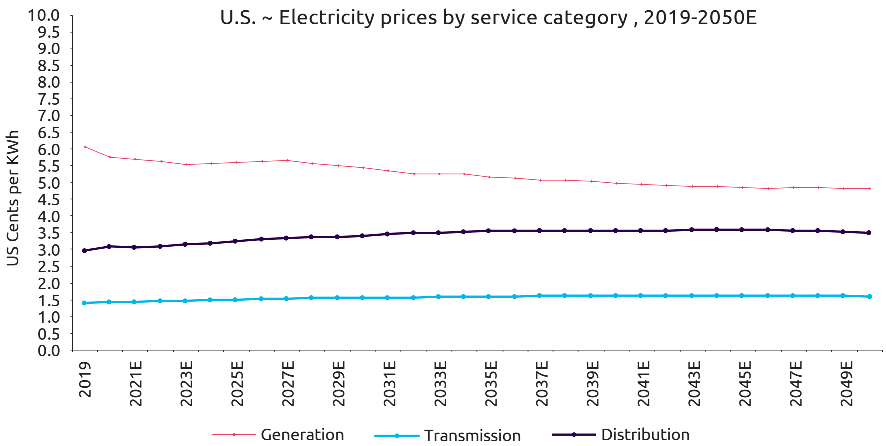
EIA predicts that while generation costs of electricity will decrease from 2019 to 2050, transmission and distribution costs will increase marginally or remain the same.

Transmission and distribution cost of electricity generation from low renewables is high.

- Renewable generating technologies—mainly solar PV and wind—have lower capacity factors than fossil fuels and nuclear technologies. In addition, more intermittent capacity is needed to replace generation that would otherwise be available from base load generating technologies.
- The distribution cost component is also high for low renewables in electricity because costs are recovered over fewer retail sales as a result of increased self-generation in the end-use sectors.

According to EIA predictions, generation cost will fall in the near future but transmission and distribution costs can witness a sharp rise due to expensive renewable distribution cost components. From 2010 through 2018, investor-owned utilities invested US$170 billion on transmission-related projects. Investments are projected to peak in 2019 and then slow from 2020 onwards. Even corporates procured a record-breaking 13.6 GW of clean energy with Google leading the way, followed by AT&T and Walmart.

Figure 3.6. U.S. ~ Electricity prices by service category, 2019-2050E (2019 cents per KWh))



Source: U.S. EIA Annual Energy Outlook, 2020

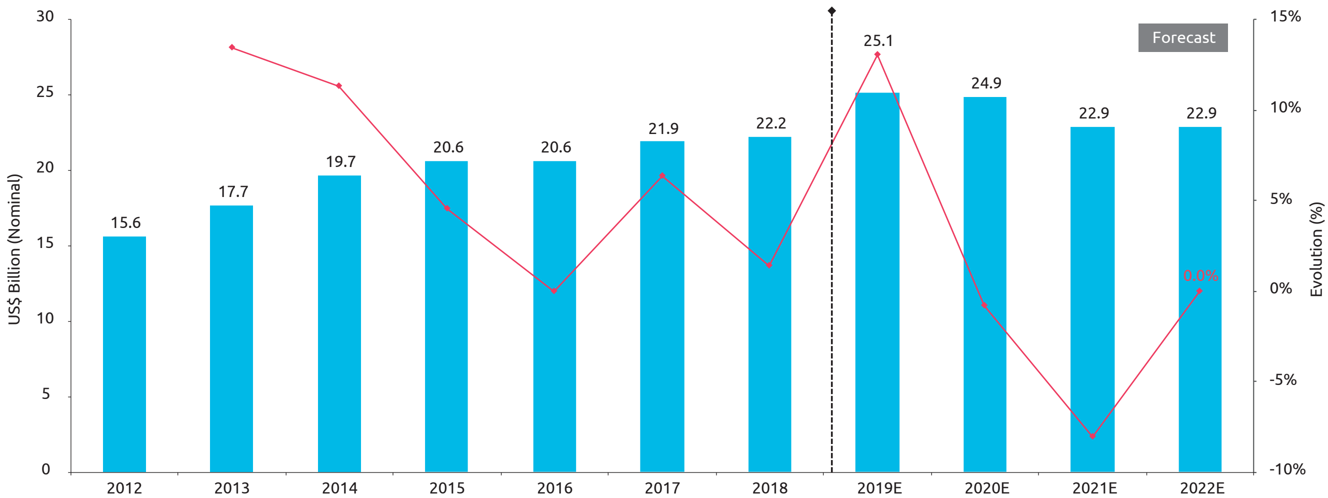
The U.S. energy sector is experiencing a paradox as electricity prices are rising while generation costs are falling. This is possible as the industry evolves from a more centralized fossil fuel-based generation base to one focused more on distributed and renewable sources.

U.S. ~ Transmission investment: Utilities have boosted their investment in transmission grid projects to facilitate the delivery of a greater volume of low-carbon electricity

Investor-owned utilities and independent transmission developers spent a record US$22.2 billion on electric transmission in 2018. This is up 1% from US$21.9 billion in 2017 (in nominal dollars) and 25% from 2013. It is also projected that investor-owned utilities and independent transmission developers will spend US$25.1 billion in 2019 on electric transmission projects

- From 2010 through 2018, investor-owned utilities pledged US$170 billion on transmission projects.
- According to Edison Electric Institute (EEI) estimates:
  - Transmission investment is likely to jump 13% in 2019 to US$25.1 billion.
  - Investment is projected to peak in 2019 and then slow from 2020 onwards.
  - Investor-owned electric companies are planning to invest approximately US$96 billion on transmission construction through 2022 (in nominal dollars).
- The transmission investment pickup is largely driven by several factors, all of which are related to the utility's fundamental aim of providing dependable, inexpensive, and safe power.
- There is also a need to substitute and improve aging power lines, resiliency planning for probable natural and man-made threats, the utilization of renewable resources and congestion reduction.

Figure 3.7. U.S. ~ Transmission Investment by Investor-owned Utilities and Independent Transmission Developers, 2012-2022E (US$ billion)



Source: BNEF ~ Sustainable Energy in America Factbook, 2020

U.S. ~ In 2019, corporates procured a record-breaking 13.6 GW of clean energy capacity, as led by Google, AT&T and Walmart. QTS Reality & Walmart invested exclusively in wind energy whereas T-Mobile supported solar energy

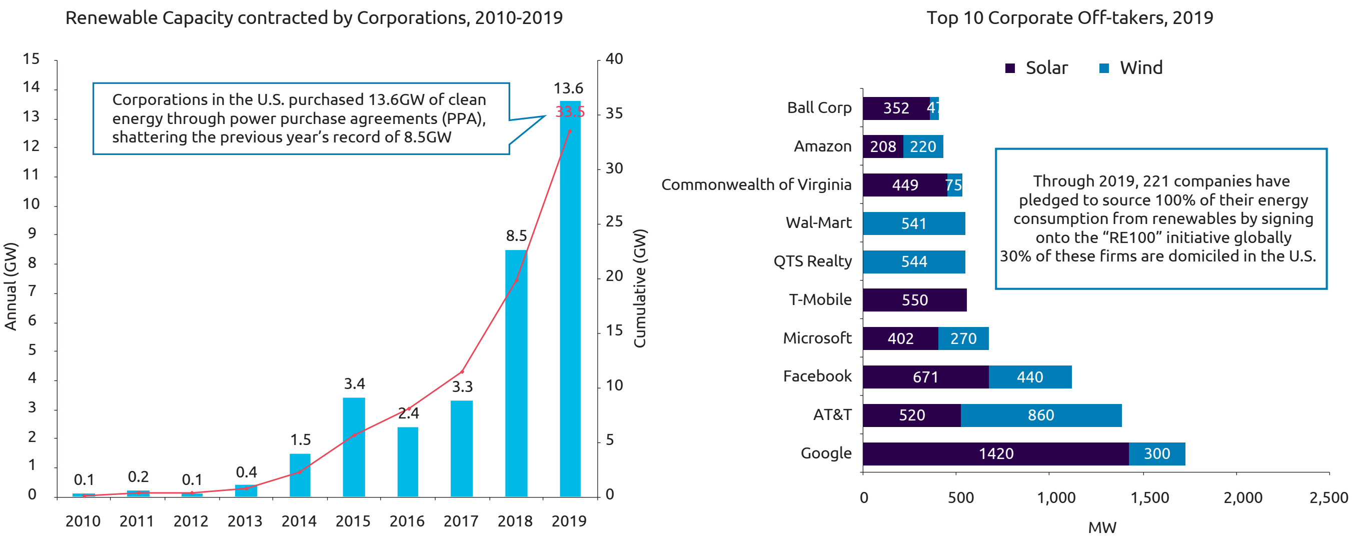
U.S. corporations purchased 13.6GW of clean energy through power purchase agreements (PPA) in 2019, overtaking 2018's record of 8.5GW

- Companies are heading to the Texas power market, where 5.5GW of these contracts have been signed. As companies aim to capture peak pricing in summer months, nearly two-thirds of PPAs signed in Texas have been for solar power.
- Buyers are seeking PPAs for risk mitigation, seizing the opportunity to reallocate term risk, weather risk and credit risk.
- Re-insurance providers like Allianz and Swiss RE have made their mark in the market with products like proxy revenue swaps and volume firming agreements, which allow them to inherit these risks from corporate buyers.
- Utilities and retailers are also proposing multiple "sleeved" programs, wherein they serve as middle-men and offtakers of clean energy contracts, bearing these risks on behalf of corporate buyers.

Google was the largest U.S. corporate offtaker in 2019, signing contracts for 1,720MW of clean energy.

- In September 2019, Google announced 936MW of solar PPAs in the U.S., leveraging a unique reverse auctioning program to sign the contracts.
- The company specified criteria for its clean energy purchases, such as technology, term length, and location. Developers participated in a timed, public auction process.

Figure 3.8. Corporate Procurement of Clean Energy, 2019 (GW)



Source: BNEF ~ Sustainable Energy in America Factbook, 2020

In 2019, U.S. companies signed contracts with wind and solar projects totaling 33.6GW—enough to power nearly 8 million homes.

Canada ~ Electricity Price: There is a considerable gap between electricity rates in the North West Territories (NWT) and the Canadian national average

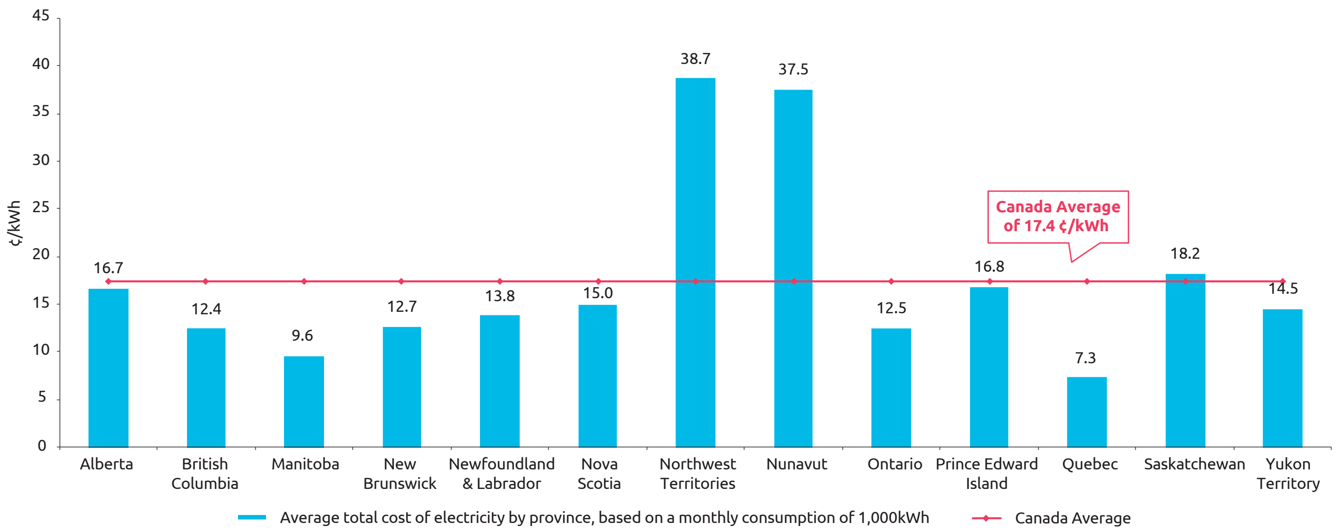
Based on the average monthly consumption of 1,000 kWh, the average residential price of electricity in Canada is $0.174 per kWh. This price includes both fixed and variable costs

- Major factors influencing the Canadian power prices are hydro reservoir level, fuel prices and cooling.

Québec has the cheapest electricity prices in all of Canada (US$ 0.073/kWh) while the Northwest Territories have the most expensive electricity prices (US$ 0.387/kWh).

- In northern Canada, where population density is low, there is limited viability of lower-cost energy infrastructures like natural gas pipelines and hydroelectric facilities. Geography also poses a challenge for the mass use of renewables. As such, remote communities in northern Canada are heavily reliant on relatively expensive and carbon-intensive energy sources like diesel.
- Electricity prices are considerably higher in the Northwest Territories and Nunavut because of low population density and expensive generation costs.
- Power costs in jurisdictions with a lot of hydroelectric generators tend to be lower.
- Most NWT communities rely on small-scale and non-integrated power systems and are not connected to a central grid.
- Many of Northwest Territories Power Corporation (NTPC)'s generation and transmission assets are nearing the completion of their design life and must be replaced. Without funding, increased electricity rates will cover the cost of infrastructure updates.
- In Nunavut, power generation facilities are almost all diesel-fired and most homes are heated by fuel oil. Hence, Nunavut imports all its fuel for the year in bulk during the summer.

Figure 3.9. Canada ~ Average total cost of electricity by province, based on a monthly consumption of 1,000kWh, 2019 (¢/kWh)



Source: Energy Hub.org, February 2020

Topic Box 3.1: Cyberattacks on NA utilities (1/2)

In 2019, 17 U.S. utilities, mostly small organizations, were the targets of cyberattacks. Canada aims to play a leadership role in establishing globally accepted standards and certification programs to significantly reduce the risk and severity of cyber threats through IIoT devices. Utilities and other sectors that are dependent on IIoT devices will also benefit from improved cyber security and the safety of Canada's energy systems.

Recent incident of cyberattacks on U.S. utilities:

- In Sept. 2019, cybersecurity firm Proofpoint revealed that 17 utilities were targeted between April and August of 2019, mainly with phishing attempts using updated macros.
- Malware labelled as "Lookback"—a Remote Access Trojan (RAT) that can access and temper system data—was part of these attacks.
- The attacks caused the utilities to lose communication with multiple power generation sites remotely located from the power control center.
  - Each system reboot to reestablish communication between controller and generation sites was effective for only five minutes. This cyberattack continued for nearly 10 hours.

In 2020, U.S. utilities remain vulnerable to cyberattacks.

- Infrastructural and mismatched standards: The U.S. system of electric delivery, which includes transmission and distribution, is required to comply with federal cyber protection standards for transmission. However, distribution systems are regulated by state bodies, which require few cyber protection standards, leaving the whole system vulnerable.
- According to the "State of the Electric Utility 2020" report from Utility Dive, 37% of U.S. utility companies have not implemented their cybersecurity programs satisfactorily.
- The Edison Electric Institute (EEI), which represents investor-owned utilities (IOUs), does not track actual cybersecurity spending.
- Accountability Office (GAO) revealed that the Department of Energy (DOE) is not actively concerned about the protection of the electrical grid against cyber attacks. A national strategy for securing the electrical grid has not yet been established.
  - The Federal Energy Regulatory Commission (FERC) has approved mandatory grid cybersecurity standards, though they are incomplete. Utilities are not fully incorporating federal guidance on grid cybersecurity.
- While the Department of Energy (DOE) established the Office of Cyber Security, Energy Security and Emergency Response, (CSESER) in 2018, it has little experience in handling cyberattacks.

Topic Box 3.1: Cyberattacks on NA utilities (2/2)

Measures taken by regulators and utilities to tackle cybersecurity breaches:

- The Securing Energy Infrastructure Act, which was included in the National Defense Authorization Act signed by President Trump in December 2019, established a two-year program "to develop a national cyber-informed engineering strategy to isolate and defend covered entities from security vulnerabilities and secure the grid against cyberattacks“.
- Other legislation includes: The Enhancing Grid Security Through Public-Private Partnerships Act, which requires DOE to establish and conduct programs to assess the cyber and physical security of electric utilities, and the Energy Cybersecurity Act, which would require DOE to develop advanced cybersecurity applications and technologies for the energy sector.
- DOE is currently working on developing a "national cyber security implementation plan" to address energy sector cybersecurity.
- The Energy and Commerce Committee has earmarked US$157 million for Cyber Security, Energy Security and Emergency Response (CSESER) in its FY 2020 budget request. CSESER has acted on a program called Cyber Analytics Tools and Techniques, which detects potential cyberattacks using information such as classified threat data from governmental and energy sector partners.

- FirstEnergy has initiated the upgrading and modernizing of its transmission system with a budget of US$6.8 billion. It has also planned to invest US$1.2 billion every year through 2021 to solidify its infrastructure on cybersecurity, identity customer opportunities and add operational flexibility. Key initiatives include:
  - Deploying devices that provide physical and electronic protections, logging and monitoring.
  - Increasing the use of data analytics to help predict, prepare for and mitigate threats.
  - Implementing third-party tests that use "friendly" hackers to attack its network to validate its technical cybersecurity control effectiveness and identify any deficiencies.
- In 2018, NextEra Energy has established the Advanced Cyber Defense Center, a state-of-the-art facility which monitors more than 40,000 systems to detect cyber threats and respond to potential incidents. The team processes around 1,200 cyber intelligence reports each month to understand existing and emerging threats.

Hydro-Québec in Canada experiences more than 500 cyber attacks each year. According to the "State of the Electric Utility 2020" report from Utility Dive, 37% of U.S. utility companies have not yet satisfactorily implemented their cybersecurity programs. Several bills, such as the Securing Energy Infrastructure Act and Enhancing Grid Security Through Public-Private Partnerships Act have been passed. Companies like NextEra Energy has started upgrading and modernizing the transmission system.

4-Financials

U.S. ~ COVID-19 impact on financials for U.S. Utilities

Utilities typically generate stable revenue, since government entities regulate the rates that they charge. Demand for electricity and gas for utilities typically remains relatively steady even during a recession. Utility stocks, therefore, tend to outperform other sectors when the economy hits a rough patch. However, the current downturn from the COVID-19 outbreak is so challenging that it is having a huge impact on U.S. utilities

U.S. utilities have taken steps to ensure they have funding needed to maintain and expand their operations during these uncertain times. For example:

- NextEra Energy sold US$1.1 billion of five-year notes at a rate more than double what it paid for similar financing in early 2019.
- American Electric Power drew on its US$1 billion credit line because that was a cheaper way to shore up its cash balance.
- Duke Energy secured new bank financing and also issued additional bonds.

Request for rate increases at risk:

- Since government entities regulate rates, utilities need to get approval for increases.
- According to an estimate from Moody's, utilities have requested US$6.4 billion in rate increases.
- Duke Energy has the largest request at US$1.5 billion, followed by Edison International at US$1.3 billion.
- Given the impact of COVID-19 on the economy, regulators might not approve these increases at this time. If they do not get approval, utilities may not grow their earnings or dividends.

Impact on growth:

- Most U.S. large electric utilities are expected to grow their earnings and dividends at a mid-single-digit annual pace over the next few years.
- However, it will be harder for them to achieve those forecasts with the COVID-19 outbreak affecting so many aspects of the sector.
- U.S. utility stocks are expected to remain uncharacteristically volatile until the economy gets back on solid ground.

Revenues U.S. ~ 2019 was a satisfactory year for utilities as most witnessed a minor increase or decrease in revenue. Changes in regulatory rates and the operating model will help sustain such results

Exelon's revenue slipped 4.4% in 2019, down to US$34.4 billion from nearly US$36 billion in 2018.

- The net income of Exelon Corporation soared a remarkable 46% due to higher utility earnings made possible by regulatory rate rises across the majority of Exelon's divisions.
- Although Exelon witnessed a decrease in revenue in 2019, ongoing infrastructure investment at Exelon's electric and gas companies is delivering better financial results than the rest of U.S. utilities.

Impact of COVID-19 on Exelon's future performance

There was no material impact on Exelon's financial statements for the first quarter of 2020 due to COVID-19.

- However, there may be a decrease in operating revenues in the first nine months of 2020 due to an unexpected reduction in electric load.
- Exelon is pursuing approximately US$250 million in cost savings across its operating companies to offset part of the expected unfavorable impacts on operating revenues created by COVID-19.

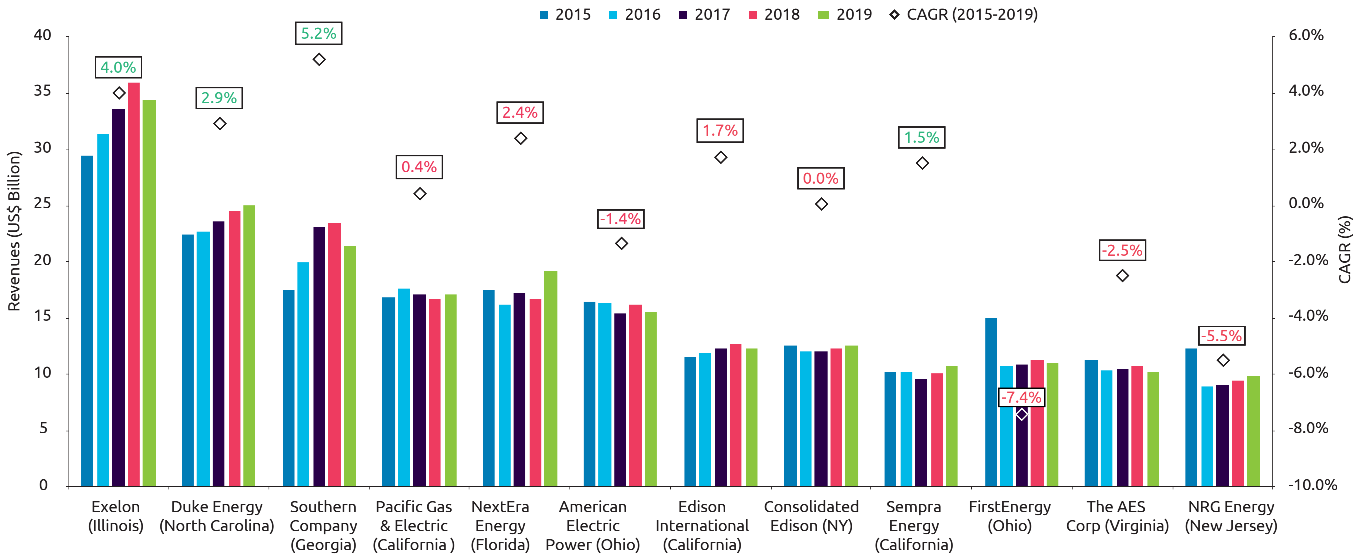
NRG Energy recorded the lowest revenue amongst the U.S. utilities.

- NRG Energy was able to generate revenue of US$9.8 billion in 2019 after witnessing a revenue increase of 3.15% in 2019 compared to 2018. The company has strengthened its balance sheet in 2019 and reduced its debt.

Texas Renewable Energy progress is limiting NRG's upside.

- NRG is well-positioned in Texas and the Northeast.
- In Texas, NRG Energy's financial performance will be affected due to modest growth in demand and a surge in renewable energy. However, the Northeast creates a stable cash source for the company to offset energy market volatility.

Figure 4.1. U.S. ~ Revenues and associated CARG, 2015-2019 (US$ billion)



Source: Thomson Reuters EIKON Data ("Total Revenue"); Capgemini Analysis

Revenues Canada ~ Uninterrupted operation of utilities in Canada in 2019 and better performance of energy marketing segments have benefitted utilities' earnings. It has been estimated that the impact of this pandemic won't create technical risks for utilities

Driven by increased sales in the Québec market, Hydro Québec's net sales volume was 208.3 TWh, close to the record of 208.9 TWh set in 2018.

- Untroubled operation of its generation, transmission and distribution facilities has allowed the organization to address the demand of the domestic market and export to neighboring markets. This supports the decarbonization of northeastern North America.
- However, net exports decreased by US$134 million compared to the previous year due to reduced demand on export markets resulting from temperature variances in the second quarter and lower market prices, which were mitigated by the company's sales and risk management strategies.

Impact of COVID -19 on Hydro Quebec's future performance:

- Hydro Quebec is attempting to reduce operating expenses by freezing 2020 management salaries and postponing the payment of bonuses to non-union employees until the third quarter of 2020.
- The company has stated that it would not be able to generate a net profit of US$2.9 billion as outlined in its 2020-2024 strategic plan.
- Hydro Quebec hopes to boost 2020 revenues with one of its main projects, Champlain Hudson Power Express (CHPE).
- In April 2020, Hydro Quebec and New York Power Authority (NYPA) partnered to provide mutual assistance to ensure uninterrupted power supply in both Québec and New York State, even though demand is critically low.

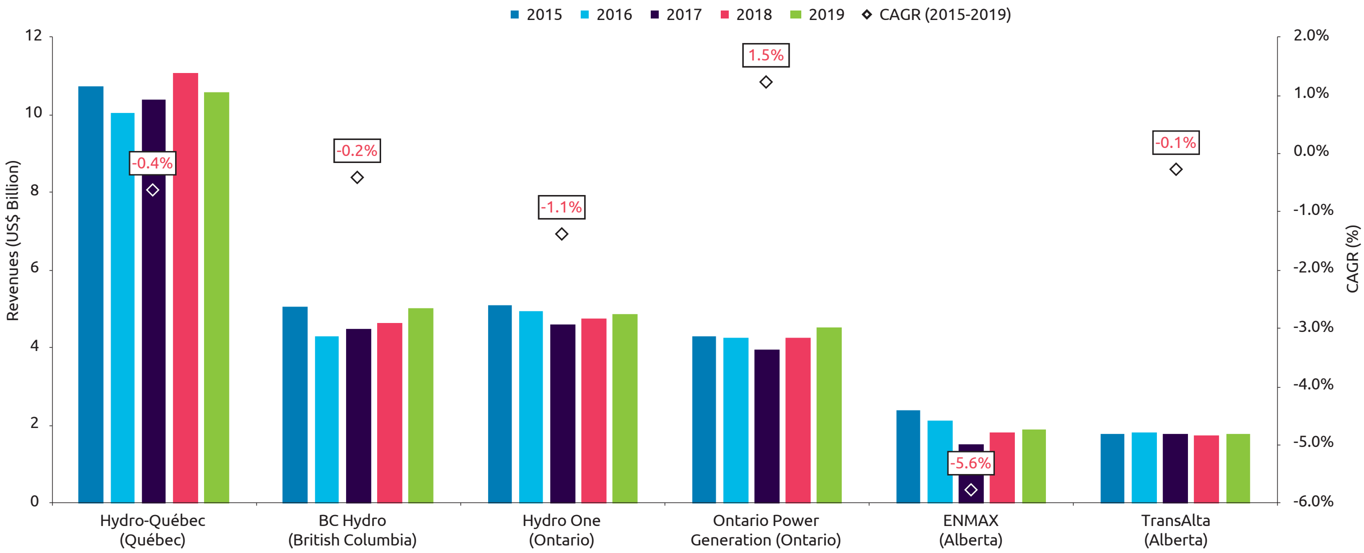
TransAlta recorded the lowest revenue amongst the Canadian utilities.

- Revenues in 2019 were US$2,347 million, up by US$98 million compared to 2018, driven by strong revenue generation from its Energy Marketing segment, as well as higher production.

COVID-19 has not had a significant impact on the Canadian electricity sector.

- No capacity augmentation or renovation projects are expected to be delayed.
- According to the Canadian Electricity Association, the electricity sector currently does not bear any technical danger.

Figure 4.2. Canada ~ Revenues and associated CARG, 2015-2019 (US$ billion)



Source: Thomson Reuters EIKON Data ("Total Revenue"); Capgemini Analysis

EBITDA margins U.S.~ With an average EBITDA margin of 33%, U.S. utilities had manageable operating expenses in 2019. However, piling operating costs and deferring recovery costs may have an impact in 2020

Although NextEra Energy's EBITDA margin fell from 50.2% in 2018 to 49.6% in 2019, it recorded the highest EBITDA margin amongst U.S. utilities

- NextEra Energy's 2019 performance was strong both financially and operationally as it was able to deliver successfully on all strategic initiatives.

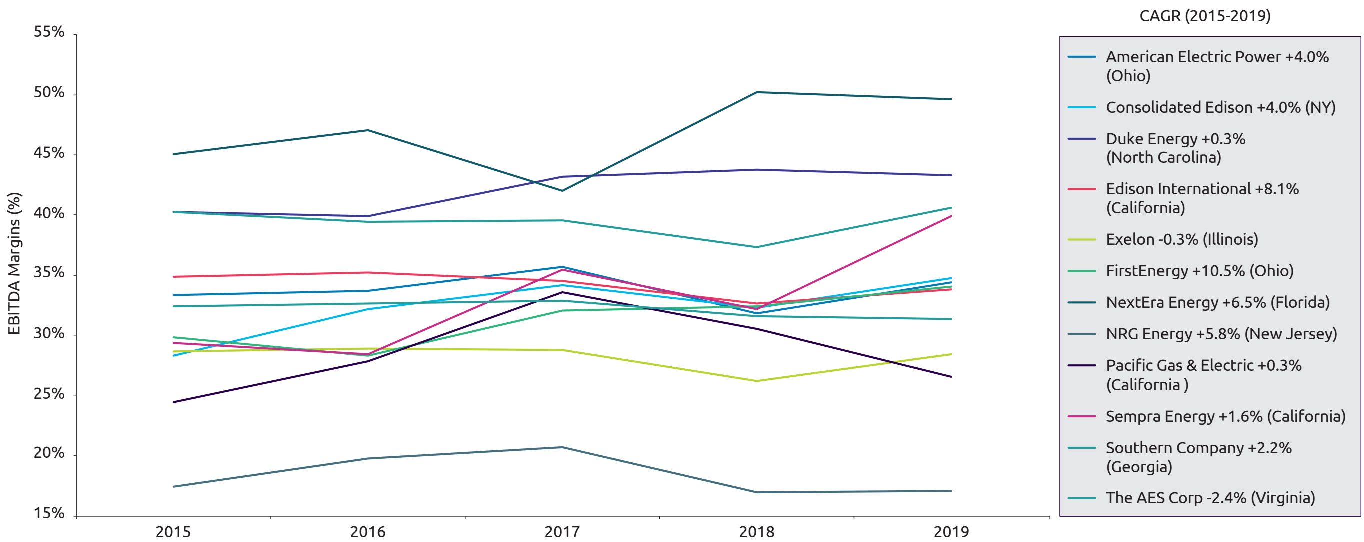
Impact of COVID-19 on NextEra Energy's future earnings:

- While the COVID-19 pandemic has created significant uncertainty throughout the economy, NextEra Energy remains well-positioned to continue to deliver on its objectives and commitments.
- NextEra Energy entered 2020 particularly well-positioned as a result of the actions that the company took in 2019. These included: two significant acquisitions; organic growth investments; and steps to reduce overall cost of capital.

NRG Energy's EBITDA margin rose from 16.9% in 2018 to 17.1% in 2019. However, it is much less than the industry median EBITDA margin of 34.4%.

- However, NRG Energy's integrated business delivered EBITDA in line with its 2019 expectations during a period of volatile market conditions, further validating the benefits of integration between retail and wholesale.

Figure 4.3. U.S. ~ EBITDA margins and associated CAGR, 2015-2019



Source: Thomson Reuters EIKON Data ("Normalized EBITDA"); Capgemini Analysis

EBITDA margins Canada ~ In 2019, Canada experienced an increase in both the number of customers and electricity demand

Hydro Quebec's EBITDA rose for for the fourth consecutive time in 2019, reaching 59.9%

Hydro Quebec has cut down its operating expenses and financial expenses marginally by 0.65% as compared to 2018.

- Managerial actions helped to absorb the higher costs resulting from inflation, salary indexing and growth in its operations.
- These factors have helped keep operating expenses low and gain a high EBITDA.

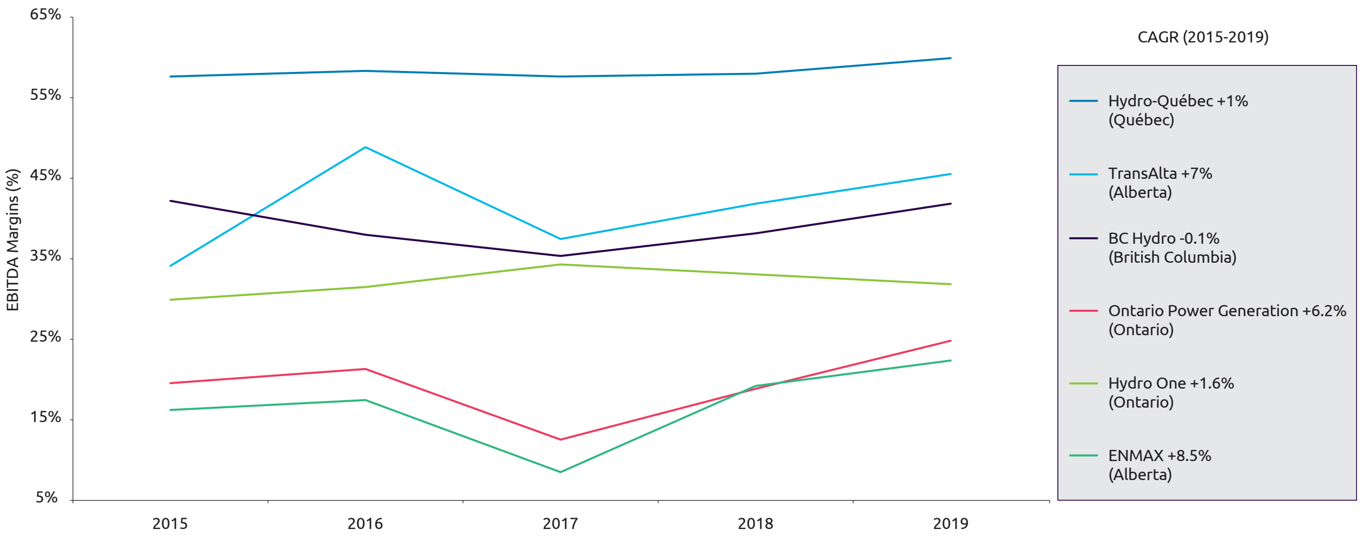
ENMAX's EBITDA margin rose from 19.1% in 2018 to 22.3% in 2019. However, it is much less than the industry median EBITDA margin of 34.4%.

- The decision of AUC to approve 2020 Performance Based Regulation (PBR) distribution rates on an interim basis and distribution tariff terms and conditions for the period of January 1, 2020 to December 31, 2020 will offset the operating margin by 3.6%. This may impact EBITDA margins for FY 2020.

Impact of COVID-19 pandemic on Canadian utilities:

- Reduced load consumption, growing payment arrears, and pandemic-related expenses may have negative implications for the utilities' credit quality.
- It will be difficult for most Canadian investor-owned utilities (IOUs) to continue to access the equity market to fund growth strategies and large capital programs.
- State-owned Hydro One has witnessed a 13% year-over-year decrease in power demand, limiting revenue in its power transmission business.

Figure 4.4. Canada ~ EBITDA Margins and associated CAGR, 2015-2019



Source: Thomson Reuters EIKON Data ("Normalized EBITDA"); Capgemini Analysis

Dividend per share ~ U.S. utilities have better dividend per share due to continued earnings and operating cash flow growth

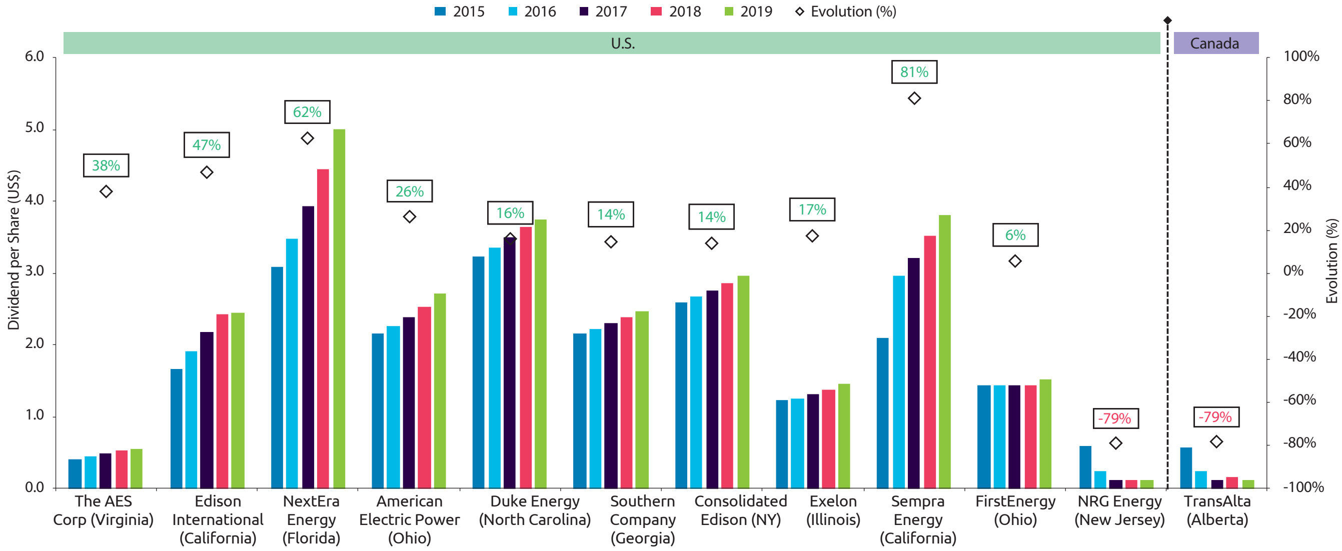
NextEra Energy recorded the highest dividend per share of US$5 in 2019, an increase of about 12.5% over the previous year. This increase is consistent with the plan announced by the company in 2018 to target 12-14% annual growth in dividends per share through 2020, off a 2017 base

- In March 2020, the board of directors of NextEra Energy approved an updated dividend policy beyond 2020. It is expected to translate to a growth in dividends per share of roughly 10% per year through at least 2022, off a 2020 base. Under this plan, dividends per share are expected to reach US$5.60.
- "The board's approval to continue to grow our dividends per share in excess of our expected adjusted earnings per share growth rate is a result of our success in executing on our industry-leading business strategy," said Jim Robo, Chairman.

Utility companies dispelled COVID-19 fears by encouraging long-term guidance and dividend policy. NextEra Energy confirmed its commitment to grow dividends despite a challenging business environment due to the ongoing COVID-19 pandemic.

- NextEra has displayed strong dividend growth with 25 years of consecutive dividend increase. Its average annual dividend increase over the past decade was roughly 10%.

Figure 4.5. U.S. and Canada ~ Dividend per Share in US$ and 2015-2019 Evolution



Source: Thomson Reuters EIKON Data ("Dividend per Share DPS"); Company Annual Reports; Capgemini Analysis

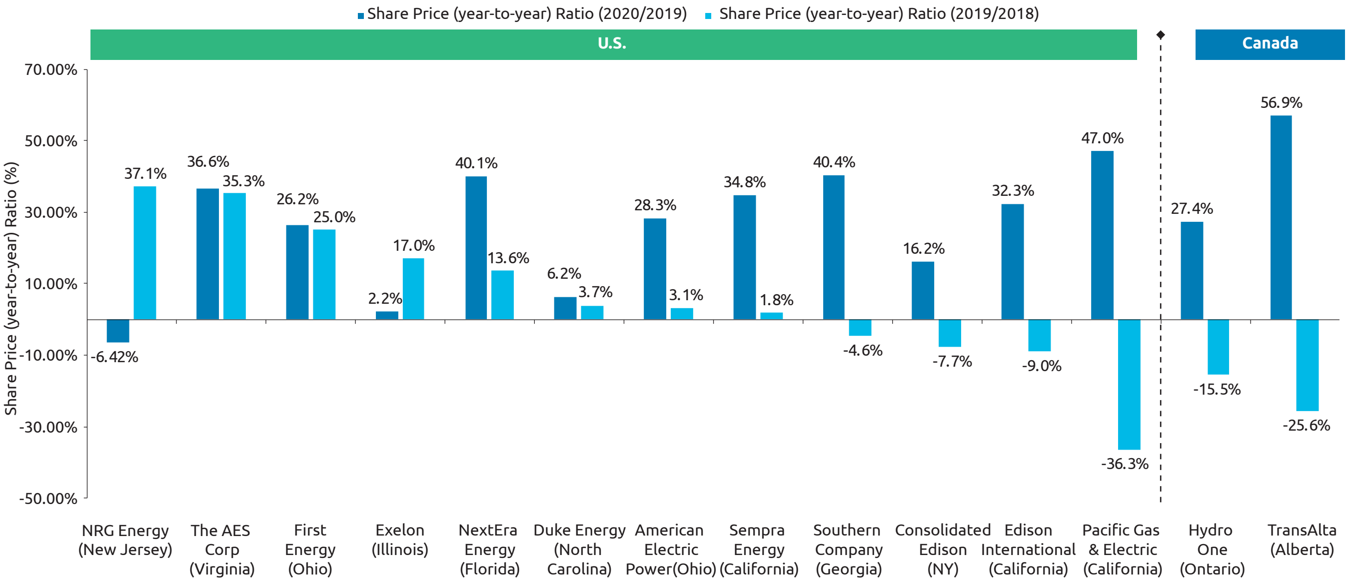
Due to outstanding control of operating and financial expenses, as well as managerial costs, utilities like NextEra Energy and Hydro Quebec were able to score better EBITDA margins and dividends per share.

Utility Stock performance ~ Lower operating costs, better dividend policies and restructuring of financial measures has prompted better utility stock performances in North America

TransAlta recorded the highest utility performance, followed by PG&E. NRG Energy is the only company with negative stock performance as of July 2020

- PG&E witnessed the maximum stock performance on a year-over-year basis after it confirmed that the company will compensate wildfire victims for losses caused by faulty equipment. The company sold more stocks than stated in an earlier agreement. This sudden change was prompted by the approval of its US$23 billion plan to emerge from bankruptcy by the state of California.
  - PG&E also has decided to restructure its vast territory into regional units so in order to improve agility and responsiveness.
- TransAlta Corporation produced the maximum stock performance and its dividend paid a good return at 6.4%. This is a positive sign of growth in the renewable energy market in Canada. Moreover, the company has a good market capitalization of US$4.19 billion.
  - By the end of Q1 2020, the company gained 15 hedge funds' portfolios. Management also shifted its strategy to boost shareholder returns using the proceeds from the Brookfield Renewable Partners (BRP) loan to fund a US$190.35 million stock repurchase program and a revised dividend policy.
  - Transalta has also stated that it will disburse "80 to 85% of cash available" for distribution to the company's shareholders on an annual basis.
- NRG Energy is the sole utility player with a negative stock performance this year.
  - NRG Energy performed well in Q2 2020 with total operating costs and expenses for the quarter amounting to US$1.75 billion, down 18.3%.
  - NRG Energy lowered its P/E ratio due to its good earnings. However, its stock performance has been impacted slightly.

Figure 4.6. U.S. and Canada ~ Utilities' Stock Performance (July 2020)



Source: Thomson Reuters EIKON Data ("Debt/Equity"); Company Annual Reports; Capgemini Analysis

PG&E holds US$34 billion in debt financing plans, thriving in utility stock performance and maintaining the lowest P/E ratio.

Leverage evolution ~ Utilities witnessed a sharp decrease in the debt/equity ratio in 2019, as compared with slight improvement in 2018

PG&E maintained the lowest debt/equity in 2019

- In Oct. 2019, PG&E Corp. lined up more than US$34 billion in debt financing to bolster its plan to exit bankruptcy protection and pay victims for the deadly wildfires caused by company power lines.
- Lenders that supported PG&E's planned reorganization include: JPMorgan; Chase Bank NA; Bank of America NA; BofA Securities Inc; Barclays Bank PLC; Citigroup Global Markets Inc; Goldman Sachs Bank USA; and Goldman Sachs Lending Partners LLC

AES Corp. maintained the highest debt/equity in 2019

- AES leverages high debt to boost returns. The company has a relatively high debt to equity ratio of 6.73%.
- The combination of a fair Return on Equity, despite taking on significant debt, suggests that the company is not doing well financially.

Figure 4.7. U.S. ~ Leverage (Debt/Equity), 2018-2019 Evolution

Utilities	2018	2019	Evolution
American Electric Power (Ohio)	1.32	1.52	↑
Consolidated Edison	1.24	1.20	↓
Duke Energy (North Carolina)	1.32	1.37	↑
Edison International (California)	1.48	1.42	↓
Exelon (Illinois)	1.19	1.17	↓
First Energy (Ohio)	2.89	3.01	↑
Next Era Energy (Florida)	1.10	1.15	↑
Pacific Gas & Electric (California)	1.74	0.3	↓
Sempra Energy (California)	1.65	1.46	↓
Southern Company (Georgia)	1.89	1.7	↓
The AES Corp (Virginia)	6.01	6.73	↑

Source: Thomson Reuters EIKON Data ("Debt/Equity"); Company Annual Reports; Capgemini Analysis

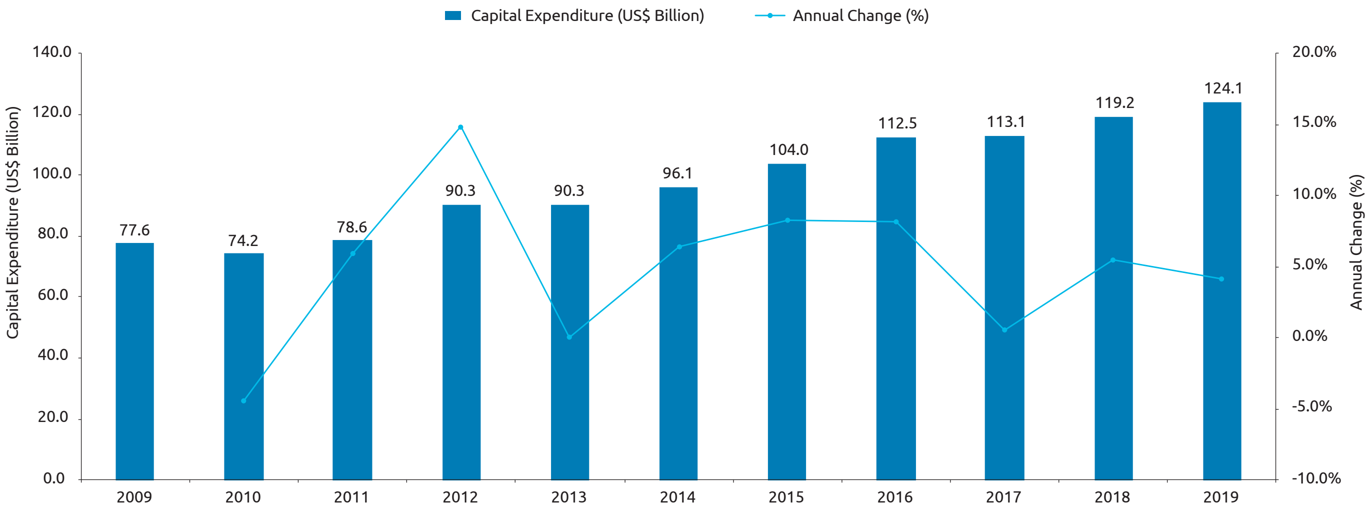
U.S. investor-owned electric utilities ~ Capital expenditures by U.S. investor-owned electric utilities totaled US$124.1 billion in 2019 compared to US$119.2 billion in 2018. However, distinguishable results are expected in 2020 as companies cut their capital expenditures

According to Edison Electric Institute, U.S. investor-owned electric utility companies continue to make significant investments to improve and expand much-needed transmission infrastructure

- A record-high US$124.1 billion of capital expenditures was witnessed in 2019, which supported the increase in regulated assets in the U.S.
  - Regulated electric assets increased by US$89.3 billion, or 7.7%, in 2019, showing a large asset growth in dollar terms.
- The 2019 capital expenditures represent the eighth consecutive annual recorded high, with this expansion well-represented across the four primary business segments.
- Asset growth is also evident in the industry's property, plant and equipment in service, which rose 7.3% from 208 to 2019 and increased 26.4% as of 2015.
- Strong growth in assets reflects the magnitude of the industry's build-out of new renewable and clean generation, new transmission, reliability-related infrastructure and other capital projects in recent years.

A record-high US$124.1 billion of capital expenditures was made in 2019 which supported the increase in regulated assets in the U.S.

Figure 4.8. U.S. Investor-owned Electric Utilities ~ Capital Expenditures, 2009-2018 (US$ billion)



Source: Edison Electric Institute ~ Annual Report of the U.S. Investor-Owned Electric Utility Industry, 2019

The high level of investment in the U.S. transmission infrastructure will enable electric utilities to improve reliability, relieve congestion, facilitate wholesale market competition and support a diverse and changing generation portfolio for the benefit of electricity customers.

Topic Box 4.1: COVID-19 recovery plans (1/2)

Companies are pushing for faster recovery by cutting capital expenditures, receiving aid from utility commission programs or through improved business practices like decoupling mechanisms, bill mitigation, rate riders and cost deferment.

Summary of recent initiatives taken by utility players to mitigate recovery plans

Country	***Utility Player***	***Key Initiatives***
U.S.	Exelon Corp	• Plans to cut costs by US$250 million by deducting capital expenditures worth US$125 million and pursuing cost recovery from regulators for incurred costs related to the pandemic.
U.S.	Duke Energy	• Reduced expenses by US$350 million to US$450 million through cost cuts in operations, maintenance and other expense reductions. • As of April 30, 2020, the company has about US$8.2 billion of available liquidity with plans to approach the capital markets to support its US$11 billion - US$12 billion capital plan for 2020.
U.S.	Pacific Gas & Electric (PG&E)	• Beginning in August 2020, PG&E will increase customers' electric bills around 5% through 2021. The company pledged to refund the amount to customers if the California Public Utilities Commission (CPUC) does the same. • PG&E has requested permission from the CPUC to recover US$899 million from its customers in order to cover wildfire mitigation investments. The request is under review.
U.S.	Edison International	• COVID-19 has impacted Edison International's capital programs worth US$19.4 million in 2020. The compound annual growth rate is forecasted at an average of 7.5% until 2023. To subsidize its effect, Edison International is following a decoupled mechanism to recover costs. • The company is also tracking non-payments through a pandemic protection memorandum account.

Country	***Utility Player***	***Key Initiatives***
U.S.	Consolidated Edison Co	• Regulators in New York approved US$70.56 million in financial assistance for ConEd customers enrolled in a low-income bill discount program. • The New York Utility Commission has permitted ConEd to recover costs of the emergency relief over five years through bill mitigation.
U.S.	FirstEnergy Corp	• With cash liquidity of US$3.5 billion, FirstEnergy is continuing to access capital markets. In Ohio & Pennsylvania, FirstEnergy has added rate riders to recover costs. In Maryland, the Public Service Commission issued an order authorizing the company to defer use for future recovery.
Canada	Hydro-Québec	• Hydro-Québec has halted all of its capital projects and is planning to scrap 2020 pay raises for its managers, as well as postpone payment of 2019 performance pay for non-unionized employees until Q3 2020.
Canada	Hydro One Ltd.	• The Ontario Energy Board has directed the company to track direct COVID-19 related costs in deferral accounts for future recoveries. Management has decided to recognize C$14 million in bad debt expense as a regulatory asset that shall be recovered later.
Canada	BC Hydro	• The Company is using deferrals for its residential and commercial markets. Large, industrial customers are deferring up to 50 percent of their power bills for the next three months. • BC Hydro has offered a three month credit on power bills for citizens whose income has been reduced due to COVID-19.

Topic Box 4.1: COVID-19 Recovery plans (2/2)

A large number of Assistance Programs from Public Utility Commissions have been created in North America to mitigate the economic effects of COVID-19. Utility companies are cutting their capital projects and costs related to operations and maintenance expenses. They have also applied billing mechanisms like deferrals, rider recovery and bill mitigation.

Financial Measures:

- Companies are taking stringent measures to address the economic crisis of COVID-19. This can come in the form of cutting costs tied to reductions in operations, maintenance and other expense or by pausing capital projects. Key utility players following this approach are Duke Energy, Hydro- Québec and Exelon Corp.

Funding from Regulators:

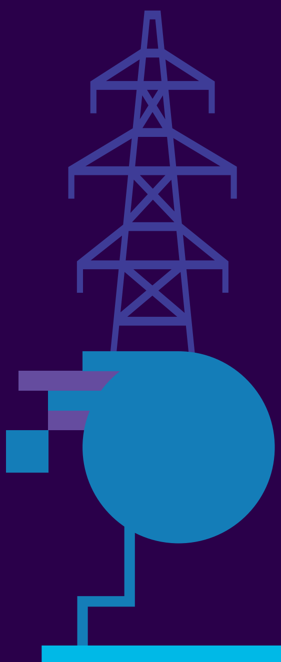
- Regulators in many states are offering Low-income Energy Assistance Program (LEAP) or Low-Income Home Energy Assistance Program (LIHEAP) to arrange payments for low-income customers through a federally funded state-supervised, county-administered system. These may include: New York Utility Commission; California Public Utilities Commission (CPUC); Ontario Energy Board; Texas PUC; Colorado Public Utilities Commission; Florida Public Service Commission; the Arkansas Public Service Commission; and Public Service Commission in Wisconsin.

Billing mechanisms:

- Companies are executing various billing schemes like payment deferrals, payment arrangements, bill mitigation, rate cases, rider recovery and others to mitigate the costs of the pandemic. BC Hydro and Hydro One are using deferrals for its residential and commercial markets.

Other utility commissions granting positive recovery rates:

- A COVID-19 Electricity Relief Program has been established with US$15 million from Electric Reliability Council of Texas (ERCOT) to reimburse retail electricity providers (REPs) for unpaid energy charges and transmission and distribution utilities (TDUs). CenterPoint Energy Houston Electric, Oncor Electric Delivery, and AEP Texas have benefited from this program.
- The Ontario province in Canada has paid generators for the loss of peak pricing and extended its winter ban on residential disconnections until July 31, 2020.



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WEMO 2020 Europe Editorial

Colette Lewiner

This editorial, focused on European energy markets, is part of the global vision described above. It analyzes the progress made in 2019 as well as the steps to be taken to ensure that Europe, which is already the region of the world most attentive to environmental issues, is on the right track to meet its climate goals.

The year 2020 was marked by the COVID-19 pandemic which will also affect the following years.

From a certain point of view the lock-down period was an anticipation of the future. On the one hand there has been a strong acceleration in digitization and remote working methods. On the other hand, on certain days the share of renewables in the electricity mix reached the level that is planned for the end of the decade. This created near blackouts which are analyzed in the following paragraphs. To avoid those blackouts, reform of the electricity market and the role of electricity transporters is proposed.

The evolution of the gas market in Europe is also examined.

The future will be even more uncertain than usual and players in the energy sector must prepare to review their strategies, their processes and their way of working in order to gain agility and to adapt to a market that will be more volatile

Electricity mix evolution in 2019 and beginning of 2020.

The main 2019 feature was the coal plant closures. The missing electricity generation was offset half by renewables generation and half by gas generation.

Energy-related GHG emissions decreased by 12% and ETS[1] emissions by 8% – a steeper decrease compared to previous years. Thanks to the implementation of "Market Stability Reserve" the price of ETS emission certificates rose in 2019, by 58% to around 25€/t by year end.
In H1 2020, after many countries locked down the population, these prices decreased to 15€/t at the end of Q1. In Q2, they rose again to similar levels as at the end of 2019. This price is still far too low to incentivize clean investment as CCUS[2] and to give a long-term perspective to investors.

Because during the slower economic period fewer emission certificates were needed; in order to maintain these prices, the EU must now reduce the number of issued carbon permits faster than previously planned.

With the economic slowdown at the beginning of 2020, energy-related CO_2 emissions in the EU declined by 8% during the first quarter of 2020 compared with the same period in 2019[3].

Estimates on year end emissions drops are difficult to do as it is unclear how the second pandemic wave will be handled. According to Carbonbrief's estimate[4] the worldwide drop could be around 5.5% of 2019's

1 ETS: European Trading System

2 CCUS; Carbon Capture Usage and Storage

3 https://www.iea.org/reports/european-union-2020

4 https://www.carbonbrief.org/analysis-coronavirus-set-to-cause-largest-ever-annual-fall-in-co2-emissions

emissions level. It is a historical drop but nowhere near enough to limit warming to less than 1.5 to 2°C above pre-industrial temperatures by 2050. To meet this target, global emissions would need to fall by some 7.6% every year of this decade.

In 2019, ***Renewables generation*** increased: wind generation increased by 14% and solar generation rose by 7%. Altogether renewables generation reached 35% of the electricity mix. In the future, increased renewables generation could be penalized by the 2019 decrease in investment in new capacities at $54.3 billion[5] (-7% compared to 2018). However, as costs are decreasing, the same euro builds more capacity.

Batteries: Although in 2019 Asia and the US dominated the electric battery market, eight battery giga-factory constructions over the next few years[6] were announced. They include:

- An American Tesla giga-factory to be built in the outskirts of Berlin,
- Chinese battery maker CATL building a factory in Germany,
- Swedish startup Northvolt, part of several giga-factory plans across Europe, from Sweden to Germany,
- Northvolt partner VW, also working on several giga-factories across Germany,
- BMZ, one of the major battery makers in Europe, planning to expand its plant in Karlstein,
- The French company SAFT, building a giga-factory in Kaiserslautern, Germany, and
- The seven-month-old start-up Britishvolt, looking at developing a 30 GWh battery manufacturing plant alongside a 200 MW solar plant, at a former RAF base in South Wales.

Gas generation rose by 12% as higher CO_2 ETS prices increased gas plants' competitiveness compared to coal generation (this was not the case in previous years).

Coal plants' generation share of the electricity mix decreased from 19% to 14.6% as many plants were stopped. This phase-out was triggered by renewables' increase and low profitability. According to a Carbon Tracker study four in five of Europe's coal-fired power plants were unprofitable, with their owners facing potential losses of €6.6bn[7].

Despite the commissioning of the Datteln 4 German coal-fired power plant (1,000 MW capacity) in May 2020, coal-fired plant closures continued in 2020 notably in the UK, Portugal, Spain, the Czech Republic, Italy and Austria.
In addition, the end of exemptions from EU emissions limits triggered the closure of seven coal power plants in Spain, as well as plants in Poland, the Czech Republic, and Slovakia that closed in June 2020.

Under National Energy Transition laws, 45% of the EU's 154 GW of coal capacity is scheduled to shut down by 2030[8]. In July 2020 Germany adopted a law that plans to phase out its 84 coal plants by 2038 with the first closures in 2020.

However, Eastern European countries such as Poland, the Czech Republic, Romania and Bulgaria continue to depend heavily on lignite power and have not adopted phase-out plans.

Coal plant closures, combined with renewables' increased capacities and exceptional consumption and weather conditions during the lock-down period, resulted in renewable energy reaching a historically high level of 40% share of the electricity mix during Q1 2020. At the same time, electricity generated by fossil fuels fell from 38% in Q1 2019 to 33% enabling the electricity generation carbon footprint to decrease by 20%.

Electricity is the most important vector for energy decarbonization and its vital importance, notably for reliable telecommunications and IT services, was evidenced during the COVID-19 crisis.

All green plans (including European models for achieving the 2030 and 2050 objectives) assume a significant growth in electricity consumption, notably for the transportation sector that is the largest fossil fuel consumer. At the beginning of 2020, widespread containment measures generated significant disruption to economic activity. With the sharp slowdown in industrial and commercial activities, demand for electricity dropped by approximately 15% to 20% across Europe and prices have even been negative during certain time intervals.

These low electricity prices are the root cause of the significant increase in public subsidies for renewable energies. For example, in France, in 2020, public support for renewable energies will be much higher than expected. Indeed, these energies have priority access to the electricity grid and many older projects[9] benefit from a feed-in tariff (FIT) for the electricity they produce guaranteed by the French State. The difference between these FITs and market prices is financed by a public charge. As

5 https://www.powermag.com/report-investment-in-renewables-hit-record-high-in-2019/

6 https://www.eenewspower.com/news/top-8-battery-gigafactory-plans-2019

7 https://carbontracker.org/four-in-five-eu-coal-plants-unprofitable-as-renewables-and-gas-power-ahead/

8 https://carbontracker.org/reports/?research-type=reports Powering down coal.

9 The French energy regulator (CRE) points out the disproportionate cost of photovoltaic support for the installations benefiting from the support system prior to the 2010 moratorium with an average purchase price of €510 / MWh (Les Echos, July 20, 2020)

market prices collapsed during the lockdown period (spot price 1€/MWh at the beginning of April, becoming negative at times), this public charge increased significantly. Consequently €5.8 bn will be needed to finance support for these energies in 2020, against a budget of €4.7 bn, resulting in an increase in public service charges for energy (CSPE)[10] which should reach €8.851 bn in 2020 (against €7.929 bn initially planned). It should grow to €9.1 bn in 2021. The financing of these charges will be even more difficult in 2020 and coming years as they are in part financed by a tax on oil (and coal) consumption that will drop because of the economic crisis and implementation of the French energy transition plan.

In 2018, the *European Commission* adopted 2030 Renewable Energy and Energy Efficiency targets of 32% of energy consumption from renewables and a 32.5% energy efficiency improvement. At the end of March 2020, the European Commission began a public consultation to gather views on its options to tighten the EU's 2030 emissions target. On September 16, the President of the European Commission, said, that Europe should set itself a target of reducing greenhouse gas emissions by at least 55% by 2030 compared to 1990 levels. The current target is a reduction of 40%. The Commission will propose an amendment on the climate law, which will have to be approved by the European Parliament and the Member States.

Meeting the 2030 renewables target will require an annual generation addition of 97 terawatt hours (TWh) for the next 10 years. Despite growing to record heights in 2019, renewables added just 64 TWh.

Accelerated renewables investments are thus needed to reach the targets. This will not happen in 2020 because of the COVID-19 containment measures delaying renewables projects construction (as with all construction projects).

The energy efficiency target is the most difficult target to reach especially when energy prices are low. In certain countries regulatory systems such as the Energy Saving Certificate (EEC) scheme were implemented to oblige energy suppliers to promote energy savings to their customers. It is based on a multi-year quantitative obligation for them to generate enough certificates in proportion to their sales. They obtain these certificates by financing energy efficiency operations and if they don't generate enough of them, they must buy them on the market.

In France, phase 4 of the EECs (for the years 2018 to 2021) establishes an obligation level of 533 TWhp (cumulative updated terawatt-hours) per year, a sharp increase compared to the obligation of 300 TWhp in 2017[11]. This scheme should cost energy suppliers nearly 9 billion euros over the years 2018 to 2020. It could be tough for them to honor these commitments in 2020 when their results will be negatively impacted by the COVID-19 crisis.

Many stimulus plans are focusing on thermal renovation of existing buildings with bullish plans that will, over time, increase energy efficiency. However, low energy prices for residential customers, rebound effects, and lack of appropriate

10 CSPE: Contribution au Service Public de l'Electricité

11 www.ecologique-solidaire.gouv.fr/sites/default/files/2020-07-02%20-%20Fiche%20Concertation%20P5%20CEE.pdf

skilled workers could decrease the forecast savings.

Electricity prices: Despite rising carbon prices (+58%), falling European gas prices (around -40%)[12] and coal prices (-34%)[12] as well as increased renewables generation pushed down power prices in almost every EU country in 2019. On average, day-ahead prices in the EU fell by €5.3 / MWh year-on-year.

During the 2020 lockdown period, prices decreased significantly. For example, the average price in France was €15.3 /MWh against €37.8 / MWh over the same period in 2019. The coronavirus crisis has also affected electricity futures markets. At the beginning of the lockdown, the prospect of a global economic slowdown and falling commodity prices led to a decline in electricity futures markets across Europe: in France, the electricity 2021 forward price fell from €45.70/MWh on January 2, 2020 to €37.4/MWh on March 17.

Forward prices for 2021 in France reached a maximum of €46.9/MWh on May 26, 2020, following EDF's announcements regarding the lower than forecast availability of the nuclear fleet during winter 2020-2021 and the year 2021.

The reduced nuclear plant availability has thus created tensions on the French capacity market, with a significant deficit of available capacity in relation to the forecast obligations.

Thus, the 2020 capacities which were exchanged last year at an average price close to €19.5/kW, were exchanged in mid-2020 at €45/kW[13].

It is unclear whether this price level reflects a lasting value of the capacity and makes it possible to attract new long-term capacities investments or electricity load shedding commitments, or if it is a short-term "panic" reaction to less nuclear generation than was forecast.

The electricity price increase is characteristic of the French market, where electricity production is largely provided by the nuclear fleet. In contrast, in Germany, where production is highly dependent on coal and gas-fired power stations, forward prices are more sensitive to fluctuations in these commodity prices and those of CO_2 emission quotas. Thus, the 2021 forward French and German prices spread that stabilized at around €1.6 /MWh before the lockdown measures, has increased since mid-March 2020 to reach a maximum of € 8.9/MWh.

After the COVID-19 crisis, will the world be greener?

Stimulus plans:

After 4 days and 4 nights of negotiations, the 27 Member States of the EU reached an agreement on July 22, 2020 on a recovery plan of €750 bn, of which 30% of expenditure will have to target climate change in order to achieve the objective of carbon neutrality in 2050.

However, this green commitment is vague as:

- The "green" conditionality of this recovery plan needs to be strengthened,
- An improved tracking methodology for the use and impact of the funds must be implemented[14].

Several member states' packages are also targeting climate change related investments.

The German recovery plan includes €30 bn for energy with notably purchase incentives for electric and hybrid vehicles, financial support for charging stations, battery production, and public investment to expand the production of low-carbon hydrogen. In contrast with Germany, which refused to allocate stimulus funds to internal combustion cars, France, which also launched an €8bn plan for its car industry, allocated only part of it to boost local manufacturing of electric and hybrid cars; the rest will include funding for new diesel or petrol car purchases[15]. Denmark has committed to invest heavily in energy efficiency improvements in social housing. Several countries have confirmed or extended their support for clean energy projects. In France, deadlines for contracting and grid connection for project developers were extended, and the level of feed-in-tariffs was not decreased.

Many political groups, NGOs, or special groups such as France's "Convention Citoyenne pour le Climat"[16] are proposing ambitious measures more or less well documented for a more sustained world. In France, these proposals would be financed by increasing taxes (raising €10 bn) in a country where citizens are already very heavily taxed and which was badly hit by the first pandemic wave[17]. Moreover, to please Green parties, the French

12 https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2020-full-report.pdf

13 https://www.energy-pool.eu/fr/resultats-des-dernieres-encheres-sur-le-mecanisme-de-capacite/

14 https://www.finance-watch.org/the-eu-recovery-plan-can-still-be-made-into-a-catalyst-for-sustainability/

15 €3,000 per vehicle

16 This group of French citizens, drawn from among the French population, proposed 150 radical measures with unclear financing to the French President in June 2020

17 In Q2 2020, French GDP decreased by 13.8% compared to a 12.1% European average

government imposed the closure of the two Fessenheim 900MW reactors, although they could (with significant upgrading works) have continued to operate for 10 years and provided carbon-free electricity.

In early July 2020 the European Commission unveiled a plan to increase the current very small share of green hydrogen in the European energy mix to 12-14% in 2050. In a first step in 2024, hydrogen generation capacity would be increased to 6 GW; this capacity should reach 40 GW in 2030. Investment needs are estimated at €180-470 bn by 2050.

Thanks to this plan, Europe could gain a central role in green hydrogen that is presently championed by Japan and more recently by China. It would also boost its two industrial champions Air Liquide and Linde.

Implementation of all those plans will depend on Europe's economic situation as balance has to be found between the future sustainability and the present virus protection and economic crises mitigation especially as many countries are likely to have a second pandemic wave.

Security of electricity supply:

Near blackouts:

The electricity consumption drop combined in Europe with favorable weather conditions, resulted in high shares of renewable electricity on the grid. Near blackouts happened in Germany and the UK, demonstrating that grids and regulations are not adapted to such high renewable's share. Some weekends, during which consumption was very low, several fossil fuel or nuclear power plants have been shut down in Europe, generating periods of negative prices.

Germany reached its renewables electricity generation record on April 21, 2020, with wind, solar and hydro accounting for a 78% share of generation[18]. A near blackout was avoided thanks to Germany's strong interconnections with other European countries.

In the UK, which has weak interconnections with continental Europe, a case of near blackout occurred on March 23, 2020 when the share of renewables increased to 60.5%. At that level balancing became challenging as the network is designed to remain stable for a renewable's share below 50%.

To deal with such an exceptional situation, National Grid signed an agreement with EDF to halt the electricity production of Sizewell B nuclear plant for at least six weeks.

It also asked smaller wind and solar electricity producers to stop generating, if necessary, in exchange for compensation. National Grid even asked OFGEM for exceptional rights to disconnect these installations from the network if needed.

Reinforcement of the electricity network by deploying more sophisticated equipment and better operating and forecasting systems, as well as the intelligent use of more data to feed them, is essential[19]. It is also necessary to adapt the design of electricity systems, market rules,

18 https://time.com/5824644/germany-coronavirus-solar/

19 https://www.thinksmartgrids.fr/wpcontent/uploads/2020/07/TSG_Livret_Plan_de_relance_vDEF_1707.pdf

and regulation of transmission and distribution network operators. Giving financial incentives to TSOs and DSOs for flexibility levers implementation remains a crucial element and an alternative to the heavy investment that often has a relatively low yield.

Regulators are aware that the current TSO and DSO remuneration models encourage copper investments and not enough fiber ones. For example, CRE, the French energy markets regulator, is organizing public consultations to reform the TURPE principles[20].

The security of electricity supply in Europe is likely to be strained during ***the winter of 2020-2021.*** Indeed, French nuclear production will be lower than in previous years:

- the ***two reactors at the Fessenheim power plant*** (1,800 MW in total) were shut down in February and June 2020.
- ***Lockdown measures*** stopped maintenance and fuel loading operations at nuclear reactor sites and, after their release, barrier measures slowed down the work. Therefore, the duration of nuclear reactor annual shutdowns was increased.

In France, EDF had to reorganize all these shutdowns, which is a complex operation with multiple constraints. The shutdowns calendar must comply with regulatory constraints related to equipment maintenance, and consider the residual nuclear fuel portion and the limited amount of skilled human resource. All these rescheduled operations have also to get the agreement of the French Nuclear Safety Authority.

In June EDF revised, for the second time, its 2020 nuclear production at 315-325 TWh (instead of 375-390 TWh planned before the pandemic). For the year 2021 the forecast is at the low level of 320 TWh.

EDF has taken several measures to increase the electricity supply security margins for the 2020-2021 winter. These will be lowest in late 2020, during fall and early winter, unlike in previous years when the period of stress is usually in January-February. For example, EDF deferred reactor shutdowns and even cancelled some of them during the summer so that in winter they would have enough fuel reserves.

EDF has implemented prudent management of hydraulic reserves, ensuring that fossil fuel power plants will be available. French authorities and EDF are now pushing electricity customers to implement demand-side flexibility which should be better remunerated.

- *In Europe,* as described above, many coal-fired power plants were shut down thus decreasing the amount of schedulable generation. The crisis also delayed permitting and construction for new renewable production units.
  For all those reasons, security of electricity supply will be tense during the fall and winter unless economic activity and related electricity consumption remain lower than their 2019 level.

Europe's gas supply patterns are changing:

2019:

- ***Record LNG imports:*** In 2019, gas consumption grew in the EU (+3.1%), as demand recovered in Spain, Germany and Italy. The most noticeable evolution relates to LNG imports: the EU imported the highest ever volume of LNG at more than 100 billion cubic meters (bcm), 42% year-on-year in the last quarter of 2019 making 27% of total gas imports[21]. As prices in Europe and Asia remained aligned, a large share of additional LNG exports supplied the European market[22].
  The main LNG provider was Qatar, followed by Russia and US with increasing competition between the two latter countries.

  In addition to these Russian LNG imports, Russia provides around 40% of EU imports by pipeline. With the continuous decrease of EU domestic production, notably linked to the Dutch Groningen field phase out, Russian export of natural gas to Western Europe has increased by 40 percent in the last five years. When and if completed, the new gas pipeline project North Stream 2 will lead to more increases over the next years.
- ***Challenges facing North-Western Europe:*** By 2022, the Netherlands will halt production at Groningen, Europe's largest onshore natural gas field, eight years earlier than initially planned. This field provided 10% of EU consumption and its closure will decrease gas supply security. It will also decrease gas production flexibility[23] at

20 TURPE: Tarifs d'Utilisation des Réseaux Publics d'Electricité

21 European Commission's (EC) report on the gas market (April 8, 2020)

22 Global editorial p2

23 https://www.iea.org/reports/global-gas-security-review-2019rope-the-impacts-of-COVID-19-and-other-influences-in-2020.p

times when flexibility needs are growing. Renewables' intermittent generation growth, coupled with declining schedulable generation, is increasing gas-fired power generation volatility.

- *Russia-China partnership:* Russia and China decided in 2014 to build a pipeline linking the two countries. This is a win-win decision as it will supply China with gas that is a "cleaner" fuel than coal and reduce Russia's dependency on its European gas sales. Named "Power of Siberia", the pipeline runs more than 3,000 kilometers across the two countries and was inaugurated in December 2019. It will enable natural gas exports of 38 bcm annually to China by 2024 and will be operated by Russia's state-owned company Gazprom. A 30-year deal was signed by Chinese President Xi Jinping and Russian leader Vladimir Putin in 2014, which is believed to be worth more than $400 bn.

2020:

- *Historical drop in EU gas consumption* at the beginning of the year. In the first five months of 2020, natural gas demand in Europe is likely to have declined by about 8 percent[24] due to the successive impacts of mild temperatures, high renewables generation, and the consequences of COVID-19. European storage was more than 70% full as of June 1, 2020, 13 points above the previous year's level. This demand situation has pushed European gas prices below the US Henry Hub whereas they held a premium in all previous years. Thus in 2020, Europe should no longer be the swing market for LNG cargoes.
- *Russia-US tensions* are crystalizing around the Nord Stream 2 project[25]. It is a 1,200 km natural gas pipeline being constructed to connect Germany and Europe to the large reserves in Northern Russia without passing through Ukraine. Gazprom will own and operate the pipeline, which has a capacity of 55 bcm/year. The pipeline was initially scheduled to start operations at the end of 2019.
  The budget for the construction of the pipeline was estimated to be €9.5 bn with Gazprom investing more than half, and the remainder to be financed by Engie, OMV, Royal Dutch Shell, Uniper, and Wintershall.

  Nord Stream 2 was almost completed, but work came to a standstill in December 2019 following a US sanctions law, which exerted enormous pressure on pipe-laying company Allseas, headquartered in Switzerland. The firm decided to withdraw its specialized ships from the project. There are plans now to complete Nord Stream 2 with the help of two Russian specialist vessels.

  However, the US administration wants to prevent the pipeline being completed as it estimates that it will increase Russia's economic and political influence in Germany and other European countries. In June 2020, Republicans and Democrat senators voted on the Protecting Europe's Security Clarification Act. In the future, US sanctions are to target everyone who's still involved in the Nord Stream 2 project, including all companies and persons contributing to equipping the pipe-laying ships, as well as IT service

24 https://www.oxfordenergy.org/wpcms/wp-content/uploads/2020/06/Natural-gas-demand-in-Europe-the-impacts-of-COVID-19-and-other-influences-in-2020.

25 https://www.offshore-technology.com/projects/nord-stream-2-pipeline/

firms, insurance companies and certifiers, and the foreign energy companies that invested in this project.

In addition, the political impact of Russian dissident Alexei Navalny poisoning in August 2020 may force Germany to disassociate itself from this project, it has supported so far, casting doubt on completion and operation of this pipeline in the near future.

- *Gazprom* posted a net loss in Q1 2020 of 116 bn Russian rubles ($1.6 bn).
  This compares to a profit of 536 bn rubles in the same quarter last year. This historical loss is mainly due to a weak ruble, lower prices, and decreased demand in Europe.

  Sales to Europe and Turkey, which account for most of Gazprom's profits, fell by 45 percent to 459 bn rubles. Volume-wise, sales dropped 17 percent to 51 bcm in the quarter under review from 62 bcm recorded last year.

Utilities are adapting to the "new normal"

Even though less profitable than their US counterparts, European utilities enjoyed a good year in ***2019*** thanks to higher electricity prices. On average, their EBITDA[26] margin was significantly higher than the five previous years' average.
As they continued to invest significantly for internal or external development, their net debt as well as leverage ratio[27] increased.

Utilities continued to deploy their portfolio transformation strategies and the mergers and acquisitions market was dynamic[28].

In January 2020, British utility SSE completed the sale of its retail business to OVO Energy for £500 million. The deal makes OVO one of the biggest suppliers in Britain, now serving almost five million customers[29].

The large European Utilities were bullish on renewable assets, developing new capacities (often through subsidiaries) and acquiring smaller players. For example, France's Engie joined a consortium of investors paying €2.2 bn for six hydroelectric assets owned by Energias de Portugal (EDP). The latter needed to divest assets as it faced a hit to its profits from Portugal's move to greener energy. Italy's ENEL purchased for $644 million a 50 percent share in US renewables assets from GE Energy Financial Services.

In 2018, France's EDF announced its ambitious solar photovoltaic plans to install 30 GW between 2020 and 2035 becoming the leader in France with a 30% market share. It acquired the Luxel group which owns 1 GW gross capacity in operation or under development in France.

The German company EnBW has acquired the French company Valeco which operates a total capacity of 276 MW in onshore wind, 56 MW in solar and has a portfolio of more than 1,700 MW of projects in development.

Utilities are investing in electricity storage, an important complement to intermittent renewable energies. EDF has therefore set itself the goal of installing 10 GW of new storage capacities around the world by 2035 and becoming, like many oil companies, a major player in smart charging. The company has created Dreeve, a joint venture with the Californian startup Nuvve.

Oil companies are also focusing on renewable energy acquisitions and thus competing with Utilities. Total, already present in solar energy, has acquired Global Wind Power France, which has a portfolio of more than 1,000 MW of onshore wind projects demonstrating its desire to develop in all renewable energies. Shell and Total were among the bidders for Dutch utility Eneco, primarily focused on renewables. It was ultimately sold to Mitsubishi and utility firm Chubu Electric Power from Japan for $4.8 billion.

Competition between oil companies and electric utilities became even clearer in France with the legal battle between EDF and Total around conditions of accessing the ARENH[30] guaranteed nuclear origin electricity during the COVID-19 linked crisis[31].

As underlined in previous WEMO editions, Chinese companies are looking to acquire assets all over the world. Chinese firms have ploughed at least €145 bn into Europe from 2010 to 2019. But investment has been slowing as several European governments tighten rules on acquisitions by foreign firms. As an example, in 2019, China Three Gorges' (CTG)[32] transaction to acquire a majority stake in Portugal's EDP collapsed amid disagreements over a cap on voting rights. This failure did not discourage the Chinese power company and in August 2020, it announced the acquisition of a 572

26 EBITDA Earnings Before Interest, Tax, Depreciations and Amortization
27 Ratio between Net Debt and EBITDA
28 https://mergers.whitecase.com/highlights/renewables-sector-drives-ma-in-energy-industry#
29 https://www.energylivenews.com/2020/01/15/sse-completes-sale-of-retail-unit-to-ovo-energy-for-500m
30 ARENH: Accès Régulé à l'Electricité Nucléaire Historique
31 https://www.planete-business.com/2020/06/04/edf-met-fin-a-des-contrats-dapprovisionnement-le-liant-a-ses-concurrents/
32 CTG has 23% of EDP
33 The sample includes Centrica, CEZ, EDF, EDP, Enel, Engie, E.ON, EnBW, Fortum, Iberdrola, Naturgy, Orsted, RWE, SSE, Uniper

MW, Spanish photovoltaic plants portfolio owned by developer X-Elio and valued at €500-600 million.

In 2020, the average revenue of a sample of large European utilities[33] decreased in H1 by roughly 4.5% compared to H1 2019. Those utilities have suffered noticeably from the energy consumption decrease during lockdown and from an increase in bad debts. During this period wholesale prices decreased strongly, however their impact was mitigated by generation hedging policies, as a significant proportion H1 2020 generation was hedged at 2019 forward prices (that were significantly higher than in 2020). Due to the same hedging policies, H1 2020 low forward prices will impact negatively on future generation (H2 and 2021) revenues.

European utilities are likely to lower their planned investments by 10-15% this year as they try to preserve cash and cope with supply chain disruptions and other delays related to the spreading coronavirus[34]. Some of them reduced their 2019 dividends, more of them could do so for 2020 if the new waves of the pandemic significantly cut into earnings.

Some retail suppliers could end up with further losses if electricity consumption does not recover to 2019 levels. Additionally, governments in countries such as the UK and France have put in place protections for vulnerable customers, which will increase debt (as working capital requirements grow) and squeeze their results.

By the end of H1 2020, following significant drops in their EBITDAs, some large integrated utilities had already announced cost cutting and divestment plans.

EDF announced at the end of July 2020, a vast savings and disposal plan to offset the effects of the health crisis on its activity that resulted in a €700 m loss for H1 2020. The utility wants to reduce its operating expenses by €500 m between 2019 and 2022 and committed to around €3 bn in new disposals by 2022.

Engie, whose net profit was reduced to zero in the first half of 2020 (compared to €2.1 bn over the same period in 2019) announced a strategic review notably in its service activities, as well as a divestment program doubled to €8 billion to allow acceleration of its investments in renewables and infrastructure activities.

Other utilities and energy investors could also launch divestment plans for non-core assets. However, in this crisis period these plans' execution could be delayed by the lack of acquirers.

Following lengthy negotiations, UK based Centrica[35] announced on July 24, 2020, that it had entered into an agreement to sell its North American energy supply, services and trading business, Direct Energy, to the American NRG Energy, for $3.625 billion in cash (equivalent to approximately £2.85 bn) on a debt free, cash free basis. However, it is pausing the sale of both Spirit Energy Ltd., its upstream oil and gas joint venture, and its 20% stake in the UK's fleet of nuclear power plants.

Some other large transactions have already seen changes. E.ON, which needs to divest additional businesses, including retail operations in Hungary and the Czech Republic, to satisfy conditions for EU approval of its mega-merger with Innogy SE, announced that it will wait for better times.

34 https://www.spglobal.com/marketintelligence/en/news-insights/blog/essential-energy-insights-june-11-2020

35 https://www.centrica.com/media-centre/news/2020/proposed-sale-of-direct-energy-for-3625-billion-to-nrg-energy/

Utilities are re-evaluating their operating models in response to the crisis. According to an E&Y survey[36], 83% said it is affecting decision-making around their global supply chains, 74% said it will change how the workforce is managed, and 72% said it will accelerate their speed to digitization. They are preparing for the "new normal" times

Conclusion

In 2019, Europe continued to be the region of the world most concerned about climate change issues. Many coal-fired power stations have therefore been closed mainly to comply with the energy transition plans adopted by EU Member States. Electricity produced by wind and solar power continued to increase and its costs continued to drop dramatically. While wind turbines are largely made in Europe, solar panels and many components of such equipment are imported from China highlighting Europe's dependence on these imports.

The specific conditions during lockdown with the drop in electricity consumption and favorable weather combined with coal plant closures, led in the first quarter of 2020 to greater electricity generation from renewable sources than from fossil fuels.

In June 2020, the governments of the European Union adopted an ambitious recovery plan of €750 billion, 30% of which will be devoted to energy transition and the achievement of the objectives of the Paris agreement on climate change. The energy-focused renovation of buildings will be one of the highlights of this plan. In the EU, France and Germany have also adopted plans to develop green hydrogen which is an area where Europe has world champions like Air Liquide and Linde. This could allow Europe to regain a global place in the storage of electricity while the production of electric batteries is mainly in Asia.

The high percentages of renewable energy observed during the lockdown period, anticipating forecasts by several years, and the near blackouts that this resulted in, showed that it was necessary to increase the flexibility of the electricity networks and reform the electricity market. Other regulations are needed to encourage, low-carbon investments and notably implementation of a carbon tax at borders, as announced by the President of the European Commission.

The disorganization of the annual maintenance and fueling operations of French nuclear reactors during containment has led to a drop in nuclear production forecasts for 2020, 2021 and probably 2022. This poses a risk to the security of electricity supply during the winter 2020-2021.

Finally, gas supply in Europe is evolving with the increase in liquefied natural gas imports, particularly from the United States, the relative decrease of piped gas, and the closure of the Dutch gas field in Groningen.

The utilities which suffered during the lockdown are reviewing their internal processes and working methods to make best use of the digitization lever.

The year 2020 and beyond will be full of uncertainties. Governments and energy players need to be nimble to adapt to this new situation.

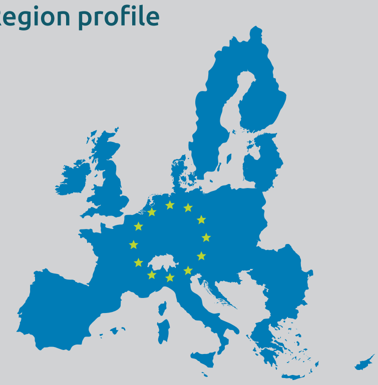
Colette Lewiner

Energy senior Advisor to Capgemini Chairman
Paris, September 18, 2020

36 https://www.ey.com/en_gl/ccb/power-utilities-mergers-acquisitions

Region description

Region profile



Region: Europe
Population: 515 million
GDP: $15.6 trillion

CO_2 footprint

- Total 2019 CO_2 emissions: 3,330 Mt
- 2019 CO_2/capita emissions: 6.47 tons

Energy demand

- 2019 energy demand: 69.81 EJ

Renewable energy

- Investments in clean energy: $76.4 bn (2019); (-2.4% from 2018)

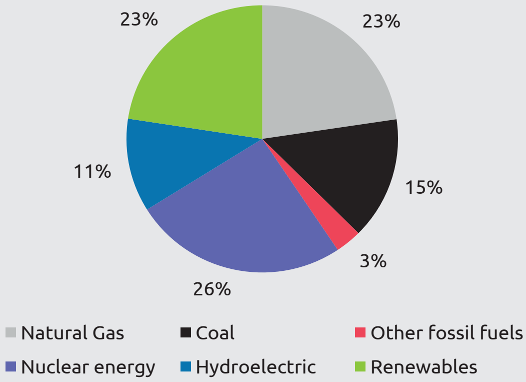
Gas

- Total natural gas production: 110 bcm
- Total natural gas consumption: 485 bcm
- LNG imports : 102 bcm

Coal

- Coal production: 4.6 EJ, down 13% from 2018
- Coal consumption: 7.7 EJ, down 18% from 2018

Electricity generation by Fuel, 2019 (TWh)



Sources: World Bank, BP Statistical Review, Eurostat, IEA, ENTSO-E, European Alternative Fuels Observatory

Electricity

- Total electricity generation capacity: 2,010 GW
- Total electricity consumption 2018: 6510 TWh
- Average electricity price: €44.3/MWh
- Electrification rate: 100%

Oil

- Total oil production: 1,531 thousand barrels daily
- Total oil consumption: 12,913 thousands barrels daily (13% of the world's total)

Electric mobility

- Number of public electricity charging stations: 164,000
- Number of electric vehicles (2019): 1.1 million
- Market growth: 3.3% of new car sales

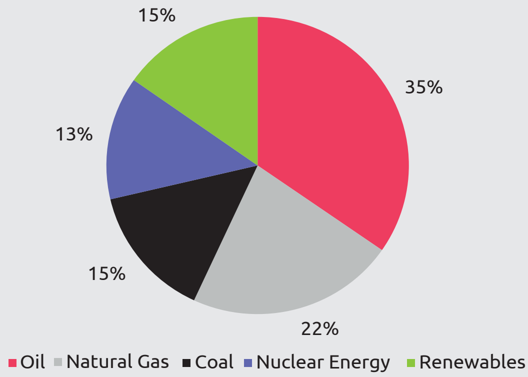
Nuclear

- Total generation: 772 TWh
- 109 nuclear power reactors in operation, 4 under construction

Country highlights

- Key policies : « Clean Energy for all Europeans » Package
- Key facts :
  - Worldwide leader on energy transition
  - 2020 GHG emissions reduction target achieved
  - Phasing out coal plants
  - Decreasing gas production
  - Increasing share of Liquefied Natural Gas in imports
  - Post-COVID stimulus packages integrating energy transition

Primary Energy Consumption by Fuel, 2019 (EJ)



Sources: World Bank, BP Statistical Review, Eurostat, IEA, ENTSO-E European Alternative Fuels Observatory

1-Climate Change & Energy Transition

Following the Clean energy for all Europeans package, the Green Deal is supporting Europe's ambition with a dedicated €1 tn investment plan to reach carbon neutrality by 2050

In December 2019, the EU published the Green Deal, a roadmap with concrete actions to fight against climate change, covering all topics related to the EU transformation along the road to sustainability

- **The Green Deal roadmap seeks to:**
  - Interconnect energy systems and improve the integration of renewable energy sources with the grid.
  - Promote innovative technologies and modern infrastructures.
  - Increase energy efficiency and ecoconception.
  - Decarbonate the gas industry and promote a smart integration in all sectors.
  - Empower consumers to make informed choices and play an active role in energy transition.
  - Increase regional and cross-border cooperation in order to better share clean energy sources.
  - Promote European energy standards and technologies at global level.
  - Harness the full potential of offshore wind in Europe.
- **The Green Deal focuses on actions that will enable the 2030 targets to be reached**
  - An update of National Energy and Climate Plans (NECP) is planned for 2023 to take new ambitions into consideration.
  - Infrastructures needed for a general greening of energy mixes, as well as offshore wind and gas, are mentioned but related technologies are not detailed.

A € 1 tn investment plan has been allocated in distinct envelopes, addressing several topics, to make the Green Deal come true

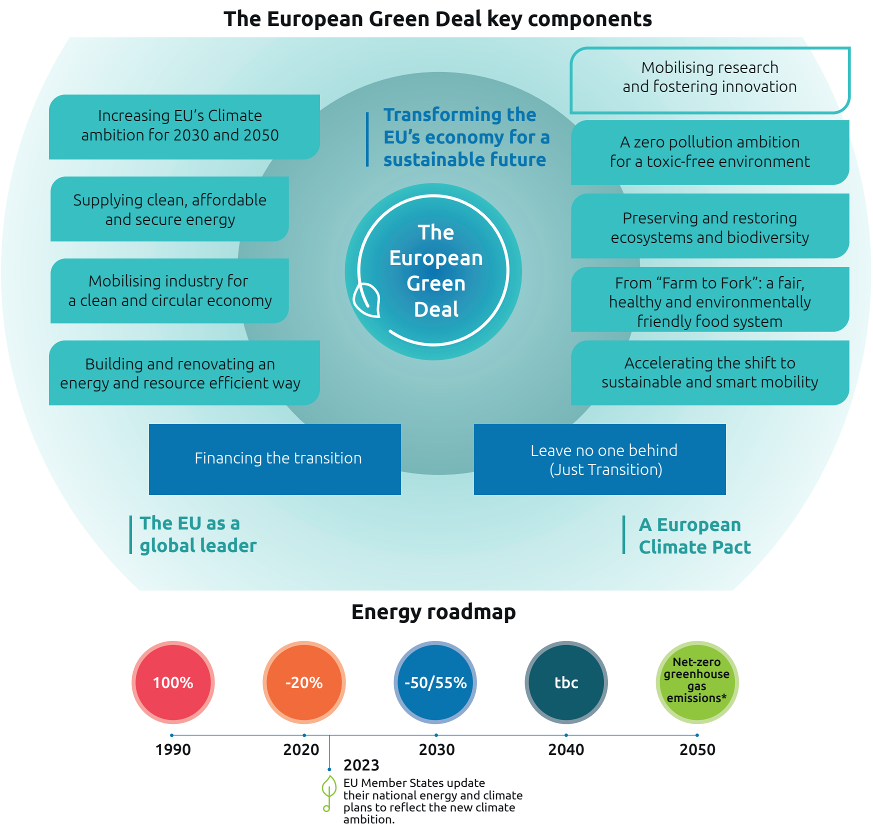
- This represents a significant investment of about €100 bn per year.
- The COVID-19 crisis is likely to have impacts, both on the translation of these energy actions at national levels and on the green investments, as part of the crisis recovery.

The funding will come from European sources, such as a share of the European budget, InvestEU, the Just Transition Mechanism and additional national sources

- Expenditures dedicated to climate and environment should reach 25% of the EU budget between 2021 and 2027 (2021-2027 multiannual financial framework).
- The InvestEU program of €650 bn will finance actions beyond climate change, to favour employment, growth and investment.
- The mechanism for a just transition aims at integrating European territories and avoiding socio-economic impacts from the transition, initially composed of a budget of €143 bn over 10 years.
- Additional funding of €114 bn will be needed from Member States to complete the package.

This budget has not been voted yet.

Figure 1.1. European roadmap toward carbon neutrality



* The emissions that will not be eliminated by 2050 will be removed e.g. via natural carbon sinks such as forests and carbon capture and storage technologies
Source: European Commission

Post-COVID-19 investments reaffirm the EU strategic orientation towards energy system integration and hydrogen

Next Generation EU's 3 pillars and programs amounts (bn€)	
1.Supporting Member States to recover	
Recovery and Resilience Facility	**672.5**
Of which GRANTS	*360*
Of which LOANS	*312.5*
REACT-EU	**47.5**
Rural development	**7.5**
Just Transition Fund	**10**
2. Kick-starting the economy and helping private investments	
Solvency Support Instrument	
InvestEU	**5.6**
Strategic Investment Facility	
3. Learning the lessons from the crisis	
Health programe	
rescEU	**1.9**
Horizon Europe	**5**
Neighbourhood, Development and International Cooperation	
Humanitarian Aid	

COVID-19 disrupted established programs and has swung the spotlight back onto the financing of a more sustainable Europe

- The EU recovery plan integrates a new mechanism: Next Generation EU (NGEU).
- This plan has a €750 bn package for 2021-2024. It shows a clear ambition to bet on energy transition and decarbonization to restart the economy.
- Despite the fact that sustainable infrastructures are mentioned in the InvestEU budget, support for the development of renewables is not discussed.
- The European Commission adopted two strategic orientations in July 2020, developed with Next Generation EU and Green Deal funding:
  – **Integration of energy systems:** including a more circular energy system centered around energy efficiency, with direct electrification of final sector use; and promotion of cleaner fuels (such as renewable hydrogen, biofuels and sustainable biogases).
  – **Hydrogen:** the ambition is to materialize hydrogen potential through investment, regulation, and the creation of markets, as well as research and innovation.
- The agreement made by European governments in July 2020 brought changes to the proposal from the European Commission, such as:
  – A new repartition of grants (390 bn€ instead of 500 bn€) and loans (360 bn€ instead of 250 bn€ initially),
  – A reduction of the Just Transition Mechanism (from 40 bn€ to 17.5 bn€),
  – A reduction of the InvestEU budget from an initial 31 bn€ to 5.6 bn€.

Most European countries achieved a reduction in their CO_2 emissions during 2019. Yet there is still a long way to go to reach the 2030 and 2050 targets

In September 2020, the European Commission proposed to revise the EU 2030 emissions reduction target with an objective of -55% compared to 1990 emissions

- The current EU target is fixed at -40% compared to 1990 levels.

The combination of slower growth in energy demand and a shift in the fuel mix away from coal and towards natural gas and renewables led to a reduction of CO_2 emissions in Europe

- The UK and Switzerland are the only countries which have been able to decrease their CO_2 emissions every year since 2015 at a CAGR of 3% and 1% respectively. The cleaner electricity mix based on gas and renewables has been the main driver for achieving CO_2 emissions reduction since 1990[1 2].
- Germany (684 Mt), the UK (387 Mt), Turkey (383 Mt), Italy (325 Mt), Poland (304 Mt) and France (299 Mt) were the biggest emitters in 2019, with France getting under 300 Mt for the first time in 5 years.
- The Netherlands, Italy and the UK remain the largest coal users.

1 CarbonBrief
2 Swissinfo

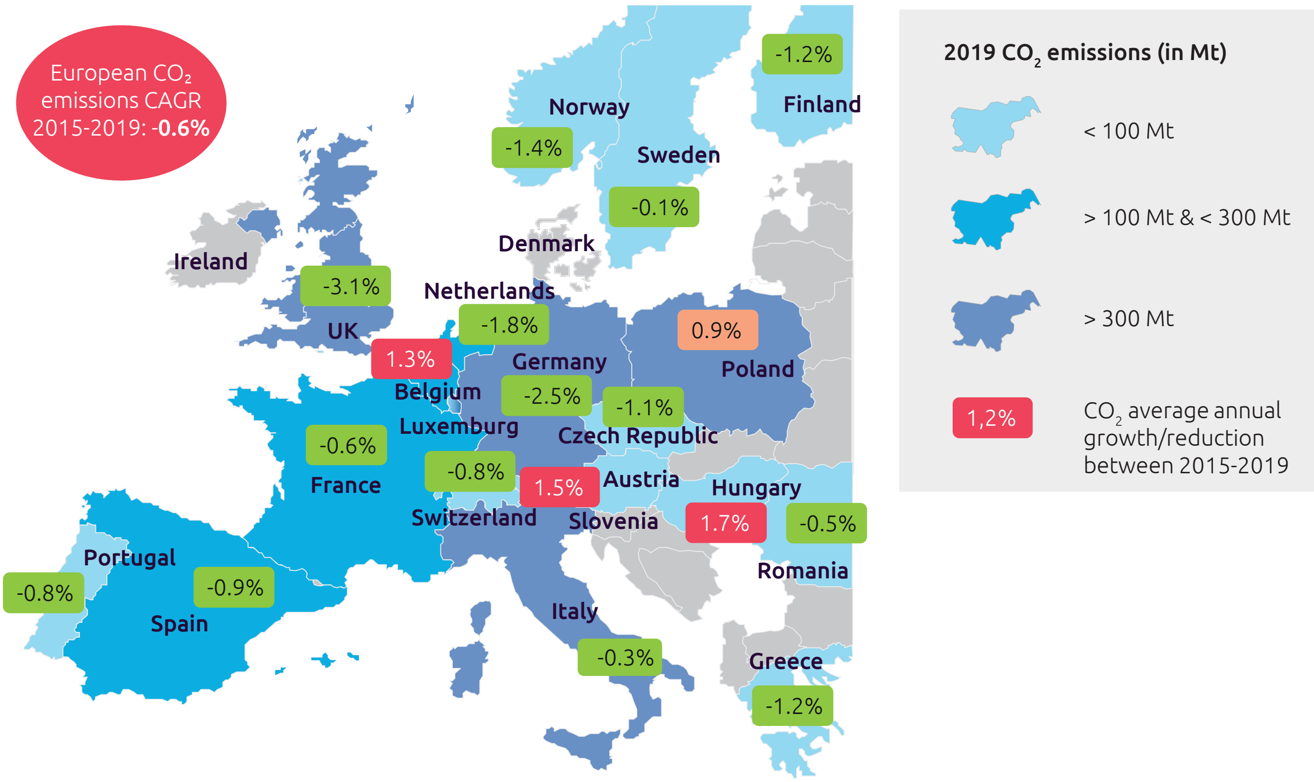
European countries achieved a reduction of 135 Mt CO_2 during 2019 with Germany, Poland and Spain in the lead.

- Germany, the largest CO_2 emitter in the EU, has achieved a reduction of its emissions by 6.5%, which also means that one third of the reduction of EU emissions in 2019 is actually due to Germany.
- Poland and Spain have also both reduced their emissions by 15 Mt in 2019 compared to 2018. However, Poland still has a positive CAGR due to the increase of its emissions from 2016 to 2018.
- Although CO_2 emissions decreased in 2019 in Europe, a few countries such as Poland, Belgium, Austria, Turkey and Hungary still have a positive CAGR for 2015-2019.

Fuel combustion and fugitive emissions from fuel (excluding transport) are the main emitters of GHG in Europe (53%)

- In 2018, the main contributors to EU GHG emissions (53%) were fuel combustion and fugitive emissions from fuel (excluding transport).
- Fuel combustion for transport (including aviation) was the second largest source with 25%, whereas agriculture, industrial processes and waste management accounted for the remaining 22%.
- GHG emissions in Europe have decreased by 21% compared to 1990 levels, which means an absolute reduction of 1,018 Mt of CO_2-e. This has enabled the EU to accomplish the 2020 target of reducing emissions by 20% compared to 1990 levels.

Figure 1.2. 2019 CO_2 emissions in Europe and associated CAGR 2015-2019



Source: Eurostat, BP Statistical Review

*Total CO_2 emissions are **forecast to drop by more than 10%** in 2020 due to the additional impact caused by COVID-19. Its effect on industry, transport and production led to a decrease in energy demand, oil demand and coal usage during Q1 2020. In addition, wind availability increased the use of renewable energy and its share in the mix.*

In 2019 and early 2020, ambitious laws were voted in order to reach 2030 targets, such as the Spanish Integrated National Energy and Climate Plan (INECP)

The Spanish INECP contains ambitious objectives above the expectations of the European Union and outperforming other European countries[1,2]

- In the latest INECP, local government seeks to increase the share of renewable energy by 42% (10% above EU objectives and 12% above other European countries) and energy efficiency by 39.5% (against the EU goal of 32.5%).
- Additionally, Spain sets out the target of interconnection levels of 15% between member states which is in line with EU objectives.
- Only in terms of reducing GHG emissions by 23% (compared to 1990) is Spain below the 2030 targets set by the EU (40%) and Green Deal (50-55%).

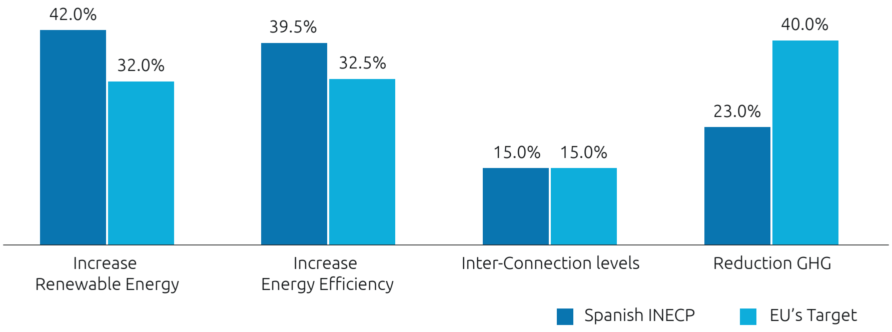
Spain has estimated that a total investment of approximately €241 bn between 2021 and 2030 will be needed in order to achieve the targets

- The investment will be distributed across different measures: saving and efficiency: 35% (€83.540 bn), renewable energy: 38% (€91.765 bn), networks and electrification: 24% (€58.579 bn), other measures: 3% (€7.528 bn)
- 80% of the investment will come from the private sector, mainly focused on the deployment of renewables, distribution and transmission networks, and a large part of the energy saving and efficiency measures; and 20% from the public sector, mainly focused on energy saving and efficiency measures, and in promoting sustainable mobility and a proactive energy transition mindset within society.
- As a result, local government expects up to 348,000 jobs to be created across renewable energy, networks, and electrification and industrial sectors.

A number of Spain's largest companies have already committed themselves in order to contribute to ambitious objectives

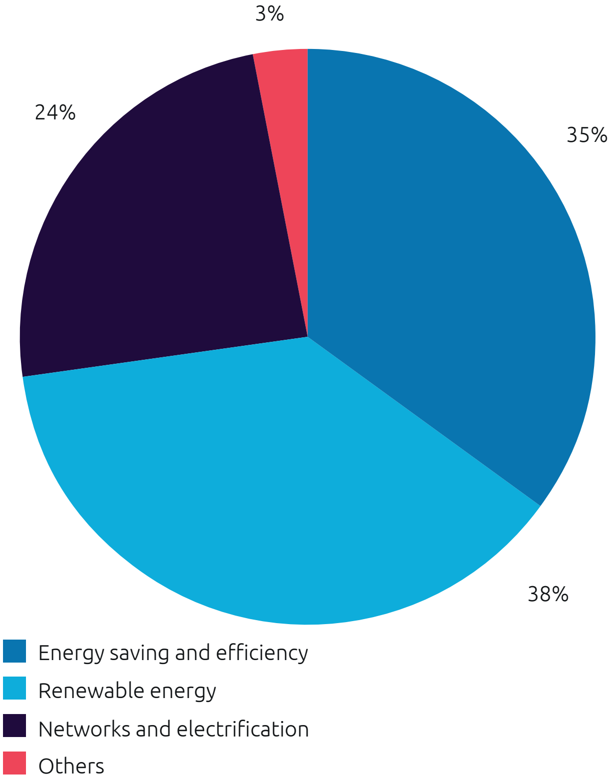
- The oil & gas company Repsol has announced its commitment to achieve net zero emissions by 2050. This goal includes production and all products[3].
- The Spanish electricity utility Iberdrola has committed to reduce the intensity of CO_2 missions by 50% by 2030 compared to 2007 and expects to be carbon neutral by 2050[4].
- Telefónica, a leading global telecommunications company, has brought forward its goal of net zero emissions in its major operations from 2050 to 2030 after already achieving a global reduction of almost 50% in emissions in 2019[5].

Figure 1.3. Spanish INECP targets compared to the EU's targets



Sources: European Commission, Spanish Integrated National Energy and Climate Plan (INECP)

Figure 1.4. Distribution of estimated investments in order to achieve the Spanish INECP targets



Source: Spanish Integrated National Energy and Climate Plan (INECP)

1 European Commission, Spanish INECP
2 European Commission
3 Repsol's website
4 Iberdrola's website
5 Telefonica's website

These climate objectives were not negatively affected by the COVID-19 crisis: Spain recently passed a law to meet the 2030 energy and climate objectives

Across the European countries, Spain has significantly reduced its CO_2 emissions due to very stringent lockdown measures and therefore also suffered a serious drop in its Gross Domestic Product (GDP)[1]

- During the lockdown period, the electricity demand dropped by approximately 20% in Q1 2020.
- In the same period CO_2 levels were reduced by 31.9% mainly due to the reduced aviation activity (-75%), surface transport (-50%) and energy production (-15%).
- Compared to Q2 2019, Spain's GDP dropped by 22.1%[2].

Due to the COVID-19 crisis, Spain published new provisions to mitigate against the negative effects of the virus, to ensure balancing in the electricity market and permit continuity in energy investments

- Currently, investment limits for transportation and distribution of electricity are determined by the Spanish GDP. This means that if there's a reduction in GDP, investments will drop. For this reason, and exceptionally, the Government decided to adjust them up to 0.0075% and 0.014% of GDP, respectively.
- The Energy Minister will use surplus income from the network to cover system costs during 2019 and 2020 as well as any transitory deviations that may appear in monthly settlements.

In order to meet renewable energy objectives, action is needed to cover intermittency and non-manageability issues intrinsic to non-storable primary energy sources

- The government will permit new concessions harnessing non-flowing hydraulic circuits in the public domain to promote reversible hydroelectric power plants.
- It will also determine a new remuneration framework based on a long-term recognition of a fixed energy price, expected to enter into force by the end of 2020.
- The government has regulated conditions for new renewable plant connections, establishing technical viability authorizations on new projects.
- Under the new mobility program, a scheme to subsidize electric cars and the infrastructure required to charge them will receive €100 million in public funding.

Buyers will receive between €400 and €4,000 from the government for purchasing a new car that meets certain requirements, and this subsidy is matched by the industry.

The return rate for investments was revised in favor of promoting renewable energy installations, cogeneration plants, and waste plants

- Alongside the National Commission on Markets and Competition, the government fixed its value for 2020-2025 at 7.09% versus the previous 7.398% (considered high due to the reduction in manufacturing costs over the last decade).

1 Spanish Official State Gazette (BOE), n°175
2 Hibridos y Electricos

Topic Box 1.1: UK's Net Zero workforce transition challenge

Transitioning to a digitally enabled and augmented workforce to help the United Kingdom reach its emissions target and transition to a net zero economy by 2050 will be a challenge as the entire country needs to support it.

Key sector operating environment changes include:

- Recognition of Climate Change emergency = need for change acceleration
- Worldwide COVID 19 pandemic = change in both working and energy demand patterns
- Digital and Data transformation across sector = intensifying competition for skills
- The UK Post-Brexit = greater need for local talent
- The evolution of the Circular Economy = Increased awareness and capabilities

For the UK to achieve its net zero ambitions, the energy sector will play a vital role in the broader business ecosystem. As part of this, the UK needs to rapidly augment the talent it needs to support its net zero plans by recruiting the right people with the right skills to deliver.

Current human capital challenges to building the net zero future:

An aging workforce: 27% of the workforce is due to retire in the next decade	43% of the sector workforce will need to be replaced or retrained	Significant increase in competition for talent within and outside of sector for in demand skills
The damage of the COVID-19 pandemic and impact on the UK economy is not yet quantifiable	Scarcity of graduate talent due to increase in science, technology, engineering and mathematics (STEM) qualifications competition	Continued diversity challenge with the sector being below UK average for gender, Black, Asian and Minority Ethnic (BAME) and disabilities

Considering the scale of change required, as well as external challenges, one report estimates that the UK needs to recruit for 400,000 jobs between now and 2050 to reach its net zero target: 260,000 of these jobs will be new and 140,000 will replace people leaving the workforce.

So where does the energy sector need to focus?

- Accelerating the development of renewable and low carbon skills – e.g. Committee on Climate Change calls for government support to train designers, builders and installers for low-carbon heating (especially heat pumps), energy and water efficiency, ventilation and thermal comfort, and property-level flood resilience.
- More innovation capabilities to challenge the industry status quo e.g. highly skilled resource to support energy technology R&D
- Greater focus on localism due to Brexit and potential ongoing impacts of COVID-19. Building a sustainable, resilient UK energy workforce
- Building the digital and data backbone – skills that are essential to realising the transformation potential of existing and future technologies

How does the UK start to build and transition the workforce?

1 Energy players need to have a robust strategic workforce plan

- Each energy player needs to have a strategic workforce plan - a view of its current workforce, the key external factors impacting on the workforce, what is needed to deliver against the future baseline– AI, automation etc.

Practically what we are seeing with our Clients

In-demand UK energy roles:

- Data scientists
- Big data architects
- Automation technicians and engineers
- Renewable energy specialists
- Digital transformation specialists
- IT project managers

These roles are based on the recently published RIIO-2 network business plans3 and our experience working with our clients.

- This allows companies to play out different scenarios e.g. Brexit workforce risk and develop skills sourcing strategies for how to develop the organization's future workforce i.e. build, buy, borrow, or bot;
- These plans could be aggregated at an industry-level to support the net zero workforce transition.

2 The sourcing strategy

Once you have the data from the workforce plan you can then, either at a company or industry level, start building your workforce.

Lay the foundations for future generations – STEM pipeline development, apprenticeships, university collaborations

Attracting in the brightest talents who want to make a meaningful contribution to society and our environment

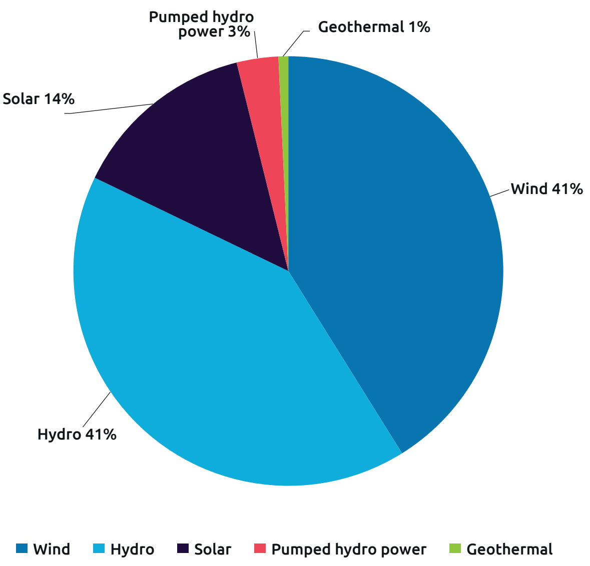
- Keeping the talent through compelling employee value propositions
- Upskilling the energy workforce at scale such as industry digital literacy
- Targeted reskilling programs for at risk workforce e.g. from automation
- Working collaboratively across industry to build new workforce capabilities at pace
- Boosting diversity and inclusiveness across the sector

The European Union is on track to meet its 2020/2030 renewables target

The EU is on track to meet its 2020 target…

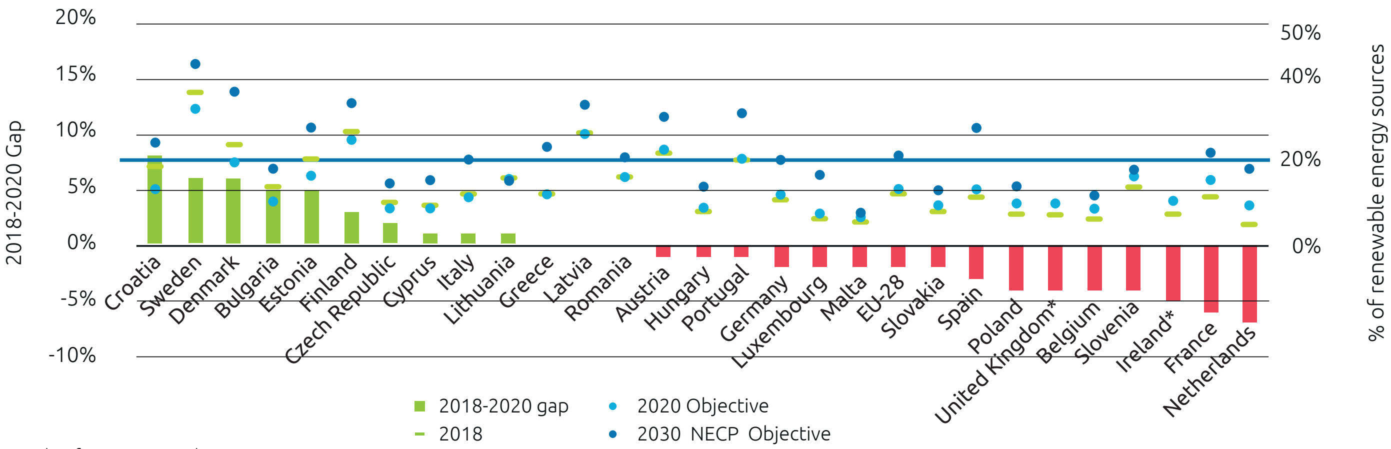
- In 2018, the share of energy from renewable sources in gross final energy consumption reached 18.0% in the EU, slightly up from 17.5% in 2017 and more than double the share in 2004 (8.5%).
- In 2018 wind power became the largest source for renewable electricity generation in the EU, now on a par with hydro. The amount of electricity generated from hydro remains similar to the level recorded a decade earlier. The growth in electricity from solar power has been dramatic, rising from just 3.8 TWh in 2007 to 128 TWh in 2018.
- In 2018, renewable energy accounted for 19.7 % of total energy use for heating and cooling in the EU. This is a significant increase from 10.4 % in 2004. Increases in industrial sectors, services and households (building sector) contributed to this growth.
- The average share of energy from renewable sources in transport increased from 1.4 % in 2004 to 8.0 % in 2018. Among the EU Member States the share of renewable energy in transport fuel consumption ranged from highs of 29.7 % in Sweden, 14.9 % in Finland and 9.8 % in Austria down to less than 4.0 % in Croatia (3.9 %), Greece (3.8 %), Estonia (3.3 %) and Cyprus (2.7 %).

Figure 1.5 EU28 Renewable electricity generation (2018)



Source: Eurostat

Figure 1.6. Share of Renewables in the Member States' gross final energy consumption in 2018



*No data for 2030 NECP Objective
Sources: Eurostat, European Commission

Europe

…even though achievements vary from one country to another

- The ranking among European members has not changed significantly since last year. Sweden tops the ranking with more than half (54,6%) of its gross final consumption coming from renewable sources, ahead of Finland (41.2 %), Latvia (40.3 %), Denmark (36.1 %) and Austria (33.4 %). At the opposite end of the scale, the lowest proportions of renewables were registered in the Netherlands (7.4 %), Malta (8.0 %), Luxembourg (9.1 %) and Belgium (9.4 %).
- The situation in countries like France or the Netherlands has worsened, and they need to increase their share of renewable energy in final energy consumption by at least 6.4% and 6.6%, respectively, to meet their 2020 targets (last year the shortfall was 5%).
- By contrast, 12 of the Member States had already surpassed their target for 2020; the extent to which the targets have been exceeded was particularly large (in the range of 5-8%) in Croatia, Sweden, Denmark and Estonia.

The share of Renewables reached record highs during the COVID-19 lockdown, up to a level expected only at the end of the decade, endangering the security of supply notably in UK and Germany

- The use of renewable energy in the form of biofuels declined in Q1 2020 as consumption of blended fuels for road transport fell. Once lockdown measures were put in place, electricity demand fell while levels of wind and solar PV held steady. This led to a noticeable step up in variable renewables' share of demand. Belgium, Italy, Germany and Hungary saw record-high hourly shares of variable renewables in electricity demand during lockdowns.

After an increase in 2018, clean energy investments remain at the same level. Renewables can play a core role in sustainable recovery strategies to emerge from the COVID-19 crisis

Investments in clean energy have stabilized over 2018-2019

- After rising in 2018, new investments in clean energy in Europe stabilized over the 2018-2019 period, though they still reflect an overall increase in investment of 13.9% since 2013. The impacts of the COVID-19 crisis may limit investments over the 2020-2021 period.

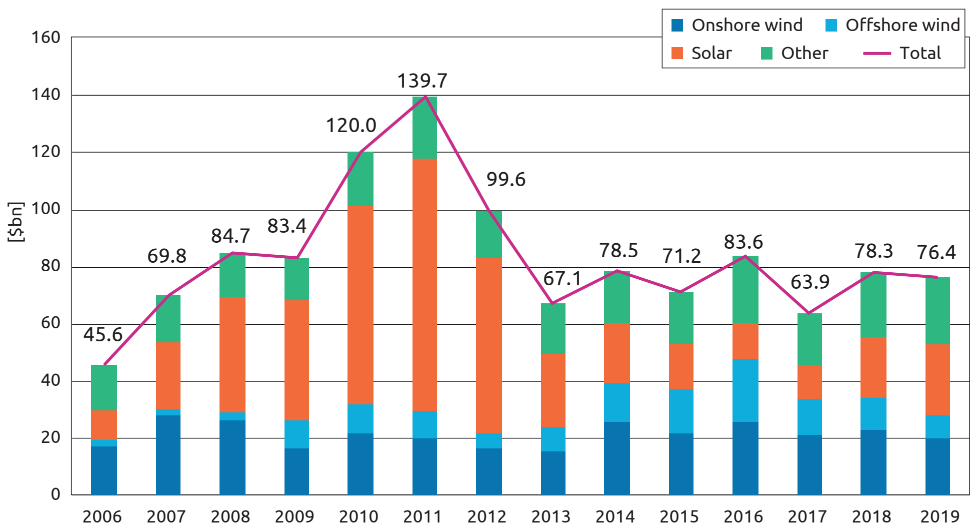
The cost of installing renewable energy is lower than ever

- This means future investments will be able to deliver far more capacity than in previous years. 2019 was the strongest growth year for solar in the EU-28 since 2010, with 16.7 GW of solar installations added, representing a 104% increase over the 8.2 GW of solar capacity added in 2018. This growth in capacity comes despite investment in solar only increasing 17.1% in 2019 from 2018.
- The declining costs for renewable electricity, particularly solar PV and wind, facilitate their integration. In the power sector, investing in solar PV and onshore wind is increasingly cost-effective compared to traditional sources. These technologies are the cheapest sources of new-build generation and have more job creation potential than fossil fuels.
- In addition, as renewable energy is becoming more cost-effective than ever, this further enables clean energy to be prioritized in economic recovery packages and come closer to meeting the goals of the Paris Agreement.

Clean energy sources can be prioritized as an engine for sustainable growth in the post-crisis recovery

- If governments take advantage of the falling costs of renewables, clean energy can also be prioritized to create a growth engine at the heart of a sustainable post-COVID-19 economic recovery, creating new jobs and ensuring future climate protection. The pandemic is a good opportunity for energy transition, as it is both a lever and accelerator for emerging from the crisis.
- The energy transition will be boosted during the post-crisis recovery and onwards by schemes and recovery packages such as the US Green Act and the European Green Deal, enabling the renewable energy sector to become more competitive and attractive. The European Green Deal, an ambitious package of measures that aims to enable European citizens and businesses to benefit from sustainable green transition, has the objective of transforming Europe into the world's first climate-neutral continent by 2050.
- Renewables still hold a stronger share in the electricity mix than prior to the COVID-19 pandemic and will be further favored by stimulus packages for sustainable recovery from 2020 onwards.

Figure 1.7. New investments in clean energy in Europe: 2006-2019 (US$ billion)



Source: BNEF 2020

Thanks to solar, net renewable power capacity rose by 42% in 2019, yet many projects planned for 2020 will be delayed until 2021 due to COVID-19 lockdown

This 42% increase is mainly due to solar power accounting for more than 50% of the RES capacity installed in 2019

- While the solar market has been mostly dominated by Germany in the past decade, Spain is now the leader with 4.9 GW added in 2019. The main driver for Spain's 2019 solar boost were its auctions in 2017, when around 4 GW of solar was awarded with a grid-connection deadline at the end of 2019[1].
- The German market continued its recent solar growth path to reach 4 GW in 2019. Like the year before, the main drivers for the country's solar boost in 2019 were self-consumption/ feed-in premiums for medium to large-scale commercial systems ranging from 40 kW to 750 kW[1].

Although onshore wind installations in Germany dropped by 55% in 2019, Europe still saw a 30% growth

- Germany's onshore wind growth in 2019 fell to its lowest level since 1998, as the policy transition from feed-in premiums to competitive auctions impacted on the projects pipeline[2].
- European onshore capacity evolution is primarily due to strong growth in Spain (2.3 GW) and Sweden (1.6 GW).

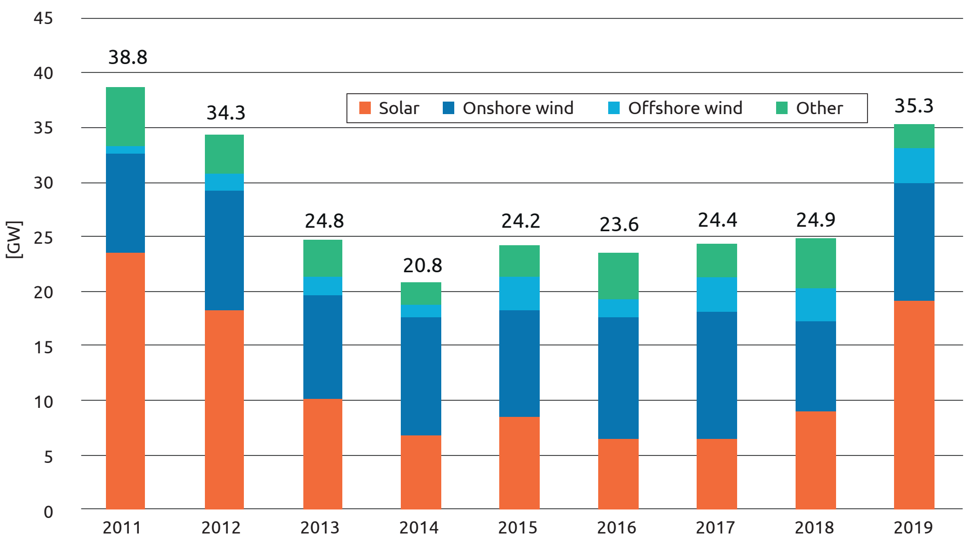
Offshore wind installation breaks a new record in Europe with 3.6 GW installed in 2019

- Europe continues to lead the offshore wind market, with around 60% (3.6 GW) of the offshore wind capacity installed in Europe.
- After China (2.3 GW), the UK and Germany are the main contributors with respectively 1.8 GW and 1.1 GW.

Despite decreasing costs of installing renewable energy, 2020 additions will decline due to the COVID-19 crisis

- According to IEA, PV additions are set to decline in 2020 as a result of the exceptionally high growth in 2019; the uncertainty related to policy transitions (particularly in Germany and Spain); the lockdown-induced construction delays; and the economic impact of COVID-19 on the business case of unsubsidized utility projects and distributed PV[2].
- 2020 wind energy installations are expected to drop by 30% compared to industry forecasts. This will depend on the how quickly activity can ramp up in the most heavily impacted countries – Spain, Italy[3].
- Uncertainty regarding how the COVID-19 crisis will evolve is likely to impact on projects' financing. Banks will be less willing to lend as they are concerned about liquidity and corporate finance. To reduce these risks on projects under development, some governments have modified support mechanisms by extending commissioning deadlines or postponing auctions.
- According to Wind Europe, the lost ground in 2020 will not be made up by 2021, and the outlook for the wind sector will mainly depend on the effectiveness of national and EU recovery plans.

Figure 1.8. Net renewable power capacity added in Europe in 2019 (GW)



Source: IRENA 2020

1 EU Market Outlook For Solar Power 2019 – 2023
2 IEA
3 Wind Europe

In 2019, power from renewable sources was the cheapest option for new-build capacity in most regions of the world

Increasing capacity factors and modules costs falling led to a remarkable reduction in the cost of solar electricity

- Electricity cost from utility scale PV fell by 13% in 2019, reaching an average LCOE of €57/MWh.
- This evolution is mainly due to the continuing fall in costs of module technology which declined by 14% between December 2018 and December 2019, reaching €0.23/W.
- In August 2020, Portugal's second solar auction has closed with record-breaking low prices of €11.14/MWh, beating the recent industry record tariff of €11.9/MWh set by the Al Dhafra project in Abu Dhabi in April 2020.

Larger turbines and lower capital costs led to a significant drop in new onshore wind capacity

- Average onshore wind LCOE declined by about 9% in 2019, reaching ~€45/MWh.
- This is mainly due to larger and cheaper wind turbines. The weighted average onshore turbine size increased by 15% between 2017 and 2019, reaching 3.1 MW.
- The shift from feed-in-tariffs to tenders and auctions pushed down the cost of energy creating a race to the lowest price.

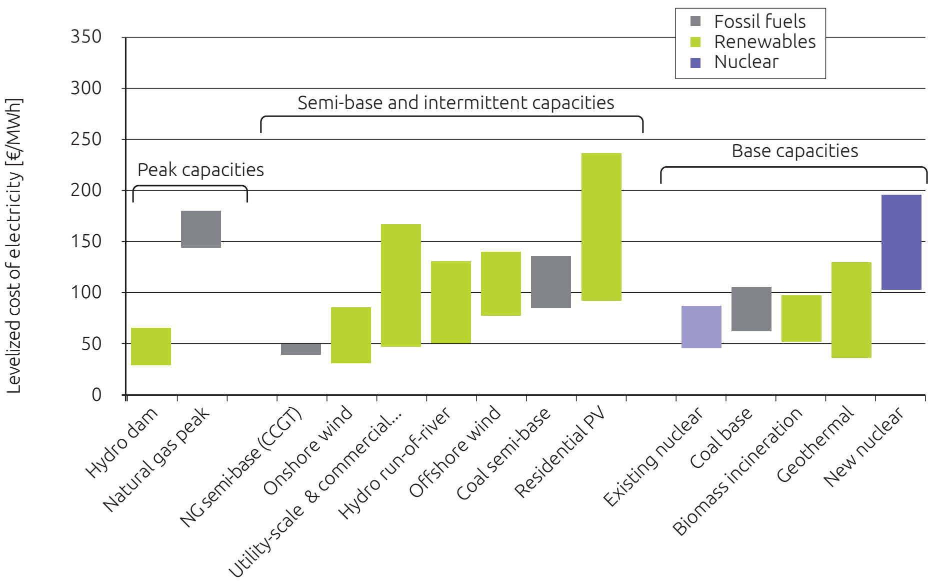
Despite increasing distance to shore and water depth, European offshore wind is more and more competitive

- In Europe, which has the largest deployment of offshore wind, projects commissioned between 2010 and 2019 recorded a 27% fall in LCOE, from €134/MWh to 99€/MWh.
- Offshore wind projects are being deployed further from land and in deeper water, with larger turbines. Turbine capacity rose from 37% to 44% in 2019.
- 2019 saw the world's largest offshore wind auction with the UK's Round 3 awarding 5.5 GW at an average price of €46.16/MWh including grid connection.
- General Electric's Haliade-X, the industry's first 12 MW turbines was installed in the Port of Rotterdam in 2019 for testing. Its commercialization is expected for 2021.

COVID-19 will impact on LCOEs; outlook for wind & solar market relies on national and EU recovery plans

- Pandemic containment led to a European and global supply chain disturbance which will likely drive up capital expenditures.
- Uncertainty regarding COVID-19 evolution may increase the cost of finance. Banks will be less disposed to lend as they are concerned about liquidity and corporate finance will be more challenging on debt.

Figure 1.9. Levelized cost of electricity for new generation built in Europe (2019)



Sources: Capgemini Invent, IRENA, BP database, Fraunhofer Institute, Commodity Markets Annual prices, Lazard, EC Europa, Ofgem; GWEC, Wind Europe, evwind, PV magazine

- **Analysis shows LCOE range for major European markets (UK, France, Germany, Spain, Italy). Assumptions on CAPEX and capital costs are based on literature research and company interviews.**
- **Analysis excludes carbon price impact. Assuming current EU ETS price at 25 €/tCO_2, If considered, LCOE would increase by €25/ MWh for coal and by €10/MWh for gas. The cost of new nuclear is based on future pressurized water technology under construction in the UK and is based on UK's Department for Business, Energy & Industrial Strategy estimates. Distinction is made between "first of a kind" (FOAK) and "nth of a kind" (NOAK)**

Electricity tariffs, the Spanish approach: Adapt behavior to energy transition, and make lower, fixed-access tariffs more widely available, using hourly pricing

Objective of the new regulation

- Simplify current access tariffs, facilitate forwarding price signal onto consumers,
- Promote efficient consumption across hours and seasons,
- The new regulation affects all the consuming segments.

Main changes with respect to the current regulation: hourly discrimination is introduced in all access tariffs

- Access Tariffs 2.0TD: same schedule for the whole year, distinguishing the central hours of the day as the most expensive periods.
- Access Tariffs 3.0TD and 6.XTD: The whole month of August disappears with period 6 and the entire month of period 5, which was previously April, May and October, disappears also.

- This change can be interpreted as an "increase in price", since the number of hours in the most expensive periods have been increased to the detriment of the more economical periods.
- In general terms, the proposal represents in practice a reduction compared to the fixed term of existing access tolls.
- It establishes the term of the excess of power of the toll. It aims at disincentivizing the hiring of undersized power subscription and to help hiring the really needed ones.
- An access tariff is introduced for supply points dedicated exclusively to the recharging of public access electric vehicles.

Expected results

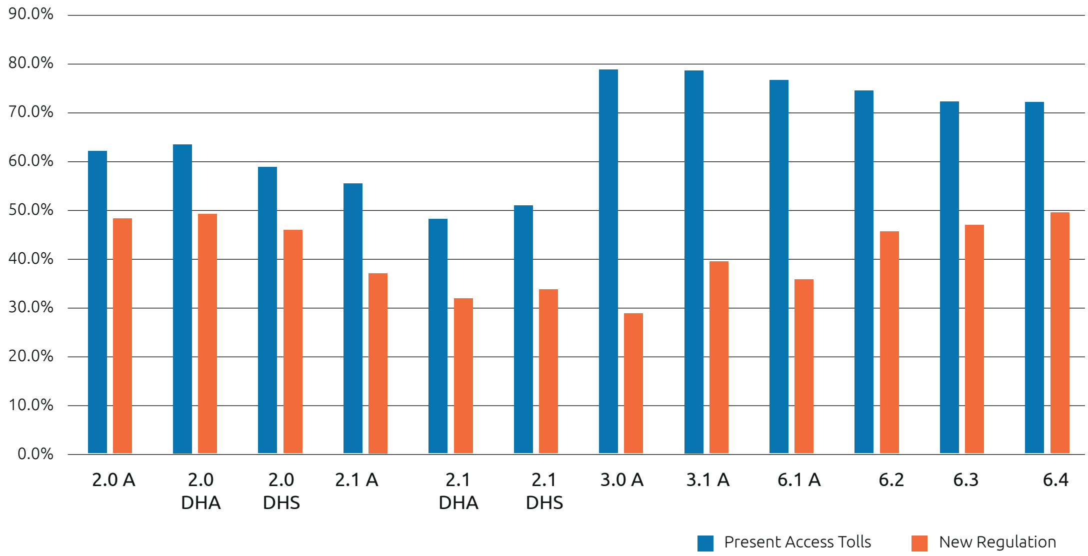
- In low voltage, the loss in access tolls will be mostly compensated through the energy term by introducing hourly discrimination.
- The medium and high voltage tolls will be recovered through the power term. This will be achieved through the revision and simplification of time periods, to induce efficient behavior

Figure 1.10. New Electricity Access Tariffs

Present situation					Circular 3/2020 (from April 1st 2020)				
Access Tariff	Voltage (kV)	Power (kW)	Power periods	Energy consumption periods	Access Tariff	Voltage (kV)	Power (kW)	Power periods	Energy consumption periods
2.0	<1	<10	1	1	**2.0 TD**	<1	<15	2	3
2.0DHA	<1	<10	1	2					
2.0DHS	<1	<10	1	3					
2.1	<1	>10 y<15	1	1					
2.1DHA	<1	>10 y<15	1	2					
2.1DHS	<1	>10 y<15	1	3					
3.0A	<1	>15	3	3	**3.0 TD**	<1	<15	6(Pn≥ Pn+1)	6
3.1A	>1 y <36	<450	3	3	Included in 6.1 TD and 6.2 TD				
6.1	>1 y <30	>450	6	6	**6.1 TD**	>1 y <30		6(Pn≥ Pn+1)	6
6.2	>30 y <72.5		6	6	**6.2 TD**	>30 y <72.5		6(Pn≥ Pn+1)	6
6.3	>72.5 y <145		6	6	**6.3 TD**	>72.5 y <145		6(Pn≥ Pn+1)	6
6.4	>145		6	6	**6.4 TD**	>145		6(Pn≥ Pn+1)	6

Source: Comisión Nacional de Mercados y Competencia

Figure 1.11. New electricity access tolls



Source: Comisión Nacional de Mercados y Competencia (CNMC)

The EU is expected to fail to reach its 2020 energy efficiency target as energy consumption (excluding COVID-19 effects) has hardly decreased, despite improvement in energy intensity

12 Member States have already reached their 2020-target but this only represents 30% of the EU primary energy consumption

- Of the 10 biggest consumers accounting for more than 80% of primary energy consumption within the EU, only two, Italy and the UK, have reached their 2020 target. In the other countries, the overall average fall was only 1% – from a drop of 5% in Belgium to an increase of 2% in Poland.
- Germany and France, Europe's two biggest consumers, with respectively 290 and 240 Mtoe of primary energy consumed in 2018, only reached 95% and 92% of their 2020 target.

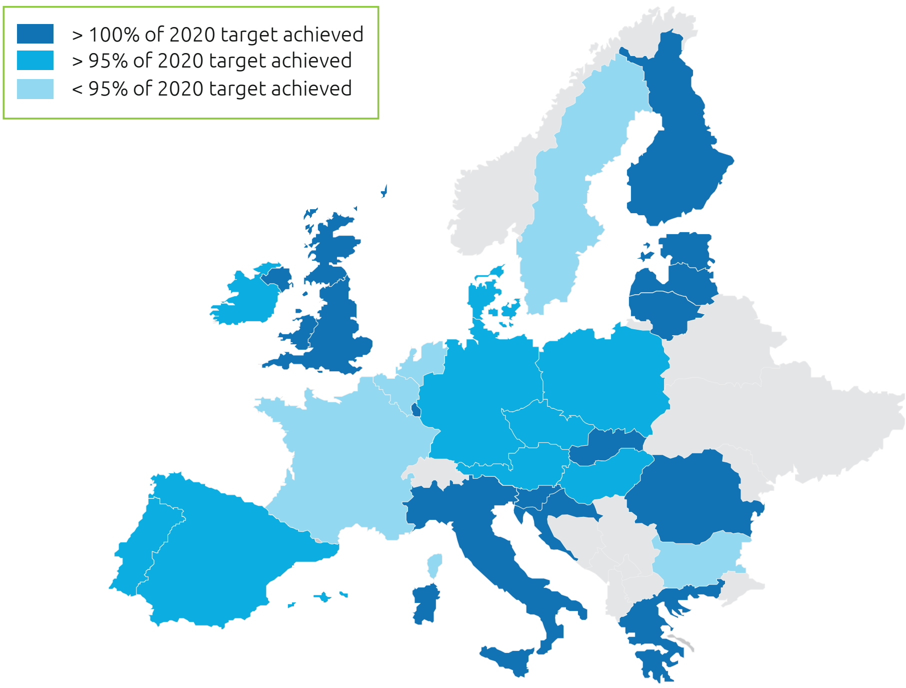
At the EU scale, primary and final energy consumption are still far from the 2020 target and have hardly decreased

- The 2020 energy efficiency objective, settled by the 2012 Directive on Energy Efficiency requires the EU to reach 20% of energy savings compared to 2007 BAU. This means that by 2020, primary and final energy consumption respectively don't exceed 1483 Mtoe and 1086 Mtoe.
- Although, in 2018, primary energy consumption decreased for the first time since 2014 (-0.67% compared to 2017), it still averages 1,552 Mtoe which means that only 16.3% of the energy efficiency target has been reached and that there is still 3.7% to reach within two years.
- Final energy consumption is still rising with 1124 Mtoe in 2018 (+0.11% compared to 2017) which means that 17.2% of energy savings have been reached. The 2.8% remaining are unlikely to be reached with the current upward trend.
- Despite the importance of energy efficiency laid out in the Green Deal, it appears very unlikely that the objective can be achieved, excluding the cyclical decrease of energy consumption due to the COVID-19 pandemic.

The drop in energy intensity year-on-year remains too weak for Europe to reach its target

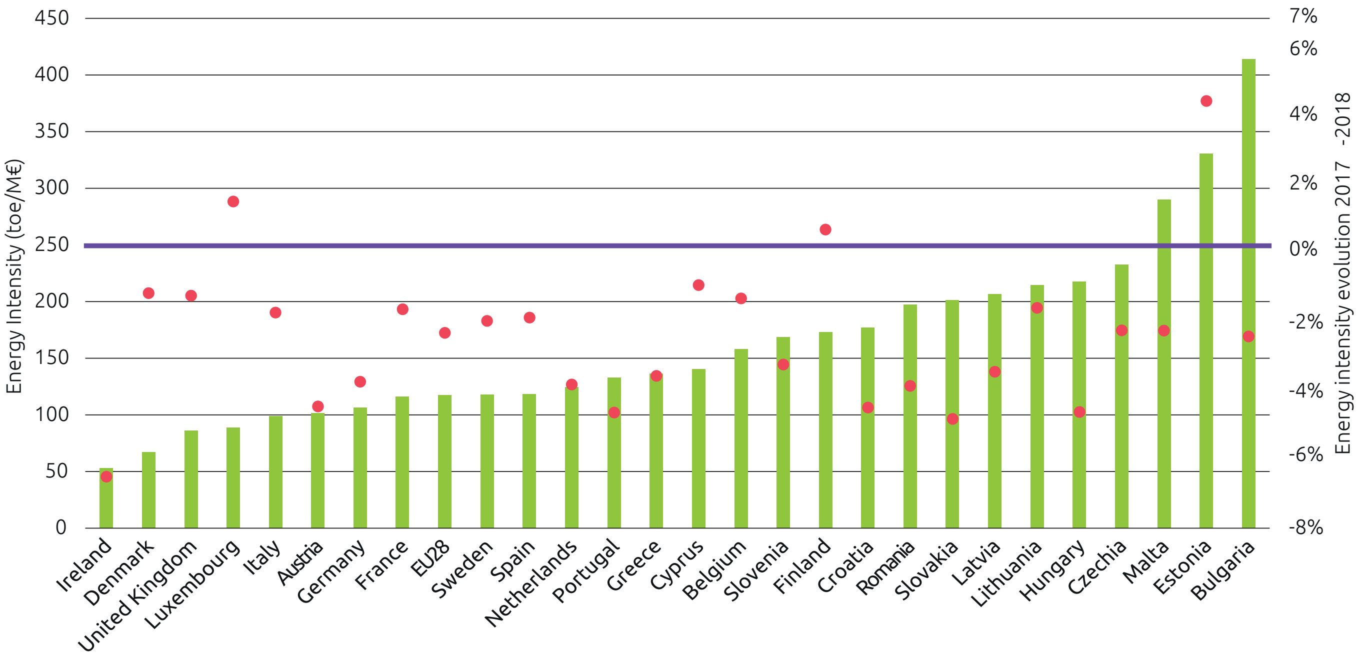
- Energy intensity fell to 125 toe/M€ GDP in 2018, a drop of 3% compared to 2017. All EU Member States have seen their energy intensity decrease except Luxembourg and Estonia. Considering the weak decrease in primary energy consumption and the upward trend in final energy consumption, it means that globally, energy efficiency is improving at the EU scale, but GDP growth remains stronger.

Figure 1.12. Map of energy consumption reduction achievement in 2018



Source: Eurostat

Figure 1.13. European countries' energy intensity (2018) and year-on-year evolution (2017-2018)



Source: Eurostat

Reaching the 2020 energy efficiency target will need more commitment from Member States than ever before

The EU 2030 energy efficiency target is more ambitious than the 2020 one and will be harder to reach – faster action is required

- The EU has the objective to reach 32.5% of energy savings compared to 2007 BAU by 2030. This means that primary and final energy consumption should respectively fall below 1,128 Mtoe and 846 Mtoe (EU27 excluding UK).
- To reach the objective, EU27 should be able to reduce its primary energy consumption by 1.6%/year between 2018 and 2030 whereas it only managed to get a 0.3%/year reduction of primary energy consumption between 2012 and 2018 (0.9%/year was needed to reach the 2020 objective between 2012 and 2020).
- Moreover, the energy savings that have already been done have targeted the easiest and most cost-effective operations.

Although energy efficiency is a priority under the Green Deal, the National Energy and Climate Plans (NECPs) proposed by Member States appear insufficient to reach the target

- The final versions of the NECPs won't enable the EU to reach the 2030 target despite revisions made following observations by the Commission on the initial NECPs. There will still be energy efficiency gaps of 3% and 3.2% in primary and final energy consumption respectively, while the gaps between the target and the initial NECPs were 6.2% and 6%.

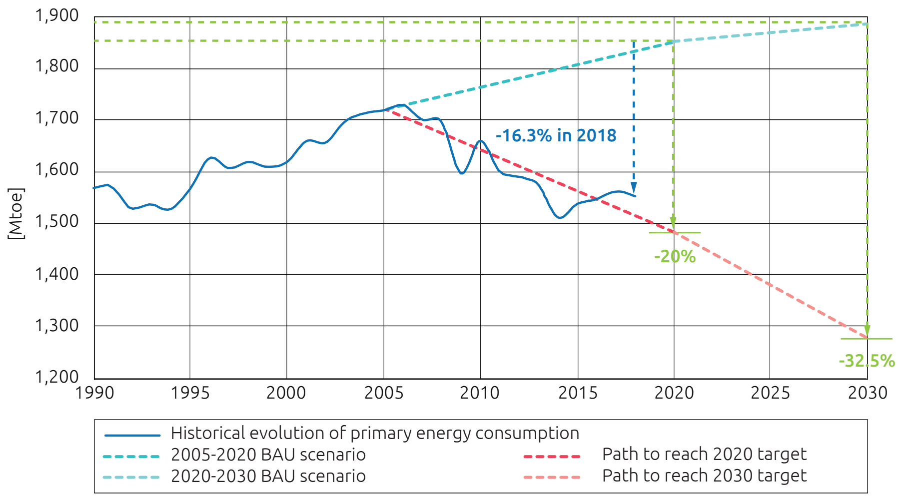
As buildings count for 40% of energy consumption, reaching the target will need significant financial investments and a better control of public fund allocation in buildings renovation

- €282 bn per year of public and private funding will be needed for building renovation in order to reach the 2030 target, according to the Commission's first estimates.
- The Commission has identified improper use of €20 bn of public funding during 2014-2020. Renovation projects have not been prioritized according to their profitability in terms of energy savings per euro invested, and effective energy savings have not been analyzed. As a consequence, for the next period, planning, control of fund allocation, and renovation project selection must be improved to ensure optimized use of public funds.

By the end of the year, all new buildings must be nearly zero-energy

- By 31 December 2020, all new buildings must be nearly zero energy according to the Energy Performance of Buildings Directive. Nearly zero energy buildings have very high energy performance. The low amount of energy they require comes mostly from renewable sources.

Figure 1.14. EU Primary energy consumption evolution and targets to 2020 and 2030



Source: EEA

Buildings renovations, though key in EU energy efficiency strategy, remain highly insufficient. Will post-COVID-19 investment recovery plans change the game?

As today's buildings will make up at least 75% of the 2050 building stock, buildings renovation rates have to improve to meet the 2030 target and form a highly efficient building stock by 2050

- The annual building energy renovation rate, which is the annual reduction of the annual energy consumption in the building stock (residential and non-residential), only reached 1% (5.6 Mtoe) in the EU28 (from 0.4% to 1.2% depending on the countries). To reach the 2030 energy efficiency and climate target, the EU must at least double or even triple the renovation rate.
- Energy renovation assesses a building's envelope, its thermal insulation, reflection, heating, cooling, and lighting equipment for potential replacement by more energy efficient means.

To maximize the benefits of energy efficiency in buildings, funding needs to be redirected towards deep renovation[1]

- In the EU28, investment has been directed towards non-energy renovations rather than energy renovation both in residential and non-residential sectors : of €770 bn/year spent in 2012-2016 on building renovation, only 36% was used for energy renovation.
- Renovation achieving small energy savings hugely outnumbers deep renovation, whether in residential or non-residential buildings. The average energy saving is around 9% per residential renovation and 17% per non-residential renovation. Although deep renovation is preferable for its greater energy savings, it will become increasingly difficult to ensure cost-effective renovation as the worst-performing buildings will already have been renovated.

Despite its importance, there have been delays in Member States submitting their long-term renovation strategies (LTRS)

- By July 2020, most EU countries had missed the March 2020 deadline to deliver their LTRS.

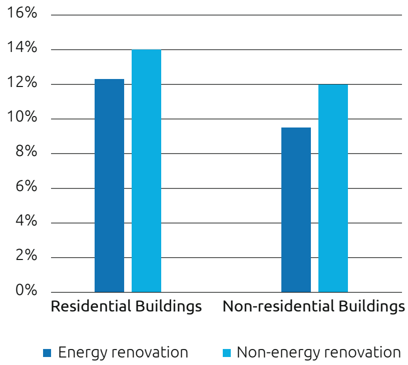
To improve efficiency in programs and operations, the EU has launched the Renovation Wave initiative

- This open platform aims to bring together the buildings and construction sector, architects and engineers and local authorities to develop innovative financing possibilities, promote energy efficiency investments in buildings and pool renovation efforts into large blocks to benefit from economies of scale.

Europe

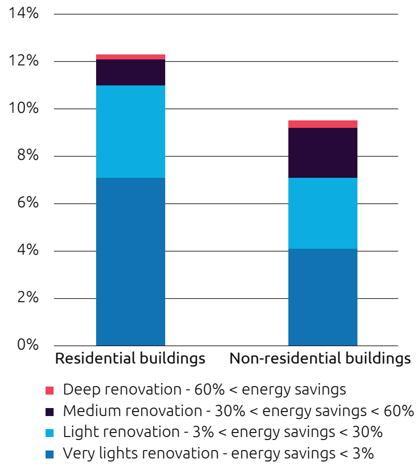
Source : 1 Comprehensive study of building energy renovation activities and the uptake of nearly zero-energy buildings in the EU (published in November 2019 – analysis of 2012-2016 figures)

Figure 1.15. Renovation rate in EU 28 (based on floor area - average 2012-2016)



Source: European Union

Figure 1.16. Repartition of energy renovation operations (based on floor area - average 2012-2016)



Source: European Union

Smart homes have great potential for energy savings – and Norway, Sweden and Denmark lead the way in Europe

Smart homes make the best use of the available energy

Smart homes can save energy thanks to:

- Heat monitoring through multiple sensors that measure the exact temperature and keep track of which rooms are in use and when,
- Solar panels connected to the smart home that ensure the energy levels of the home are always optimal and can make the home self-sustaining,
- Smart lighting or LED lights connected to solar-powered generators and smart power strips,
- Phone apps that keep track of electricity consumption of every home appliance and suggest ways to save,
- Smart appliances such as blinds, dishwashers, washing machines, dryers or microwaves.

The pursuit of energy efficiency in buildings and cities is steering attention towards new digital technologies and IoT to enable greater control, optimization and analytics that can apply at the building scale as well as at the neighborhood scale. IoT in buildings can optimize energy management, allow interoperability between devices and systems, and even enable interaction with the energy grid.

The potential for energy savings in smart homes is under-exploited due both to incompatibility between devices and to security vulnerabilities

- The penetration rate of energy management smart homes in Europe is 9% in 2020, but it is expected to increase more rapidly thanks to the technologies themselves becoming cheaper, as well as smart speakers that simplify the control of smart home services.
- Nevertheless, smart energy represents only 13% while security represents 21% of the smart home market and global sales are expected to decline by 5-10% in 2019-2020 depending upon the effect of the coronavirus.

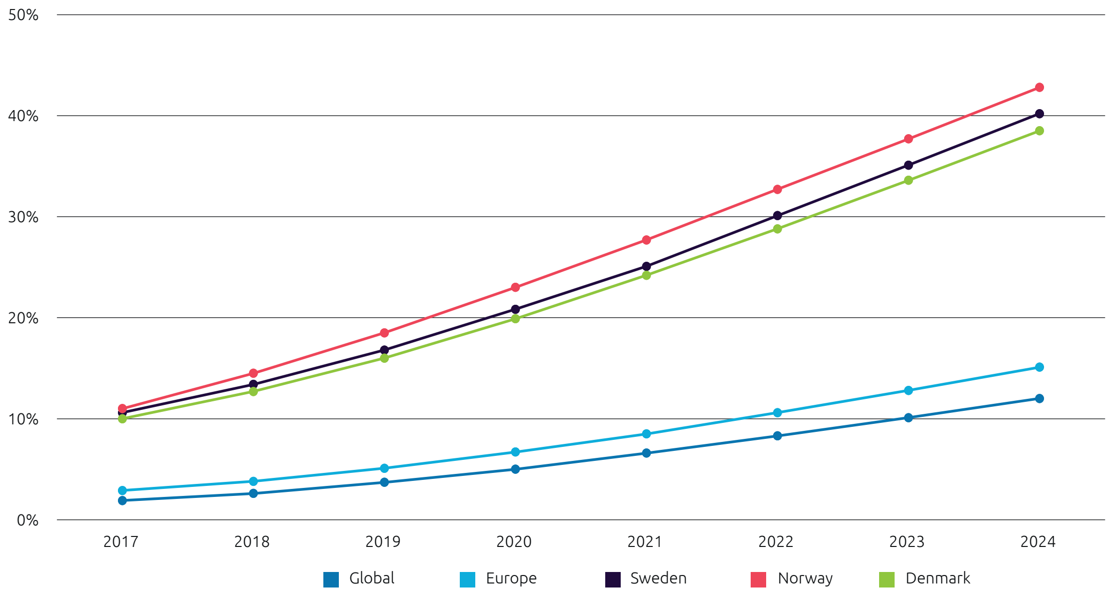
However, widespread acceptance of smart technology is affected by several factors:

- Many devices do not communicate in an integrated way or even using the same network platform (Amazon, Google, Samsung and Apple).
- The lack of compatibility between different solutions can cause security vulnerabilities, which in turn requires increased standardization between platforms.
- The real estate sector has not advanced quickly in terms of technology.
- The smart-home ecosystem is continuing to expand rapidly, and market growth rates might be accelerated with 5G implementation.

Norway, Sweden and Denmark are Europe's leaders in smart home energy management

- Revenue is expected to show an annual growth rate (CAGR 2020-2024) of:
  - **Norway:** 0% resulting in a projected market volume of US$119.2m by 2024.
  - **Sweden:** 13.5% resulting in a projected market volume of US$197.6m by 2024.
  - **Denmark:** 13.4% resulting in a projected market volume of US$119m by 2024.
- The three countries expect to double the number of households with energy management smart devices from 2020 to 2024.

Figure 1.17. Penetration rate of Energy Management Smart Homes



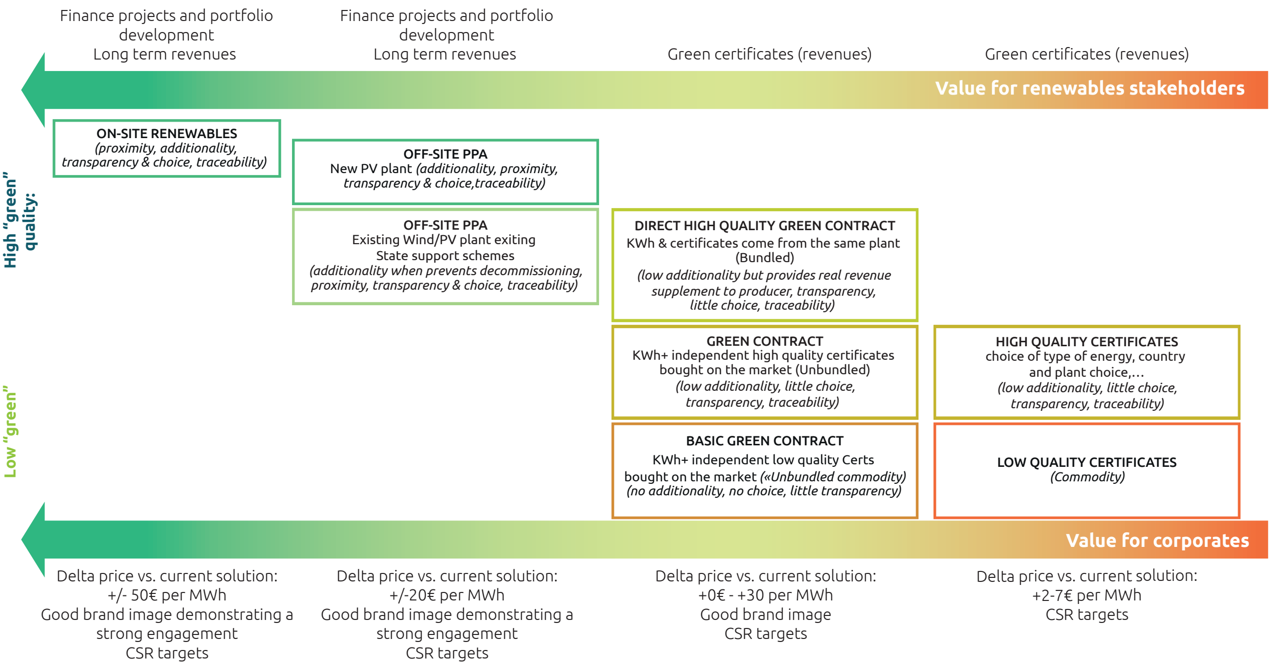
Source: Statista

Promoting green energy generates pocket prices for corporates

Encouraging the use of energy from renewable sources is no longer only a government or state concern – corporates can find real value there.

The wide range of offers, services and activities relating to green energy provide opportunities for corporates to share in the development of renewables. As consumers and, more globally, stakeholders become increasingly concerned about climate change, playing a part in energy transition has become a valuable aspect of a company's brand image. Economically, the choice of renewables for corporates may at this stage appear only as an investment, but it could well be profitable in the future, especially in the case of onsite renewables. Thus, renewables stakeholders and corporates can collaborate in a win-win relationship, sustaining the development of green energy.

Figure 1.18. Green electricity consumption alternatives for corporates and renewable energy stakeholders pocket prices



Source: Capgemini analysis

With subsidies potentially declining, corporate power purchase agreements (PPAs) could become a key support to renewables while securing energy costs for business consumers

Corporate PPA market keeps rising worldwide (+43% of corporate PPA volumes between 2018 and 2019), led by America (+6.6 GW, 80% in the US)

- Corporate PPA volumes for clean energy reached a new high of 19.5 GW in 2019, with more than 100 corporations in 23 countries contributing, leading to a global volume of 55 GW.
- The rise was mainly driven by the US, but Europe and Asia hit new annual volumes of 1-2 GW.
- Technology companies were still the main buyers, led by Google, Facebook, Amazon and Microsoft. But this trend should be mitigated by the rise of corporate sustainability commitments (around 400 companies set a science-based target in 2019), where renewable energy consumption is often a strong strategic pillar.

In Europe, corporate PPAs now extend beyond Nordic countries

- Europe represents 9.8 GW of corporate PPAs, dominated by wind (85% of signed PPAs for the period 2013-2018). However, solar is on the rise, led by the Spanish market with a 4.39 GW pipeline in January 2020, followed by Italy (1.91 GW) and Germany (1.05 GW).
- Even though Nordic countries were historically the most important corporate PPA buyers, new countries continue to join in. For example, France and Italy signed their first PPAs in 2019.
- The ICT sector is the main corporate PPA contractor with 25 PPAs, but high consumption sectors such as heavy industry and transport are catching up, with respectively 17 and 12 PPAs signed in 2019.

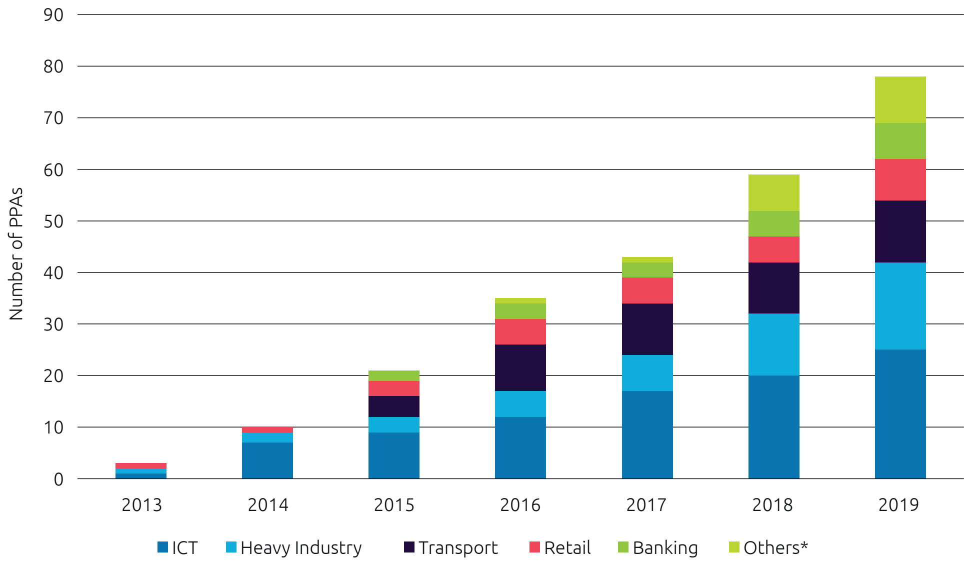
Corporate PPA prices are more and more competitive

- In April 2020, a BNEF report identified Spain and Sweden as having the cheapest average corporate PPA prices in Europe for solar and wind electricity: in Spain for solar at €35.3 per MWh and in Sweden for wind at €30.5 per MWh. The report revealed big differences in renewable energy PPA prices across Europe, with the UK being the most expensive per MWh at €52.3 for solar and €49.7 for wind.
- Prices may struggle to fall since signed contract durations are shorter than in the US. It is estimated that in Europe a €1.5-2.5 per MWh premium is typically charged for terms of 15-20 years.

Is the COVID-19 crisis going to break the trend?

- There is uncertainty about the impact of the COVID-19 crisis on corporate PPAs, even though some contracts were finalized during the crisis.
- The main impacts in the short to medium term could be lower electricity demand from corporates and maybe a return of renewables subsidies in green recovery plans.

Figure 1.19. Cumulative number of PPA signed in Europe by sector



*Others: Consumer goods, Automotive, Pharmaceuticals, Consortia, Water industry, Logistics
Source: WindEurope

Europe's demand for thermal energy exceeds that for electricity

Thermal demand accounts for 50% of Europe's overall energy consumption and emissions

- Thermal energy is produced using almost all available forms of energy generation – by burning gas, coal, oil, or biomass; via electricity; or via natural temperature sinks such as seawater cooling.
- Around 50% of thermal energy demand is for heating spaces for both industrial and residential/commercial use. The next largest source of demand is industrial process heat, such as for cement and steel manufacturing, followed by water heating, cooking, and various types of cooling.
- The share of gas can vary depending on seasonal demand fluctuations. Coal and oil are decreasing while wind, solar, biomass, and geothermal energy have been steadily increasing.

Decarbonizing thermal heat can progress via electrification, improved efficiency, and development of shared solutions like district heating and cooling

- Electrification of heat has continued to accelerate along with renewable electricity generation and could eventually lead to a potential 50% reduction in the overall GHG emissions from heat. One enabler of this has been the accelerating adoption of heat pumps which offer a cost-effective way of electrifying heat. Currently technical solutions for electrification of heat up to 1,000°C are mature with higher heat applications continuing to be developed.
- On a large scale, district heating and CHP can also both optimize the production, distribution, and use of heat but can also enable larger scale emissions mitigation strategies such as CCUS. District heating has high (52%) market penetration in Sweden, but countries like the UK, Belgium, and the Netherlands still have market shares of only 1-4%.
- Most thermal energy is wasted. Improving efficiency, insulation, and process optimization can significantly reduce the amount of wasted heat. This can include technology improvements like phase-change insulation and printed-circuit heat exchangers.

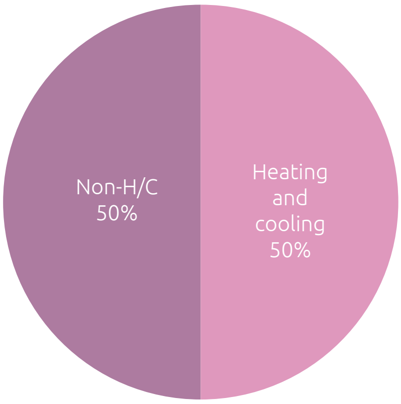
High temperature industrial heat

- High temperature industrial heat comes from a variety of applications and includes cement and steel production. These processes are difficult to electrify, dependent on long-lifetime infrastructure and value chains, and often have limited investment capacity to deploy fully decarbonized production.

High-volume cooling including data centers and district cooling

- Most major players have significant, ambitious emissions targets including Apple and Microsoft. Demand for cooling has remained high, but design measures such as "free cooling" help minimize the GHG impact of increased data center installations.

Figure 1.20. Heating and cooling energy demand in the EU (2015)



Sources: Heat Roadmap Europe

Thermal energy represents one of the largest and most complex areas of energy demand and as such has a significant and difficult path towards decarbonization. Spread across residential, industrial, and tertiary heating, the largest sector of demand in Europe is heating spaces. Electrification and efficiency are both needed to continue decarbonization progress.

Sources: Outlook for biogas and Prospects for organic growth World Energy Outlook Special Report biomethane, 2020 ; A greener gas grid: what are the options? White paper - Sustainable Gas Institute | Imperial College London, 2017

Thermal supply is still mostly fossil-based, despite the potential for alternatives: massive attention to its decarbonization is needed

Heating and cooling supply includes a wide range of energy sources

- There is no one technology or practice that will decarbonize these applications; instead a wide range of improvements including efficiency, CCUS, and electrification must be made.
- Due to the massive quantity of energy required and variation in demand on an hourly and seasonal scale, heating and cooling demands are a major driver of energy imports, particularly in the form of Russian and Norwegian natural gas. Natural gas in itself is a potent greenhouse gas, but increasing the energy mix so that gas replaces coal has a considerable positive effect in terms of CO_2 and also acts as a lever to balance intermittent energy sources like wind and solar.
- As efficiency in both heating and insulation continues to improve, the heating demand for most countries in Europe is forcasted to fall whereas the energy needed for cooling expected to grow in most countries in the coming years. In 2016 the European Commission formulated the EU Strategy on Heating and Cooling, focusing on decarbonizing heating and cooling via promoting low-carbon energy sources and improving energy efficiency (particularly in buildings).

Combustion

- Combustion from fossil fuels still represents a large majority of the energy supply for heating and cooling. Decarbonizing this fuel can be done by substituting with an alternative, low-carbon fuel or by capturing and storing or utilizing the emissions via CCUS.
- One source of low carbon combustion heat is biomass or waste. In countries such as Sweden this acts as a significant source of energy, but its impact on the environment has both positive and negative aspects. Biomass investment in Europe increased 12% in 2019 to €3.1 billion.
- Blue and green fuels like methane offer a drop-in way to decarbonize existing infrastructure but the economics are still not competitive with grey methane in most circumstances. Blue or green hydrogen also can act as a decarbonization tool although the amount that can be blended with methane in existing pipelines is still being tested but industrial scale trials, like H21, are maturing.

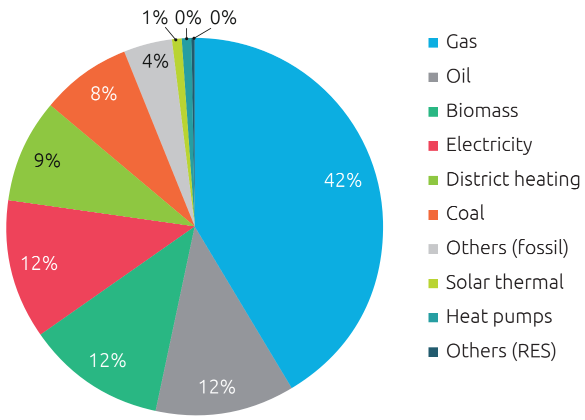
Electrification

- The carbon impact of electrified heat is limited by the energy mix of the electricity grid. As renewable energy investments continue to grow, the emissions intensity from heating and cooling will drop.

Direct sources

- Direct heating and cooling via solar, geothermal, or other natural temperature sinks continues to grow but 2019 has not seen any major breakthroughs.

Figure 1.21. Heating and cooling energy sources (2015)



Sources: Heat Roadmap Europe

Due to the wide range of heat demand, energy sources used for heat are diverse and often dependent on infrastructure. Natural gas is the largest component, used both for high-temperature industrial heat and seasonal heating of residential buildings on a continental scale. In contrast to electricity, biomass and heat recycling are also large sources of supply.

Sources: Outlook for biogas and Prospects for organic growth World Energy Outlook Special Report biomethane, 2020 ; A greener gas grid: what are the options? White paper - Sustainable Gas Institute | Imperial College London, 2017

Electrification and district heating and cooling will help decarbonize the thermal supply

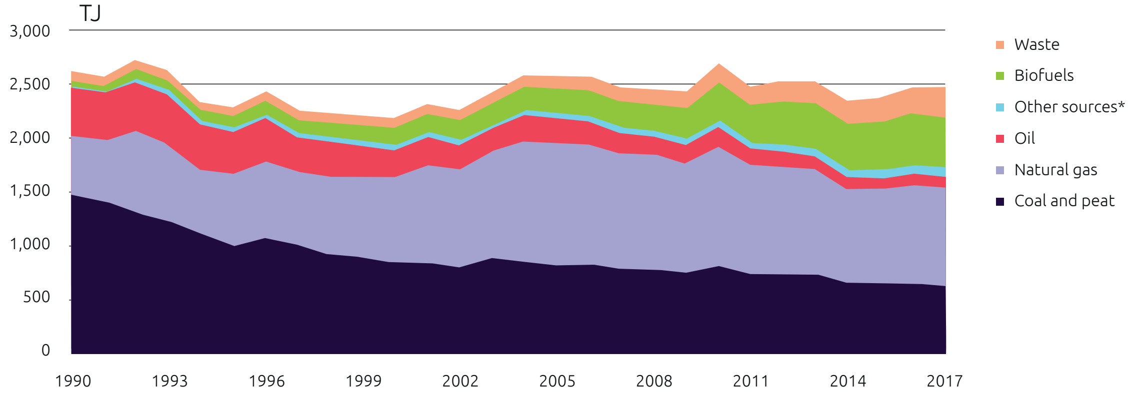
Driven by heat pump installations, electrification of heat has continued to accelerate along with renewable electricity generation

- Heat pumps are a major lever in low-volume heating, particularly in residential sector. They are highly efficient and, as technology development and manufacturing scale have improved, have become a very commercial investment implementable on a individual household scale. The heat pump market in Europe grew 12% in 2018 and currently there are almost 14M heat pumps installed across the continent.
- According to the IEA, heat pumps could satisfy 90% of the world's heating needs while reducing the carbon footprint and this will accelerate along with renewables penetration.
- If sales across Europe grow to the level of Norway in 2014, there is a potential market of up to 7M heat pumps per year across the EU.

District heating must switch from fossil fuels to biomass and geothermal sources and from "circular" recycled heat from waste or lost high-grade industry heat

- District heating and co-generation are highlighted by the European Commissions as having strong decarbonization potential and in some EU countries their market share is approximately 20%. This varies strongly across countries, with Sweden using >80% biomass, Greece 100% coal and peat and Portugal 100% natural gas for their district heating.
- Much of the district heating in place is dependent on industrial process heat, often itself dependent on fossil fuels and their accompnaying emissions. Investment in district heating and cooling infrastructure instead acts as a first step towards decarbonization, enabling switching to green gas, hydrogen, biomass, or biofuels at a later date.
- Burning waste and biofuels utilizes renewable fuel sources but in most of Europe this is done in relatively inefficient boilers and stoves. At the cutting edge, Fortum is planning on implementing a CCS facility at a waste-to-energy plant in Oslo, Norway.

Figure 1.22. District heating energy consumption in the EU (2017)



Sources: IEA World Energy Balances 2019

Electrification of heat can reduce the emissions by up to 50%. One of the main drivers of this has been the deployment of heat pumps. In addition, sharing heating on a city-wide scale via CHP and district heating allows for economies of scale, efficient use of biomass and heat recycling, and can enable future decarbonization via CCUS. Finally, investment in efficiency measures like modern insulation can have a large and immediate impact across Europe.

Green gas killed by electrification – is there a one-size-fits-all solution or could combining them improve resiliency of the energy system and increase local circular economies?

Is electrification the only solution to decarbonate thermal usage?

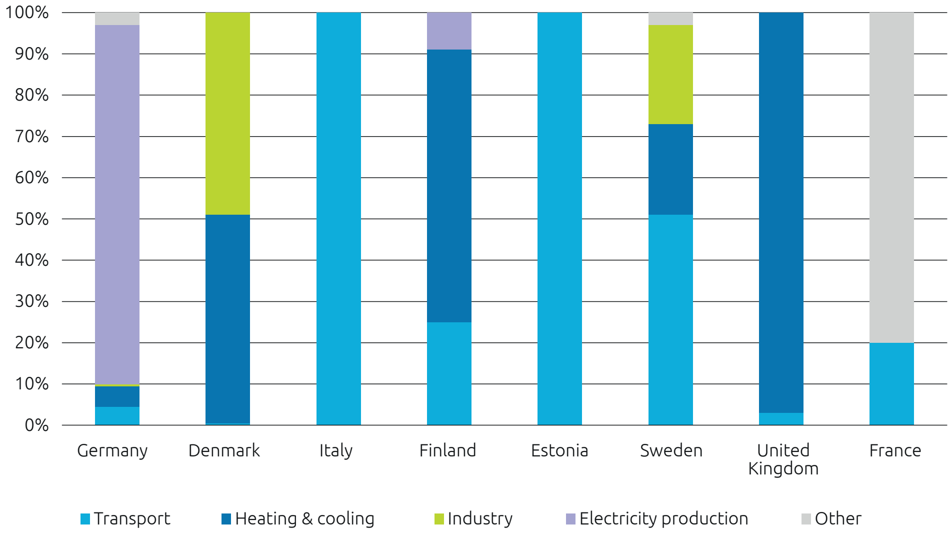
- he revised EU Renewable Energy Directive set up an indicative target of a 1.3% increase in renewables in heat for 2021-2030. Heat generation is still dominated by natural gas in Europe, with ~40% market share.
- In industry, electrification rate is, in average, a third of total heating energy demand. This is mainly due to the growing use of heat pumps, with a potential of 50% of electrification in 2050. In residential heating, electrification is also rising, but fossil fuels still represent 75% of the energy supply.
- Even if electrification of heat is possible in most of the countries, several barriers to a 100% coverage can be highlighted:
  - Electrification must be for the benefit of CO_2 savings, i.e. heat electrification must be done only where the electricity supply is not CO_2 intensive,
  - Some “services” provided by gas could be difficult to reproduce, especially int the case of balancing peak loads with variable supply,
  - Industries would have to adapt their processes to new heating sources, which is not always possible,
  - The amount of electricity required to satisfy all Europe's winter demand for heat would outpace its electricity production capacity.
- Thus, apart from biomass, solar thermal or geothermal solutions, greening heating will require direct decarbonization of gas, with green gas such as biomethane and hydrogen injection to gas grids. Power-to-gas will play a major role as well, as it is strongly linked with renewable energy storage.

From now on, green gas production and gas grid development are key

- Low pressure gas networks, used for residential or small business supply, can already carry biomethane. These networks are well developed in some countries, such as the UK, leaving the opportunity to increase the amount of green gas in the gas mix. Developing biomethane in the current grid requires CAPEX for new connection infrastructure, upgrades of existing grid and storage. However, as network operators regularly upgrades their assets, it can be argued that theses costs may already be taken into account in future investments, and so do not represent additional costs.
- Hydrogen is perceived as a strong future contributor to a greener gas grid, but investments required to develop it are still high. Current projects to shift local grids to hydrogen supply are ongoing and demonstrate promising results, such as the H21 project.

Sources: Outlook for biogas and Prospects for organic growth World Energy Outlook Special Report biomethane, 2020 ; A greener gas grid: what are the options? White paper - Sustainable Gas Institute | Imperial College London, 2017

Figure 1.23. Consumption of biomethane in Europe per country and sectors



Source: Mapping the state of play of renewable gases in Europe – REGATRACE, February 2020 ; Panorama du Gaz renouvelable 2019

Decarbonizing heating and cooling is complex and requires multiple levers. A 100% electrified heating system seems complicated to establish, since winter heating demand is high in some European countries, and industries cannot always adapt their processes to new heating sources. Despite that, solutions other than fossil fuels exist. As biomethane can be injected into low pressure gas networks and contribute to sustain a whole circular economy system, this pathway should be investigated and developed. Hydrogen is also perceived as a serious route, even though the costs of developing a hydrogen grid (or low-pressure gas network conversion) may be higher.

Recyclability of batteries and technology innovations are two main pillars to recover European sovereignty

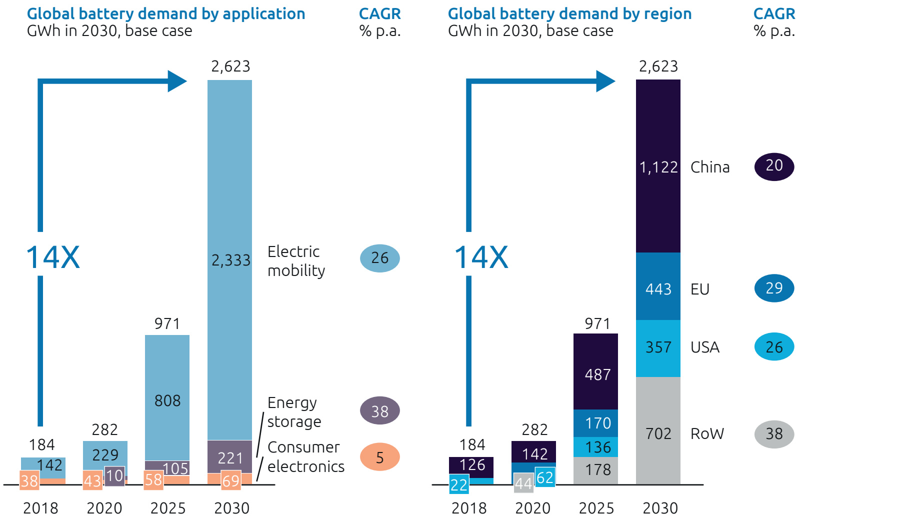
Batteries recycling is key both on the environmental and geopolitical fronts

- Electricity storage led by the lithium-ion technology represents a market size from $22 billion in 2019 to $118 billion in 2030 according to BNEF. Batteries dedicated to electric mobility represent 90% (see figure 1.24) of the global battery demand in 2030 which is why our WEMO analysis is focused on this sector. On the economic aspect, the full cost of recycling a car battery is around €1,000 (€30 for a bike). According to the IEA, by 2030 15%-30% of new car sales will be EVs. Today, China recycles 69% of the batteries in the world.
- The study written by IFRI1 on lithium-ion batteries states that the recycling potential of batteries in the EU is significant and represents a triple challenges: (1) environmental, because recycling allows energy savings compared to mining; (2) economic, because the development of a recycling infrastructure and an industrial ecosystem linked to electricity storage will create jobs and value; (3) strategic, because it will allow the recovery of mineral resources which the EU does not exploit on its own lands, and which can be re-injected directly into EU industries.
- To tackle these challenges, several initiatives are appearing in Europe. Fortum, BASF, and Nornickel announced their plan for a battery recycling cluster in Harjavalta, Finland, serving the electric vehicle market. Another project, called ReLieVe, led by Eramet, BASF and Suez has been financed by the EU and the German car manufacturer Audi with the Belgian company Umicore also joined forces to cooperate on a closed loop, use and recycling, for cobalt and nickel.

Promising technologies could squeeze the Chinese hegemony in the long term

- The project Battery 2030+ is a large-scale, long-term European research initiative with the vision of inventing the sustainable batteries of the future, to enable Europe to reach the goals envisaged in the European Green Deal working on several fields including manufacturability, recyclability, sensing and self-healing.
- While the current commercialized technology is the battery based on a liquid electrolyte, many technologies are studied such as sodium-ion, multivalent metal-ion and metal-air for post-lithium battery chemistries and all-solid-state lithium-ion or lithium-sulfur for lithium battery chemistries. However, none of them should be commercially ready by 2030, which is why lithium-ion batteries will lead the market in the next decade.
- According to Battery 2030+, global battery demand should multiply by 14 by 2030. Europe will be the second market worldwide. This trend emphasizes the urgent need for Europe to develop its own local supply chain for batteries to make it resilient and preserve its sovereignty in the mobility and energy sectors.

Figure 1.24. Expected growth in global battery demand by application (left) and region (right)



Source: Battery 2030+, European Union

The COVID-19 crisis has made crystal clear the need to make the European lithium-ion battery supply chain self-sufficient

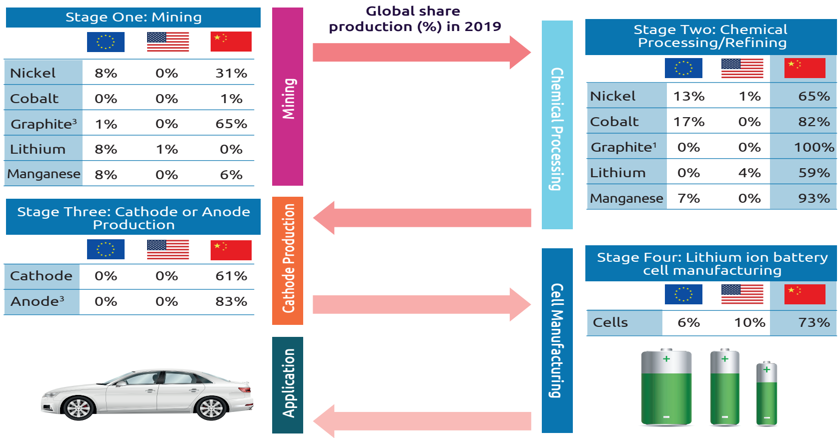
The production of many of the raw materials for batteries is concentrated in a few countries. This makes those supply chains especially vulnerable

- European car manufacturers had to lower their production even before the COVID-19 crisis hit Europe because they ran short in supplies of battery cells.
- European dependence is not only related to the manufacture of batteries, but occurs throughout much of their value chain, from extraction and processing of raw materials to the preparation of necessary treatment processes for recycling.
- For specific links in the supply chain, a few countries own a worldwide monopoly, especially for the extraction of rare earths and metals. To reverse this trend, a growing number of projects to mine lithium in Europe have been initiated. A project in the Czech Republic led by the company Cinovec plans to extract lithium and tin (stage 1); the Infinity lithium project plans to deliver lithium hydroxide, a key component in batteries (stage 2) and a BASF plant in Schwarzheide, Germany will produce cathode materials by 2022 (stage 3).

The lithium ion battery supply chain is evolving into a local-global hybrid model

- In this model the raw materials travel the longest distance but the majority of the components along the supply chain, including cathode production, anode finishing, battery cell and pack manufacturing, EV assembly, and battery recycling are manufactured and shipped continentally, locally, or even on one integrated site (giga-factory)
- China is already implementing this strategy. The further downstream of the supply chain, the more dominant China's position is. For example, in 2019, China mined 1-6% of the world's cobalt but refined 82% of cobalt chemicals and, similarly with lithium, only accounted for 5-10% of extraction but 59% of global chemical production.
- Europe is trying to follow this path. According to the European Commission, four projects of sustainable lithium extraction have been financed for a total of 2 billion euros and should satisfy 80% of the European demand in the battery sector by 2025.
- The final objective behind this strategy is to make Europe as independent as possible on the whole supply chain of EV batteries.

Figure 1.25. The Lithium ion battery to electric vehicule (EV) supply chain in 2020



Stage One: Mining	EU	US	China
Nickel	8%	0%	31%
Cobalt	0%	0%	1%
Graphite[3]	1%	0%	65%
Lithium	8%	1%	0%
Manganese	8%	0%	6%

Stage Two: Chemical Processing/Refining	EU	US	China
Nickel	13%	1%	65%
Cobalt	17%	0%	82%
Graphite[1]	0%	0%	100%
Lithium	0%	4%	59%
Manganese	7%	0%	93%

Stage Three: Cathode or Anode Production	EU	US	China
Cathode	0%	0%	61%
Anode[3]	0%	0%	83%

Stage Four: Lithium ion battery cell manufacturing	EU	US	China
Cells	6%	10%	73%

1 Flake Graphite Feedstock, All Anode Nature & Synthetic
Source: Benchmark Mineral Intelligence

Battery gigafactory projects are emerging all over the world: China is paving the way, and Europe is trying to catch up because batteries represent 40% of an electric car's value

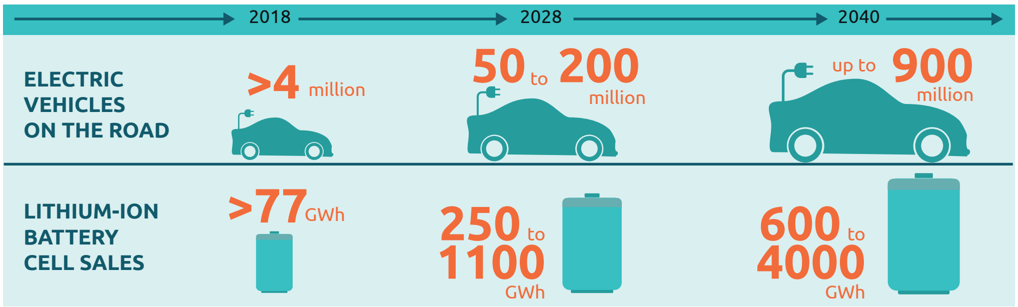
Battery production is a strategic imperative for Europe in the context of clean energy transition and is a key component in the competitiveness of its automotive sector

- The European Commission is promoting a cross-border and integrated European approach covering the whole value chain of the battery ecosystem. Battery production is key as they represent until 40% of an EV value according to the European Commission (EC).
- According to the EC, from 2025 onwards Europe could capture a battery market of up to EUR 250 billion a year, served by at least 10 to 20 Gigafactories (battery cells mass production facilities) to cover EU demand.
- In 2019, around 150-190GWh of lithium-ion batteries were produced worldwide. Only 3% of this production was in Europe. China produced 65-72%, the US produced 9% and the rest was produced in Japan and Korea. Asia produced in total 85-90% of lithium-ion batteries.

Gigafactories are spreading in China, Europe and the US

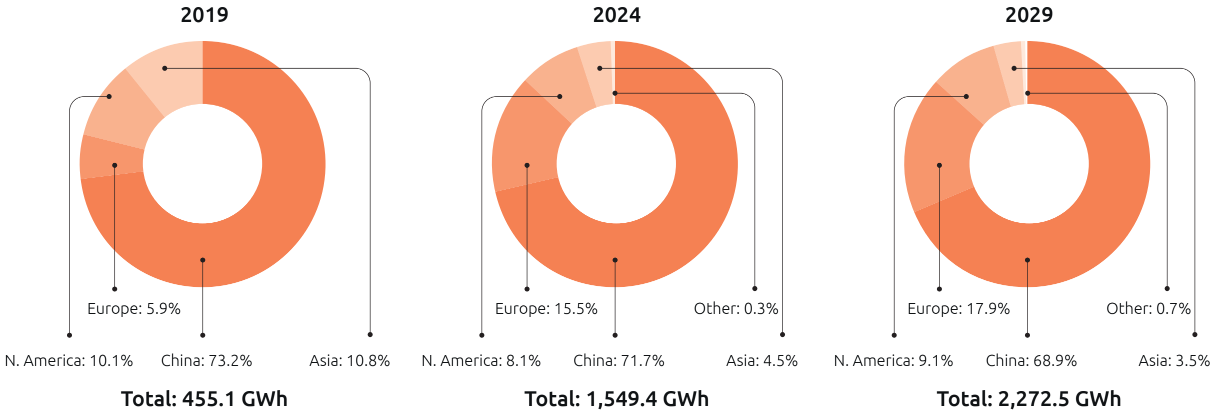
- From April 2019 to April 2020, China built 46 gigafactories: Europe has 6 factories of this type and the US only 3 which means that China is building the equivalent of one gigafactory every week whereas the US builds a gigafactory every four months. China is taking the lead while Europe is struggling to speed up.
- However, data from Benchmark Mineral Intelligence (BMI), a London-based price reporting agency, predicts that by 2030 Europe will increase its market share in the megafactory market from 6% in 2019 to 18% in 2029. This would make the region the second largest producer of lithium-ion batteries after China. Germany leads the way for the future of European battery production capacity, with plans to reach almost half of the continent's proposed total by 2030. Despite these encouraging figures, of the 136 lithium ion battery plants in the pipeline to 2029, 101 are based in China. China should own almost 70% of the market in 2029.
- Another aspect is that the average size of an operational lithium-ion gigafactory around the world grew from 0.5GWh in 2015 to 7.28GWh in 2020. The forecast established by BMI sets the capacity at 18.9GWh in 2030. So far, the largest lithium-ion battery plant in the world is Tesla's gigafactory which has an operational capacity of 37GWh and is on track to reach 60-70GWh by 2023.
- 75% of the costs of battery cells are material costs and only 25% comes from production costs. Hence, the cost structure for highly automated products, like batteries, is comparable in Europe as it is in China, Japan and South Korea. Consequently, gigafactories are essential to make European batteries competitive.

Figure 1.26. Circulating EV number and related battery cell sales evolution



Source: Joint Research Centre, European Commission

Figure 1.27. Megafactory capacity by region



Source: Benchmark Mineral Intelligence, Lithium-Ion Battery Megafactory Assessment, February 2020

Large-scale industrialization of renewable hydrogen production is key to lower costs and leverage on H2 as a new energy carrier for a carbon-neutral future

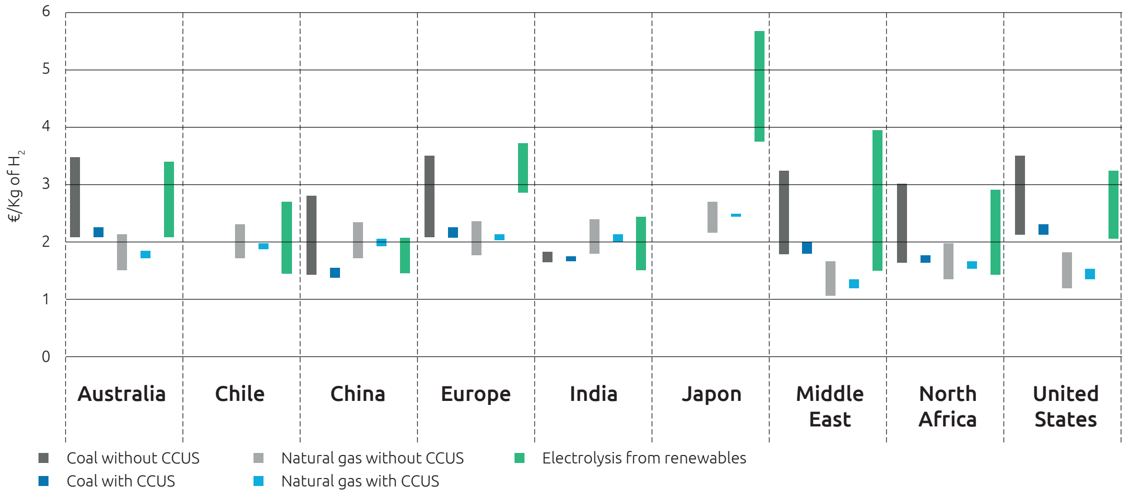
Green hydrogen is in competition with grey and blue alternatives

- As of 2020, over 95% of EU's hydrogen is grey hydrogen produced from gas (SMR process) and coal (ATR process), emitting up to 100 $MtCO_2$ in the EU alone. Grey hydrogen costs at industrial scale are as low as 0.9 to 1.2 €/Kg.
- Blue hydrogen combines grey hydrogen with carbon capture. It is generally seen as a short-term solution competitive with grey hydrogen if carbon tax is above 44€/ tCO_2.
- Green hydrogen is produced through water electrolysis powered with electricity from renewable sources. It is still the most expensive with costs in the 3.5- 6 €/kg range in Europe today.
- Within the EU, only 4% of total hydrogen production is green, coming from the 300 currently operating electrolysis-based plants. To meet EU ambitions, increasing electrolyzer capacity and overall efficiency is essential to scale up production.

The final target to get full competitiveness both with grey hydrogen and even with fossil fuels, as methane, is to get green hydrogen in the 1-1.5 €/Kg range by 2030

- Low-cost green hydrogen will be achieved by scaling up both electrolysis plants in industrial clusters and renewable power plants in areas with the best potential.
- Electricity remains the dominant cost driver accounting for 60 to 80% of the cost per kg of hydrogen. Significant cost declines are expected in offshore wind production, in onshore wind for instance in Ukraine and above all in solar PV with new technologies and production located in Southern Europe and North Africa.
- Cutting electrolyser costs is the second issue to be solved. IEA, IRENA and BNEF estimate that costs should drop from €900/kW to €450/kW in 2030.
- Hydrogen Europe proposes that 40 GW of electrolyser capacity be fully operational by 2030 producing 4.4 million tons of hydrogen with up to 170,000 local jobs.
- Accelerated policies based on giga-scale hydrogen plants could lower costs to €250/kW in 2030.
- The EU must continue to be a global leader in the electrolyzer manufacturing industry. Owing to their expertise in electrolysis-based chlorine production, multiple European companies (e.g: ThyssenKrupp, NEL, Siemens, Sunfire) already offer large advanced electrolyzers for hydrogen using the most relevant technologies: alkaline, PEM and SOEC.

Figure 1.28. Hydrogen production costs per source in different parts of the world



Source: IEA - The Future of Hydrogen

Blue hydrogen combining grey fossil hydrogen from SMRs with carbon capture would be the continuity solution.

Green hydrogen is a promising and sustainable long term solution. Green hydrogen could be competitive if large scale production was accelerated in the next decade, with low-cost solar and wind and large electrolyser plants.

Hydrogen's versatility creates decarbonization opportunities across a range of applications in multiple high-emission industries

Hydrogen is the cornerstone of several industrial processes such as refining, ammonia for fertilizers and methanol - and demand for green H2 will grow

- The EU currently produces 9.8 million tons of hydrogen per year, with a turnover of €2 billion. Hydrogen is primarily used for industrial applications, nowadays dominated by oil refining and ammonia production with 45% and 38% of total production.
- As shown in figure 1.29, leveraging green hydrogen in these two sectors alone could avoid more than 70 $MtCO_2$ per year. A report from the IEA estimates that hydrogen demand from existing mature applications such as these will continue to grow by 2030.

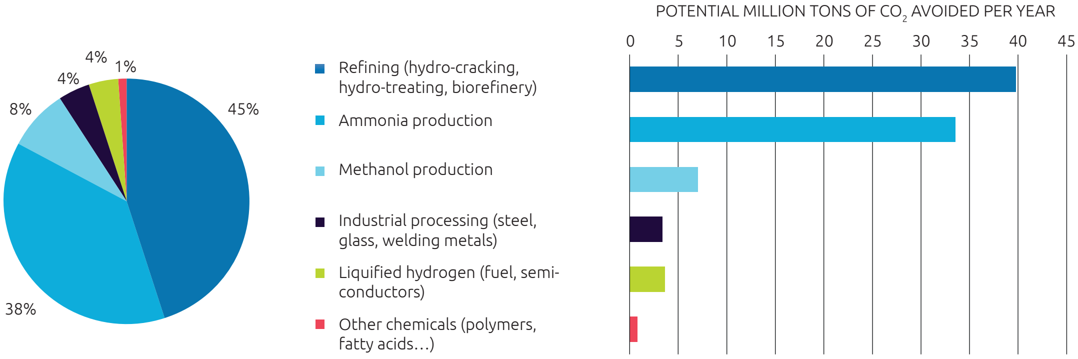
In the near future green H2 versatility will also serve needs in steel, glass, long range transport, food etc

- The IEA estimated that hydrogen will progressively replace fossil fuels in high temperature industrial processes (e.g. iron and steel production). It could also help reducing emissions from heating in the building sector.
- Public and private investment is increasingly targeting projects to use hydrogen as a fuel in aviation and marine transport, benefiting from limited electricity-based alternatives.
- The fuel cell car market remains a small one, even compared to the EV market as a whole with only a few fuel cell passenger cars sold in Europe (2,067 vehicles). Almost half were in Germany (643) and France (382), followed by the UK (237), Netherlands (230) and Norway (195). Trucks and heavy duty vehicles are a better application for hydrogen.

Current development trends are illustrated by numerous initiatives throughout the EU seeking to address key challenges

- Green hydrogen industrialization: The Westküste 100 project aims at developing a hydrogen economy at industrial scale within the coast of Schlesing-Holstein, Germany, leveraging on regional wind energy and geological storage potential.
- Infrastructure as a success factor: The port of Rotterdam is building a public hydrogen network to support industrial activities. Initially set to link a Shell-owned electrolyser to its refinery, it now aims to build up the infrastructure to support a vast hydrogen cluster.
- Full hydrogen value chain support: The Hydrogen for Climate Action initiative, supported by the EU as an IPCEI, has developed a portfolio of 11 projects tackling the entire hydrogen value chain. From electrolysis generation to industry uses and distribution, these projects aim to reduce emissions by 35 $MtCO_2$/year.

Figure 1.29. Hydrogen consumption per activity in 2019 & potential CO_2 emissions avoided with green H2



Source: Hydrogen Roadmap Europe Report & Capgemini Analysis

The addition of present and new applications is further establishing hydrogen as a vital commodity for the evolution and operation of many industries. Technological progress and environmental stakes have fostered the emergence of major initiatives in regional clusters, showing a renewed trend to grant hydrogen a critical role within the European economy.

Both EU countries and energy players perceive hydrogen as a new priority, resulting in the unparalleled emergence of national regulations and corporate strategies

Germany Hydrogen Strategy 2020

- Germany announced a 9 bn€ hydrogen strategy in June 2020. Its aim is to promote the production and integration of hydrogen to make it market-ready and competitive. With a clear emphasis on green hydrogen, the strategy is structured in four pillars:
  - Production & Infrastructure: Includes building 5 GW of green hydrogen production by 2030, 10 GW by 2040 and supporting hydrogen gas station networks.
  - Research, Development & Innovation: Looking to define a R&D&I roadmap, supporting research in sectors such as aviation and shipping.
  - Applications: Focus on implementing schemes for transport, industry and heating.
  - International: 2bn€ to be invested in international with EU partnerships to develop pilot programs and define common initiatives and emissions standards.

Netherlands Government Strategy on Hydrogen

- The Netherlands seeks to develop a zero-carbon hydrogen supply chain leveraging international cooperation and trading thanks to its location, ports and extensive gas grid.
- The strategy aims to promote hydrogen production and demand on Dutch ports and industrial clusters, thus reducing costs and developing the infrastructure for a large-scale integration targeting transport and electricity sectors.

Norway Hydrogen Strategy 2020

- Published in June 2020, Norway's strategy addresses research and commercialization ambitions to develop green and blue hydrogen production from a national perspective.
- The strategy primarily targets the maritime sector, heavy transportation and industrial processes owing to the small amount of non-emission alternatives in these areas.

Denmark Energy Islands Strategy 2020

- The Danish parliament approved a landmark climate agreement in June 2020 including several initiatives linked to renewable energy.
- Major interest on investing in the development of Power-to-X technologies leveraging on hydrogen's versatility to provide sustainable fuel to ships, planes and trucks.
- Further developing carbon capture technology identified as an interesting transitional solution to increase hydrogen production in the near future while reducing emissions.

Companies from the energy and transport industries have started to shift their strategies towards hydrogen, undertaking both joint and independent projects

- In May 2020, a consortium of companies launched the joint "Choose Renewable Hydrogen" initiative to acknowledge and support the EU's leadership towards decarbonizing the economy. Eight of Europe's industry-leading companies (Akuo Energy, BayWa, EDP, Enel, Iberdrola, MHI Vestas, Ørsted, and Vestas) together aim to promote renewable energy and hydrogen to drive the transition to clean energy.

- ENGIE has partnered with fertilizer producer Yara to study the feasibility of producing ammonia from green hydrogen. To this end, companies are planning to build a 66 MW electrolyser powered with renewable electricity in order to reduce carbon emissions.
- Danish energy company Ørsted has formed a partnership with national shipping and aviation players, such as Maersk and Copenhagen airports, to develop a world leading green hydrogen hub to produce sustainable fuels.
- Following Norway's shift towards hydrogen, Equinor is heavily involved in the hydrogen transition. It has signed a 10M€ deal with ShipFC to test long distance ship transport powered by fuel cells and green ammonia (used as a hydrogen bond to ease operation).
- Enel plans to launch its hydrogen business in 2021, installing electrolysers for green hydrogen production. The European utility aims to reach carbon neutrality by 2050.
- Repsol has set goals for 2030 to increase electrolyser efficiency (25-30%) while reducing its CAPEX by 30% to start producing green hydrogen at industrial level.
- Alstom continues to develop the Coradia iLint hydrogen train program. While already operational in Germany, these trains have been successfully tested in the Netherlands, and the group has recently partnered with Snam to develop hydrogen trains in Italy.

At the European scale the Commission has also unveiled its Hydrogen Strategy 2020

In July 2020, the European Commission presented a roadmap targeting key areas and investment priorities for the coming years to effectively deploy hydrogen in Europe, seeking to reduce GHG emissions, create local jobs and reinforce EU's global leadership

- Main priority is to develop renewable hydrogen production, primarily using wind and solar energy, to achieve climate neutrality and a long-term carbon neutral integrated energy system. To this end, EU's strategy is structured in three phases with different objectives:
  - 2020-2024: install at least 6 GW of renewable hydrogen electrolysers in the EU and produce up to 1 million tons of renewable hydrogen to decarbonize existing hydrogen production.
  - 2025-2030: increase green hydrogen production capacity to 40 GW and generate up to 10 million tons of renewable hydrogen in the EU.
  - 2030-2050: ensure technical maturity of all renewable hydrogen-related technologies (electrolyser manufacturing, infrastructure…) in order to be deployed at large scale, reaching all hard-to-decarbonise sectors.
- An investment agenda from now to 2030 has been established leveraging on EU funds and European Investment Bank financing:
  - Electrolysers: estimated investments ranging from €24 to 42 billion.
  - Scaling up renewable power generation: €220 to 340 billion required to provide around 80 to 120 GW of renewable electricity for green hydrogen production.
  - Carbon capture and storage for existing hydrogen plants: at least €11 billion needed to upgrade half of the existing hydrogen production sites with CCS and storage capabilities.
  - Infrastructure: around €65 billion required for hydrogen transport, distribution and storage.

Europe

- To achieve these goals, the European Clean Hydrogen Alliance has been created to lead the implementation of the EU hydrogen strategy and support investments. Its role along the entire hydrogen value chain includes building up a pipeline of viable investment projects and ensuring that they have the necessary visibility and support.
- Other organizations and initiatives will be appointed for further project recommendations and investment support (IPCEI Strategic Forum, InvestEU programe, REACT-EU initiative).
- Simultaneously boosting hydrogen demand and scaling up production has been identified as a major challenge. The EU Hydrogen Strategy sets the following actions to address it:
  - Boosting demand in end-use sectors must be achieved by replacing carbon-intensive hydrogen in chemical and heavy industries and developing applications in the transport sector (e.g. trains, ships…). Investing in high cost hydrogen-based equipment is the main restriction, thus demand side incentives and support policies are required.
  - Scaling up hydrogen production according to EU goals is limited by renewable electricity and technology costs. Support schemes from Member States and EU institutions are needed to make hydrogen production cost-competitive. Agreeing on a European criteria to certify technologies and emissions for green and blue hydrogen is key to give clarity to investors.
- To build a supportive framework, the EU considers hydrogen infrastructure a priority. Infrastructure planning and deployment must be accounted for in the Trans-European Networks for Energy policy and the Ten-Year Network Development Plan for gas infrastructure. Market rules and legislation have to be reviewed according to hydrogen requirements.
- Research and innovation must be encouraged leveraging on international cooperation to launch pilot projects throughout the hydrogen value chain (e.g. Clean Hydrogen Partnership).

Topic Box 1.2: Overview of the promotion of innovative sectors in the EU

In order to achieve Europe's clean energy transition and to foster sustainable growth in the context of recovery from the COVID-19 crisis, the EU and its Member States have set out a number of key actions to support innovative sectors such as hydrogen and batteries.

The adoption of an ambitious European strategy and the creation of a European alliance seem to mark a turning point for the promotion of clean and renewable hydrogen

Deploying hydrogen in Europe faces important challenges that Member States cannot address alone

Almost all Member States have included plans for clean hydrogen in their National Energy and Climate Plans (NECP), 26 have signed up to the Hydrogen Initiative and 14 have included hydrogen in the context of their alternative fuels infrastructure policy frameworks. Some have already adopted national strategies or are in the process of adopting one.

For instance, in June 2018, France presented its Hydrogen Plan including an investment of €100 million per year for five years. In comparison, in June 2020, Germany announced that €9 billion of the €130 billion euros of the recovery plan will be invested in the development of hydrogen.

The EU aims at kick-starting the EU hydrogen industry

On July 8, 2020, the European Commission (EC) published the European Hydrogen Strategy (EHS), a strategy for a climate-neutral Europe. In order to boost and scale up hydrogen production, distribution and use, the EHS sets a three-step approach to install at least 6 GW by 2024, 40 GW of renewable hydrogen electrolyzers by 2030 and a fully matured hydrogen economy and a trans-European hydrogen network by 2050. To this end, the EC is considering bringing into play several important state aid mechanisms, such as:

- Tendering systems for Carbon Contracts for Difference scheme (CCfD), a long term contract with a public counterpart which would remunerate the investor by paying the difference between the CO_2 strike price and the actual CO_2 price in the Emission Trading System (ETS);
- Recommendations by the Strategic Forum on Important Projects of Common European Interest (IPCEI), which includes subsidies to companies participating in a project that (i) contributes to strategic EU objectives, (ii) involves several Member States, (iii) involves private financing by the beneficiaries, (iv) generates positive spillover effects across the EU and (v) is highly ambitious in terms of research and innovation. Several Member States, including Belgium and France, have already invited companies to submit proposals.

In July 2020, the European Clean Hydrogen Alliance (ECH2A) was announced. Bringing together industry, national and local public authorities, research organizations, civil society and other stakeholders, this cooperative platform will play a crucial role in facilitating the implementation of the EHS by identifying and building up a clear pipeline of viable investment projects along the hydrogen value chain.

Welcomed by the sector, the strategy adopted by the EC is ambitious. Nevertheless, its success will depend on its ability to federate the initiatives of the Member States, which to date has not been achieved.

At the instigation of the EC, Member States have stepped up their support for industry-led projects related to batteries, in particular through the creation of an "Airbus-style consortium"

Given the scale and speed of investment needed, the development of a competitive and sustainable battery manufacturing industry in Europe cannot be dealt at the national level

It is estimated that 20-30 gigafactories for battery cells production alone will have to be built in Europe and their related ecosystem will need to be considerably strengthened. In 2018, the European share of global cell manufacturing was just 3%, while Asia's share was 85%.

In this context, although some Member States have elaborated national plans to promote the development of batteries, their support is essentially part of a cross-border and integrated European approach. For instance, launched in 2019, the plan "Producing in France the cars of tomorrow" has notably led to the emergence of a Franco- German industrial project for car batteries at the origin of the Airbus of batteries.

Following the adoption of a European strategy and the creation of an European alliance, the EC has now approved a battery-related IPCEI

In October 2017, the EC launched the European Battery Alliance (EBA), a cooperation platform which gathers together the EC, interested Member States, the European Investment Bank and more than 120 key industrial and innovation actors in order to create a competitive manufacturing value chain in Europe with sustainable battery cells at its core.

In May 2018, the EC adopted a Strategic Action Plan for Batteries (SAPB). This plan brought together a set of measures to support national, regional and industrial efforts to build a battery value chain in Europe, embracing raw materials extraction, sourcing and processing, battery materials, cell production, battery systems, as well as re-use and recycling.

In December 2019, the EC approved a major IPCEI dubbed "the Airbus of batteries". Initiated by France and Germany, the project involves 17 direct participants, mainly industrial players like BASF, Solvay and BMW, from the seven Member States (Belgium, Finland, France, Germany, Italy, Poland and Sweden), some with activities in more than one Member State. Its aim is to support the development of highly innovative and sustainable technologies for lithium-ion batteries that last longer, have shorter charging times, and are safer and more environmentally friendly than those currently available. Member States will provide up to approximately €3.2 billion in funding for this project, which is expected to unlock an additional €5 billion in private investments. The completion of the overall project is planned for 2031.

A second battery-related IPCEI coordinated by Germany is planned for 2024.

***"Batteries are at the heart of the industrial revolution and I am convinced that Europe has what it takes to become the world's leader in innovation, decarbonisation and digitization"*, Vice-President of Energy Union Maroš Šefčovic**

Renewables share in transportation continues to increase: Biofuels are the main contributors to the target for 2020 but fossil fuels still represent the 92%

Transport is the only major European economic sector in which GHG emissions have increased in recent years

- GHG emissions from transport (including international aviation but excluding maritime shipping) account for around one quarter of the EU's total GHG emissions.
- In 2018, specific emissions from newly registered passenger cars increased for the second consecutive year, reaching 120.4 gCO_2/km.

All EU countries, except Sweden and Finland, need to increase their renewable energy usage in transportation to comply with the 2020 target

- The average share of energy from renewable sources in transport increased from 1.5 % in 2004 to 8.03 % in 2018. Among the EU Member States the share of renewable energy in transport fuel consumption ranged from highs of 29.7 % in Sweden, 14.9 % in Finland and 9.8 % in Austria down to less than 4.0 % in Croatia (3.9 %), Greece (3.8 %), Estonia (3.3 %) and Cyprus (2.7 %).

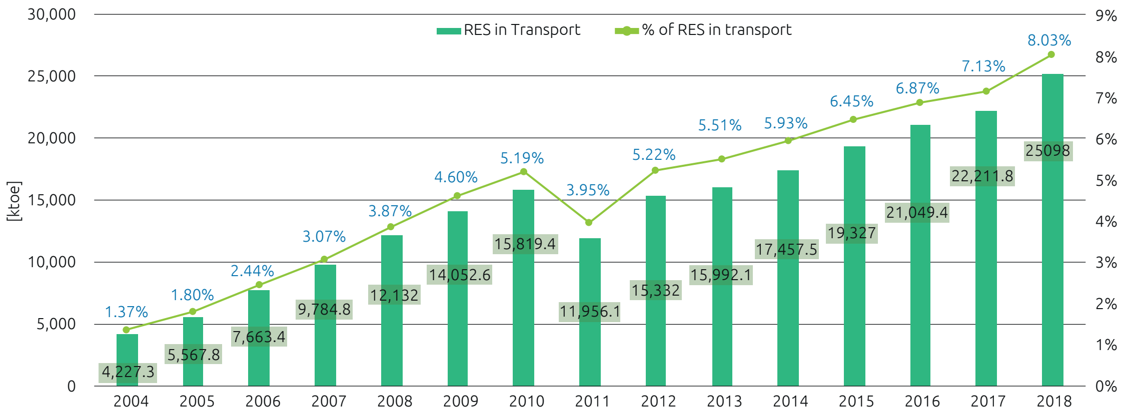
The 10 % target is expected to be met primarily through biofuels

- Biofuels and bioliquids are instrumental in helping EU countries meet their 10% renewables target in transport. Only biofuels complying with the sustainability criteria set in the Renewable Energy Directive and the Fuel Quality Directive (2009/30/EC) are considered to reach this target.

Renewable electricity penetration is accelerating across every transportation sector

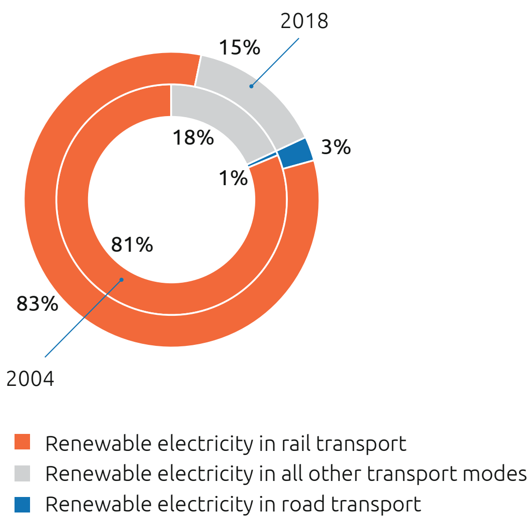
- Trams, buses and passengers' vehicles powered by renewable electricity need to become the predominant forms of city transport. In sectors such as aviation, shipping and long-haul road transport, biofuels and electric-fuels derived from renewable hydrogen will play a central role.
- Of all transportation modes, the largest amount of renewable electricity is used by rail transport (more than 80%), because for rail the transition to RES usage is easier than others: As soon as cities or communities start to buy electricity from renewable sources, the transformation is complete. However, the situation is more complicated for other transportation modes (road, aviation, maritime), therefore the EU is trying to improve legal frameworks and boost technological progress.
- In road transport, electrification will continue to increase led by electric cars, motorbikes and buses. However, energy from fossil fuels will still be the most common source: By 2030, 70% of transport fuel will still be petroleum based despite ambitious objectives on e-mobility.

Figure 1.30. Evolution of Renewable Energy Consumption in the Transport Sector in EU28 (ktoe and %)



Source: Eurostat SHARES 2018

Figure 1.31. Renewable Energy in transport in Europe (%) 2004 vs 2018



Source: Eurostat SHARES 2018

COVID-19 decreased urban mobility by 70% in average, but by 81% for public transportation vs 67% for driving, therefore impairing progress on sustainable mobility

Public transport was affected the most by the pandemic, and the effects going forward cannot be fully assessed

- Public transport is struggling worldwide with reduced passenger load factors of 50 to 90%, resulting in revenue losses of up to 75%.
- In the city of Munich alone, there are currently revenue losses of €30 to 50 million - per month. Transport for London (TfL) estimates that €2.29 billion will be needed to keep the system running until autumn 2020.
- Shared mobility going through the same challenges when looking at it as a means of personal transportation: usage is down by 70% in some cities.
- The loss of confidence in public transport, both from authorities and citizens, threatens to cause even more damage in the medium term, raising the risk of a spike in car traffic.

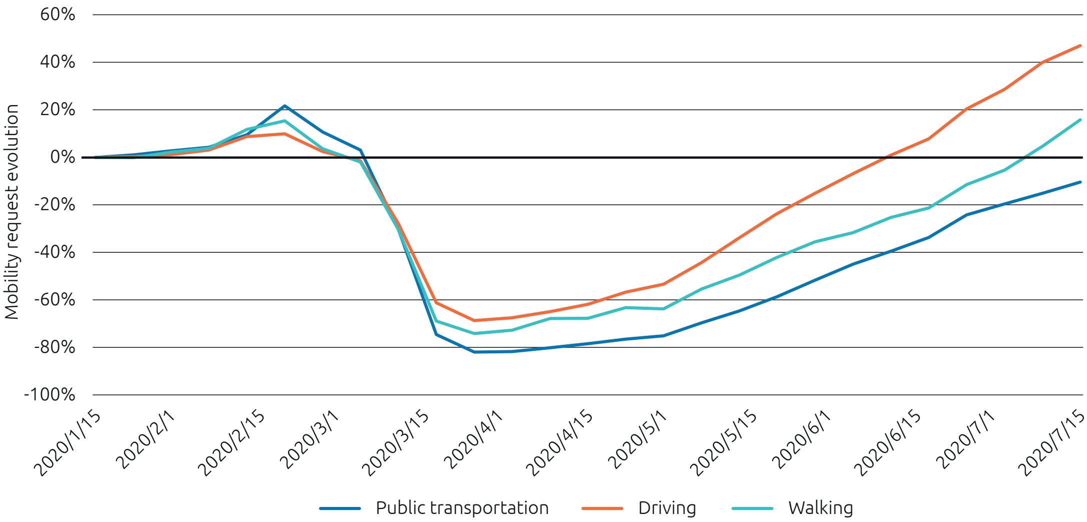
Renewed interest for individual transport can also be an opportunity to promote both the electric vehicle and other active forms of mobility

- As part of economic recovery efforts, countries like France, Germany, Spain and the UK announced increased support measures towards e-vehicles buyers for 2020 and onwards.
- Other targeted and direct support measures, such as for charging infrastructure and financial aid to buy EV corporate fleets, buses and trucks, could also help.
- A more active mobility could also be arising: in May 2020, bicycle traffic in Paris was greater than 50% compared to the traffic recorded in May 2019. On top of that, many European cities responded to lockdown with the creation of more bicycle lanes and the redistribution of public space to pedestrians. The challenge now is to make them last.

But city inhabitants are in fact demanding fewer cars: it's time to rethink mobility collectively

- A survey of 7,500 people in 21 European cities and published in June showed that 64% of citizens do not want to return to the levels of contamination prior to confinement, even if that means less space for cars.
- The transport sector will benefit from a record support and recovery plan (€15 billion for the aeronautics sector, €5 billion for Renault, …). However, it would be unfortunate if these funds go mainly for the air and automotive sectors rather than for public transport.

Figure 1.32. European mobility request evolution during COVID-19



Source: Apple Mobility Trends Report

Specific targeted measures to support public transport need to be part of recovery plans. Investments in hygiene measures like disinfection, mask wearing and social distancing are a must to revive the use of public transport. But the combined efforts of private and public sectors must also be put in play to cope with the necessary solutions from all perspectives: business models, technology, regulation, campaigns/behaviors, etc. FabMob, the French accelerator empowering the mobility ecosystem could be a good example of these joint efforts.

Electrification is one of the four megatrends reshaping the future of mobility, along with shared services, connectivity and autonomous driving

Sales of EVs represented 4.3% of global European car sales in Q1 2020, a rise of 58% compared to Q1 2019, despite a depleted global car market due to COVID-19

- Plug-in electric vehicles, including hybrid vehicles, accounted for 7% of the sales for the same period.
- The International Energy Agency has forecast that the market share of EVs in Europe could be around 23 % in 2030.
- In Europe, the German market leads in plug-in EV sales. However, Norway has the largest share of EV registrations, accounting for more than 60% of new plug-in EVs registered.

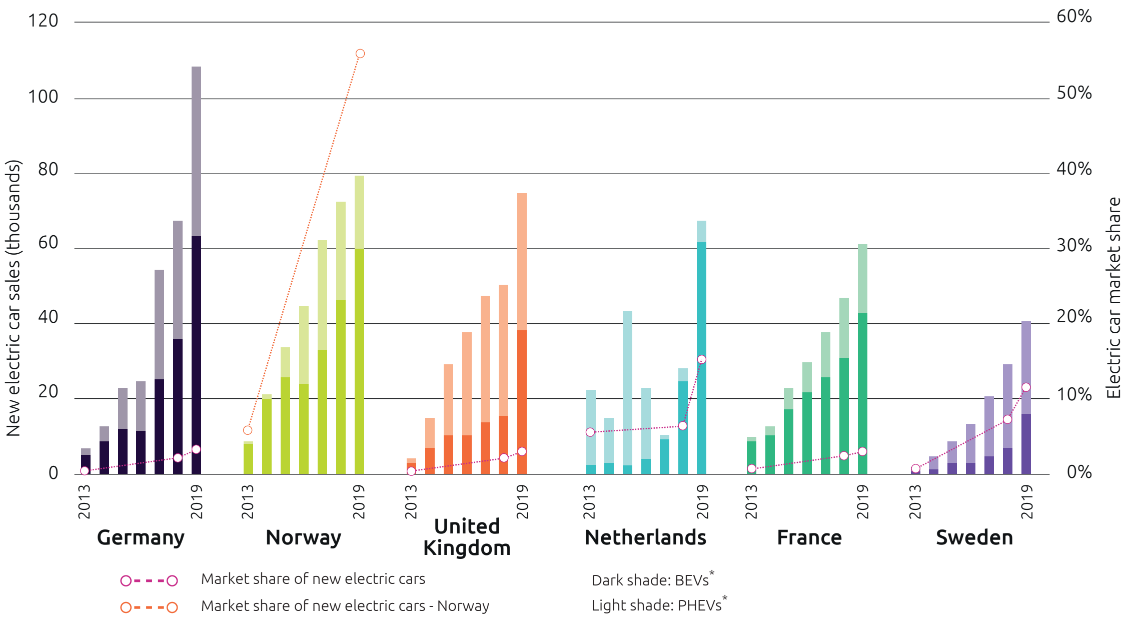
Representative improvements in technology and a wider variety of electric car models on offer have encouraged consumer purchase decisions

- The number of electric car models available to consumers in Europe is expected to triple by 2021. Carmakers are forecast to bring 92 fully electric models and 118 plug-in hybrid models to market in 2021.
- Other types of electric road vehicles are also increasing. Around 1.66 million e-bikes were sold in the EU in 2016, compared to only 98,000 in 2006. This number is expected to further increase to 62 million by 2030.
- Demand for electric buses, as well as motorcycles, mopeds and scooters, is growing significantly. However, demand for electric trucks is still limited, waiting on technological progress on batteries. In 2020, there are around 2,500 electric buses in Europe – a relatively small number compared to the 725,000 buses, mostly diesel, in operation.

Despite its rapid growth, the EU market for such vehicles is still small, and largely dependent on support policies that are being tailored to support market transition

- In Flanders (Belgium), EV owners are often fully exempted from paying the vehicle registration tax.
- Germany exempts EVs from the annual circulation tax for a period of 10 years and Austria exempts EVs from the consumption/pollution tax, ownership tax and company car tax.
- In Ireland, EV owners pay the minimum rate of the road tax and some European countries such as France offer grants for swapping a diesel car for a new electric one.

Figure 1.33. New electric car sales



* BEVs = battery electric vehicles — PHEVs = plug-in hybrid electric vehicles
Source: IEA Global EV Outlook 2020

To achieve momentum for the adoption of EVs throughout the EU, it is essential that Member States invest in it.

Recovery packages must favor EVs and put the diesel subsidy to one side.

Charging infrastructure needs further work by all players to unlock the potential of e-mobility and it is key to the EU becoming climate neutral by 2050

The limited availability of public charging points in Europe will be the main barrier when potential buyers consider EVs

- Charging infrastructure will soon become the main barrier to EV purchase, ahead of falling prices and increased driving range.
- The future of the EV charging ecosystem depends on changes along four dimensions: EV charging, autonomous vehicle technologies, customer expectations, and changing regulatory environments. Carmakers agree that stronger EU rules must be introduced with clear targets for charging points.
- The complexity of the EV charging infrastructure incentivizes all players to develop innovative solutions but as business models are constantly revised, it's tricky to forecast financial returns and economic benefits.

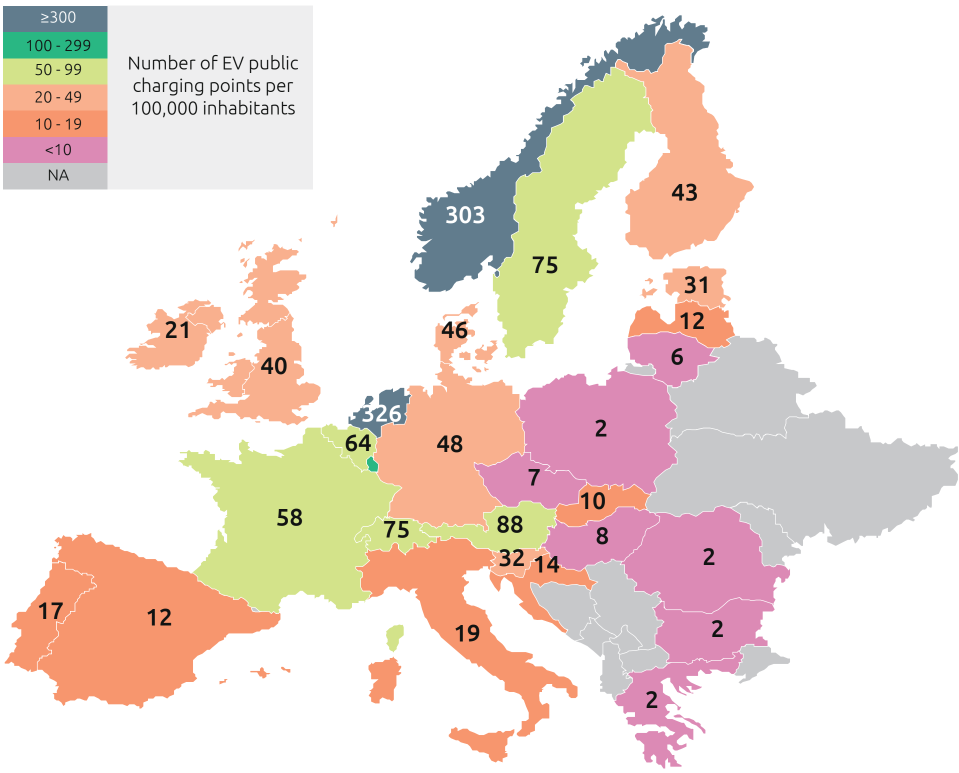
Development of urban and suburban charging points needs to accelerate because by 2030 it will be essential if it is to sustain the rise in EVs needed as part of Europe's long-term climate objectives

- The number of EVs on the road worldwide is estimated to grow from 4 million at the end of 2018 to 125 million by 2030. The Netherlands, Germany, France, Sweden and Italy will be leading the way, having the highest number of public charging points in 2020.
- Fast charging network availability on roads is essential to enable drivers to travel longer distances and to incentivize potential EV purchasers. Many projects are underway, such as the group of five European OEMs building a fast charger network of 400 stations by 2020.
- E-mobility uptake will happen in successive waves: frontrunners (Western and Nordic countries), followers (Italy, Portugal and Spain) and slow starters (EU13 and Greece).

Competition in the e-mobility market is moving from who has the greatest number of charging stations to which companies provide the best UX

- In Eastern Europe, charging hubs are emerging to cater for a wider range of users, by installing multiple chargers and parking spaces, as well as different types of charger.
- Greater attention is being given to improving the charging experience for EV users. eCharge4Drivers is an H2020 project running from June 2020 to May 2024 and deployed by a consortium of 32 partners. The objectives are to develop and demonstrate user-friendly charging stations and innovative charging solutions, enhance smart services for the users, and foster the broad implementation of charging infrastructure in Europe.

Figure 1.34. Electric Vehicles public charging points (2020)



Source: European Alternative Fuels Observatory

The cumulative cost for public charging infrastructure to date is estimated to be €12 billion with roughly €20 billion of investment needed for private charging by 2030. Some level of financial support will be needed to build the basic infrastructure until the late 2020s.

Europe

2-Infrastructure & Adequacy of Supply

Electricity market

In 2019, temperatures reached record highs, new renewables capacity was commissioned, and Europe's adequacy of supply was not endangered

- Net EU power capacity increased by 22.1 GW in 2019, mainly led by renewables, with six countries becoming coal-free.
- For the first time since 2014, European electricity consumption decreased in 2019 (-2%), dragged down by warm weather and stagnation in industrial activity.
- The combination of rising carbon prices, falling gas and coal prices, and increased renewables generation pushed down the out-turn power prices in almost every EU country in 2019, reaching €44.32/MWh.
- Marked by the COVID-19 crisis, H1 2020 saw unprecedented drops in electricity consumption (-10%) and generation, as well as prices (-43%).

In the short term, adequacy of supply should not be at risk; in the long term it will be impacted by generation and consumption patterns that are less predictable

- By 2030, most European countries will have phased out coal. Low carbon capacities are expected to represent 77% of the mix, while coal will only account for 4%.
- This will be explained by a higher share of renewables in the generation mix: by 2040, they should amount to 73-78% of the ~4000 TWh generated annually by the EU-27.
- Future adequacy of supply will then rely on development of technologies such as stationary batteries and Demand Side Response (DSR) in order to allow flexibility, the reinforced integration of EU markets, and the development/maintenance of low carbon generation such as hydrogen and nuclear capacities.

Despite the COVID-19 pandemic and postponed deadlines, EU market integration is progressing, driven by increasingly efficient mechanisms

- Nearly all member states have reached the 10% interconnection target set for 2020 and are now heading for the 15% target by 2030.
- Intraday and day-ahead market coupling is still progressing with, respectively, Italy and Greece expected to join intraday and 4MMC countries, and Greece expected to join day-ahead coupling, in 2020.
- A first major step was reached in capacity pooling, with the launch of the TERRE project in January 2020 and the Frequency Containment Reserve (FCR) mechanism getting closer to real time.

At a local level, smart meter deployment is progressing rather slowly

- A prerequisite for smart grids, smart meter deployment is expected to achieve only a 43% penetration rate in the EU by the end of 2020 and 77% by 2024 – way behind the 80% target set for 2020.
- Despite a growing number of smart grid projects launched by the Joint Research Centre (JRC) and a greater number in the demonstrator phase (43%), smart grid development remains at an early stage.

Net EU power capacity increased by 22.1 GW (1.8%) in 2019

EU electricity generation capacity continued to increase thanks to an additional 29.9 GW from renewable sources

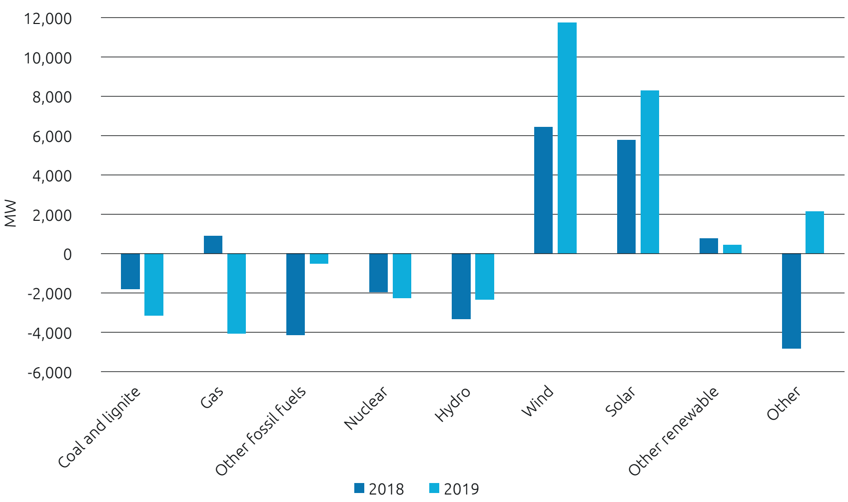
- The EU installed 13.2 GW of new wind capacity in 2019, a 30.7% increase compared to 2018. The increase in installed wind capacity was chiefly supported by the UK (+2.4 GW), Spain (+2.3 GW), Germany (+2.1 GW) and Sweden (+1.6 GW)1. Further significant projects were commissioned during 2019, including:
  - In the UK, the offshore Hornsea One wind farm (1,218 MW)[1]
  - In Germany, the offshore Merkur (396 MW)[2], Deutsche Bucht (252 MW)[3] and EnBW Hohe See (497 MW)[4] wind farms
- In 2019, solar capacity showed the strongest growth since 2010 with 16.7 GW new capacity:
  - Spain regained its position as Europe's top solar market with 4.7 GW followed by Germany (4 GW), Netherlands (2.5 GW) and France (1.1 GW)[5].
  - Solar PV became more and more competitive due to a significant decrease in structural costs. Electricity can be generated at a LCOE (Levelized Cost Of Energy) of 0.03 €/kWh in Southern Europe and 0.05 €/kWh in Northern Europe[5].

Decommissioning of fossil fuel capacity continued with an additional 6.8 GW phased out

- Six countries in Europe became coal-free and 14 others decided to phase out coal nationally by 2030 (e.g. by 2022 for France, 2025 for Italy, 2028 for Greece)[6]. In July 2020, Germany passed legislation to phase out coal-fired power generation by 2038.
- In addition, two nuclear power plants accounting for a total 3.2 GW capacity were decommissioned: Philippsburg in December 2019[7] and Fessenheim in February 2020[8].

Europe

Figure 2.1. Evolution of the capacity mix in the EU 2018-2019 [MW]



Source: Agora Energiewende

1 Wind Energy in Europe in 2019, Trends and statistics, Wind Europe
2 Merkur Offshore Wind Farm, Empowering Intelligence | 4C Offshore (https://www.4coffshore.com/windfarms/merkur-germany-de26.html)
3 Deutsche Bucht, Renewable energy from the North Sea (https://www.owf-deutsche-bucht.de/wind-farm/)
4 EnBW Hohe See and Albatros wind farms (https://www.enbw.com/renewable-energy/wind-energy/our-offshore-wind-farms/hohe-see/)
5 EU Market Outlook for Solar Power (2019 – 2023), SolarPower Europe
6 The European Power Sector in 2019, Agora Energiewende
7 Germany shuts down Philippsburg 2, Nuclear Engineering International
8 France completes closure of Fessenheim plant, World Nuclear News

Electricity consumption decreased by 2% in 2019 to reach 3,239 TWh

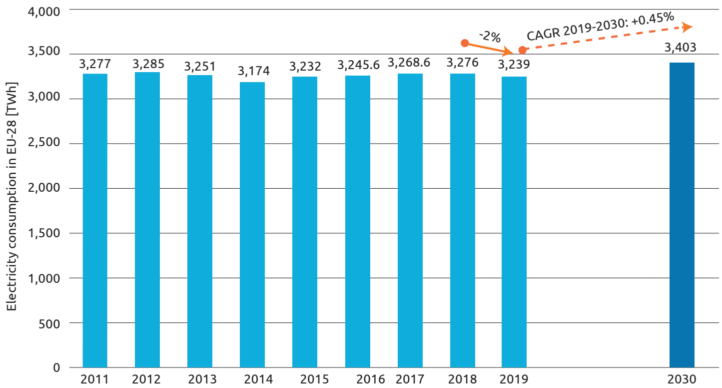
Warm weather and stagnation in industrial activity dragged down power demand:

- In July 2019, a heatwave reached Northern Europe and strongly increased power demand for air conditioning. However, the overall consumption decrease follows in the wake of the hottest winter in Europe and the warmest December on record. According to the European Union's climate change monitoring agency, the average temperature over Europe in December 2019 was 3.2°C warmer than average[1]. This warm season reduced power demands for heating and compensated for summer peak loads[2].
- In addition, stagnation in automotive manufacturing production and a weakening metals industry curbed demand[3].

Over the last decade, overall power consumption remained between 3.2 and 3.3 TWh with a decrease in Western Europe power consumption compensating for the increase in Eastern Europe:

- Driven by economic growth, electricity demand from business and industrial sectors has been increasing in Eastern Europe (Lithuania +14%, Poland +11% over the decade). Since 2008, Poland's industrial electricity demand has increased by 31.5% and the commercial and public services electricity demand increased by 20.8%[4].
- Other European countries saw decreases in electricity consumption (Luxembourg -10%, Germany -7%, France -5% over the decade). This decrease was mainly due to reinforcement of energy efficiency policies and the transition within the economy to new services that requirefour to five time less electricity than the industrial sector[5].

Figure 2.2. Electricity consumption in the EU (2011 to 2019, 2030 projections)



Source : Agora Energiewende

1 https://climate.copernicus.eu/surface-air-temperature-december-2019
2 Agora Energiewende and Sandbag (2020): The European Power Sector in 2019: Up-to-Date Analysis on the Electricity Transition
3 Quarterly report on European Electricity Markets, European Commission
4 Poland Key energy statistics, 2018, IEA
5 Bilan électrique 2019, RTE

Power generation in the EU decreased by 1% (-43 TWh) to reach 3,222 TWh

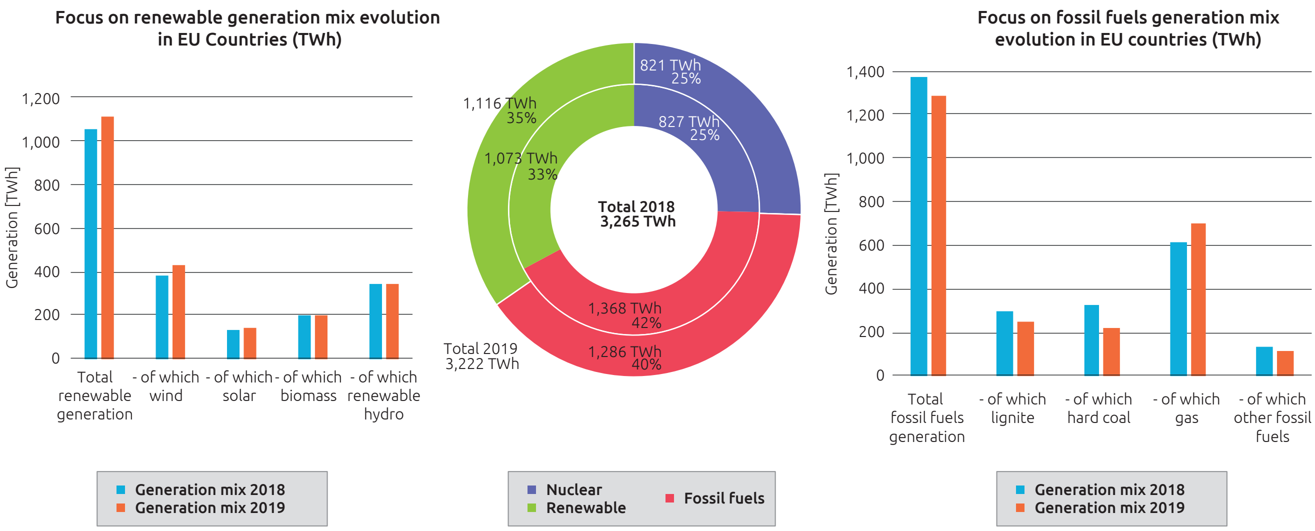
The share of renewable energy in EU generation reached 34.6%, with a 65 TWh increase in 2019:

- The surge in generation was mainly due to the strong increase in wind generation (+54 TWh), particularly in France, Germany, Spain and Sweden, for example.
- Overall solar generation rose by 7% (+9.5 TWh) in 2019 to represent 4% of Europe's electricity mix[1]. The generation increase is due to new capacities and high solar insulation over Europe during the summer.

The share of conventional power continued to fall in 2019 (-4%) driven by decreasing coal generation:

- Hard coal generation decreased by 24% (150 TWh) in 2019. Lignite generation followed the same trend and fell by 16% (49 TWh).
- Rising prices for CO_2 emissions, along with hard coal phase out, triggered fuel switching from coal to gas and increased gas power generation by 73 TWh (12%) in 2019.
- Since 2012, energy from hard coal and lignite has fallen by 424 TWh, benefiting gas (+116 TWh) and renewables (+335 TWh)[1].
- Overall, nuclear power generation remained stable. Nuclear unavailability in some countries was compensated for by high availability in Belgium's nuclear power sector[2].

Figure 2.3. Evolution of the Power generation mix in the EU 2018-2019



Source: Eurostat

1 Agora Energiewende and Sandbag (2020): The European Power Sector in 2019: Up-to-Date Analysis on the Electricity Transition
2 Quarterly report on European Electricity Markets, European Commission

Security of supply issues in Europe were reassuringly minor considering the above average temperatures

Several heatwaves were recorded during summer 2019 with no major impact on electricity supply

- Summer 2019 was characterized by 1.1°C above average temperatures (compared to the 1981-2010 norm) in the June-August period. It was the 4th warmest summer recorded since at least 1979[1].
- In June, large system imbalances were recorded in Germany for 3 days. Transmission System Operators (TSOs) activated all interruptible loads and system reserves and activated emergency power in Germany and in nearby TSOs. In August, a lightning strike caused the biggest blackout in the UK for a decade, bringing down a gas-fired plant and an offshore wind farm: National Grid was unable to cover the twin outages because it didn't have enough backup[2].
- High generation from renewable energy sources and low demand were recorded in Belgium and France. As a result, those countries modulated their nuclear generation as a reaction to market signals.
- Hydro levels were near average by the end of the summer season in most regions even though lower than average precipitation was recorded in France and Austria, and in Italy the level was only slightly above the historic minimum[3].

Despite a very warm winter, a few events put security of supply at risk[4]

- Winter 2019/2020 was the warmest ever recorded in Europe with mild temperatures in northern and eastern Europe. The average temperature was almost 1.4°C higher than during the previous warmest winter (2015/2016)[1].
- In December 2019, the Malta–Sicily Interconnector was damaged by a ship's anchor causing a nationwide blackout for approximately three hours. Emergency gas turbines were promptly activated.
- Several winter storms were recorded in northwestern Europe during winter 2019/2020. In Germany, they occasionally caused wind generation to peak, with a new record reached on February 22.
- In Sweden, unplanned outages of nuclear facilities were recorded, due to technical failures either of power plant elements or of grid elements connecting them to the power network. Nevertheless, supply margins remained sufficiently steady.
- In May, the UK changed the rules to allow network operators to halt the supply of electricity from renewables when demand falls to avoid overloading the grid and causing blackouts[5].

1 Copernicus – Surface air temperature maps 2019
2 ENTSOE - Winter Outlook 2019 / 2020 Summer Review 2019
3 Agora Energiewende and Sandbag (2020): The European Power Sector in 2019: Up-to-Date Analysis on the Electricity Transition
4 ENTSOE - 2020 Winter Review / Summer Outlook 2019/2020
5 Bloomberg Law - National Grid Asks for Emergency Powers to Avoid U.K. Blackouts

On average, day-ahead prices in the EU fell by €5.3/MWh year-on-year

The combination of rising carbon prices, falling gas and coal prices and increased renewables generation pushed down the out-turn power prices in almost every EU country in 2019[1]

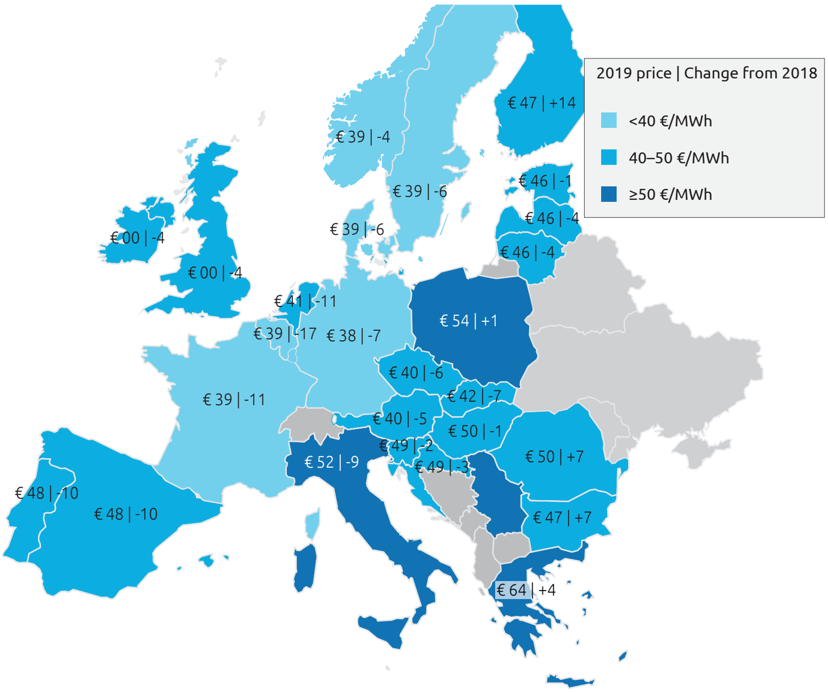
- Belgium's wholesale prices decreased by 16 EUR/MWh on average, due to nuclear plants coming back online after long downtimes.
- UK power prices decreased by 16 EUR/MWh thanks to wind generation that increased by 14% year-on-year.
- Countries whose power systems are characterized by a high coal share were affected by the higher carbon prices, resulting in a 17 EUR/MWh average price increase in Bulgaria and 1.3 EUR/MWh in Poland.
- In an annual comparison, all markets saw prices coming down from record high levels in Q4 2018. The biggest decreases happened in Belgium (-45%), Ireland and France (both -36%), the Netherlands, Portugal and Spain (all -35%)[2].

H1 2020 is mainly characterized by the COVID-19 lockdown and above average temperatures causing demand and the electricity spot price to fall sharply especially during April[3]

- The electricity demand decreased due to the lockdown reaching an all time low during April. As an example, demand in Italy fell to 19,917 GWh, the lowest since 2000.
- Average monthly prices registered in all European electricity markets were the lowest in the last six years at the very least: the German market recorded its lowest monthly price in the last 19 years.
- In all markets, the average monthly price was below €30/MWh. The Nord Pool market registered the lowest average at €5.22/MWh, the highest average was registered by the British N2EX, at €27.62/MWh.

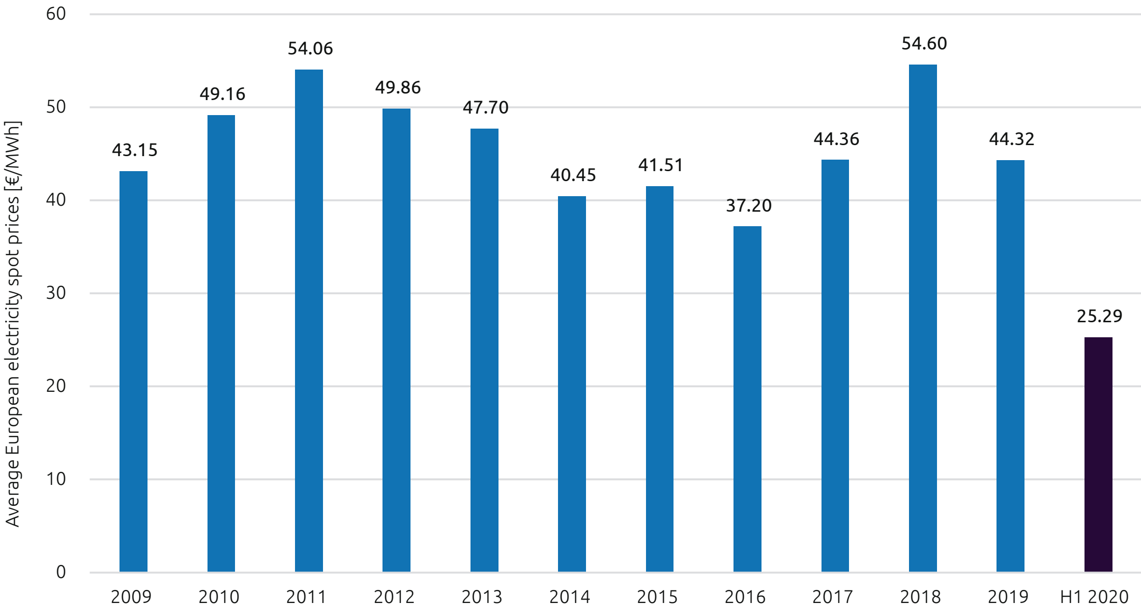
1 Agora Energiewende and Sandbag (2020): The European Power Sector in 2019: Up-to-Date Analysis on the Electricity Transition
2 European Commission, Electricity market quarterly reports 2020
3 Aleasoft – Energy forcasting: Historical fall in demand and prices of the European electricity markets in April

Figure 2.4. Average day-ahead prices in the EU 2018-2019



Source: Agora Energiewende

Figure 2.5. Average European electricity spot price (2009 to H1 2020)



Source: Power Exchange websites

Europe

The total traded volume in 2019 decreased by 5% year-on-year to 11,847 TWh

The changes in electricity flows across Europe in 2019 mostly relate to changes in Europe's hydro and nuclear generation[1]

- Most countries experienced a decline in trading activity in 2019. Spain, where volumes rose 17% year-on-year, was a notable exception. The largest annual falls in total traded volumes were recorded in Belgium (-42%), the Nordic markets (-11%) and the Netherlands (-10%) mainly over the counter[2].
- France and Germany were the two largest exporters in 2019, even though their combined outflows declined by 20 TWh due to:
  - Multiple outages of French nuclear capacities;
  - High generation from the Belgian nuclear fleet that pushed the less competitive German coal and lignite power stations out of the merit order and turned Belgium into a net exporter for the first time in 10 years;
  - Record high generation of Swiss and Austrian hydro power plants
- Sweden reinforced its position as the Scandinavian export leader, increasing its net outflows by 9 TWh year-on-year in 2019. This was due to increased hydro and wind generation, mainly at the expense of Norway, which significantly reduced production from its hydro reservoirs and cut its annual net exports to the EU from 10 TWh to zero.

1 Agora Energiewende and Sandbag (2020): The European Power Sector in 2019: Up-to-Date Analysis on the Electricity Transition

2 Market Observatory for Energy 2019, European Commission

FOCUS: The increasing need for storage capacity

The growing share of intermittent and decentralized sources in the generation mix had led to a significant increase in the installed storage capacity across the EU[1 2]

- Pumped hydro represents one of the oldest and most mature ways to store energy. With an efficiency factor of about 80% and very fast response times, it accounts for 97% of the EU's current energy storage capacity.
- The UK emerges as the leading market, both in terms of operational storage capacity (570 MW) and planned new facilities (4,929 MW). Moreover, co-located renewable and storage installations are being developed across the country and almost all existing projects are likely to be supported by renewable energy incentive regimes such as the Renewables Obligation (RO), Feed-in Tariffs (FITs) or Contract for Differences (CfDs)[3].
- In Germany, more than 200 MW of storage capacity were added in 2019 with a total installed capacity reaching roughly 509 MW. However, planned changes in the regulatory environment, rising renewables penetration and announced closures of thermal generation capacities should create new opportunities here as well.
- Another important area of growth for battery systems has been residential storage and self generation. Indeed, the significant reduction of investment costs and various incentivizing mechanisms has encouraged consumers to store their PV generation. Germany, with approximately 55,000 home storage units (for a total of 230 MW in power output) installed in 2019, remains by far the biggest European market.

Storage deployment remains strongly dependent on supportive policy and market frameworks[4]

- Markets are created as/where incentives are introduced, meaning that progress varies greatly between regions and countries. Few countries have set up place specific support schemes to develop pumped hydro storage (e.g. discount on grid tariffs in Belgium) and/or adapted their power market to allow development of storage (e.g. minimum bid size of 1MW, adapted bid formats such as "loop blocks")[1].
- Technology costs for battery storage continue to drop, mainly due to the rapid scale-up of battery manufacturing for electric vehicles (EVs), stimulating deployment in the power sector. Industry reports show that sales-weighted battery pack prices in 2019 were an average of $156/kWh, down from more than $1,100/kWh in 2010[5].

1 European Commission - Study on energy storage: Contribution to the security of the electricity supply in Europe

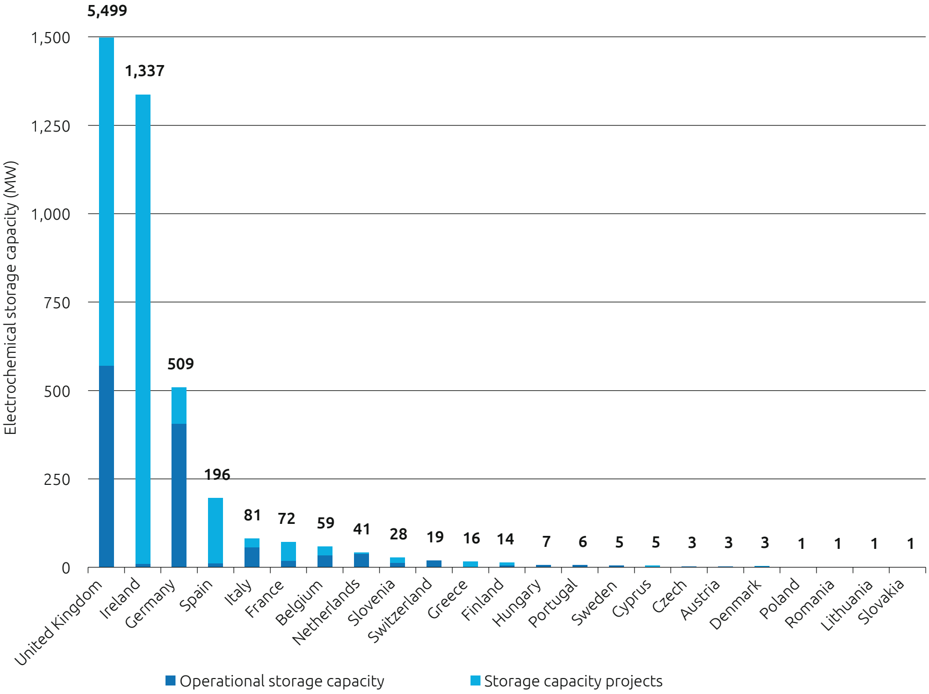
2 European Commission, Electricity market quarterly reports 2019 (Q4)

3 Norton Rose Fulbright - Scaling up energy storage in the UK

4 IEA – Annual storage deployment

5 IEA – Global EV outlook 2020

Figure 2.6. Electrochemical storage capacity in Europe



Source: European Commission

If all countries achieve their National Energy and Climate Plan (NECP) targets, low carbon capacities are expected to reach 77% of the EU's power mix by 2030

The next 10 years in Europe will be marked by an acceleration of current trends: enhanced coal phase-out plans, use of gas plants as a transition fuel to decarbonization, and growth of renewables capacity boosted by cost reductions

- Shares of coal for electricity generation will decrease to 8% by 2025 and 4% by 2030, as most member states plan to completely phase out coal at some point in the next 10 years.
  - Sweden and Austria closed their last coal-fired power plants in April 2020 and will be followed by France (2022), Slovakia and Portugal (2023), the UK (2024) and Italy (2025).
  - Seven member states still plan to burn coal beyond 2030. Among these, Hungary's final NECP does not contemplate measures to reduce the use of coal by 2030. As for Romania, the government plans to keep almost 2 GW of installed coal capacity at least until 2030 and to use natural gas to a considerable extent as a transition fuel to decarbonization[1].
- Renewables capacity is expected to continue increasing, with new projects in the next few years. For example:
  - France plans to auction in 2021 two projects for floating wind farms in Morbihan, for a total capacity of 500-750 MW[2].
  - In Spain, the Francisco Pizarro photovoltaic plant is expected to go live in 2021, when it will be the largest solar power plant in Europe with 590 MWp installed capacity[3].

The 2020 Ten-Year Network Development Plan (TYNDP) scenario report assesses three scenarios delivering a low-carbon energy system for Europe by 2050: National Trends (NT), Global Ambition (GA), and Distributed Energy (DE)

- Across all three scenarios there is an increase in renewables capacity, mainly from wind and solar power. However, the speed of uptake varies.

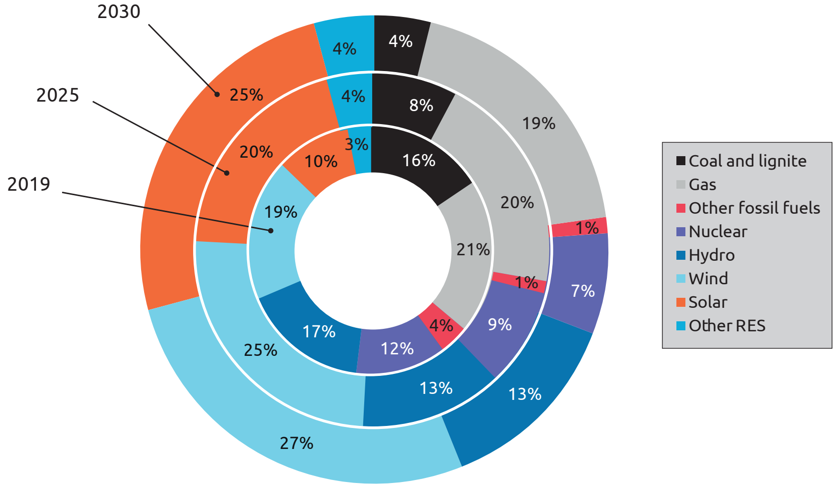
1 http://www.caneurope.org/docman/energy-union-governance/3613-opportunities-and-gaps-in-final-necps/file
2 https://www.letelegramme.fr/economie/cet-autre-projet-d-eolien-flottant-au-large-de-groix-et-belle-ile-en-mer-10-09-2020-12613903.php
3 https://www.iberdrola.com/about-us/lines-business/flagship-projects/francisco-pizarro-photovoltaic-plant

– The NT scenario is based on member countries' NECPs and is thus compliant with the EU-28's 2030 Climate and Energy Framework. Should countries stay their course, wind and solar would represent more than half the EU-28's capacity mix.

– The GA scenario focuses on centralized generation and economies of scale, thus leading to cost reductions in emerging technologies : offshore wind is expected to benefit particularly from this situation, reaching more than 150 GW in 2040.

– DE is led by a decentralized approach to energy transition and an active energy market role for prosumers, driving decarbonization by investing in small-scale solutions and circular approaches. Onshore wind and especially solar capacities are expected to increase dramatically by 2040.

Figure 2.7. Forecast of the European Capacity Mix 2019 – 2025 – 2030



Source: ENTSO-E

As the EU is likely to reach its 2030 renewables target, new scenarios forecast the share of renewables to reach up to 78% of the power generation mix in 2040

The EU-27 is expected surpass its 2030 target of 32% energy consumption met with renewables, despite growth in energy demand anticipated by an increase in Europe's GDP over the next decade

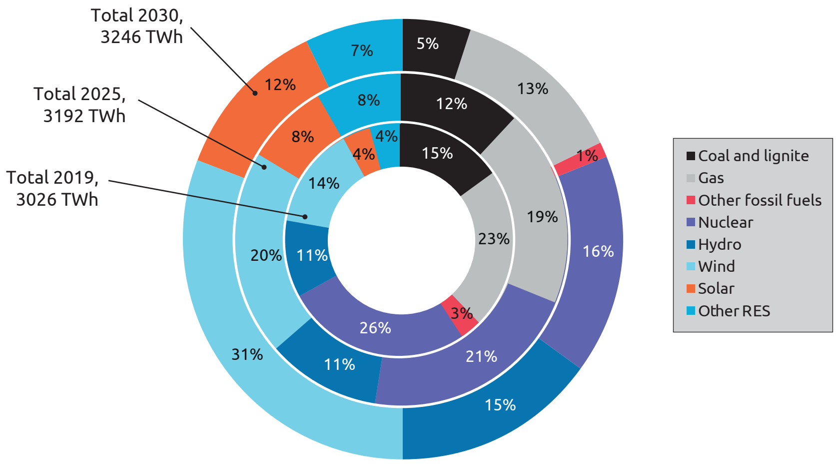
- According to planned and existing measures submitted by member countries in their final National Energy Climate Plans, the share of renewables in final energy consumption should reach 33.1-33.7% by 2030[1].
- In the wake of the COVID-19 pandemic, the European Commission has proposed raising its ambitions regarding GHG emissions reduction. By June 2021 this ambition will be translated into new policies, including a new target for the share of renewables in the power generation mix[2].

All long-term scenarios point towards increasing electrification of end-uses across all sectors, resulting in higher demand and thus higher power generation forecast in 2040

- In the EU-27, although energy demand is expected to decrease by at least a third compared to today's levels, direct electricity demand (today at ~3,000 TWh) could reach from ~3,500 TWh to ~3,800 TWh, depending on various scenarios expressed in the TYNDP report[3]:
  – Higher electricity demand is linked to widespread electrification of all sectors, especially transport and residential with the uptake of EVs and heat pumps.
  – Electricity demand in the residential sector could be tempered with national investment in energy efficiency, while investment in digitally enabled technologies (such as smart metering, smart charging for EVs) would help control peak electricity demand.
- By 2040, the EU-27 could be generating up to ~4,000 TWh, with the share of renewables somewhere between 73-78%, including 14% from solar and 41% from wind.

1 https://ec.europa.eu/commission/presscorner/detail/en/fs_20_1611
2 https://ec.europa.eu/clima/policies/strategies/2030_en
3 https://www.entsos-tyndp2020-scenarios.eu/

Figure 2.8. Forecast of the European Generation Mix 2019–2025–2030



Source: ENTSO-E

In the short term, adequacy of supply should not be at risk, but in the long term it will be impacted by less predictable generation and consumption patterns

In the short term, adequacy of supply should not be at risk, except for islands and a few continental market zones[1]

- The market-modelling results led by ENTSO-E for the year 2021 do not indicate significant adequacy issues in most European countries. Continental Europe's interconnected system is expected to be adequate in 2021 although islands such as Malta and Sicily continue to be vulnerable to loss of load[1].
- However, decommissioning and/or phasing out policies will strongly impact on adequacy of supply for member countries. For example, in 2021 France will have the second highest loss-of-load probability (LLP) in the EU-27 (after Malta), set at four hours. This result is linked to the planned decommissioning of two nuclear units by mid-2020 and to the postponed commissioning of a new nuclear plant to 2023.

In the long term, the TYNDP 2020 scenario report foresees less predictable patterns both in consumption and generation implying the need to develop and deploy at scale new solutions and technologies

- As electricity demand will increase in the long term (up to ~3,800 TWh in 2040), future consumption patterns are expected to become less and less predictable. Combined with the deployment of intermittent DERs (58% in 2040) and coal phase-out lowering the available controllable capacities, a growing amount of flexibility will be required to ensure adequacy of supply in Europe[2].

- To avoid a "flexibility gap", new solutions and technologies need to be introduced and developed.
  - Development of batteries in the EU will be driven both by consumers (residential and industrial) and by grid operators : by 2040 the total installed capacity of batteries connected to the European power system could reach ~50 TWh[2].
  - Demand-Side Response (DSR) development is still slow in the EU, mainly due to a lack of clear information on the opportunity customers have to engage in it (beyond price-based flexibility)[3]. In 2040, DSR technologies should amount to ~7 TWh in a Distributed Energy scenario.
- In addition to these new technologies, to secure long-term adequacy of supply:
  - The EU has fostered the progressive integration of its power markets and networks, taking further the interoperability of member countries' networks and standardization of suppliers' offers. It will be key in enabling a flexible network, addressing flexible output and input patterns.
  - The EC and EU member states are adjusting their energy policies in order to develop or maintain complementary low carbon energy sources such as hydrogen (with a European target of 6 GW of electrolysis capacity by 2024 and 40 GW by 2030)[4] or nuclear (e.g. Poland plans to build 6-9 GW nuclear capacity by 2040[5], other European countries such as France or the UK[6] plan to invest in next-gen nuclear technologies).

1 https://www.entsoe.eu/outlooks/midterm/
2 https://www.entsos-tyndp2020-scenarios.eu/
3 https://ec.europa.eu/energy/sites/ener/files/documents/eg3_final_report_demand_side_flexiblity_2019.04.15.pdf
4 https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf
5 https://www.reuters.com/article/us-poland-coal-idUSKBN25Z1G3
6 https://www.gov.uk/government/news/40-million-to-kick-start-next-gen-nuclear-technology

The implementation of the network codes continues supporting the progressive integration of EU markets and networks

Despite delays incurred by the COVID-19 crisis, the implementation of the network codes continues through the development of each article

- In particular, European Agency for the Cooperation of Energy Regulators (ACER) has decided to monitor more precisely the implementation of the Requirement for Generators & High Voltage Direct Current Connections Network codes by requesting additional implementation information to be provided each year by the TSOs and DSOs of each Member State[1].
- In line with the Forward Capacity Allocation Regulation, TSOs have submitted their proposal regarding the Firmness and Remuneration Costs Methodology of long-term transmission rights (LTTRs)[1]. This proposal aims at setting the sharing principles of the costs incurred by the remuneration of the LTTRs in case of congestion, and according to the corresponding (capacity) allocation mechanism (i.e. flow based, implicit …).
- Finally, as ENTSO-E is heading towards more integrated markets (Capacity Allocation & Congestion Management network code), the operating modes put into place are proving efficient as the market zones merging projects are becoming more frequent. In fact, regarding intraday coupling, it allows them to gradually assess and implement the coupling at Member State level (via local implementation projects or LIPs), resulting in the coupled zones described later.

In addition to the network codes implementation and after the finalization of their publication in 2018, ENTSO-E has set new goals for the TSOs and network codes

- In order to protect TSOs' systems and network operation tools against cyber-attacks, ENTSO-E developed a Cyber Security Strategy. This was approved in early 2019, and focuses on activities such as cybersecurity design and identification requirements for cybersecurity testing, to ensure pan-European interoperability via data exchange standards.

1 ENTSO-E

Interconnections are benefiting from additional funding via the Connecting Europe Facility, which enables targeted infrastructure investment to meet the EU's long-term consumption forecast

All EU countries apart from Spain have reached their 2020 target of a 10% interconnected network and are on track to reach the next 15% target for 2030

- Eastern EU countries have the highest interconnection rates and have already exceeded the 2030 target.
- In the western EU, France, Germany, Italy and the UK represent 37% of EU electricity consumption[1]. they are involved in several major interconnection projects that would enable them and neighboring countries to reach the 15% target by 2030.
- Spain's interconnection projects with Portugal and France, due be commissioned in 2021 and 2027 respectively, will bring its interconnection level to 10% and pave the way for the 2030 target[2].

The TYNDP and Projects of Common Interest (PCIs) remain the main tools for selecting interconnection projects that will enable Europe to build its Green Deal electricity network[3]

- Among the 173 projects included in the 2020 TYNDP updated by ENTSO-E in February 2020, 145 were carried over from the previous TYNDP and 43 were rejected. Although more storage projects were present than in the 2018 TYNDP, transmission and interconnection projects remain predominant with respectively 86% and 50% of the total number of projects[4].
- 61 of the 2020 TYNDP projects are PCIs, including 36 interconnection projects.
- Among them is the Celtic Interconnector, a planned undersea link to allow the exchange of electricity between Ireland and France. It should be completed in 2026.

Europe

The Connecting Europe Facility energy allocation has doubled for the 2021-2027 period

- For its second phase (2021-2027), the energy sector is gaining more attention as its allocated fund will reach €8.7 billion (20% of the total CEF envelope vs. €4.8 billion and 16% during the first phase in 2014-2020)5. Thirty-three of the 61 PCIs have benefited from CEF funding[5].

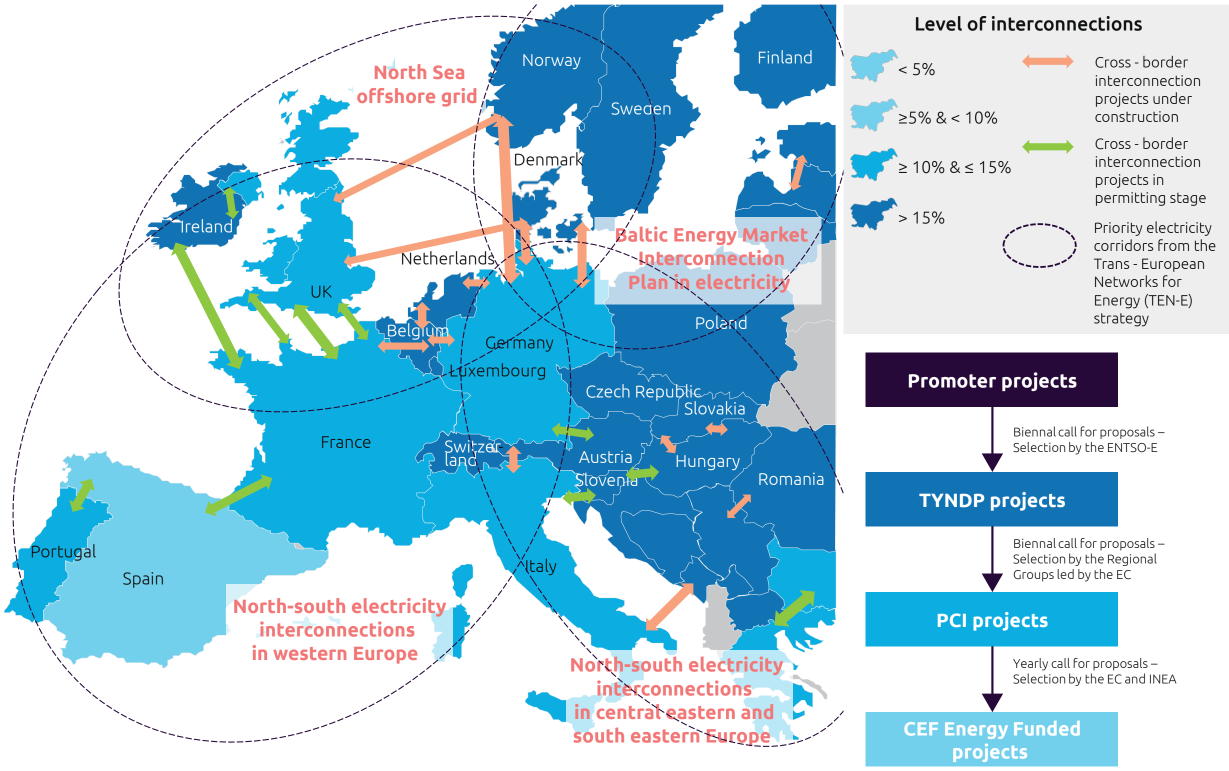
In response to the EU consultation, European regulators are studying ways to reinforce the PCI and CEF selection process to ensure the relevance and realization of projects[6]

All stakeholders – including national regulators and ACER[7] – are involved in the redesign of the PCI and CEF selection process, in particular to:

- Improve the cost-benefit assessment methodology supporting each project, therefore reinforcing the relevance of the project selection;
- Improve the scenario modelling (e.g. renewables surges) in which submitted projects are included.

1 Enerdata
2 ENTSO-E
3 European Commission, ENTSO-E
4 ENTSO-E, Capgemini analysis
5 European Commission, Capgemini analysis
6 European Commission
7 CRE

Figure 2.9. Map of interconnections in Europe



Sources: ENSTO-E TYNDP, European Commission, Red Eléctrica de España

Market integration keeps moving forward, further securing the EU's adequacy of supply

Day-ahead market coupling: development confirmed in numerous countries

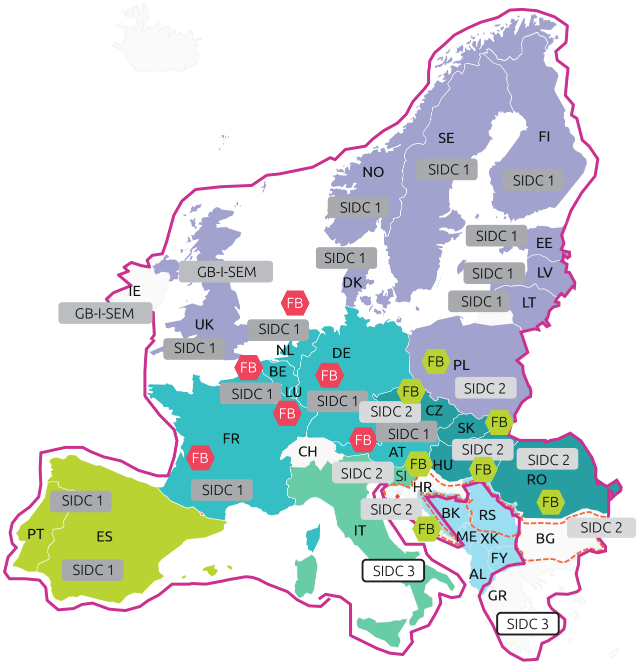
- The National Regulatory Authorities of the DE-AT-PL-4MMC countries (also called the Interim Coupling Project) have confirmed the connection between 4MMC and Multi-Regional Coupling (MRC); prior to the COVID-19 outbreak, go-live was expected1 by Q3 2020[1].
- Greece is also expected to join the MRC via the Italian Border Working Table (IBWT): the Italian-Greek interconnection is expected to be integrated in the market coupling by the end of 2020[2]. The Bulgarian-Greek interconnection integration has not been planned yet.
- In addition, Flow-Based Market Coupling is expected to go live in the core countries (i.e. CWE countries plus Croatia, Czech Republic, Hungary, Luxembourg, Poland, Romania, Slovakia and Slovenia) by Q2/Q3 2021 after a Q4 2020 report (integration of the 4MMC countries being a priority)[1].

Intra-day market coupling continues to grow

- In early 2020, several countries saw a surge in intraday traded volumes. Hungary, for example, recorded an average monthly trading volume of around 75,600 MWh from December 2019 to February 2020 compared to 7,600 MWh[3] in the same period of the preceding year. Since Single IntraDay Coupling (SIDC) went live in June 2018, 36 million trades have been executed[3].
- This surge is linked with the expansion of the coupled zone. In November 2019, the second SIDC wave was launched, allowing Bulgaria, Croatia, Czech Republic, Hungary, Poland, Romania and Slovenia to be coupled with the first wave countries[1].
- Prior to the COVID-19 outbreak, a third wave1 (to include Italy and Greece) was expected by Q3 2020.

1 ENTSO-E
2 RAE
3 TSCNET

Figure 2.10. Map of electricity market and market coupling in the EU



Coupling areas

SDAC (Single Day-Ahead Coupling)*

Coupling under study

Day Ahead coupling projects

	Entry date	Coupling region
	Nov 2010	**CWE** (Central Western Europe)
	Feb 2014	**NWE** (North Western Europe)
	May 2014	**SWE** (South Western Europe)
	Nov 2014	**4 MMC** (4 Markets Market Coupling)
	Feb 2015	**IBWT** (Italian Borders Market Coupling)
FB	May 2015	**Core FB MC** (Core Flow Based Market Coupling) 1st wave - CWE FB
	Jan 2018	**WB6** (Western Balkan)
FB	Q2 - Q3 2021	**Core FB MC** (2nd wave)

Intra day coupling project

	Go-live date	Coupling project
SIDC 1	2018	**SIDC** (Single IntraDay Coupling, 1st wave)
GB-I-SEM	2018	**GBISEM**
SIDC 2	2019	**SIDC** (2nd wave)
SIDC 3	2020	**SIDC** (3rd wave)*

**SDAC and SIDC as scheduled for the end of 2020*
Sources: ENTSO, All NEMO Committee, Power exchanges

Implementation of capacity mechanisms in European countries is progressing but still has a long way to go before effective deployment for the whole of the EU

Western European countries are the most active in capacity mechanisms whereas peripheral countries participate in only a few of them

- France, Germany, Italy, Switzerland, Austria, Czech Republic, Belgium and the Netherlands are driving the development of capacity mechanisms and are operational members of at least four of them. In contrast, eastern and northern countries are often involved only as observers[1].
- Unlike the other capacity mechanisms, in which numerous countries participate, the Frequency Containment Reserve (FCR) is only used by seven countries.
- Capacity mechanisms will increase competition, reduce demand, and then lead to the shutdown of the most expensive capacities and to socioeconomic concerns in some countries[2]. This may explain, at least partially, why some countries are not participating in some capacity mechanisms.

An important first step regarding power pooling was reached in H1 2020 with the Frequency Containment Reserves (FCR) and Trans European Replacement Reserves Exchange (TERRE) projects[1]

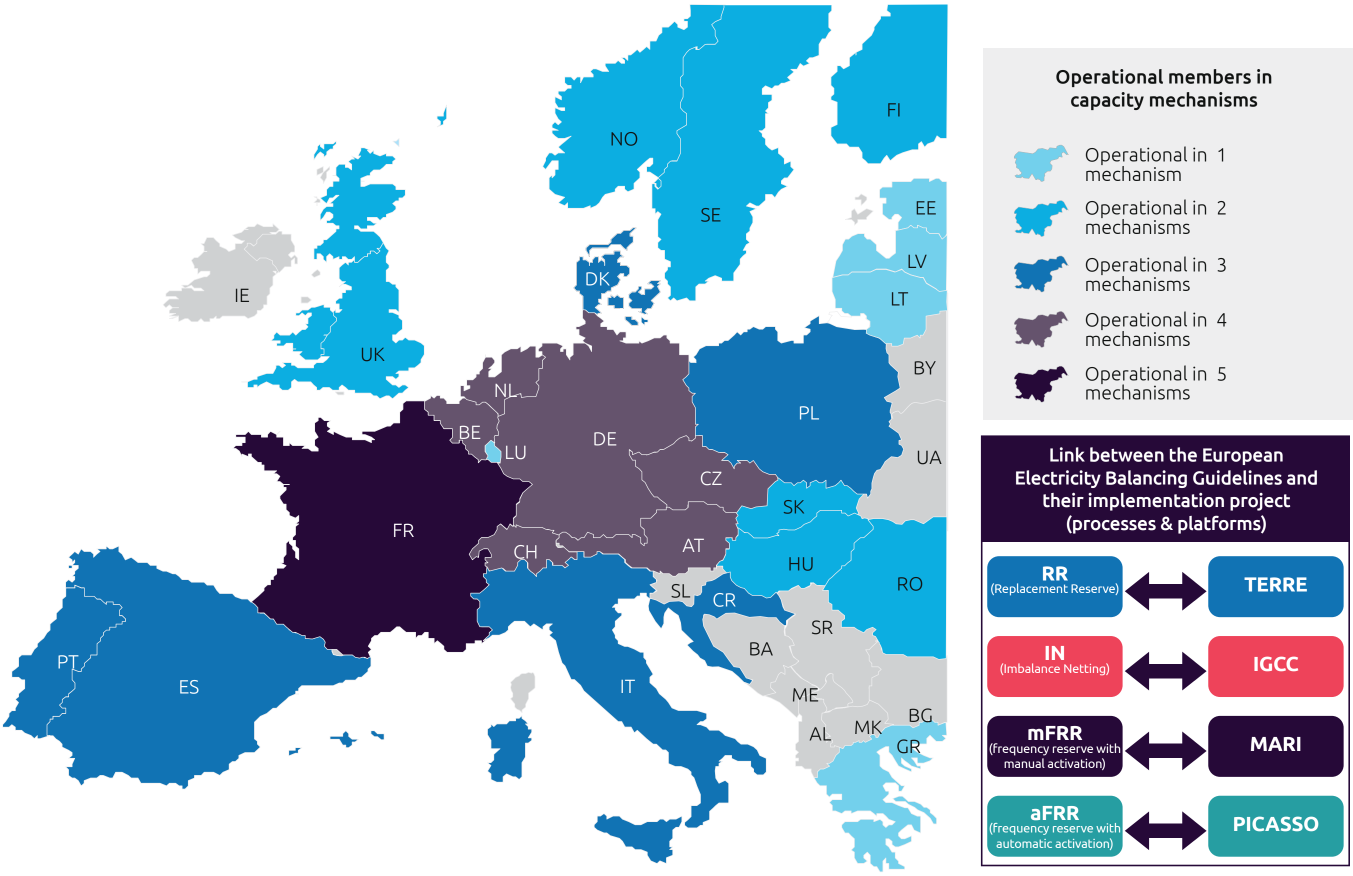
- After several postponements (cf. previous WEMO editions), the TERRE project to deliver a replacement reserves (RR) platform went live in January 2020. The Czech TSO, ČEPS, was the first to connect to the platform, quickly followed by Spain's REE. Unfortunately, the COVID-19 pandemic then forced the remaining six TSOs to delay their integration, but it is anticipated that they will join the platform by the end of 2020, except for PSE (Poland).
- The FCR mechanism continued to develop, reducing the product length from one day to four hours and bringing the FCR market closer to real time.

The MARI, PICASSO and IGCC capacity mechanism projects continued to face delays by TSOs[1]

- 17 of the 25 TSOs involved in the PICASSO projects plan to go live in Q2 2022, (the others will join the platform later).
- 24 of the 33 TSOs involved in the MARI projects plan to go live in Q2 2022, (the others will join the platform later).
- The IGCC platform go-live date, postponed from 2019, has yet to be decided.

1 ENTSO-E
2 EUROPEAN SCIENTIST

Figure 2.11. Map of capacity mechanisms in Europe



Source: ENTSO-E

Smart grid deployment at scale remains mixed among member states despite EU efforts to promote the transformation

Electricity smart meter rollout again fell short of the EU's ambition, with adoption rates dropping for the third consecutive year

- The adoption of smart meters in Europe is driven by the rollout target of 80% market penetration by 2020, established by the EU in the 2009 third energy package.
  - The estimated total of installed electricity smart meters is 123 million, which would correspond to a 43% penetration rate by the end of 2020.
  - After downward revisions in 2018 and 2019, the penetration rate is expected to reach 77% by 2024[1].

Delays in rollout reflect large variations between countries in terms of regulations, local utility markets, and willingness to adopt smart meters

- The development of smart metering systems has been carried out gradually through the adoption of numerous legislative measures during the last decades. The third energy package (including several EU directives)[1] requires member states to define national rollout plans with the objective of installing smart meters for more than 80% of consumers by 2020.
- Denmark has already reached the EU target, and a further six countries have even finished their large-scale rollout – Estonia, Finland, Malta, Spain, Sweden and Italy, which is already proceeding with the second generation rollout.
- France has continued to pursue its installation roadmap with more than 8 million additional units installed in 2019. This represents 68% of its 35 million smart meters target, which should be reached by 2021[2].
- In contrast, some countries have chosen different deployment strategies:
  - In Germany only consumers whose annual power consumption is more than 6,000 kWh and producers above 7 kW have to be equipped with a smart metering system[3].
  - In Belgium, the region of Wallonia is proceeding as in Germany, whereas Flanders is undertaking mandatory installation of smart meters in new constructions and renovations, while customers in other segments of the market will be entitled to have a smart meter installed if they wish[3].

Smart grid projects are being deployed at scale, promoting coordination between TSOs and DSOs in EU member states

- The European Commission's Joint Research Centre (JRC) identified around 950 smart grid projects throughout Europe with the objective of efficiently operating and planning the distribution and transmission networks, given the growing penetration levels of renewable energy sources and to ensure a competitive and properly functioning integrated energy market.
- The three PCIs below are part of the EU's list of six key infrastructure projects, identified in 2019, that meet the EU policy objectives of affordable, secure and sustainable energy.
- SINCRO.GRID is integrating dispersed units for electricity generation from renewable energy sources into transmission and distribution systems in Slovenia and Croatia. The project includes the deployment of compensation devices, a battery electricity storage system, and a virtual cross-border control center by 2021[4]. compensation devices, a battery electricity storage system, as well as a virtual cross-border control center by 2020-2021[4]
- Smart Border Initiative aims to implement a cross-border smart grid at distribution network level between France's Grand Est Region and Germany's Saarland, integrating smart mobility solutions and multi-energy subsystems, with the aim of improving the region's energy efficiency, security of supply and network resilience[4]
- Data Bridge plans to build a common European data bridge platform, which will enable integration of different data types (i.e. smart metering data, network operational data, market data) and the potential to develop scalable and replicable solutions for the EU[4].

1 Benchmarking smart metering deployment in the EU-28, European Commission December 2019
2 Enedis
3 Supporting Country Fiches accompanying the report Benchmarking smart metering deployment in the EU-28, European Commission December 2019
4 Projects of Common interest, European Union

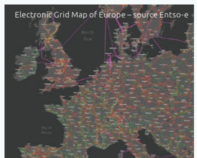
Topic box 2.1: Enabled by digitalization, energy networks are expected to expand their role by the opening up of data

The Energy Data Taskforce has provided an integrated data and digital strategy for the UK energy network

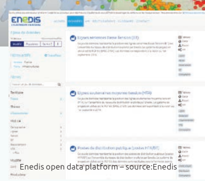
- In July 2019, the report by the Energy Data Taskforce was published, with five key recommendations for network companies to move towards a modern, digitalized energy system.
- The government will use legislative and regulatory measures to require network companies to adopt the principle that data should be open, discoverable, searchable and understandable.
- In January 2020, the Data Best Practice Guidance was published highlighting the principles and techniques that network companies should take in order to make data the core of their digital transformations.
- This has increased focus on data significantly. For example, innovation projects have sprung up:
  - Western Power Distribution has established a project that allows a real-time link between itself and the SCADA systems operated by the national transmission company, such that data on either system can be viewed on the other in real time.
  - Scottish Power Networks has established a project that will seek to use the opportunity provided by the Going Carbon Neutral project at Ashton Hayes to better understand how DNOs can facilitate the transition to a low carbon economy

Energy maps and data portals have spread as they remain an easy way to provide access to open energy data

- At a country level, one of the best examples is AREMI, a website for map-based access to Australian spatial data relevant to the renewable energy industry and considered to be a key instrument for investors.


Electronic Grid Map of Europe – source Entso-e


Map of connections capacity, Scotland
Source: ENA UK


Enedis open data platform – source:Enedis

- ENTSO-E has also launched a spatial map of the European grid, providing information on power flows and power statistics. Its Manual of Procedure ensures standardization of how TSOs and other players exchange data, what the related governance roles should be, and how transparency is maintained.
- In the UK, a project run by the Energy Network Association in 2020 piloted a web-based heat map of connections within Scotland.
- In France, the Union Française de l'Électricité has produced recommendations about open data and references open data platforms produced by RTE and Enedis as stepping-stones. These open data platforms are not in the form of maps but can be associated with spatial information.

The future landscape...

- The Australian example is a good indication of how things will develop. To what extent European countries embark on this journey is dependent on local regulation and capabilities, but also collaboration across national boundaries. The basic requirement is to have clean, accurate and real-time data. This requires a shift for all network companies and impacts on their entire organization.

Topic box 2.2: The nuclear industry in Europe will face numerous challenges ahead as the volume of reactors entering into decommissioning is booming

Nuclear power plants (NPPs) are shutting down in almost all regions for various reasons

NPPs in operation are aging (over 65% of the 450 power plants have been operating for more than 30 years as of 2018[1]) and many are likely to shut down despite the approved life extension programmes in France or the US due to:

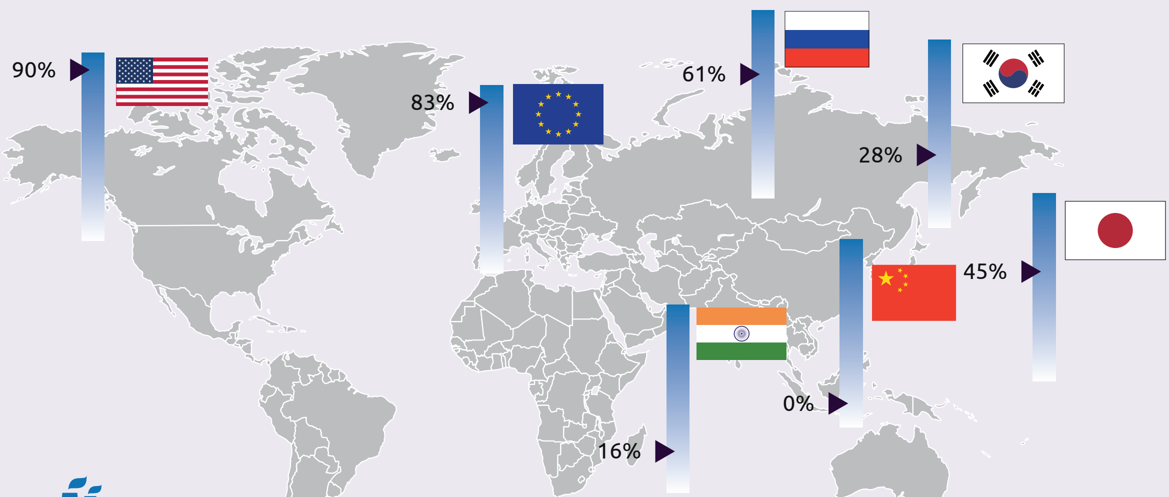
- The decision of some governments to close nuclear power plants after the Fukushima accidents. Germany adopted an amendment in July 2011 to progressively close its nuclear power plants until 2022[2].
- Willingness to reduce the share of nuclear generation in the electricity mix. The French government has legislated for a 50% reduction in the nuclear share by 2035[3].
- The prerequisite for joining the EU to shut down reactors if not integrating a containment vessel (Bulgaria, Armenia, Lithuania)[1].
- The competitiveness of other sources of energy like cheaper shale gas coming from indigenous fields and renewables marked by the emergence of new technologies and the decrease in battery price[4].

The challenges of decommissioning can be transformed into a success for the European industry

The market for NPP decommissioning is likely to grow worldwide and especially in Europe. But it is at the early stage of its development with very few projects completed so far (only 5 in Europe, all in Germany, as of 2019[5]) and future ones subject to swift changes in the regulations. Different trends are observed worldwide for the decommissioning of NPPs and they raise some critical questions:

- The local population expects the utility and the local nuclear authority to take quick and thoughtful decisions that ensure its safety and preservation of the staff. Which appropriate strategy should be adopted: immediate dismantling, deferred dismantling or entombment?
- Financial risks have to be mitigated to ensure the project is delivered as planned. Do the companies in charge of the project have the financial capability to cover all the costs (direct and indirect) and deliver the project on time?
- Decommissioning a NPP requires specific expertise, such as waste management. Do the companies involved in the decommissioning process have the technical capabilities and the resources to carry out the project?
- Decommissioning a NPP requires access to a reliable set of data that reflects the asset's information as-operated. How can one ensure the traceability and veracity of the information during the plant's entire lifecycle?
- These questions translate into numerous challenges for European companies and decision-makers. Eyes are turned now towards innovation as new technologies are likely to be an accelerator for the industry to thrive and to reduce uncertainties. First use cases are emerging and companies should build a strategy to benefit from the resulting operational experience.
- Will the decision makers establish regulation that foster further innovation and will the main corporations boost partnerships at the international level to share knowledge and expertise?

Figure 2.12. Percentage of nuclear power capacity over 30 years for the main regions



~240 reactors will enter into a decommissioning process during the 2030 - 2050 period

$ This represents a potential market worth **US$120 billion** to **US$240 billion**

Main hypothesis:
Average lifespan of a NPP : 50 years
Cost for the decommissioning of one unit : US$500 million to US$1 000 million

Sources : International Energy Agency, Connaissance des Énergies, World Nuclear Association, Capgemini Analysis and various sources

1 Institut de Radioprotection et de surêté nucléaire
2 International Atomic Energy Agency
3 Loi relative à l'énergie et au climat of the 8th November 2019
4 Bloomberg
5 World Nuclear Industry Status Report

Stages of decommissioning and presentation of the main actors

The 3 stages of the decommissioning process

Operation

Step 1 – Shuting down of the nuclear reactor – 1 to 3 years
- Fuel discharge
- Circuit drainage
- Dismantling of ancillary equipment

Step 2 – Dismantling of buildings and equipment (except for the nuclear island building) – 5 to 10 years
- Dismantling of the conventional island equipment
- Conditioning of nuclear wastes
- Waste disposal and storage

Step 3 – Dismantling of the nuclear island building – 10 to 15 years
- Dismantling of the containment vessel
- Dismantling of the nuclear island
- Remediation of soils

The different actors involved in the decommissioning process

Utilities (asset operators)
- Planning and financing of decommissioning activities during the operating phase
- Contribution to the organization and execution of NPPs' decommissioning

EDF, Exelon, Entergy, CGN

Decision-makers (Government, local nuclear authority...)
- Strategic decisions at the regional level for decommissioning activities and waste management
- Definition of standards and norms for the industry

asn, U.S.NRC, NRA JAPAN

Specific companies (corporations, SMEs...)
- Service provider to utilities and asset operators
- Contribution to the organization and execution of NPPs' decommissioning

orano, SIEMENS, SPIE, SNC-LAVALIN, NorthStar

The main challenges in establishing a robust and competitive European market for nuclear decommissioning

Main challenges for the actors

Utilities (asset operators)

- **Diversifying its activities to deliver competitive projects on time**
Utilities might develop business lines and services to adapt to the growing volume of reactors entering a decommissioning process, and pursue opportunities to standardize the delivery model.
- **Mitigating and reducing the risks during the decommissioning phase**
Utilities can explore the possibility to share the risks with other companies (E.g. through a special purpose vehicle) by adopting the appropriate contractual framework.
- **Reducing uncertainties due to waste management and disposal**
Platforms may be considered (or a network of platforms) for waste treatment and disposal in order to treat the critical volume to be competitive and to pool the resources and expertise together.

Decision-makers

- **Securing the right decommissioning strategy at the regional level**
Immediate dismantling (use of existing workforce, impacts of change in the regulation avoided) is preferable compared to deferred dismantling (lack of expertise, potential additional costs arising from change in the regulation) or entombment (unpredictable risks, constant supervision of site).
- **Ensuring a clear and transparent allocation of responsibility**
Keeping the utility liable (total or partial) for the decommissioning process could encourage them to plan in advance and to ensure the safety of the local population.
- **Implementing the appropriate regulation for waste management**
Disposal and storage of radioactive waste should be planned in advance and regulated through the appropriate legal framework.

Specific companies (corporations, SMEs...)

- **Developing offers which complement utilities' activities**
Entering into partnerships (or being a subcontractor of a local corporation like in Japan) is a way to propose high-end services for which the local utility has not developed: waste treatment and disposal, engineering and advisory thanks to operational experience from previous decommissioning projects, R&D...
- **Developing the capabilities and the network to have an international reach**
Less mature markets lack the expertise needed to cover the entire value chain of decommissioning. This could represent a great opportunity for specific companies to develop their business and gather the operational experience.

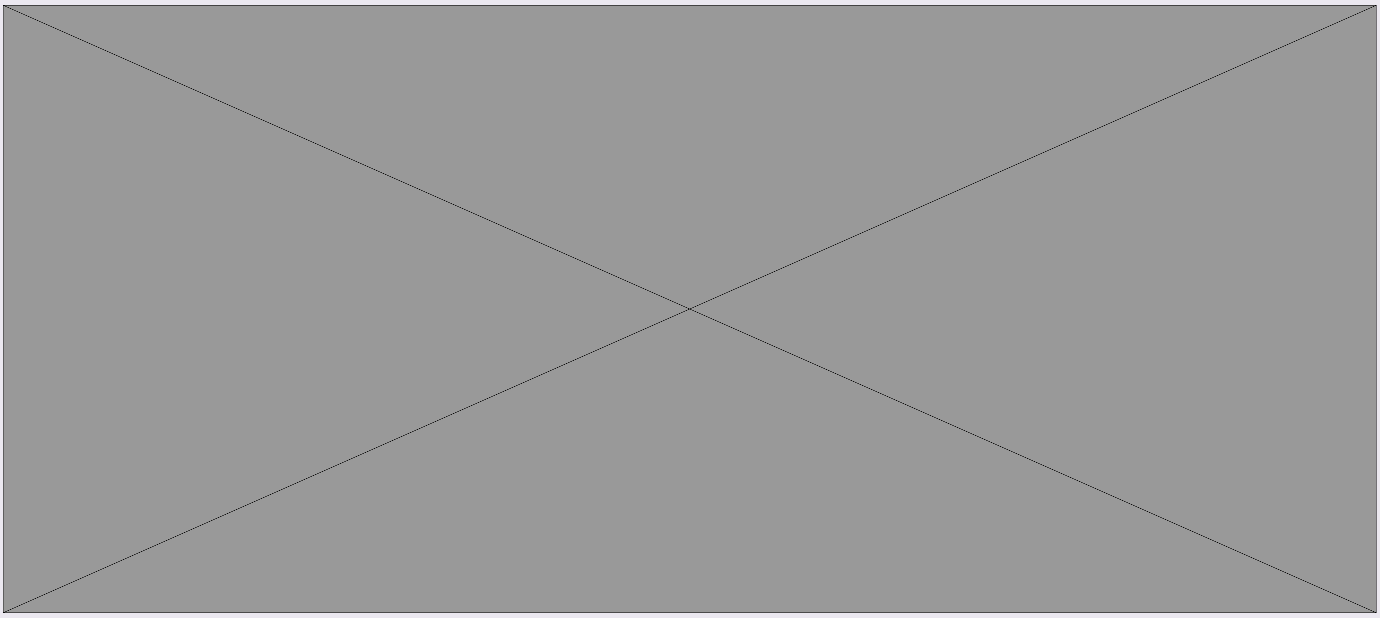
Main examples

- EDF which has revamped its decommissioning activities around the **subsidiary Cyclife adding new services** to the existing business line: **project management** (Cyclife Engineering) and **digital solution** (Cyclife Digital Solutions)[1].
- German utilities have **pooled their expertise** and **workforce** together into a **common enterprise** Gesellschaft für Nuklear-Service GmbH (GNS)[2] specialized in **waste management and storage services** (main shareholders are PreussenElektra, RWE, SNE and Vattenfall).

- In France, the ASN (Autorité de Sûreté de Nucléaire) **encourages immediate dismantling** which is consistent with IAEA recommendations[3].
- In Germany, as of 2017, the **Federal Government is in charge of the final disposal of nuclear waste** (payments are made by utilities to a special fund)[4].
- In the US, the **NRC** (Nuclear Regulatory Commission) **approved the sale of NPPs to specialized companies** (hence a transfer of responsibility) despite concerns expressed by local authorities as for the dismantling of the Pilgrim site[5].

- **NorthStar,** a US based company specialized in demolition, **partnered** with **Orano** USA, the subsidiary of the French nuclear company Orano, **to undertake the decommissioning of Crystal River 3**[6].
- A report of the EU-Japan Centre for Industrial Cooperation suggests **European companies could partner with Japanese companies** and **provide services** in areas for which there is a lack of expertise or experience in the country[7].

Reducing uncertainties by adopting a strategy based upon existing digital and technological use cases



1 SIXENCE Group
2 UK Government
3 ASSYSTEM
4 Nuclear Engineering International
5 SNC LAVALIN
6 EDF Cyclife
7 https://www.power-technology.com/

Gas market

Demand | Gas demand reached a 9-year high due to a surge in gas-generated electricity in Europe

- Generation of electricity from gas increased dramatically (+15%) in the EU28 as an alternative to coal (higher CO_2 prices), encouraged by lower gas prices
- Gas-fired electricity drove an overall growth in natural gas demand, overcompensating for the reduced need for heating caused by mild weather.
- Lockdowns and economical impacts of COVID-19 reduced demand by 16%, year-on-year, in April and May. For 2020 as a whole, a reduction of 4% is expected.

Production | 7.5% decline in production with obstacles to come

- EU28 production continued to decrease (-7.5%), and Netherlands production may be cut by half in 2022 with the Groningen shutdown.
- The EU28 covers 23% of its natural gas demand with indigenous production.
- Norway production stalled (-5.7% behind the 2017 peak), yet remained the largest producer in Europe
- Eastern Mediterranean is a promising exploration area with major discoveries made in the last two years

Pipeline imports | Piped gas remains the mainstream supply, as European production declined and LNG supply increased

- Though piped gas still covers 60% of EU28 gas demand, net piped gas imports decreased by 4% over 2019. LNG competed fiercely with piped gas in several countries, as evidenced by the year-on-year comparison for piped gas and LNG volumes.
- In 2019 as a whole, Russia supplied 55% of the gas imported by pipeline towards the EU28. Norway's share remained stable at around 35%.
- Imports from both Algeria and Libya have shown great volatility over the last few years, reflecting the competitiveness of import prices and supply availability concerns (occasional disruptions) in these two countries.

LNG imports | LNG imports nearly doubled, as the LNG supply diversifies, and EU28 gas production declines

- LNG volumes nearly doubled over a year (+86%), reaching 102.5 bcm of imports. In 2019, LNG met 21% of the EU28 gas demand.
- In the EU28, since Q2 of 2019, imports of LNG stand higher than local gas production, making LNG the second source of supply after pipelines. For 2019 as a whole, local production is still slightly ahead (at 111 bcm).
- The US overtook Qatar, Russia, Nigeria, to become the leading LNG supplier of the EU28 by Q4 2019. In Q1 2020, 30% of imported LNG was supplied by the US.

Storage | Market opportunities led to historically high volumes of stored gas, topping at 98% capacity

- Storage used at 98% during October 2019, a 5 years-high. Market opportunities and political uncertainty listed as explaining factors
- 16 bcm of storage projects (+16% capacity) to increase security of supply. Of which, 9 bcm to be commissioned by 2023.
- New storage capacity will prove useful to integrate hydrogen, green gas, financed by the Green Deal.

Topic Box 2.3 Gas markets, the Green Deal and the Taxonomy Regulation

- The Green Deal and the Taxonomy Regulation are separate but related parts of the EU's Sustainable Finance Action Plan.
- Fossil natural gas still faces challenges to be labeled as sustainable by the taxonomy. By the end of the year, several 'delegated act' laws should clarify this position.
- Fossil gas will still most likely benefit from the Just Transition Fund (€17 billion), which is part of the Green Deal.
- Green gas and hydrogen will certainly benefit from the complete Green Deal (€1 trillion), and increased private funding, as it will certainly be labeled sustainable by the taxonomy.

- **Gas demand reached a 9-years high (485 bcm) due to a surge in gas-generated electricity in Europe**
- **EU28 domestic gas production kept declining (-7.1% over 2019), and Norway's production stalled (-5.7% behind the 2017 peak). The EU28 covered 23% of its natural gas demand with indigenous production (111 bcm), while Norway produced 118 bcm.**
- **The US and Russia have flooded the European gas market with LNG, driving prices down and LNG volumes up (102.5 bcm of LNG, +86% over 2019)**
- **Russia supplied 37% of all gas consumed in the EU28, through LNG and pipelines. After recently making its way to Europe through LNG imports, US gas accounted for 3% of all gas consumed in the EU28 in 2019.**

Demand | Gas demand reached a 9-year high due to a leap of gas-generated electricity in Europe

EU28 natural gas demand increased by 3% in 2019 to reach 485 bcm[1]

After last year's setback in natural gas demand, consumption resumed its growth for the fourth time in five years, driven by a large increase in gas-fired electricity.

- The weather remained mild across Europe, implying low natural gas demand for the residential sector during the heating season[2].
- Among the six largest gas consumers in the EU[1]: consumption increased in Spain (+14%), Germany (+7.6%), Netherlands (+2.9%), Italy (+2.3%), and France (+2.1%) while it slightly decreased in the UK (-2.4%)

Gas-fired electricity increased by 15%[2], and mitigated lower demand in heating

In 2019 as a whole, gas-fired generation in the EU increased by 88 TWh[4] (15%), and represented 23% of the total EU generation. These 88 TWh translate into approximately 18 bcm[3] of natural gas, contributing to demand growth despite mild weather and a slow economy. The high CO_2 prices encouraged many European countries to switch from coal to gas for generating needed electricity, encouraged also by record low gas prices.

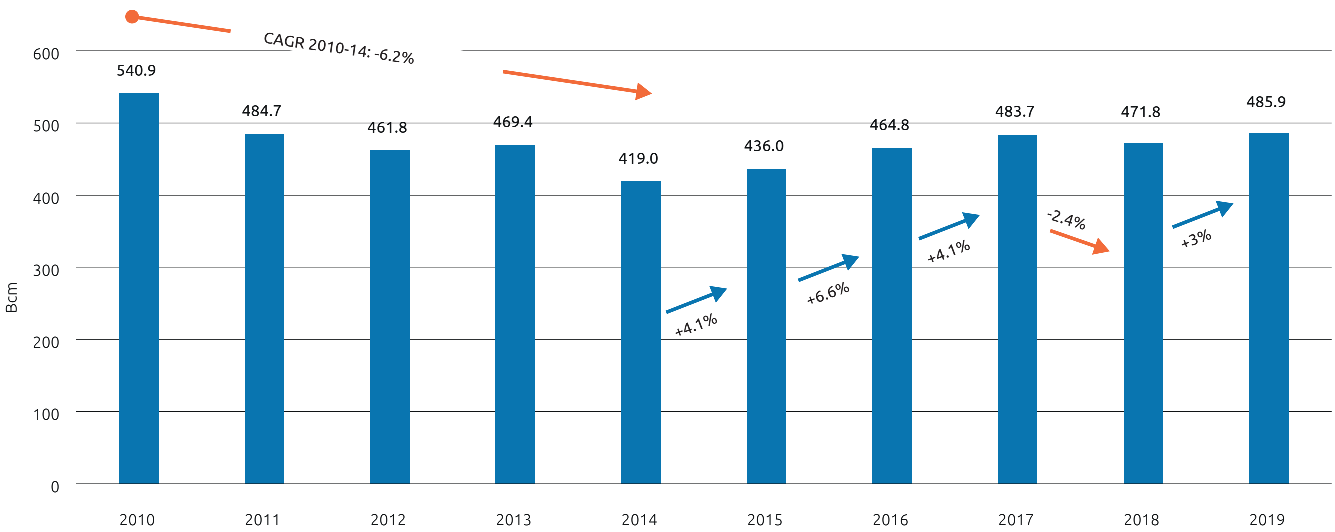
- Over 2019, electricity production from gas-fired power plants increased[4] by 48% in Spain, 30% in France, 23% in the Netherlands, and 13% in Germany.
- The UK remains the EU's largest producer of electricity through natural gas (up by 0.7% at 129.9 TWh)[4], owing to higher electricity prices than the rest of the EU28, and therefore increased profitability.

COVID-19 and the lockdowns affected consumption in 2020

At the peak of the pandemic in April and May, natural gas consumption decreased by 16% year-on-year across the EU28, Norway, Switzerland, and Serbia[5]. For 2020 as a whole, European gas demand is now expected[6] to be 4% lower than in 2019.

1 Eurostat
2 Quarterly report on European gas market, Q1 to Q4 2019
3 Supposing a ~50% conversion efficiency, pursuant to the clean spark spread definition
4 Eurostat
5 OxfordEnergy. "The impacts of COVID-19 and other influences in 2020"
6 IEA, Gas 2020 report

Figure 2.13. Gas consumption in EU28 (bcm) in 2019



Source: Eurostat

- **Generation of electricity from gas increased dramatically (+15%) in the EU28 as an alternative to coal (higher CO_2 prices) encouraged by lower gas prices**
- **Gas-fired electricity has driven overall growth in natural gas demand, overcompensating for the reduced need for heating caused by mild weather.**
- **Lockdowns and economic impacts of COVID-19 reduced demand by 16% year-on-year in April and May. For 2020 as a whole, a reduction of 4% is expected.**

Production | 7.5% decline in production and obstacles to come

EU28 natural gas production fell 7.5% from 119 to 110[1] bcm in 2019

The decrease in natural gas production during 2019 was seen in all major EU28 producers: Italy (-10.9%), Germany (-4.0%), Netherlands (-13.0%), and the UK (-2.2%).

- Since 2017, the UK has been the largest gas producer in the EU28, overtaking the Netherlands. UK production is stable, with newer assets just compensating for the decline of older ones. For instance, while the UK's new asset – Culzean – entered into production in Q2 2019, historical assets in the Central North Sea (CNS) are expected to be decommissioned.
- A series of earthquakes in 2018 and 2019 has driven the Netherlands to accelerate the shutdown of the Groningen field operated by Shell and ExxonMobil. A decision was taken by the Minister of Economics to have the production fall to zero by mid 2022[2]. However, due to the importance of this field (17.5 bcm in 2019, half of the Netherlands production) the Dutch government wants to keep the field operational until 2026, in case of shortfall of gas supplies.

Norway will keep its leading position in Europe despite difficulties

Despite natural gas production that stalls (-5.7% since its peak), Norway remains by far the main gas producer in Europe with 119 bcm – more than the entire EU28 gas production.

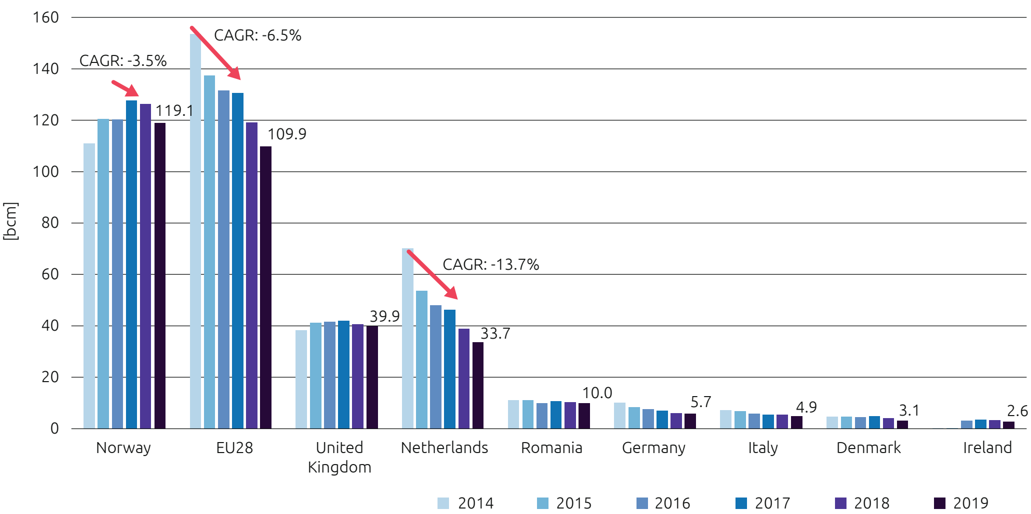
- Natural gas production is expected by the Norwegian Petroleum directorate to remain stable until 2024 despite 2019 numbers[3].
- Norway will host two of the top 30 high-impact wells to be drilled in 2020, both in the Barents Sea[4]. On the list of new reservoirs to be commissioned, Peon is expected to produce 30 bcm

The Eastern Mediterranean is emerging as a possibility for Europe to develop its indigenous gas production, and reduce reliance on Norway and Russia

The Eastern Mediterranean has held many opportunities since the discovery of the giant Zohr gas field in offshore Egypt.

- ExxonMobil and Eni respectively evaluated discoveries of Glaucus (Cyprus) and Nour (Egypt) to 109 and 19 bcm in 2019. However, there are geopolitical impediments, such as disputes between Turkey, Cyprus and Greece[5].

Figure 2.14. Domestic gas production over time (bcm)

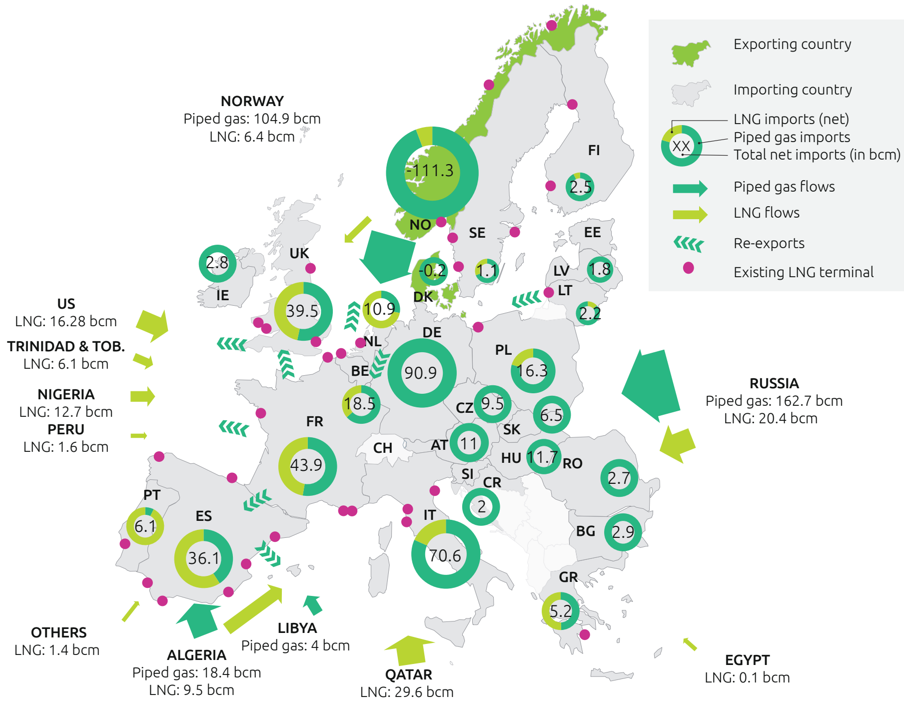


Source: Eurostat

1 Eurostat
2 Reuters, Netherlands to halt groningen gas production by 2022
3 https://www.arctictoday.com/norway-pushes-forward-on-more-oil-and-gas-production/
4 https://www.rystadenergy.com/newsevents/news/press-releases/most-of-worlds-top-30-high-impact-wells-for-2020-seen-in-africa-and-the-americas/
5 https://www.worldoil.com/news/2020/7/22/turkey-ignores-greece-s-dispute-moves-on-with-mediterranean-seismic-surveys

- **EU28 production continued to decrease (-7.5%), and Netherlands production may be cut by half in 2022 with the Groningen shutdown.**
- **The EU28 covers 23% of its natural gas demand with indigenous production**
- **Norway production stalled (-5.7% behind the 2017 peak), yet remains the largest producer in Europe**
- **Eastern Mediterranean is a promising exploration area with major discoveries made in the last two years**

Figure 2.15. Map of gas imports (2019)



Sources: Eurostat, GIIGNL

Pipeline imports | Piped gas remains the primary supply, as European production declines and LNG supply increases

Pipelines remain the primary supply, while LNG imports grow quickly

Piped gas is still the major source of supply for the EU28, covering 60% of gas demand to reach 294.7 bcm[1] (-4% vs. 2018) of net supply. Over 2019, the total (pipeline + LNG) gas import bill amounted to €69 billion[2], down from €98 billion in 2018, principally owing to lower gas import prices.

- As the EU28 imports more LNG than ever, new pipeline projects from regasification terminals towards inland are planned (see figure 2.18).
- In 2019, the UK imported 37.6% less gas through pipelines, but more than doubled its LNG imports (from 6.7 bcm in 2018 to 18.4 bcm in 2019) mainly due to the supplies from the US and Russia that are overwhelming the market and driving prices lower. Similarly, piped gas imports decreased in all countries equipped with LNG terminals: France, Spain, Belgium and the Netherlands (see figure 2.17).

Russia remains the leading supplier to the EU28

- Despite the EU's aim to reduce this dependency, Russia remained its largest pipeline gas supplier, covering 55% of pipeline imports. Russia's main supply channels[2] are via Ukraine (46%), Nord Stream (33%) and Belarus (21%).
- Norway's market share[1] increased (35%), Algeria decreased (6%).

Commitment continues on major pipeline projects in Europe

In order to support EU gas demand and diversify gas supply channels, several gas pipeline projects are in the design phase or are close to completion (see figure 2.18):

- The **Nord Stream 2** pipeline is nearly completed, soon to supply Europe with an additional 55 bcm per year. This would allow more Russian gas to flow to Europe, and compete with American LNG; therefore, political tensions from the USA[3] continue to affect the project. The pipeline is co-financed by 5 European companies, and Russia's Gazprom.
- The **Trans Adriatic Pipeline (TAP)** is intended to diversify Europe's energy supply by transporting Caspian natural gas to Europe. It is expected to begin transporting gas in Q4 2020.

1 Eurostat data and GIIGNL annual report
2 EC, quarterly report on European Gas Market, Q4 2019.
3 Financial Times, US senators' letter on Nord Stream 2 sparks outrage in Germany.

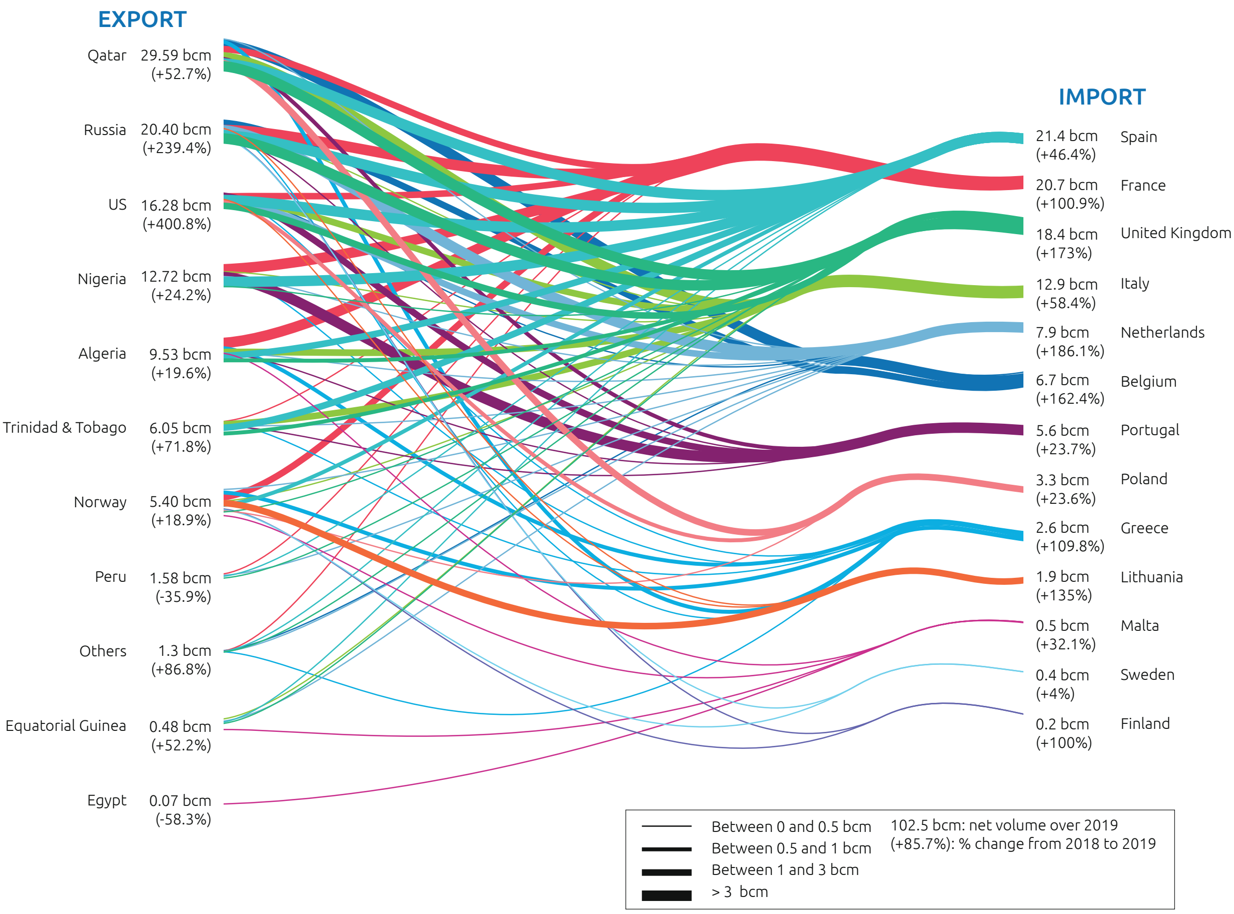
Figure 2.16. Piped Gas imports to Europe in 2019 (bcm)

	Net pipeline imports in 2019 (bcm)	%change 2019/18	CAGR 2019/15
EU-28	294.7	-3.9%	+4.1%
Germany	90.9	+8.2%	+5.7%
Italy	57.7	-2.8%	+1.2%
United Kingdom	21.1	-37.6%	+5%
France	23.1	-30%	-8.7%
Spain	14.7	-13.4%	-1%
Belgium	11.8	-22.9%	-4.6%
Poland	13.0	+5.3%	+2.1%
Czechia	9.5	+19%	+6.3%
Austria	11.3	+41.7%	+17.2%
Hungary	11.7	+50.8%	+16.9%
Slovakia	6.5	+58.3%	+10.1%
Netherlands	3.1	-22.8%	-
Greece	2.6	-29.4%	+0.3%
Other EU	18.0	+2.8%	-4.9%
Denmark	(0.2)	-81.8%	-39.2%

Other EU : Bulgaria, Croatia, Estonia, Finland, Ireland, Latvia, Luxembourg, Lithuania, Portugal, Romania, Slovenia, Sweden
Sources: Eurostat data and GIIGNL annual report

- **Though piped gas still covers 60% of EU28 gas demand, net piped gas imports decreased by 4% over 2019. LNG competes fiercely with piped gas in several countries, as evidenced by the year-on-year comparison for piped gas and LNG volumes.**
- **In 2019 as a whole, Russia supplied 55% of the gas imported by pipeline to the EU28. Norway's share is stable at around 35%.**
- **Imports from both Algeria and Libya showed great volatility over the last few years, reflecting the competitiveness issue of import prices and supply availability concerns (occasional disruptions) in these two countries.**

Figure 2.17. LNG imports to Europe in bcm (2019)



Source: GIIGNL

LNG imports | LNG imports nearly doubled, as LNG supply diversified, and EU28 gas production declined

LNG imports nearly doubled in 2019 and continued to increase in Q1 2020

EU28 LNG imports increased by 86% in 2019 (reaching 102.5 bcm[1]) meeting 21% of EU28 gas demand compared to 12% in 2018.

- All 13 EU28 countries that have LNG terminals, saw a positive trend in their LNG imports (figure 2.17), mainly due to LNG supply growth and the low spread between the Asian and European spot markets.
- The UK and France were the key growth drivers adding over 22 bcm[1] compared to 2018. In addition, Spain, which maintained its position as the largest EU28 importer, along with the Netherlands, Belgium and Italy increased their imports by 20 bcm[1].
- In Q1 2020, LNG imports continued its high growth trend, increasing by 26% year-on-year[2].

The US became the leading LNG supplier in Q4 2019 and Q1 2020

The US and Russia joined Qatar as the most important LNG suppliers to Europe, overtaking Nigeria and Algeria despite their increasing LNG supplies to the EU.

- In 2019 as a whole, the US was the third largest supplier to the EU28 with an increase in exports of 400%. However, on a quarterly basis the US became the leading supplier in Q4 2019 and in Q1 2020, ensuring 30%[1] of the total EU imports in Q1 2020.
- The US positive supply growth trend was driven by several export trains coming online in 2019 and in 2020 (i.e. Freeport, Cameron).
- Russia, despite a staggering +239% increase of exports to the EU28, reached second place when considering 2019 as a whole.

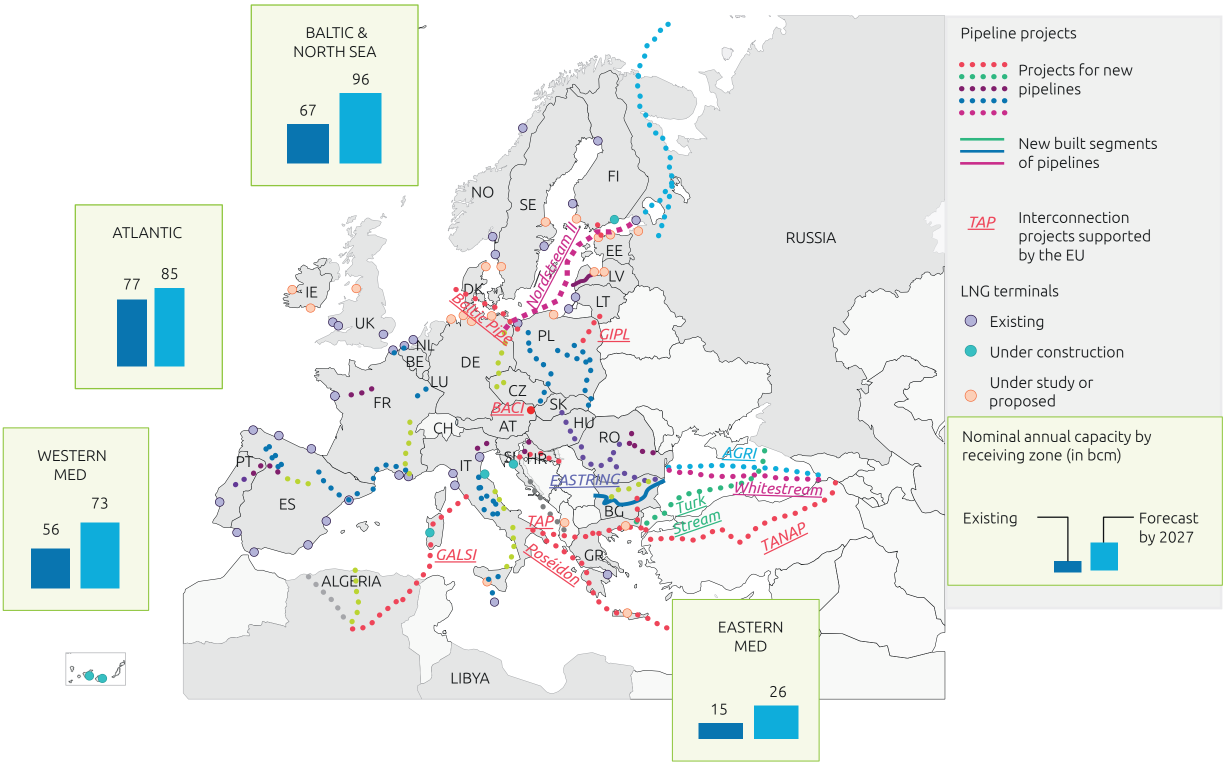
EU28 took advantage of their existing regasification infrastructure to support the LNG import growth

- In 2019, the EU28 average regasification utilization rate jumped to 48% (compared to 26% in 2018)[1,3].
- There is a contrast between different regions in Europe in terms of their utilization rates[4]. For instance, Italy import terminals were running at ~90% utilization rate, whereas Spanish terminals were underutilized. This could be explained by the Spanish high regasification capacity and low liquidity of the Iberian gas hub.
- There was a slight increase in EU28 regasification capacity (216 bcm[3] in 2019 compared to 211 bcm in 2018). Queued projects[3] could bring that figure up to 266 bcm by 2023, and 280 bcm by 2027.

1 GIIGNL, with unit conversion applied
2 EC Q4 2019 & Q1 2020 Report - Energy on European Gas Markets
3 GLE Investment database
4 Emerton, market Insights, January 2020, Exhibit 2. https://www.emerton.co/app/uploads/2020/01/Market-insight-LNG_Jan-2020.pdf

- **LNG volumes nearly doubled over a year (+86%), reaching 102.5 bcm of imports. In 2019, LNG met 21% of the EU28 gas demand.**
- **In the EU28, since Q2 2019, imports of LNG stand higher than local gas production, making LNG the second source of supply after pipelines. For 2019 as a whole, local production was still slightly ahead (at 111 bcm).**
- **The US overtook Qatar, Russia and Nigeria to become the leading LNG supplier to the EU28 by Q4 2019. By Q1 2020, 30% of imported LNG was being supplied by the US.**

Figure 2.18. Map of pipelines and LNG terminals projects (2020)



Sources: GIE, ENTSO-G, European Commission Projects of Common Interest

- **Pipeline projects in Portugal, Spain, France, and Poland will connect LNG regasification terminals and inland, as LNG imports grow**
- **LNG receiving capacity to reach 280 bcm by 2027, a 30% increase from current capacity (216 bcm)**
- **Several pipeline projects supported by the EU will reinforce the Italian gas hub: TAP (10 bcm/year), Poséidon (12 bcm/year) and GALSI (8 bcm/year)**

Storage | Market opportunities led to historic high volumes of stored gas, topping at 98% capacity

Storage reached 98% in October 2019 – a five-year high due to market opportunities and political uncertainty

- Significantly increasing LNG imports in Europe, up by 42% compared to Q4 2018, and high send-outs to the gas grid in many countries resulted in competitive gas prices across the EU compared to the past 3 years. Since the stored gas was purchased at a higher price than the current offer, many market operators preferred to rely on transactions rather than storage withdrawals.
- Furthermore, delay in the renewal of the Russian gas transit agreement with Ukraine[1], representing a principal supply route to the EU, may have triggered risk-averse behavior by storage operators.

The EU28 is expected to add 16 bcm[1] storage capacity, 9 bcm[2] of which by 2023

- Overall EU28 storage capacity remained at 99 bcm by the end of 2019[3]. Therefore, the 16 bcm planned projects represent a sizeable increase in storage capacity. Italy and the UK respectively account for 37% and 25% of the new capacity to be Commissioned[2].
- As evidenced by the high usage rate (figure 2.19), additional capacity is important to secure the EU supply, especially during winter. Furthermore, the additional storage will help to contribute towards the 2050 carbon neutrality EU objective, as renewable hydrogen and biomethane may be produced intermittently, and thus require storage. For instance, the EU has already proposed to connect 44 bcm worth of hydrogen to the networks by 2030[4]. See the topic box on EU policies for more insights about upcoming investments.

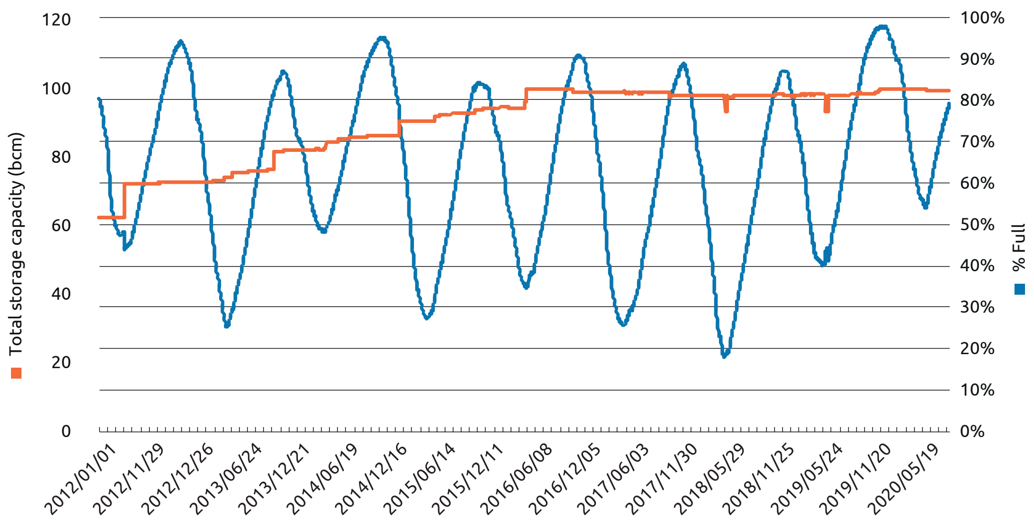
1 European Commission Quarterly report on European Gas market, issue of Q4 2019

2 Gas infrastructure Europe. Database 2018: https://www.gie.eu/maps_data/downloads/2018/Storage_DB_Dec2018.xlsx

3 Gas infrastructure Europe

4 EC, hydrogen strategy proposal. 2x40GW of hydrogen, producing 5.5TWh/year per GW of electrolyzer, and using a conversion factor of 10TWh/bcm. https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf

Figure 2.19. Gas storage



Source: GIE AGSI

- **Storage reached 98% during October 2019, a five-years high. Market opportunities and political uncertainty were contributing factors**
- **16 bcm of storage projects (+16% capacity) are planned to increase security of supply of which 9 bcm will be commissioned by 2023.**
- **New storage capacity will prove useful to integrate green hydrogen, financed by the Green Deal**

Topic Box 2.3: A summary for gas markets regarding upcoming EU policies (Green Deal, Taxonomy Regulation)

New policies can be difficult to grasp, even more so when they are still in the making. Therefore, we offer below a summary of the key facts and insights relevant to gas markets.

Green deal: how are the gas markets involved?

As of today, the laws related to the Green Deal have not yet been adopted. A key component of the Green Deal is the proposed 'Climate Law' embedding a legal commitment for the EU to achieve climate neutrality by 2050. To meet this objective, the EU will mobilize €1 trillion over the next decade, relying on several mechanisms[1].

One such mechanism is the Just Transition Mechanism, which will mobilize €100 billion[1] over 2021-2027 to assist regions in transitioning away from greenhouse gas-intensive industries (coal, lignite, oil shale, or carbon-intensive industries). About €17[2] billion is allocated to the Just Transition Fund, which could[3] finance fossil gas activities (as gas is less carbon intensive than coal). For comparison, the size of the EU28 wholesale gas market was about €70 billion in 2019.

Another major mechanism is InvestEU, which will mobilize over €279 billion of public and private funding. This mechanism will enforce the Taxonomy Regulation, as private funding is involved. Therefore, eligibility to this fund is taxonomy-dependent (see explanations below). In that regard, fossil gas activities and gas network investments may be ineligible, while green gas and hydrogen activities would be. For instance, by 2030 the EC plans to have 40 GW renewable hydrogen electrolysers in Europe, and another 40 GW for export to the EU, enough to cover 9% of current EU28 natural gas consumption.[4]

Taxonomy Regulation: how will private investment in gas markets be affected?

The Taxonomy Regulation, stemming from the EU's Sustainable Finance Action Plan, was adopted in June 2020. This work started in 2018, before the Green Deal, and was initially designed for private investments[5]: it is a separate regulation from the Green Deal. However, the two policies are intertwined, as the Green Deal suggests[6] the use of taxonomy to monitor public investment whenever possible. Enforcing the Taxonomy Regulation will lead to:

- A clear, EU-wide, legal framework to label investments and activities as sustainable. The framework evaluates the contribution towards six themes (such as climate change mitigation, and a circular economy), using 'technical screening criteria'. These criteria will be later defined in 'delegated act' laws.
- New requirements in:
  - Disclosure for financial products, for example explaining how they contribute to sustainability.
  - Non-financial reporting for firms within the scope of the Non- Financial Reporting Directive, for example explaining what share of their investment and turnover counts towards sustainability[7]

The technical screening criteria, which define whether an activity is sustainable or not, have still to be adopted. However, the expert group on taxonomy has made propositions which will be difficult to meet for fossil gas, such as emitting less than 100gCO_2e/kWh[7] (currently gas emits 490gCO_2e/kWhelec, and about 200gCO_2e/kWhheat). Furthermore, in order not to impede energy transition, the expert group has proposed not considering investment in gas networks as sustainable, unless the investment is a retrofit enabling green gas and hydrogen[7].

- **The Green Deal and the Taxonomy Regulation (part of the EU's Sustainable Finance Action Plan), are separated through related regulations.**
- **Fossil natural gas still faces challenges in order to be labeled as sustainable by the taxonomy. By the end of 2020, several 'delegated act' laws should clarify this position.**
- **Even if not labeled as 'sustainable' by the taxonomy, fossil gas will still most likely benefit from the Just Transition Fund (€17 billion), which is part of the Green Deal.**
- **Green gas and hydrogen would benefit from the complete Green Deal (€1 trillion), and increased private funding, as they will certainly be labeled sustainable by the taxonomy.**

1 EC communication, figure 3. https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020DC0021&from=FR

2 Enerpresse, issue n°12617, published on 22nd of July, 2020

3 Amendment adopted on 16th of September 2020 for Just Transition Fund, allowing derogations from the Taxonomy for gas. Enerpresse, issue n°12659, published on 18th of September

4 EC, hydrogen strategy. https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf

5 EC communication, page 10. https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52020DC0021&from=FR

6 EC proposed text for Green Deal. Article 7 mentions the Taxonomy Regulation, but only if the investment is within its scope. Link.

7 TEG final report on the EU taxonomy. Chapter 3.2 for the firm reporting requirements. Page 21 for the stance on natural gas and the 100gCO_2/kWh threshold. Link.

3-Supply & Final Customer

Residential market

Residential prices – key findings

1. In 2019 we saw an annual residential electricity price increase across the EU with significant price disparity across the region as the maturity of competition differed and government levies on energy increased.
2. The average consumer in a major European city is paying an annual energy bill of €1,542 or 8% of their disposable income. Typically, after housing and transport, energy is third largest cost for households.
3. Across the region we have seen an increase in competition in the last decade with the number of nation-wide energy suppliers in Europe increasing from 450 in 2013, to triple that amount in 2018 to 1,450 suppliers. Switching from a default electricity tariff could save consumers in the EU region over €100 or around 10% per year. This is higher in countries with higher levels of competition with potential savings as much as €300 per year per fuel (or 30% of the average annual bill).
4. High competition has put pressure on prices, enabling European countries to invest in their clean energy future (with government levies imposed on energy costs in order to fund this investment). Europe is exploiting positively the benefits of competition, allowing large investment in the sector transformation and a cleaner energy future
5. In line with the European Council's Clean Energy Targets, government levies on residential energy prices have steadily increased in the last 5 years as many countries move away from fossil fuels, towards renewable energy.
6. Since April 2020, the COVID-19 pandemic has led to a slight decrease in energy prices across the EU region. In addition to the 3% average price fall as a consequence of the pandemic, a set of measures were taken by the energy industry to alleviate the burden on energy customers experiencing economic hardship.

The energy fuel mix only partially explains the price disparity across the region

- The energy fuel mix of a country is a factor in the price disparity across the region – for example, Finland, Iceland and Norway have lower prices due to their reliance on inexpensive hydro production. However this only goes part of the way to explaining the significant price disparity for residential energy customers across the region. The level of competition in the market, and the magnitude of government levies are also key factors in energy prices.

Over the last 2 decades, the residential energy sector has opened to competition in Europe

- Across Europe we see that countries are at different stages of maturity of competition, with varying success.
  - Mature market – over 50 different suppliers, 200+ products offered to customers, role of incumbents decreasing – e.g. the UK, Germany, Norway, Spain
  - Developing market – less than 40 suppliers, role of incumbents still over 80%, new entrants offering differing products to customers – e.g. France
  - Laggards – limited number of suppliers (less than 15) or no competition, role of incumbents over 80%, products offered to customers limited - e.g. Lithuania, Hungary.

- Average consumers in major cities across Europe are paying 8% of their disposable income on energy costs (both electricity and gas). This is much higher in countries where competition has progress to make including Portugal (11%), Bulgaria (16%) and France (10%).
- Switching rates across European markets have increased with many seeing more than 12% customer churn per year.

With the regular increase of government taxes and subsidies to support clean energy targets, energy prices have increased with Europe investing in its clean energy future

- The magnitude of government levies and associated regulatory requirements in Europe is high with the average at 40% of residential energy bills. This includes policy costs for green energy targets and to ensure security of supply in the future.
- In some countries we have seen a significant increase since 2015 due to Europe's Clean Energy Targets (introduced in October 2014). We have seen a steep increase since 2015 in government levies in order to accelerate clean energy targets and support the move towards renewable energy. For example, in 2019 54% of Germany's energy mix was renewables, relative to 40% in 2008. Similarly, the UK has seen a steep increase with renewables making up 32% of the UK's energy mix in 2019, relative to 5% in 2008.

The COVID-19 pandemic has led the largest decrease in prices between February and April of the latest 5-year period (2015-2020) for the region

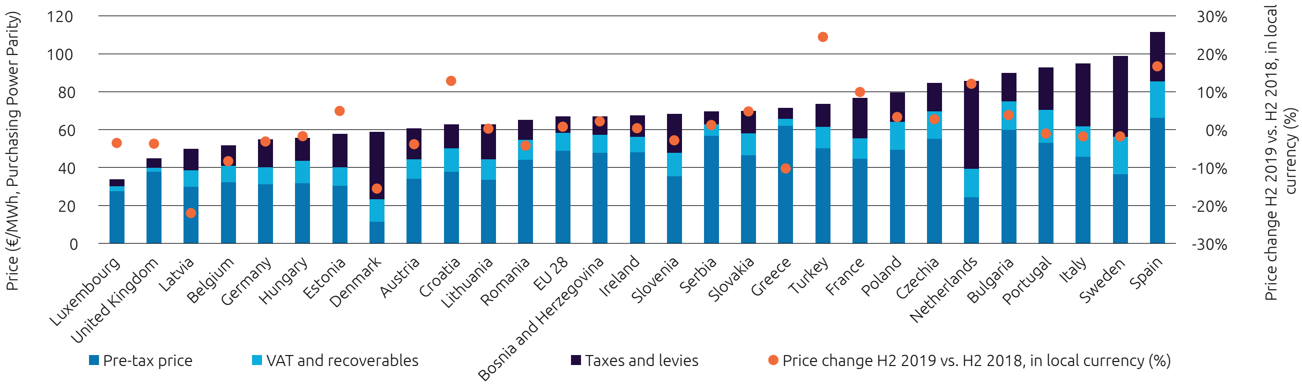
- The average price decrease that took place between February and April 2020 is the largest of the latest 5-year period (2015-2020) for the region, for both electricity and gas residential retail markets. In addition to the price fall as a consequence of the pandemic (-3% on average), a set of measures have been introduced by the energy industry to alleviate the burden on energy customers experiencing economic hardship. These measures were either determined by local governments and regulatory authorities or were the direct initiative of energy market players (suppliers and in some cases DSOs).
- The COVID-19 pandemic has made energy companies more vulnerable – although it is too soon to see the impact on their revenue profitability.

Residential energy prices increased in most European countries in 2019

The cost of residential electricity increased across Europe with significant price disparity across the region according to the extent of government levies on energy

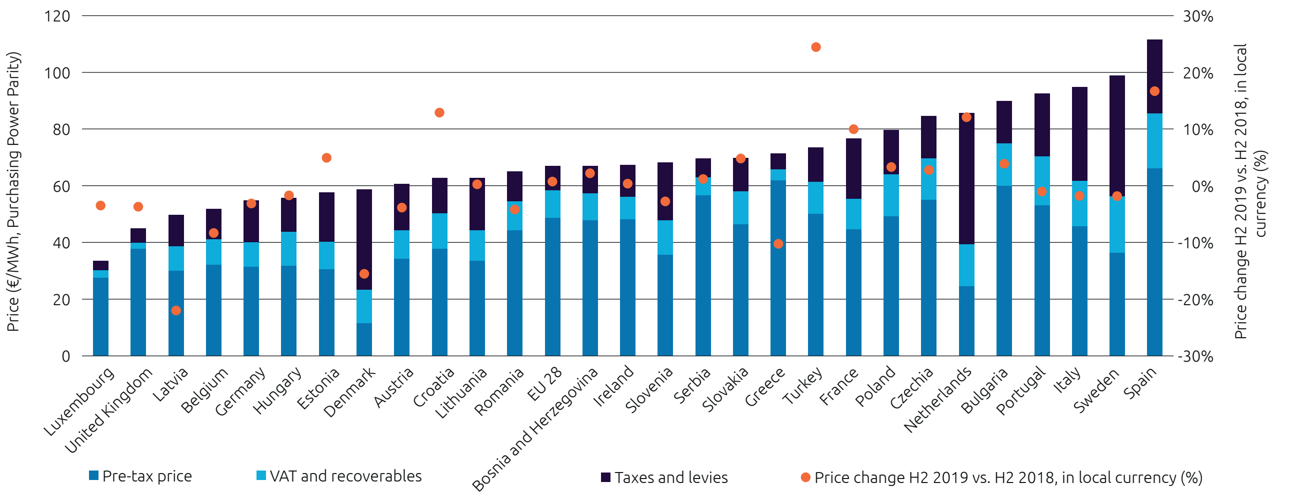
- Residential electricity prices across the EU28 have increased by 3% between 2018 and 2019 (from €211.8/MWh to €216.8/MWh). This is compared to an inflation increase of 1% across the region.
- Residential gas prices across the EU28 saw a slight increase of 1% between 2018 and 2019 (from €66.4/MWh to €66.9/MWh).
- In 23 out of 28 countries, residential electricity prices rose between 2018 and 2019. For 13 of these countries the increase was more than 5% including France (6%), Luxembourg (7%), the UK (8%) and Slovakia (8%). There has been an increase in residential gas prices in 14 of the 28

Figure 3.1. Residential electricity prices in Europe - all taxes included (H2 2019 compared to H2 2018, in local currency)



Source: Eurostat

Figure 3.2. Residential gas prices in Europe - all taxes included (H2 2019 compared to H2 2018, in local currency)



Source: Eurostat

countries with the average increase at just over 7% between 2018 and 2019.

- There is great disparity across EU countries, with residential gas prices in Spain (€111/MWh), Sweden (€99/MWh), Italy (€95/MWh), and Portugal (€92.6/MWh), – more than double the residential gas prices in Luxembourg (€33/MWh), the UK (€45/MWh), and Latvia (€49/MWh).
- There is also great disparity across EU countries with residential electricity prices in Turkey (€291/MWh), Romania (€278/MWh), and Germany (€279/MWh), – more than double the residential electricity prices in Iceland (€99/MWh), Norway (€121/MWh), Finland(€143/MWh), and Serbia (€144/MWh).
- Several factors contributed to the price disparity across the EU region including: the energy fuel mix, the level of competition and government levies. We have also seen a price impact from COVID-19 in H1 2020. Each of these is discussed in more detail bellow.

Europe has embraced competition in the residential energy market since 2007, with a few exceptions

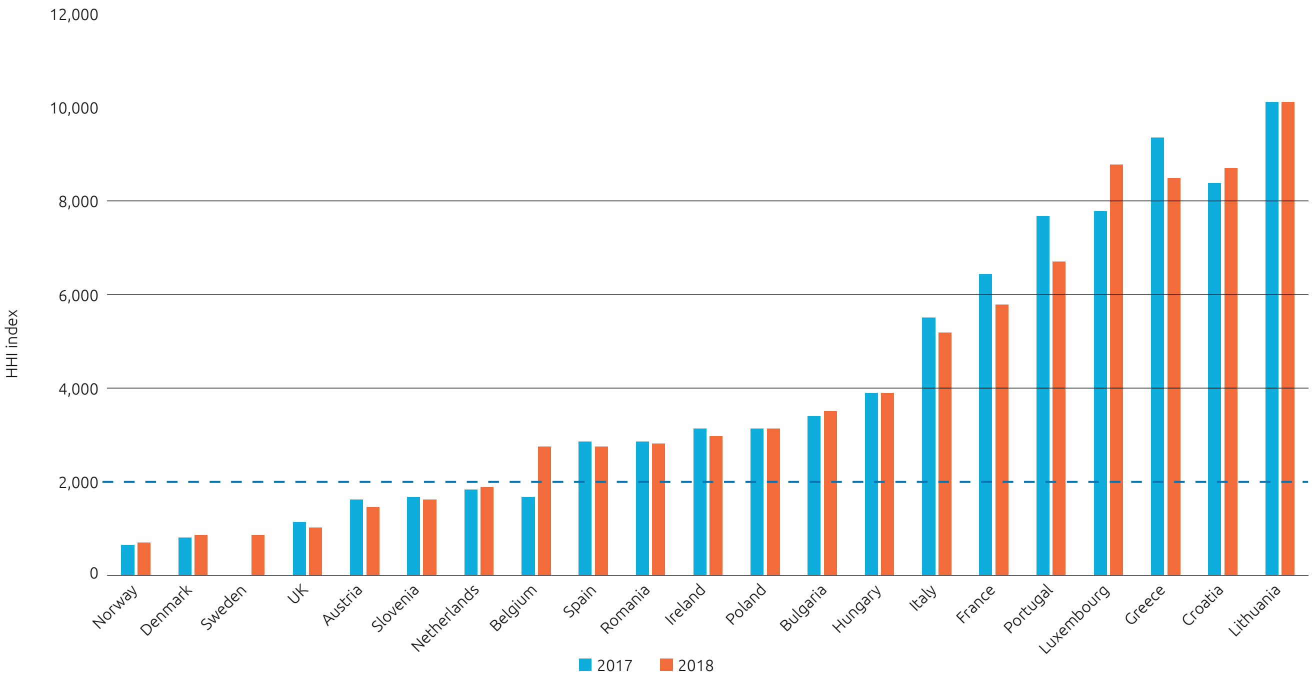
Across the region, competition has increased in the last decade with the number of nation-wide energy suppliers in Europe tripling from 450 in 2013 to 1,450 in 2018 (noting there are many other suppliers that are not nation-wide but more regionally based). Key drivers of this change have been more competition friendly regulation and digitization removing barriers to entry

- Over the last decade, the retail energy sector has opened to competition in the EU. Key indicators of the level of competition in a market include: the number of suppliers, the range of products available to customers and the role of incumbents. The Herfindahl-Hirschman Index (HHI) measures market concentration and provides insights into how competitive a market is. The closer a market is to being a monopoly, the higher will be the measure of concentration.
- Across the EU we see that countries are at different stages of maturity of competition, with varying success.

1. **Mature market** (HHI below 1,000) – over 50 different suppliers, 200+ products offered to customers, role of incumbents decreasing – e.g. UK, Denmark, Norway, Sweden
2. **Developing market** (HHI between 1,000-3,000) – less than 40 suppliers, role of incumbents less than 80%, new entrants emerging with new offerings and products to customers – e.g. France
3. **Laggards** (HHI above 3,000) – limited number of suppliers (less than 15) or no competition, role of incumbents over 80%, products offered to customers limited - e.g. Lithuania, Hungary

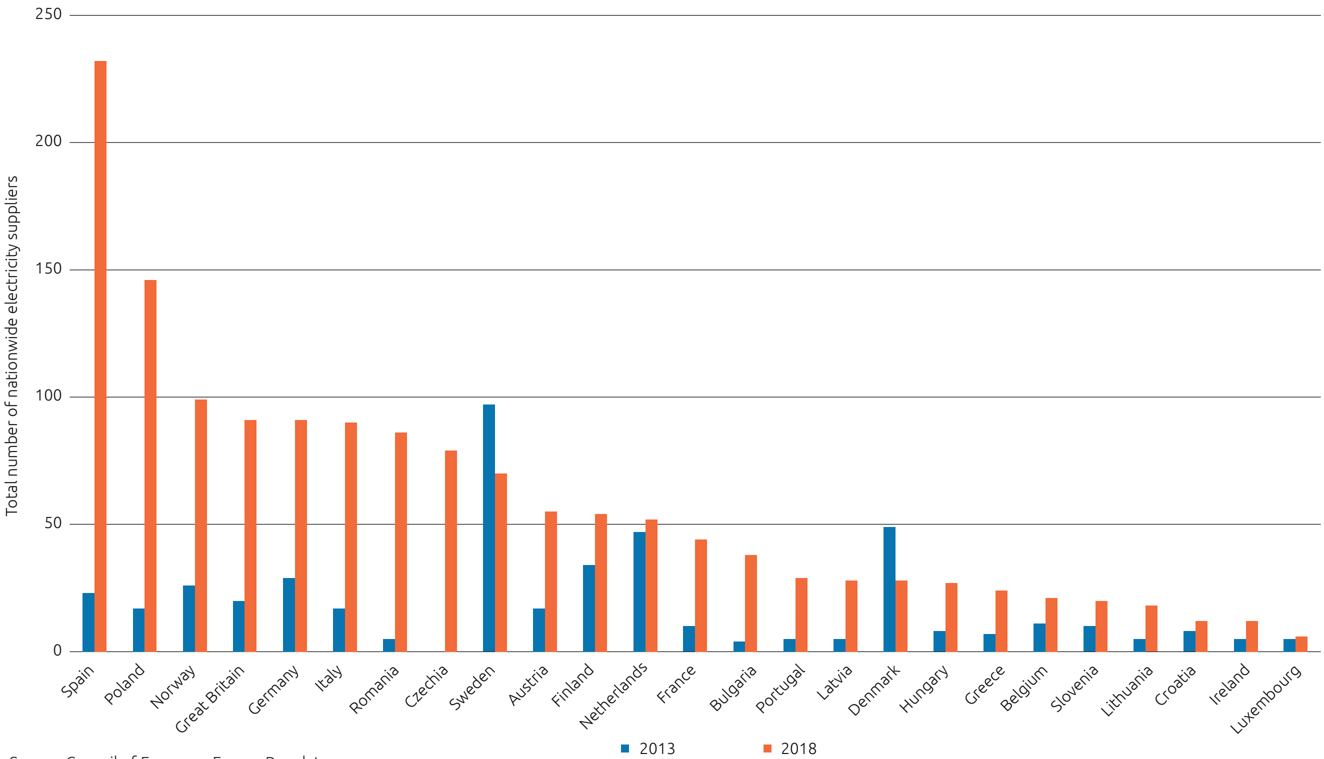
Note: Typically markets with HHI below 1,000 are considered as unconcentrated, markets with HHI between 1,000 and 3,000 as concentrated, and markets with HHI above 3,000 as highly concentrated.

Figure 3.3. HHI index for European household market (2017 and 2018)



Source: Council of European Energy Regulators

Figure 3.4. Total number of nationwide electricity suppliers



Source: Council of European Energy Regulators

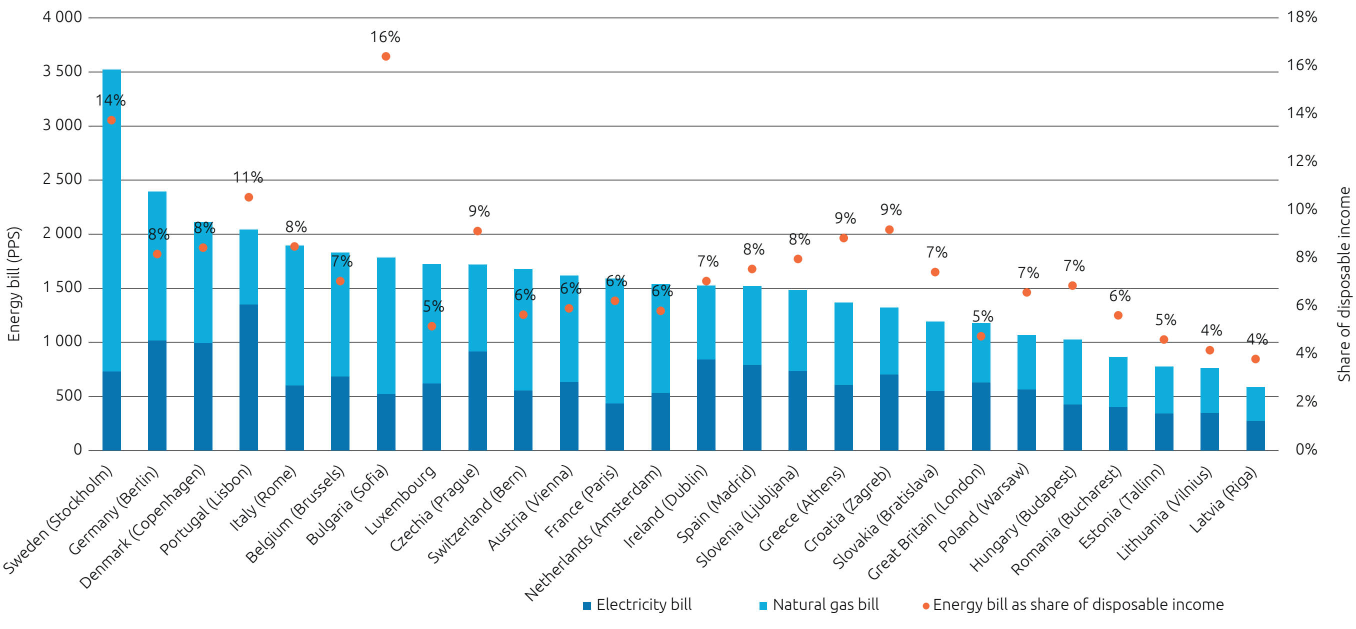
Residential energy costs remained a substantial part of household spending with a typical consumer in a major European city spending 8% of their disposable income on energy

The average consumer in a major European city is paying an annual energy bill of €1,542 or 8% of their disposable income. The downward pressure on prices, due to competition, has meant that Europe can invest in its clean energy future

- As a percentage of household income, residential energy costs (across both electricity and gas) vary across the region.

This is based on average typical consumption across major cities (in PPS). In countries where competition is higher, consumers are paying a smaller share of their disposable income including the UK (5%) and the Netherlands (6%). In countries where competition is lower, consumers are paying more as a percentage of their disposable income for energy including Portugal (11%), Greece (9%) and Spain (9%). The

Figure 3.5. Typical European household energy bill and its share of disposable income (2019)



Source: VaasaETT

highest as a percentage of disposable income is paid in Bulgaria at 16%. These levels could be seen as unsustainable.

- In four countries the annual bill for the average domestic consumer (PPS) was more than €2,000 – including Sweden (€3250), Germany (€2393), Denmark (€2110) and Portugal (€2045).
- High competition has put downward pressure on prices, enabling European countries to invest in their clean energy future (with government levies imposed on energy costs in order to fund this investment). Europe is exploiting the benefit of high competition, as these countries are now able to invest in the transformation of the sector for a cleaner energy future.

Residential energy market – switching rates across the region depend on the level of competition with most markets having a switching rate of over 10% per year

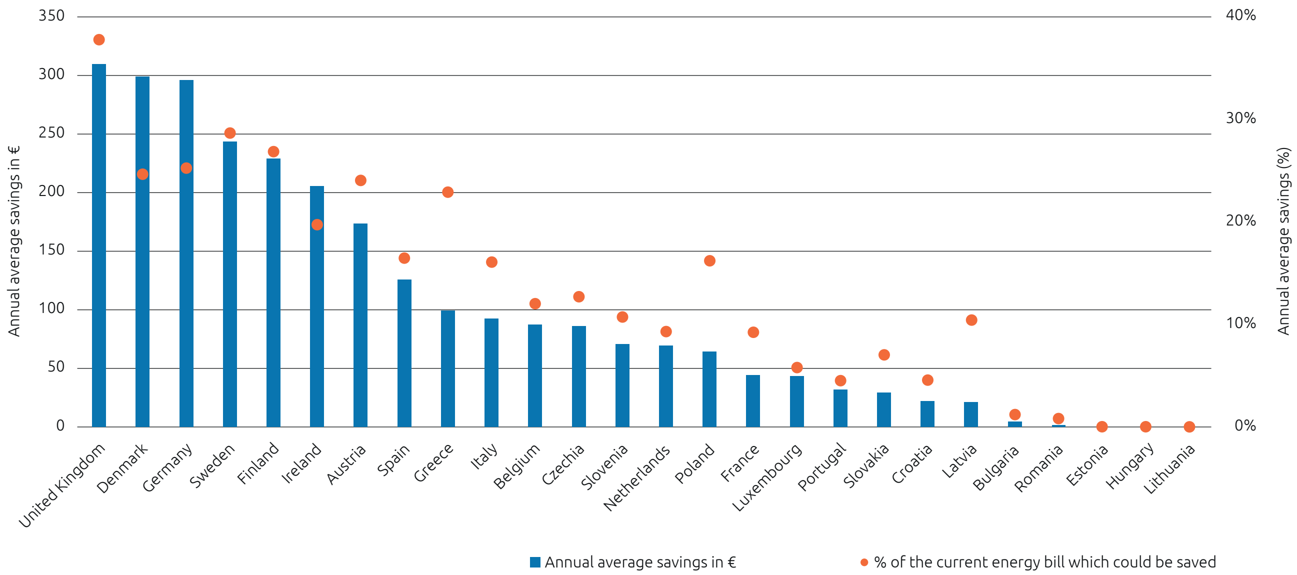
Switching from a default electricity tariff could save consumers in the EU region over €100 or c.10%. This is higher in countries with higher levels of competition with potential savings as high as €300 per year per fuel (or 30% of the average annual bill)

- In countries with a high level of competition the savings available from switching to the cheapest tariff available are significant for customers. This includes the UK (€309), Denmark (€299), Germany (€296) and Sweden (€243). The savings in these countries could be as high as 30% for consumers if they switch away from their incumbent supplier.
- In countries where competition is emerging the savings are significantly less. This may not be providing the incentives for consumers to switch away from their default electricity tariff thus stifling competition. This includes France (€44 saving), Portugal (€32 saving), and Lithuania (€43 saving).

Switching rates across European markets have increased with many seeing more than 12% customer churn per year

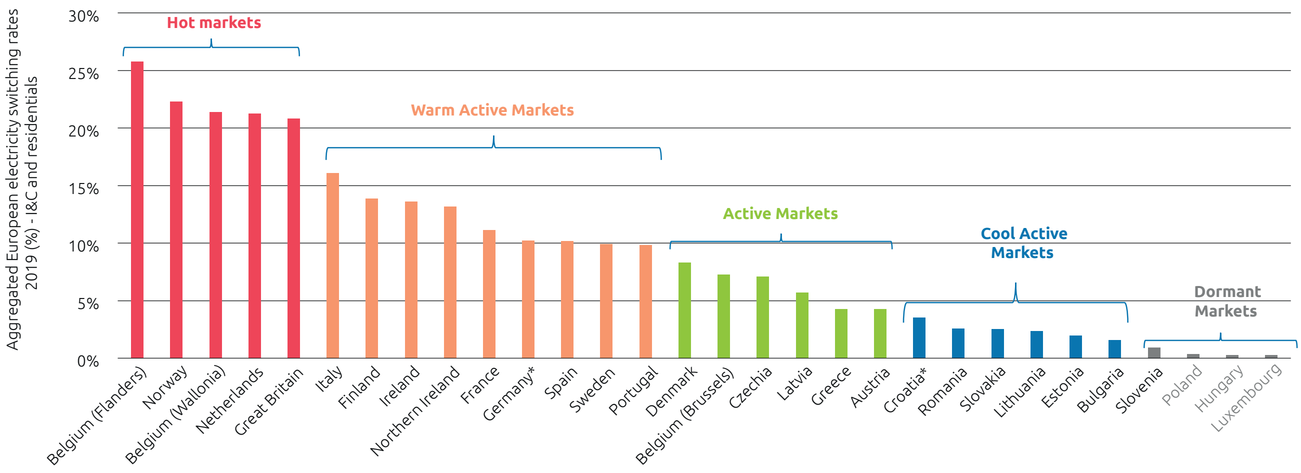
- This means that on average Europeans in active markets (excluding dormant markets) are switching energy suppliers once every 8 years. In Norway and the UK this is more frequent (once every 4 or 5 years) while in Denmark and Portugal it is more like every 12 years.

Figure 3.6. Absolute and % savings switching from the default electricity tariff to the cheapest available



Source: VaasaETT

Figure 3.7. Aggregated European electricity switching rates (2019)



Source: VaasaETT Utility Customer Switching Research Project

Government levies and associated policy initiatives increased across Europe in order to support the move towards renewables and to meet the European Council's clean energy targets

Moving towards renewable energy

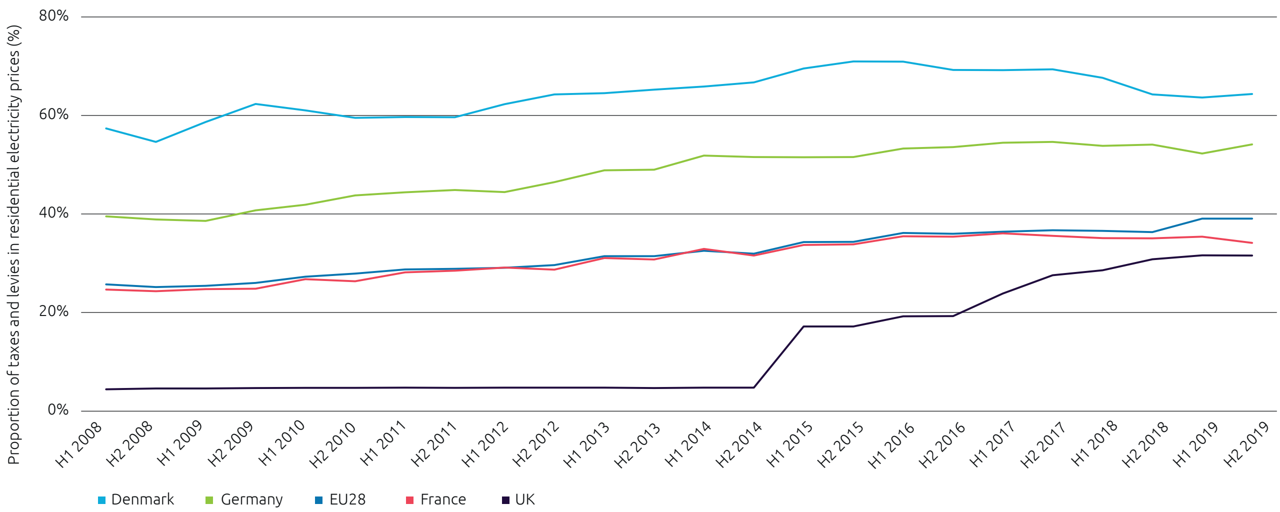
In the EU28 the average energy fuel mix is 47% fossil fuels, 25% nuclear, 15% solar / wind and 12% hydro. However, there has been a clear move towards renewables in many countries across the region since the introduction of the European Council's Clean Energy Framework including:

- **Germany** – generation from renewables increased to 40% in 2019
- **UK** – "coal free" for 40 days+ in 2020
- **France** – phasing out of fossil fuels (aiming for 35% decrease in 2028 compared to 2012 levels)
- **Denmark** – solar and wind production make up 49% of energy generation
- **Ireland and Lithuania** – growth in wind and solar production with 28% and 30% of energy generation, respectively

In line with the European Council's clean energy targets, government levies on residential electricity prices have steadily increased in the last 5 years.

- In 2019 the level of government levies as a proportion of residential electricity prices was high with the average across the EU28 at 40%. This includes policy costs for green energy targets and to ensure security of supply in the future. The cost of these initiatives is paid by the current consumers of electricity as they are added directly to their bill.
- In some countries –including Denmark, the UK, France and Germany – we have seen a significant increase in the proportion of government levies on residential electricity prices in recent years.
- The Clean Energy framework adopted by the European Council in 2014 (and updated in 2018) has been a driving force for these green energy initiatives. Key targets by 2030 across the EU28 include:
  - At least 40% cuts in greenhouse gas emissions (from 1990 levels)
  - At least 32% share of renewable energy
  - At least 32.5% improvement in energy efficiency (relative to business as usual scenario)
- High government levies, in order to accelerate clean energy targets and support the move towards renewable energy, are seen in Denmark (64%), Germany (54%), the UK (32%), France (34%). These countries have typically exceeded and beyond the European clean energy targets.

Figure 3.8. Proportion for taxes and levies in residential electricity prices



Source: Eurostat

Spotlight ~ Government policies on residential energy

Denmark has set itself a 100% renewable energy target by 2050

Denmark has set itself the objective of having 100% renewable energy by 2050, which implies decarbonizing the use of electricity and heat in particular. The country has already initiated:

- Growth in the share of wind and solar power in electricity generation
- Conversion of coal-fired power plants to biomass
- Use of biomass cogeneration to decarbonize heat

Germany has a dedicated levy on electricity from renewable energies with support available for investments in these renewable technologies

The charge on electricity from renewable energies, called "EEG - Umlage", aims to support the development of renewable energies in the electricity sector (BMWi 1), following the example of the CSPE in France. This has led to high levels of subsidies for renewable energy, causing a steep increase in residential prices.

- The introduction of calls for tenders for renewable energies from 2017 onwards (Germany-Energy 2) has helped to limit the upward trend
- The massive development of renewable energies combined with falling wholesale market prices has dramatically increased the support costs for renewable energies.
- EEG – Umlage has been a nearly constant c.25% of residential prices over the last 2 years.

France is striving for carbon neutrality by 2028[1]

- To be in line with EU clean targets for 2050, France has a Multi-Annual Energy Plan (agreed very recently in 2020) until 2028 to reduce fossil fuel energy consumption
- Support schemes in France for electric renewables are mostly feed-in-premiums (FiPs) "complément de rémunération" (~similar to Contracts for Difference (CfDs) in the UK) obtained through calls for tenders. For green gas, it's a mix of feed-in-tariffs (FiTs) and direct grants.
- The support costs for renewable electricity are financed through the Contribution au Service Public de l'Electricité (CSPE), a domestic tax on final electricity consumption in France, paid by the final consumer. Electric renewables represent a majority of the CSPE.

The UK is aiming to bring all greenhouse gas emissions to net zero by 2050[2]

- In June 2019, the UK passed laws to end its contribution to global warming by 2050.The target will require the UK to bring all greenhouse gas emissions to net zero by 2050, compared with the previous target of at least 80% reduction from 1990 levels.
- The UK has already reduced emissions by 42% and has put clean growth at the heart of its recent Industrial Strategy. This could see the number of "green collar jobs" grow to 2 million and the value of exports from the low carbon economy grow to £170 billion a year by 2030.
- The UK's 2050 net zero target — one of the most ambitious in the world — was recommended by the Committee on Climate Change, the UK's independent climate advisory body. Net zero means any emissions would be balanced by schemes to offset an equivalent amount of greenhouse gases from the atmosphere, such as planting trees or using technology like carbon capture and storage

1 https://www.ecologique-solidaire.gouv.fr/sites/default/files/14.%20PPE%20-English%20 Executive%20summary%20for%20public%20consultation.pdf

2 https://greengb.campaign.gov.uk

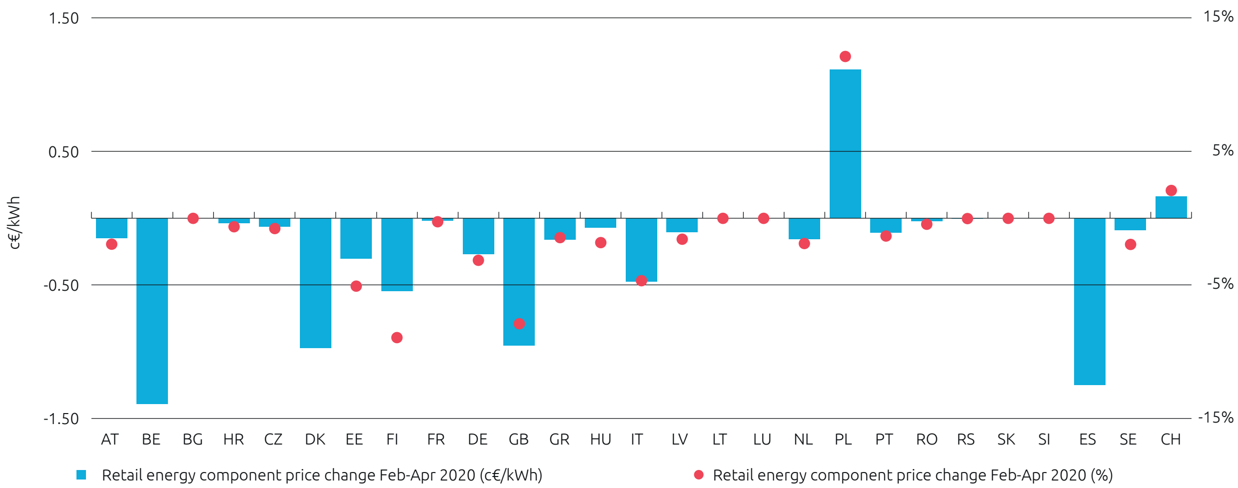
COVID-19 led to a price cuts for residential electricity and gas (February to April 2020) with emergency measures introduced by many countries to support vulnerable customers

The retail energy price decrease across the EU region between February and April 2020 was in excess of 3% (energy component of final bill)

- Although when looking at energy price changes between February and April throughout the years there is generally a decreasing trend, the average price decrease that took place between February and April 2020 is the largest of the latest 5-year period (2015-2020) for the EU28, for both electricity and natural gas residential retail markets.
- It is hard to tell with certainty to what extent the price reduction is associated with the decreased demand due to the pandemic. With a recent reduction in wholesale prices due to a lack of demand, we could see the wholesale energy part of the bill decreasing. However, as commodity prices account for 30-40% of the final customer bill, this decrease will have limited effect.
- Nevertheless, the energy price component change for households shows a clear decrease in most EU28 countries. Note that the duration of residential contracts is typically 12 months, so many customers won't see an immediate price impact. The residential price decreases are reflective of the decrease in wholesale prices over the same period.
  - Prices fell in Denmark (-19%), UK (-8%), Finland (-9%) and Spain (-16%)
  - The only significant increase was in Poland at 12%
  - Despite a drop in wholesale prices, retail prices saw only a minimal change (~ -3%) in Germany
- In addition to the price cuts due to the pandemic, measures were taken by the energy industry to alleviate the burden on customers experiencing through economic hardships. Governments across the EU28 agreed to emergency measures with the energy industry to ensure vulnerable people remain supplied during the quarantine. The measures include reducing or pausing debt repayments/ bill payments, offering credits to vulnerable customers, and suspending disconnections for non-payment.
- These measures are either determined by the local governments, or regulatory authorities, or were the direct initiative of energy market players (energy suppliers and in some cases DSOs).

Europe

Figure 3.9. Change to energy component of electricity bill (transportation and taxes not included)



Source: VaasaETT

Topic box 3.1: How new players have disrupted the UK market ?

Octopus, Bulb, Ovo ... You've probably heard of these companies changing the UK energy retail market. Although they've had different growth strategies, one thing they have in common is that they are thriving on three pillars that are painfully missing from the other players in the market.

The first pillar is customer's trust. The traditional energy providers are taking advantage of being seen as "boring" for customers still largely reluctant to spend much time or effort to look for the best energy deals. They lure customers with a good deal on the first year (often losing money on it) and then hiking them on an expensive but profitable tariff from year 2, hoping for that customers won't notice the change.

The disruptors are doing the opposite. Octopus is communicating regularly with their customers regarding offers, plunge pricing alerts and others. Disruptors are truly siding with customers to get the best deals and making sure they are benefiting from it. There is nothing like trustful customers to attract more customers. Check the three disruptors' website homepage: the first thing you see is their Trustpilot shiny 5 stars. These are nowhere to be seen on their competitors' websites.

The second pillar is their technology - The incumbents have decades of entangled legacy systems making every technical change a real nightmare. The disruptors have opted for simpler tools, sometimes built in-house, and focused on the customer and cost-efficiency. This include multi-channel customer journeys.

The CEOs of these companies will happily claim they are on their way to becoming a technology company like AirBnB or Amazon. Thanks to the savings they make with their efficient systems, their customers can benefit from it with cheaper prices, and often, better service too. Octopus Energy in particular has also combined this with effective marketing to customers.

The last pillar is embracing change. While the traditional providers are constantly struggling to keep up with the latest tariff or environmental regulation, the disruptors are ahead of the game and do even better than the regulator stipulates.

Rather than spending millions in marketing to sell the same old products, they also have a better sense of the trends and will propose offers that meet these increasing demands. Some examples are green and zero carbon energy. This includes Octopus Energy embracing EV charging, and solar panels as part of their residential market offering.

It's hard not to be impressed by the success of Octopus and the others, but there is still one test they'll have to pass to actually take over our traditional incumbents: the critical size. As they get more and more customers, it's going to be harder for them to maintain the same level of customer satisfaction at the same low cost. Similarly, the technology we deem flexible and cost-efficient today might be obsolete within five years, as the legacy systems of the Big Six are to us today.

Time will tell if these disruptors have intrinsically developed a future-proof structure to redefine the energy retail market, or if they owe their success only to the flexibility and dynamism of smaller companies.

We are seeing similar digital retailers emerge in other markets including Tibber in Germany. Tibber has a fully digital transaction processes and customer interfaces (sales, service, invoicing) via app, email and instant messaging. Tibber is truly revolutionizing the German market by having no call centre (no calls service).

In order to ensure digital retailers succeed, regulation (and regulators) must not stand in their way, and must also innovate to ensure the market itself is open to innovation Government and regulators have an important role in enabling innovation – they need to ensure that regulation is able to evolve and be dynamic to keep up with market changes.

Topic box 3.2: New customer propositions... and new entrants?

In the last decade, we have seen the type of energy products offered to customers expand including solar panels and smart energy management services. More importantly, the companies providing energy services also changed. Traditional energy companies are now competing with some new rivals. Did you know you can purchase energy services when you pick your new electric car from Volkswagen? Other car manufacturers and operators of EVs charging points could also enter the market, with EVs changing customer's energy profile.

Consumers are not just interested in how they purchase energy, but also how it's generated, how it's used in their home, as well as selling energy back to the grid. This is with the support from solar panels on their roofs and battery storage facilities in their homes… all purchased from the Amazon or IKEA websites!

Despite the current tough market conditions and relatively small margins on offer in the residential energy market - there is significant opportunity to "own the home". This includes providing energy with home services such as energy efficiency opportunities, EV charging, solar panels, battery storage, micro-grids and overall 'smart home' management. Google's Nest products for example, provide convenience and connectivity in the home with an emphasis on 'smart connected living' and energy efficiency.

With the emphasis on green living and 'sustainability at home' increasing due to COVID-19 pandemic, there will be more demand for green, digital and sustainable living - changing the way consumers purchase and use energy in their homes.

The question is… can incumbent energy providers keep up with changing customer demands or will they be left behind as the way consumers purchase and use energy evolves?

*"**VW's Elli** is a provider of energy and charging solutions. As part of the Volkswagen Group we will be the first provider on the market to offer a **seamless and holistic energy and charging experience** for electric car drivers. As the supplier of Volkswagen Naturstrom®, we are opening up an entirely new business area for the Group. In the new world of mobility, the topics of energy and the automobile will become increasingly closely linked – we intend to grasp this opportunity."*

Source: https://www.volkswagen.co.uk/need-help/news/electric-life

*"Picture yourself being able to wake up, raise your blinds to let in that lovely morning sun, listen to some music and still not have to get out of bed. How lovely, right? When you improve the IQ of your home, life itself runs a bit smoother as well ... there's an **IKEA Home smart product** to create an intuitive flow for you."*

Source: https://www.ikea.com/gb/en/this-is-ikea/sustainable-everyday/home-solar-pubf1153c43

*"**Google Nest** is partnering with energy firms on **Rush Hour Rewards** to allow thermostat owners to automatically adjust the temperature of their homes during peak energy usage times. When you sign up, your Nest thermostat will make changes to the temperature in your home on a handful of those peak energy usage afternoons during the summer. This **lowers the energy demand** while still keeping you comfortable."*

Source: https://store.google.com/gb/category/connected_home?

*"The world is changing... and **Shell** is changing too. This means being involved at almost every stage of the power supply system, from generating electricity, to buying and selling it, to supplying it directly to customers. Shell Energy offers renewable electricity as standard to all residential customers as well as a range of **smart home technologies.** All the electricity from Shell Energy Retail comes from 100% **renewable sources** like wind, solar and biomass."*

Source: https://www.shell.co.uk/shell-energy.html

In collaboration with Energy UK

Topic box 3.3: Trends in the UK energy retail market

2019 marked another year of change for the UK energy retail sector. Not only did 2019 see the start of the Default Tariff Cap (DTC), capping the unit cost of energy for domestic customers on default tariffs, but also, to the surprise of many, continued positive longer-term trends on customer engagement, as a record breaking 6.4 million customers switched their electricity supplier, a 9% increase on 2018. Overall, almost half (49%) of domestic consumers engaged with the market in 2019, an 8% point increase on 2018, by either comparing available tariffs or switching their current tariff and/or supplier.

At the same time, suppliers have also been delivering better service for their customers. In 2019 the level of complaints fell by 9% compared to 2018. Over three-quarters (78%) of domestic customers were satisfied with their energy supplier. Current workstreams such as the Faster Switching program and finalising the rollout of smart meters will help suppliers improve their services even further.

The sector has also continued to focus on customers in vulnerable circumstances or in or at risk of fuel poverty. This includes measures through social schemes that focus on energy efficiency improvements and energy bill rebates during the winter. At the end of 2018, the Energy Company Obligation (ECO), the energy efficiency programme financed through customer bills, was amended to a purely social scheme that now focus on fuel poor households only. In 2019, the scheme installed 221,000 energy efficiency measures which are expected to bring combined bill savings of £2bn over the lifetime of the measures.

Later this year, Energy UK will also be launching a new voluntary Vulnerability Commitment for suppliers. This independently monitored code of conduct further improves the standards of support for vulnerable households and shows that suppliers are willing to go above and beyond to protect customers in vulnerable circumstances.

While these are positive trends from a customer perspective, 2019 was a challenging year for energy suppliers, as demonstrated by their latest financial statements which suggest general unprofitability within the sector, especially in the domestic market. This was partly due to the introduction of the DTC, which the UK's energy regulator noted would negatively impact on profitability across the domestic retail market so as to incentivize supplier efficiencies. Alongside the DTC, a large selection of competitive tariffs and a vigorous, sometimes unsustainable, competition for customers also contributed to numerous market exits in 2019 and a number of high-profile mergers (npower and E.ON) and acquisitions (SSE's domestic supply business to OVO Energy).

These challenging conditions have been exacerbated by the COVID- 19 pandemic in 2020, as the economy slowed down under the lockdown. In addition to suppliers facing higher non-commodity costs as a result of changes in demand, we know that many households and businesses continue to struggle to make ends meet and pay for essentials, like energy. As seen in the press, there are significant concerns across the sector about resulting challenges like non-payment and bad debt. The end of temporary government support schemes, like furlough, is likely to make things more challenging over the coming months.

Industrial and commercial market

Industrial and commercial prices – key findings

Significant price disparity in the EU for I&C customers

- The cost of energy is a large part of the cost to do business. This is particularly the case for the manufacturing sectors and heavy industry which are high consumers of electricity. The energy cost could be one of the deciding factor in where to do business in the EU / globally for these companies.
- Across the EU region, I&C gas prices decrease significantly between 2018 and 2019. In most of these countries this decrease is more than 10%. Across the EU, I&C electricity prices increase by an average of 7% from 2018 to 2019.

PPAs changing the market

Power purchase agreements (PPAs) have historically developed in the United States and Europe, supported by CSR strategies.

PPAs from renewable energy plants continue to be the main focus of attention. Rising market values for renewables will lead to higher demand for PPAs among customers, because they provide a competitive alternative for electricity procurement. This trend will only intensify as the prices for CO_2 certificates are expected to rise.

Other factors driving the further commercialization of PPAs across the EU region include:

– Further reduction in the LCOE (levelized cost of electricity) of renewable energy

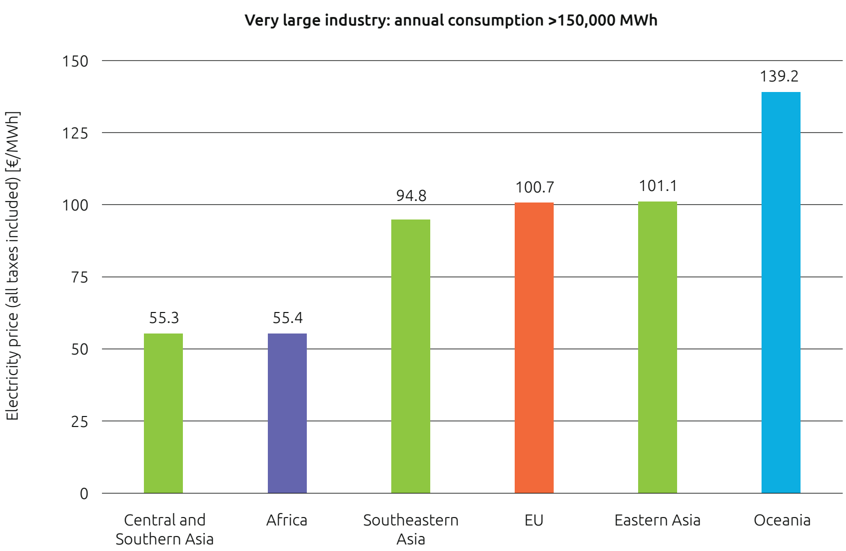
– PPAs as an economic alternative to existing support schemes (mostly tendering or auction systems) for renewable energies

– Increasing demand and interest of customers to purchase green electricity through PPAs to reduce their own CO2 footprint and to match their unique consumption and carbon demands to the market in a cost efficient manner.

Due to the further commercialization and digitalization of energy procurement for larger customers, more and more service providers are positioning themselves as intermediaries and traders who first contract green electricity volumes directly from the plant operators (via merchant PPA) and then sell them on (via corporate PPA).

The reasons why PPA can be seen as a game changer are numerous. They reduce the classical dependence of renewable energy projects on existing support regimes for renewables. The expansion of renewable energies can take place regardless of the attractiveness of a country's support regime. PPAs can also be used to mitigate the uncertainties associated with the development of electricity prices on the trading side (keyword: cannibalization of RES). On the demand side, a completely new procurement option opens up for companies and larger end consumers that goes far beyond mere guarantees of origin. Due to the significant reduction in the LCOE of renewable energies, attractive conditions for PPAs are also possible.

Figure 3.10. Worldwide Industrial & Commercial electricity retail prices comparison



Source: VaasaETT

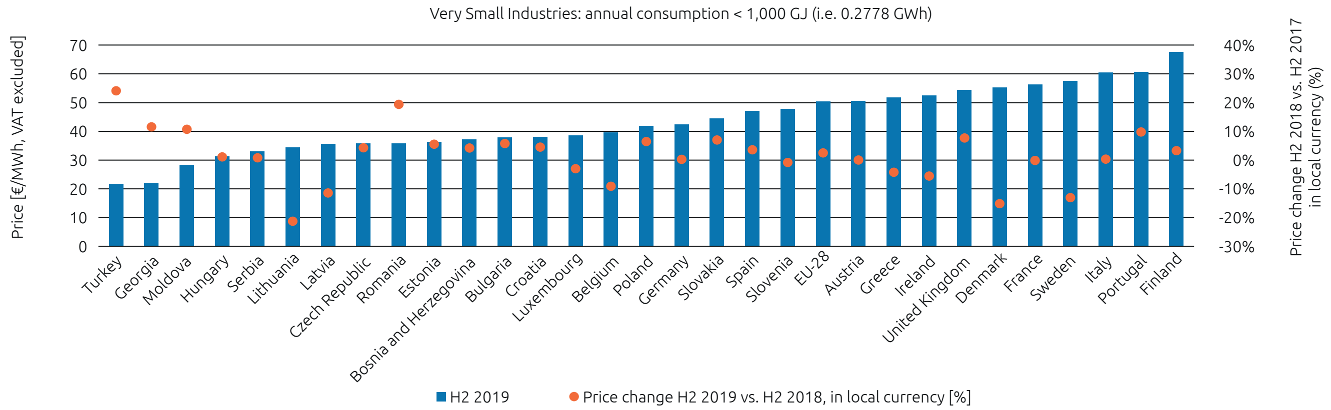
Europe

Small and medium I&C gas prices ~ Significant price disparity across the region with majority seeing decreases in gas prices

Great disparity in I&C gas prices for small consumption levels across each market

- For small I&C customers (annual consumption less than 1,000 GWh) there has been a decrease in most of the EU28 countries in the last year.
- Significant disparity in the prices across the region - with Finland (€67/MWh), Portugal (€61/MWh) and Italy (€60/MWh)- more than triple the price in Turkey (€21/MWh), Georgia (€22/MWh) and Moldova (€28)/MWh).
- For five countries more than a 10% increase including Turkey (26%), Moldova (11%), Romania (17%), Portugal (10%) and UK (10%). For 3 countries more than 15% decrease including: Lithuania (21%), Denmark (15%), and Sweden (15%).

Figure 3.11. Industrial & Commercial gas prices in Europe – VAT excluded

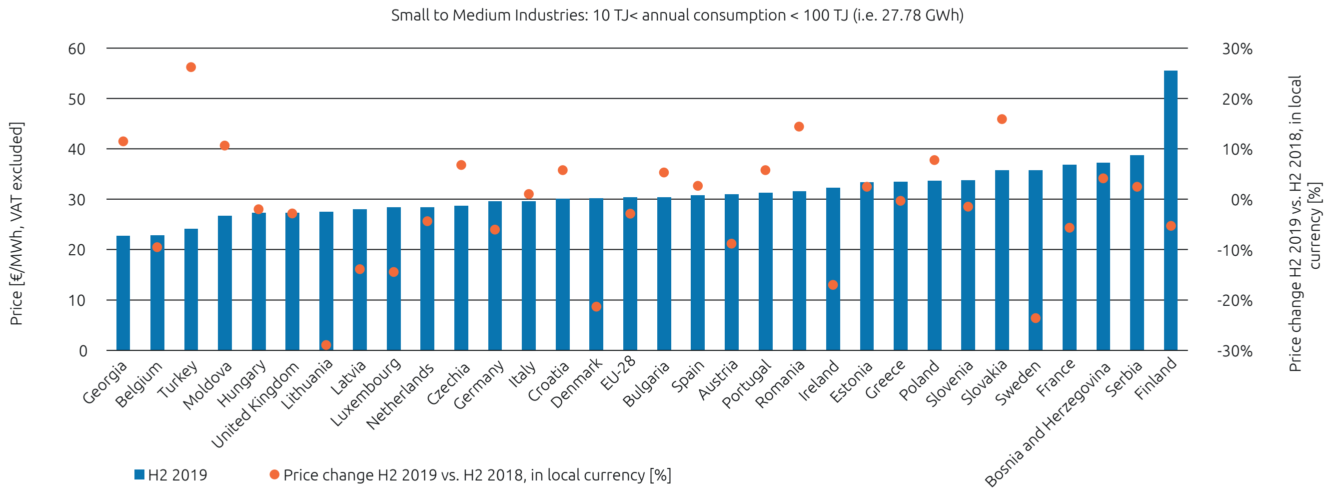


Source: Eurostat

Great disparity in I&C gas prices for medium consumption levels across each market

- For medium I&C customers (annual consumption between 10 TJ and 100 TJ) there has been a decrease in most of the EU28 countries in the last year.
- Significant disparity in the prices across the region - with Finland (€55/MWh), S erbia (€38/MWh) and France. (€37/MWh)- significantly higher than the price in Georgia (€23/MWh), Belgium (€23/MWh) and Turkey (€24)/MWh).
- For five countries more than a 10% increase including: Turkey (26%), Moldova (11%), Romania (14%) and Slovakia (16%) and Georgia (11%). For three countries more than 20% decrease including: Lithuania (29%), Denmark (21%) and Sweden (24%).

Figure 3.12. Industrial & Commercial gas prices in Europe – VAT excluded



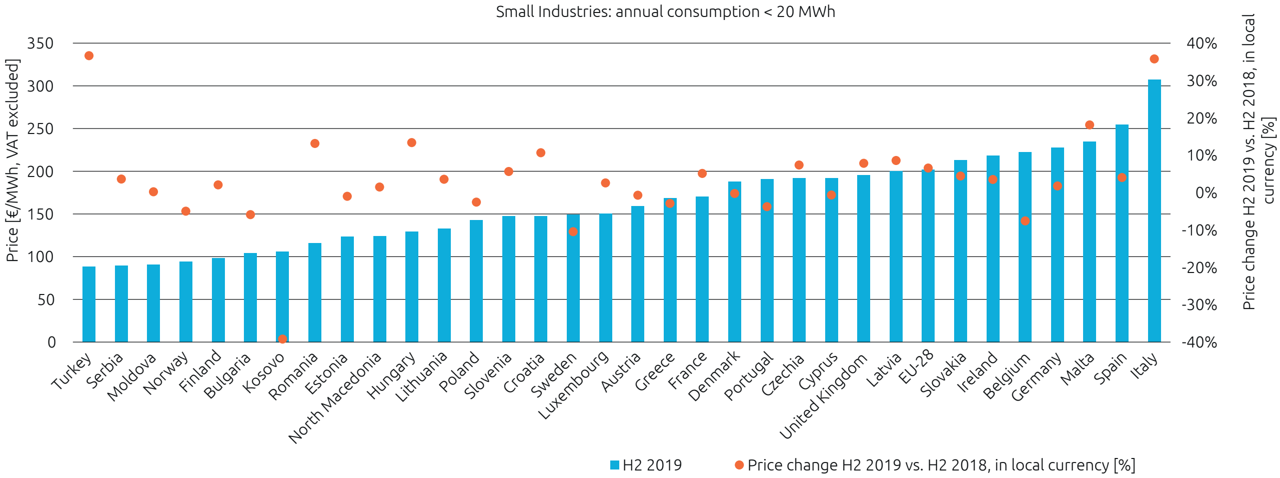
Source: Eurostat

Small and medium I&C electricity prices ~ prices rose in most of the EU28 with significant increases experienced by some customers

Medium I&C electricity customers (with annual consumption between 500MWh and 2GWh) have seen small decreases across the region

- For medium I&C customers (annual consumption between 500MWh and 2GWh) there was a decrease in the electricity price for most of the EU region countries in the last year. However, in some countries we saw steep increases.
- For three countries more than a 15% increase including: Turkey (38%), Hungary (18%) and Romania (20%).
- Significant disparity in the prices across the region - with Cyprus (€180/MWh), Italy (€161/MWh), Germany (€158)/MWh) and UK (€156)/MWh)- more than double the price in Kosovo (€68/MWh), Denmark (€68/MWh), Sweden (€69/MWh) and Finland (€72/MWh).

Figure 3.13. Industrial & Commercial electricity prices in EU28 – VAT excluded



Source: Eurostat

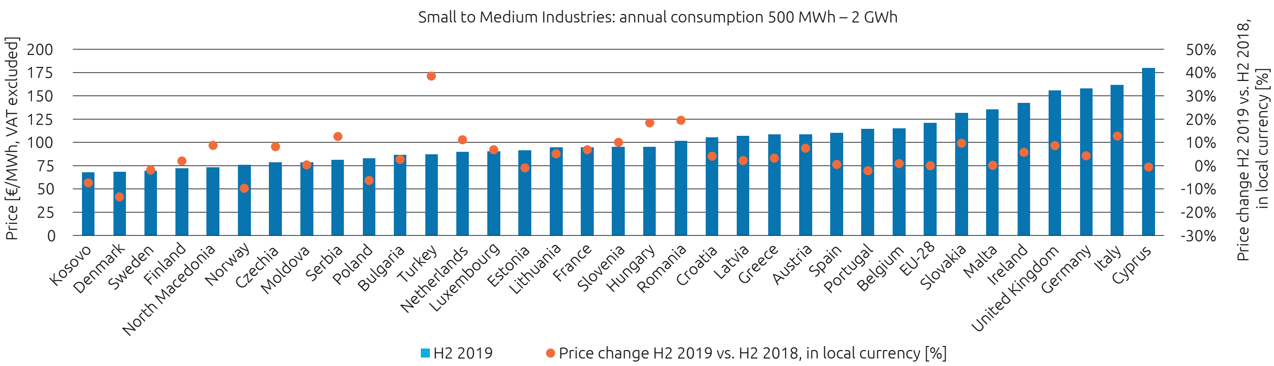
Medium I&C electricity customers (with annual consumption between 500MWh and 2GWh) have seen small decreases across the region

- For medium I&C customers (annual consumption between 500MWh and 2GWh) there was a decrease in the electricity price for the majority of the EU region countries in the last year. However, in most countries we saw steep increases.

- For three countries more than a 15% increase including: Turkey (38%), Hungary (18%) and Romania (20%).

- Significant disparity in the prices across the region - with Cyprus (€180/MWh), Italy (€161/MWh), Germany (€158)/MWh) and UK (€156)/MWh)- more than double the price in Kosovo (€68/MWh), Denmark (€68/MWh), Sweden (€69)/MWh) and Finland (€72/MWh).

Figure 3.14. Industrial & Commercial electricity prices in Europe – VAT excluded



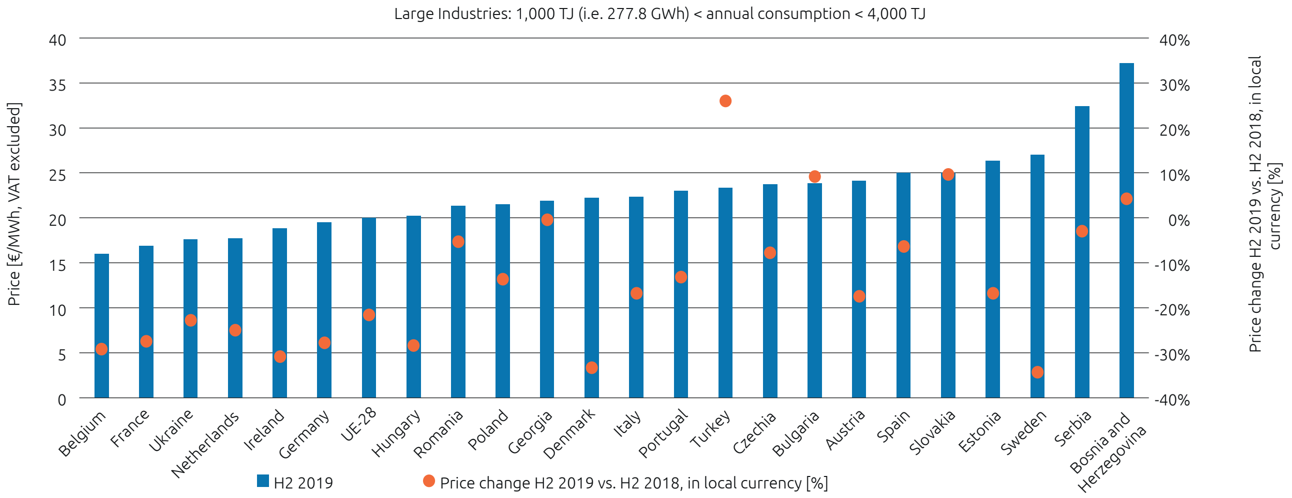
Source: Eurostat

Large I&C market ~ Significant gas price decreases across the majority of EU28 countries in 2019, with price increases for electricity

Large I&C electricity customers (with annual consumption between 20GWh and 70GWh) have seen increases in price

- For large I&C customers (annual consumption between 20-70 GWh) there has been an increase in electricity price for the majority of the EU28 in the last year.
- In 7 countries we saw a decrease of more than 25% including Belgium (29%), France (27%), Ireland (31%), Germany (28%), Hungary (28%), Denmark (33%) and Sweden (34%).
- There was significant disparity between countries in the region with Sweden (€27/MWh), Serbia (€33/MWh) and Bosnia & Herzegovina (€37/MWh) – more than double than the prices in in Belgium (€16/MWh), France (€17/MWh, the UK (€18/ MWh and Netherlands (€18/MWh).

Figure 3.15. Industrial & Commercial gas prices in Europe – VAT excluded

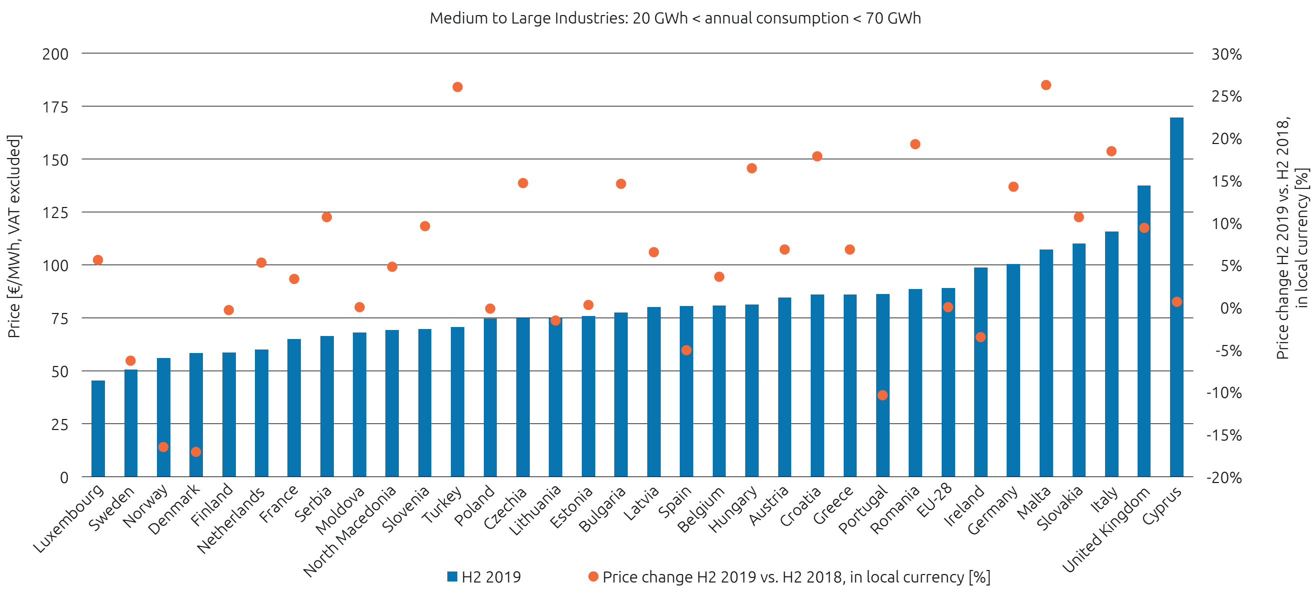


Source: Eurostat

Large I&C electricity customers (with annual consumption between 20GWh and 70GWh) saw increases in price

- For large I&C customers (annual consumption between 20-70 GWh) there was an increase in the electricity price for the majority of the EU28 countries in the last year.
- In 5 countries the increase was above or near 20% including: Turkey (26%), Croatia (18%), Romania (20%), Malta (26%), and Italy (18%)
- There was significant disparity in the prices with Cyprus (€169/MWh), UK (€137/MWh) and Italy (€115)/MWh)- more than double the price than Luxemburg (€45/MWh), Norway (€56/MWh), Sweden (€50/MWh) and Netherlands (€59/MWh).

Figure 3.16. Industrial & Commercial electricity prices in Europe – VAT excluded



Source: Eurostat

Topic box 3.4: Acceleration of PPAs in Europe

In 2020, PPAs from renewable energy plants continue to be the main focus of attention. Even though wholesale prices have fallen as a result of COVID-19, making it somewhat less attractive in the short term, especially for industrial suppliers of green electricity, the medium term is already pointing in the right direction. Forward prices for electricity are back to pre-crisis levels, which will also be reflected in rising market values for renewable energies. Conversely, rising wholesale prices and thus rising market values for renewables will lead to higher demand for PPAs among customers, because they provide a competitive alternative for electricity procurement. This trend will only intensify as the prices for CO_2 certificates are expected to rise.

Other factors driving the further commercialization of PPAs across the EU region include:

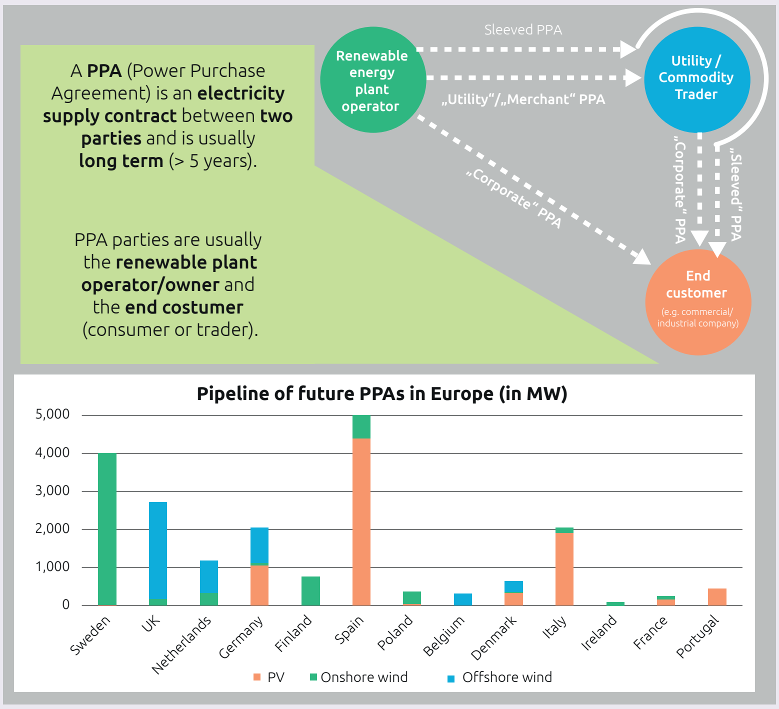
- Further reduction in the LCOE (levelized cost of electricity) of renewable energy
- PPAs as an economic alternative to existing support schemes (mostly tendering or auction systems) for renewable energies
- Increasing demand and interest from customers to purchase green electricity through PPAs to reduce their own CO_2 footprint.

In addition to corporate PPAs, sleeved PPAs are likely to play an increasingly role, especially in markets with high aspirations for a continued operation of renewable energy plants after the expiration of the support period. Figure 3.17 below shows the various models with parties involved. Offsite PPAs, in which the offtake and generation locations are physically far apart, will become the standard. Financial or virtual PPAs will also be replaced more and more by actual contracts. Due to the further commercialization and digitalization of energy procurement for larger customers, more and more service providers are positioning themselves as intermediaries and traders who first contract green electricity volumes directly from the plant operators (via merchant PPA) and then sell them on (Corporate PPA).

PPAs are enabling differentiation and business model innovation within the utility and power sector - and this is accelerated by reduced barriers to entry and increased competitiveness.

The illustration on the right-hand side also shows the anticipated pipeline for PPAs in Europe with Spain, Sweden, Italy and Germany leading the way.

Figure 3.17. Explanation of PPAs and pipeline of future PPAs



Source: Solarify

4-Financials

Who are the companies in our study sample?

A varied selection of 16 European utilities at a glance

Our sample includes the 16 major European utilities, established in 10 different countries.

This sample presents a good view of the European energy sector's evolution covering coal, gas, nuclear and renewables production.

This table should be read in conjunction with the analysis and comparisons that follow.

Figure 4.1. Dashboard of the main energy & Utility companies in Europe

GEOGRAPHIC MIX AS % OF TURNOVER: Europe, North America, Others, South America

	MARKET CAPITALIZATION (€BN) AS OF 3RD SEPT	NUMBER OF CUSTOMERS (MILLIONS)	RENEWABLE ENERGY SHARE AS % OF TURNOVER (0-20% / 21-50% / 51-100%)
Enel	77.8	73.3	21-50%
Iberdrola	68.6	34	21-50%
Ørsted	50.7	1.9	51-100%
Engie	29.6	24	0-20%
EDF	28.1	38.9	0-20%
E.ON	27.3	51	0-20%
RWE [1]	22.9	21.7	0-20%
EDP	17.7	11.4	0-20%
Fortum [2,3]	15.6	2.5	21-50%
Naturgy	16.4	18	0-20%
SSE	16.1	3.5	21-50%
EnBW [1]	13.4	5.5	0-20%
Uniper [4]	10.0	2	0-20%
CEZ	9.2	8	0-20%
Centrica	3.4	25	0-20%
Vattenfall [5]	-	14.8	0-20%

[1] *Number of customers in 2018*
[2] *Geographic mix including Russia*
[3] *Renewable energy share as % of capital expenditure*
[4] *Geographic mix including Turkey*
[5] *Non-listed company*
Sources: Annual reports, Bloomberg, various others

High wholesale prices counterbalanced flat consumption due to a mild winter and economic slowdown

Despite some negative macroeconomic trends, utilities performed well, increasing their revenue by 1.8% on average

- In 2019, utilities faced a significant drop in international commodity prices, especially oil, gas and coal. Macroeconomic and political instability, uncertainty about Brexit, increasing trade tensions between the United States and China as well as warmer weather conditions put pressure on retail prices.
- However, the global evolution for our sample shows an increase of 1.8% on average in revenue compared to 2018. Eight out of the 16 companies saw their revenue increase leveraging high wholesale prices (in 2019 44.32€/MWh), the highest since 2014 excluding 2018 which was extraordinarily high (54.60€/MWh), and stable consumption levels.

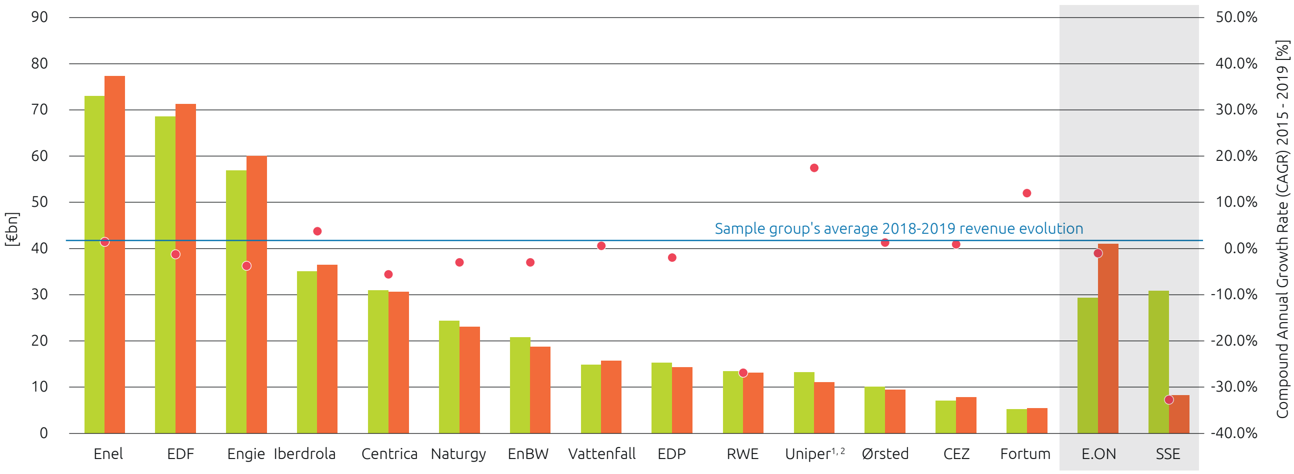
Portfolio reorganization (M&A) tended to be more frequent and seemed to have a positive impact on revenue

- E.ON and CEZ showed a strong performance with a gain of more than 10% in revenue in 2019 vs. 2018. Fortum showed a strong positive CAGR for 2015-2019 following a successful implementation of its strategy and a progressive acquisition of Uniper.
- E.ON saw an impressive increase of 39.5% in revenue, largely as a result of the takeover of the Innogy group. Higher power and gas sales in Germany and higher sales prices and sales volume in other European countries contributed to the outperforming result.
- It is interesting to note the renewed increase in revenue of the Italian and French utilities. Enel performed positively in Infrastructure and Networks, particularly in Latin America, and saw an increase in trading activities. EDF saw good results in France and in the UK, primarily thanks to positive electricity and capacity prices and an increase in gas sales, compensating for losses in market share. As for Engie, increasing sales of client solutions due to multiple acquisitions and increasing energy sales in North America and Europe resulted in a 5.4% increase in revenue.

German (apart from E.ON) and British utilities saw an erosion of revenue due to loss in sales and regulatory changes

- SSE lost 73.2% of revenue mainly due to a significant operating loss in the Energy Portfolio Management division – caused by persistently high gas prices – adding to uncertainty about the UK leaving the EU. In addition, in September 2019 and facing strong erosion of its customer base, SSE sold its retail activities, reducing the scope of its operations.
- Uniper and EnBW lost revenue due the decline in sales. In addition, Uniper sold its activities in France reducing its scope.

Figure 4.2. 2018 & 2019 revenue in € billion and CAGR 2015-2019



[1] Uniper figures correspond only to European revenue
[2] 2016-2019 CAGR
Disclaimer: E.ON and SSE have not been considered for average revenue evolution because of important scope changes.
Source: Thomson Reuters EIKON data ("Total revenue")

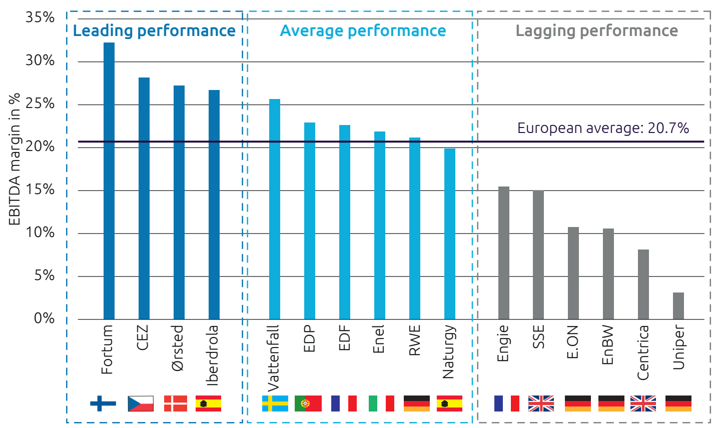
EBITDA margins bounced back after a 3-year downward trend, but still reflect performance discrepancies among European utilities

- EBITDA margins increased across the sample group thanks to better management of operational expenses, higher achieved electricity prices and a very good performance from renewable energy sources.
- After a period of decline for EBITDA margins – from 22.7% in 2015 to 18.9% in 2018 – European utilities showed a better performance in 2019 with an average EBITDA margin increasing to 20.7%. This was achieved thanks to higher realized prices and continuing efforts to increase operational excellence.
- However, Europe is still lagging behind the US whose average peaked at 37.0% thanks to favorable market conditions (lower operational-related taxes, lower cost of work, etc.).

EBITDA margin evolution					
	2015	2016	2017	2018	2019
Utilities average in Europe	22.7%	20.7%	19.0%	18.9%	20.7%
Trend in Europe	↑	↓	↓	→	↑
Utilities average US	34.4%	34.8%	36.0%	35.6%	37.0%

- It should be noted in the previous table that:
  - The methodology used is the EBITDA-weighted average and not the arithmetic mean.
  - The amendments made by Reuters for the figures prior to 2019 were taken into consideration. It does not change the order of magnitude of the US averages nor the 2019 European upward trend.
  - Discrepancies are observed among European utilities' performance, and the studied sample of companies can be split into 3 different groups based on their EBITDA margins.

Figure 4.3. 2019 EBITDA margin

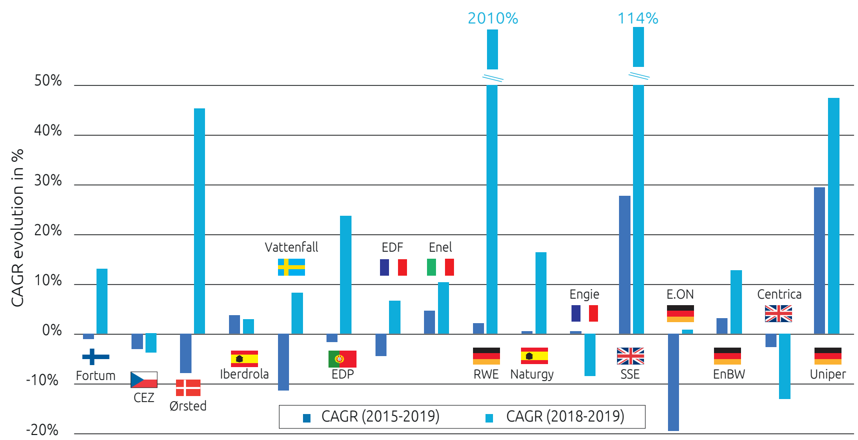


Source: Thomson Reuters EIKON data ("Normalized EBITDA")

Leading utilities with highest EBITDA margins

- These companies increased their EBITDA margins thanks to a good overall operational performance, low carbon intensity and higher achieved prices.
- Some of those companies are well ahead of their competitors:
  - Fortum clearly improved its result in the generation segment thanks to higher hydro and nuclear volumes and higher achieved prices. In addition, its share of profit from associated companies increased mostly thanks to Uniper's higher result from the reinstatement of the UK capacity market in Q4 2019 ;
  - Ørsted successfully implemented its performance plan driven by increased generation from its offshore and onshore wind segment.

Figure 4.4. 2Y and 5Y CAGR evolution for EBITDA margin



Source: Thomson Reuters EIKON data ("Normalized EBITDA")

Utilities with EBITDA margins around the sector average

- These companies achieved lower EBITDA margins than the leading group but still improved their performance compared with 2018 thanks to pursuing efforts to achieve efficiency gains and control expenses
- In this context, RWE improved its EBITDA margin remarkably from 1% in 2018 to 21.1% in 2019. This was due to the successful acquisition of E.ON's renewables business and the reinstatement of the UK capacity market (creating a new market for E.ON)
- It is notable that EDP continued to successfully implement its strategic plan to be a leader in renewables in 2030. Its EBITDA margin increased from 18.5% in 2018 to 22.9% in 2019, thanks to higher volumes and realized prices in solar and wind and the benefits from its growth and asset rotation strategy. The recent joint venture created with Engie and the underlying assets sale may affect EDP's margin after assets consolidation

Utilities lagging behind the sector average

- These companies achieved the lowest EBITDA margins in 2019. This can be explained by various reasons including:
  - adverse weather conditions
  - lower production volumes
  - challenging market conditions and regulations (for instance, lower achieved gas prices and adverse UK residential supply tariff cap)
- Key priorities for those companies are to:
  - optimize their assets portfolios
  - implement resilient strategies to face challenging market conditions
- It is however notable that progress is on track for some German utilities, while British ones are facing challenging situations:
  - E.ON successfully acquired Innogy's Network and Sales businesses, enabling it to close 2019 with satisfactory results – a slight increase in the EBITDA margin from 10.6% in 2018 to 10.7% in 2019. The company focuses on network activities, characterized by a predictable profitability
  - SSE more than doubled its EBITDA margin from 7% in 2018 to 15% in 2019, mainly due to the reinstatement of the UK capacity market, favorable weather conditions and an increase in wind power capacity (largely from the Beatrice offshore wind farm). However, SSE announced in September 2019 the sale of its Energy Services business to OVO Energy Limited and the very probable upcoming sale of its gas generation portfolio
  - Centrica revealed a considerable 13% drop in its EBITDA margin year-on-year. This was mostly due to lower achieved gas prices, the government's imposition of a price cap on consumer tariffs and the resulting unbridled competition among the major players in the UK

Net debt increased as companies leveraged the favorable financial conjuncture, and M&A synergies occurred

Utilities made the most of favorable financial leverage

Net debt increased globally for European utilities, and so did the EBITDA:

- Average net debt increased by ~25% on the 2018 – 2019 period
- Average EBITDA increased by ~14% on the 2018 – 2019 period

These figures have resulted in a stronger average leverage ratio, going from 3x (2018) to 3.7x (2019). However, we can still distinguish a few different dynamics within this global one.

Greater competition requires improvement in balance sheet use and financial structure management

- Today's economic conjuncture makes it attractive for companies to leverage as much as they can, since interest on debts is pretty low (EURIBOR 3M ranging from -0.31% to -0.447% in 2019). The systematic increase in debt level can thus be explained by the fact that, in an ever more challenging environment, companies need to enhance the return for shareholders (decreasing their WACC by increasing the part of debt within investments) as well as reaching a critical size via M&As, etc. In the future, we could see a reduction in the number of utilities as well as an increased market share for the remaining ones.

Specific cases:

- **SSE** is facing a number of challenges that are strongly impacting on their financial results. On one hand, the company is struggling with erosion of its customer base, leading to a decrease in energy selling (because the competition is always stronger). On the other hand, the merger with Npower (which took place between Q4 2018 and 2019) will lead to an increase in SSE's debt in the coming years. Finally, the company is suffering from UK energy regulations. In the coming years, cash surpluses should come from the sale of SSE retail activities to Ovo (Sept. 2019)
- **Ørsted** experienced a sharp increase in its net debt in 2019. Two factors explain this: firstly, the company has been under-utilizing its balance sheet for years (in terms of debt mobilization) - making any variation significant. Secondly, two acquisitions in the renewables sector were made in 2019 (Taiwan & USA). Ørsted plans to maximize the renewables part in its generation mix, ensuring the future and reducing maintenance related costs.

Post M&A synergies are taking place

- **E.ON** net debt significantly increased in 2019 relative to 2018 following the integration of Innogy's operations (and related debt) within its balance sheet. This increase in debt is thus strongly linked to post-acquisition and doesn't represent an operation risk for E.ON at the time. Of course, the E.ON EBITDA increased regarding 2018 for the same reasons.
- **RWE**'s net debt increased greatly – despite selling Innogy to E.ON – especially because of its strong vulnerability to the increasing provisions for nuclear and coal decommissioning in Germany. A claim is currently in progress, asking for the German government to financially support it.
- The remaining companies in our sample showed a leverage ratio similar to the previous year, meaning that their debt level evolved in correlation with their EBITDA.

Figure 4.5. Net debt and EBITDA in € million and leverage ratios for 2018 and 2019

	2019 Net Debt [€m] (2018-2019 evolution)		2019 EBITDA [€m] (2018-2019 evolution)		Leverage ratio 2019	Leverage ratio 2018
Uniper	986	(47.8%)	2,031	(3.7%)	0.5x	0.3x
Ørsted	3,102	(611.5%)	2,564	(35.4%)	1.2x	0.2x
RWE	3,481	(1112.9%)	2,788	(1935.0%)	1.2x	2.1x
Vattenfall	7,562	(20.5%)	4,035	(14.9%)	1.9x	1.8x
Centrica	5,384	(11.9%)	2,490	(-13.1%)	2.2x	1.7x
EDF	46,861	(26.4%)	16,134	(11.2%)	2.9x	2.6x
CEZ	6,502	(7.0%)	2,209	(6.8%)	2.9x	2.9x
Fortum	5,507	(-4.1%)	1,758	(17.5%)	3.1x	3.8x
Engie	30,516	(17.6%)	9,297	(-3.3%)	3.3x	2.7x
Enel	64,727	(7.3%)	16,978	(17.6%)	3.8x	4.2x
Naturgy	18,272	(0.4%)	4,587	(10.5%)	4.0x	4.4x
Iberdrola	47,235	(13.8%)	9,730	(7.3%)	4.9x	4.6x
EnBW	10,016	(59.5%)	1,976	(2.4%)	5.1x	3.3x
EDP	20,147	(4.6%)	3,284	(16.4%)	6.1x	6.8x
E.ON	32,865	(313.5%)	4,393	(40.9%)	7.5x	2.5x
SSE	10,381	(8.9%)	1,241	(-42.8%)	8.4x	4.4x
Average					3.7x	3.0x

Sources: Thomson Reuters EIKON data ("Normalized EBITDA" & "Net Debt Incl. Pref. Stock & Min.Interest STND")

Dividends per share (DPS) followed EBITDA margin levels

Centrica plans to reduce costs by $1.25 bn each year to 2020 to make its long-term financial situation viable. This includes a reduction of 4,000 jobs – 10% of its workforce. And it plans to delay the sale of its controlling stake in Spirit Energy due to the instability of the financial and energy sectors. In this context, its DPS continued to drop.

SSE's EBITDA margin increased by 15% in 2019 mainly due to a significant rise in electricity output as a result of more favorable weather conditions, increasing cash availability and paying a higher DPS compared to 2018 (from €1.07 to €1.11).

EDF and Engie increased their DPS in 2019

EDF's 2019 revenue increased by 4% compared to 2018, due to overall growth in fuel and energy sales: in this context the DPS increased by 48%compared to 2018. **Engie** increased its DPS from 0.75 to 0.80 in 2019, due to the increase in nuclear availability and the performance of energy management activities. The year 2019 was marked by a series of achievements that contributed to the Group's growth dynamic, in particular the commissioning of 3.0 GW of new renewable energy production capacities (4 times higher than 2018).

German companies further increased their DPS, confirming their recovery

The four German companies showed increases between 7% (E.ON) and 28% (Uniper). **RWE** had a good EBITDA performance (21.1% EBITDA margin in 2019), thanks to the transaction with E.ON renewables, the recovery of the UK capacity market and excellent trading performance. For **Uniper**, the dividend volume has thus more than doubled within three years. This reflects the strong recovery in the operating business as well as the success of a strategy with ongoing portfolio optimization and the success of implemented cost-cutting programs.

Ørsted: The Danish energy company has taken a radical turn to become the world leader in offshore wind power

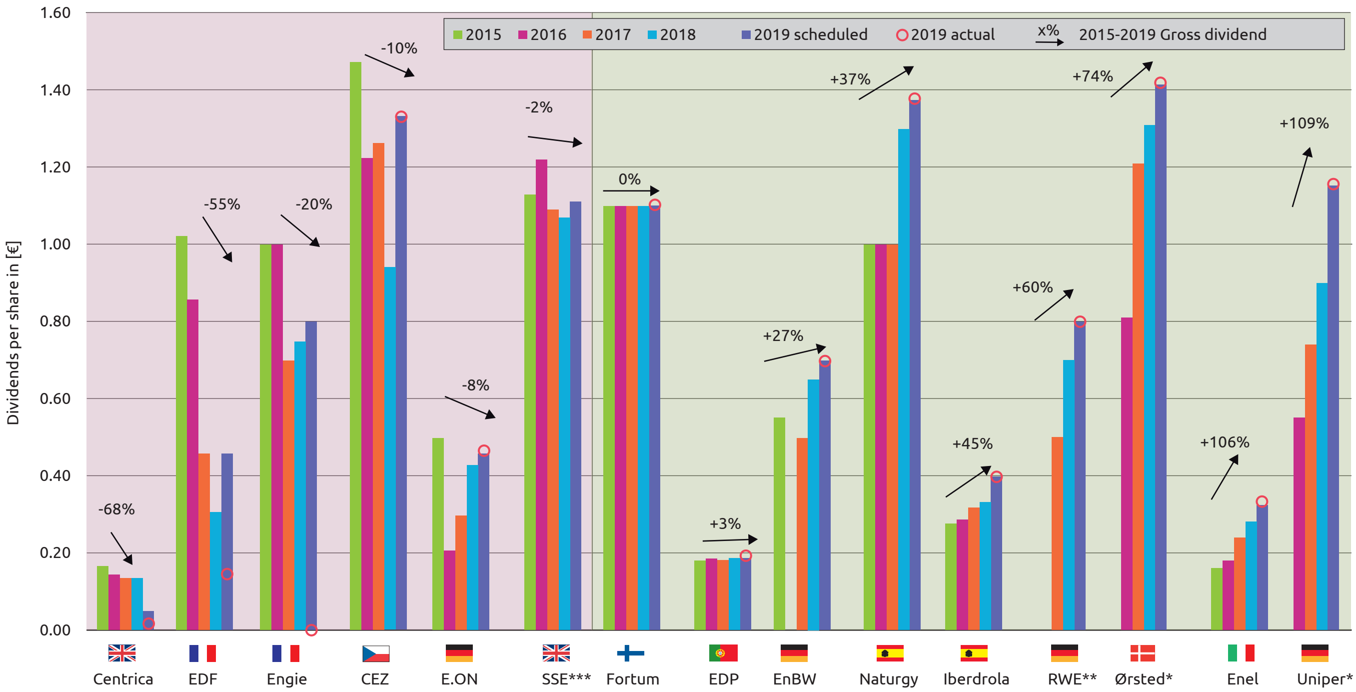
In 2019, EBITDA increased significantly. It was driven by an increase in generation from offshore and onshore wind farms (representing 33% of the increase) and high earnings from trading activities. The green share of heat and power generation increased to a new high of 86%. That allows a significant increase in DPS of 74% from 2016 to 2019

Spanish companies' DPS also continued to rise

Iberdrola revenue increased by 3.9% in 2019 (from €35 bn to €36.4 bn), thanks to the good operational performance of all its businesses, especially the performance of the networks business, which allowed the company to increase its DPS by 21% in 2019 compared to 2018

Naturgy had a consolidated EBITDA in the period amounting to €4,562 million, a 13.5% increase compared to 2018, supported by a positive performance in the infrastructure businesses, the new commercial strategy in supply activity, and efficiency gains

Figure 4.6. Dividends per share in € and 2015-2019 evolution



** 2016-2019 evolution*
*** 2017-2019 evolution*
**** SSE 2019 actual dividend still to be confirmed*
Source: Thomson Reuters EIKON data ("Dividend per Share DPS"), Companies' websites

Stock performance

The trend of the previous year continued until the end of 2019 accentuated by the COVID-19 crisis which led to a collapse in March 2020

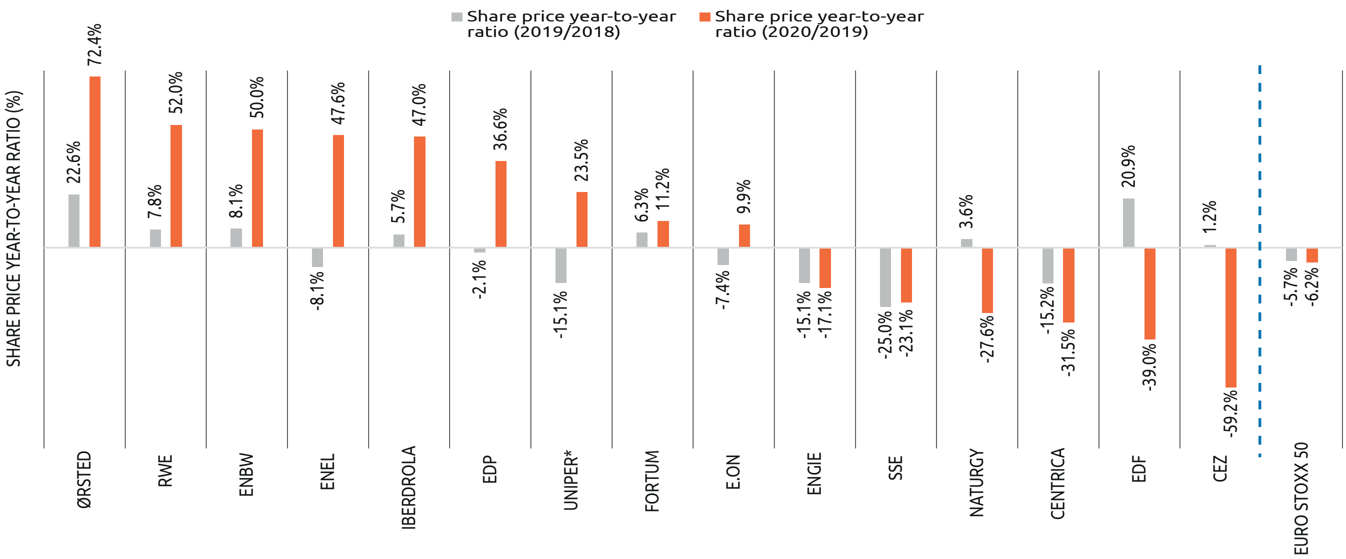
Stock performance in 2019 may represent validation of company strategies, the financial or political background, or simply be an indication of investors' trust in the energy market. With a few exceptions, the previous year's trend became more pronounced for most companies.

After the COVID-19 crash that affected all companies in March 2020, most share prices went up again, but only the stocks of companies promoting renewable energies have been able to recover or exceed their January levels. Indeed, stakeholders were pushing for decarbonized production.

To go further

- For all German utilities share prices rose on the stock market in 2020, thanks to the priority of renewables on the grid for ENBW. For RWE, Uniper and E.ON the desire for rapid economic recovery after the crash avoided an unwanted drop in stock performance
- In the UK, SSE and Centrica's share prices continued to fall by 23% and 31.5% respectively. Centrica was particularly affected by the coronavirus crisis and failed to regain its January level
- In France, after a very good year in 2019 thanks to the increase in the CO_2 price affecting all its competitors, EDF's share price plummeted in 2020 especially following the COVID-19 crisis. EDF has been particularly affected by:
  - Reduced electricity consumption combined with renewable energy sources having grid priority.
  - The probable obligation to buy back electricity that was originally sold at the price set by the ARENH mechanism but at today's higher market price.
  - The anticipated drop in nuclear production due to the delay in maintenance caused by the COVID-19 crisis.
- Engie's share price continued to drop, particularly because Engie is bogged down with governance problems.
- In Spain, Iberdrola's share price is the only one to have risen continuously between 2015-2020 (+116% over the last five years) confirming that companies providing electricity from renewable sources are doing very well. In contrast, Naturgy suffered (-21%) from the reduction in remuneration in the distribution of electricity in Spain
- The continuous outstanding performance (up 72.4% in 2020 after a rise of 22% in 2019) of Ørsted must be highlighted. Ørsted is the perfect example of responsible investment (switching to a 100% renewables production mix) in the utilities: they are becoming one of the global leaders in offshore wind energy. This performance is likely to continue: Ørsted has just signed the largest renewable electricity contract in the world
- Finally, Enel rebounded significantly after positive analyses by Swiss banks that estimated Enel could be a key player in the energy transition process

Figure 4.7. Utilities' stock performance



Note: Vattenfall is not included anymore as it is now a non-listed company
Source: Thomson Reuters EIKON data, Bloomberg

Utilities' credit rating remained stable on average

Overview

In 2020, ratings remained broadly stable. No company received a better credit rating and two companies were downrated from A- to BBB+.

European utilities are more resilient to the effects of COVID-19 than most other sectors given the essential service they provide, the regulated or long-term contracted nature of a portion of their activities, and their relatively better access to capital markets. Operationally, most utilities have developed and unveiled contingency plans to manage such a disruption and protect critical infrastructure.

EDF and Engie were downrated

EDF sharply revised its French nuclear output for 2020-2022 because of more COVID-19-related outages and a shift in maintenance work schedules over the next two years. The group's adjusted debt exceeded €48 billion by year-end 2019 compared with €37 billion at year-end 2018. EDF is much more exposed to volatile power prices than its main rivals, like Enel or Iberdrola, given its significant generation capacity comprising sizable nuclear and hydro assets.

Engie saw its credit score downrated from A- to BBB+ given a sharper looming European recession amid the COVID-19 pandemic. Engie's earnings (€10.4 billion EBITDA as of fiscal year 2019) will likely decline due to weaker operating conditions in its Client Solutions and Merchant Power businesses. S&P Global Ratings believes the dividend suspension in 2020 and some likely cuts in investments will not be enough to offset the resulting deterioration of credit metrics.

Figure 4.8. Standard & Poor's credit ratings

Company	31/12/2015	31/12/2016	27/07/2017	27/07/2018	27/07/2019	21/07/2020
EnBW	A-	A-	A-	A-	A-	A-
CEZ	A-	A-	A-	A-	A-	A-
EDF	A+	A-	A-	A-	A-	BBB+
Engie	A	A-	A-	A-	A-	BBB+
SSE	A-	A-	A-	A-	BBB+	BBB+
Vattenfall	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+
Ørsted	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+
Iberdrola	BBB	BBB+	BBB+	BBB+	BBB+	BBB+
Enel	BBB	BBB+	BBB	BBB+	BBB+	BBB+
Centrica	BBB+	BBB+	BBB+	BBB+	BBB	BBB
Fortum	BBB+	BBB+	BBB+	BBB	BBB	BBB
E.ON	BBB+	BBB+	BBB	BBB	BBB	BBB
Naturgy	BBB	BBB	BBB	BBB	BBB	BBB
Uniper	N/A	BBB-	BBB-	BBB	BBB	BBB
EDP	BB+	BB+	BB+	BBB-	BBB-	BBB-
RWE[1]	BBB	BBB-	BBB-			

1 Following RWE's decision to end ratings by S&P in 2018, this is the last time the company appears in this table
Source: Companies' websites

With energy transition as a priority and coal being phased out, Utilities reported a compelling carbon intensity decrease – about -10% CAGR

Europe keeps on strengthening its carbon pricing regulations to foster emission cuts

- The Market Stability Reserve entered into force in January 2019 and intended to decrease the oversupply of emission quotas in the EU ETS and to support the carbon price upwards
- The EU ETS carbon price hit record levels in 2019, ranging from 18 €/tCO_2 to 29 €/tCO_2. In the context of historically low gas prices, it was high enough to trigger substitution of coal by gas. Carbon price regulations, combined with public opinion and pressure from shareholders, has been pushing utilities to decrease their CO_2 emissions

Utilities with high carbon intensities kept up efforts to cut emissions

- Despite actions taken to emit less CO_2, German utilities kept showing the highest carbon intensities in Europe in 2019
- **RWE** had the highest carbon intensity with 599 gCO_2/kWh, yet with a significant 12% decrease in 2019 thanks to the substantial reduction of lignite and hard coal use in power plants. Its target is carbon neutrality in 2040 by growing its renewables and clean fuels while phasing out coal
- **Naturgy** achieved 301 gCO_2/kWh in 2019 – a 12% drop compared with 2018, mostly thanks to the use of gas as a substitute for coal. In 2019, the company strongly developed its wind and solar energy facilities in Spain and announced the phase-out of all its coal-fired plants

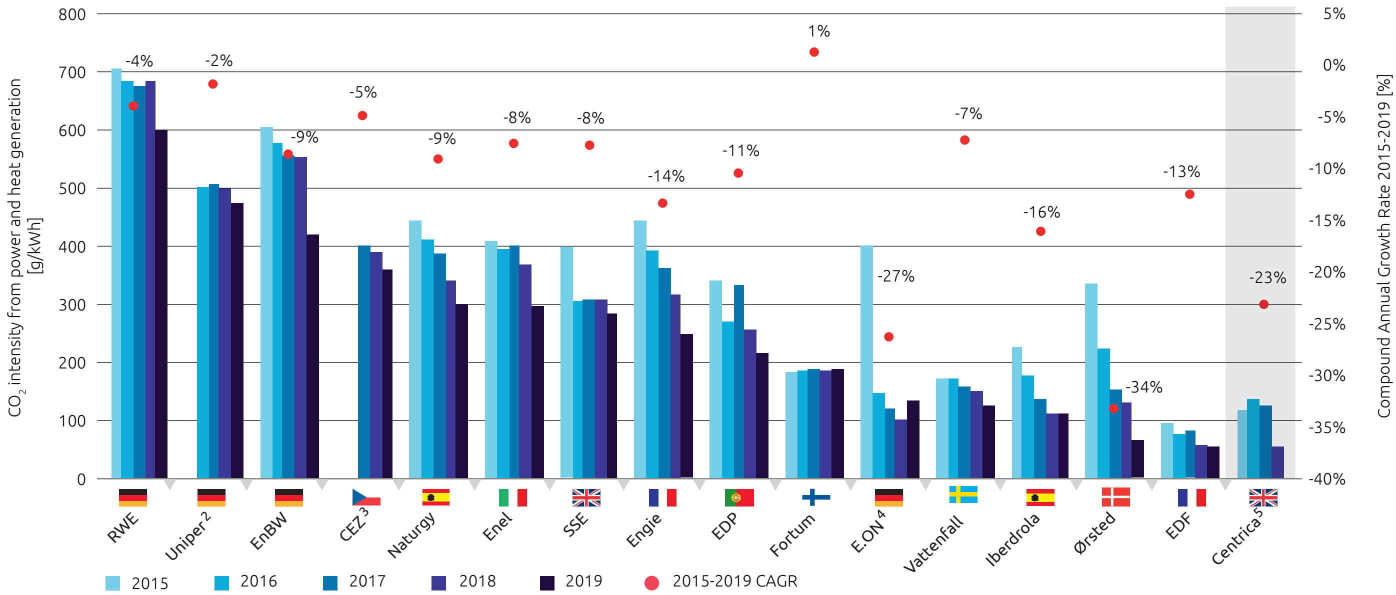
Utilities with a notable shift toward low carbon intensity

- Some utilities reported remarkable drops in their carbon intensities, thanks to their pursued growth in renewables (wind and solar mostly) and their coal phase-out:
- **Ørsted** achieved a 50% cut in 2019, mostly thanks to the bioconversion of the coal-fired Asnæs power plant into biomass and its pursued efforts to become a world leader in wind with the commissioning of the Hornsea 1 offshore and the Lockett onshore wind farms
- **EnBW**, the third biggest emitter in terms of carbon intensity (419 gCO_2/kWh), lowered emissions by 24% in 2019. It was mainly due to the drop in the use of coal and the increase in offshore wind power generation, with the notable commissioning of the Hohe See and Albatros offshore wind farms (609 MW)
- **Engie** decreased emissions by 21% in 2019, by phasing out coal and natural gas activities. This is in line with its ambitious objective of cutting carbon intensity by 52% compared to 2017
- **Enel** cut emissions by 20% in 2019 by pursuing its renewables growth and its fast coal exit. It announced in September 2019 the 2030 target of a 70% cut in carbon intensity compared to 2017

Utilities with historically low and stable carbon intensities

- **EDF** achieved 55 gCO_2/kWh in 2019, mainly thanks to its low-carbon nuclear production and the closing of coal-fired plants partially replaced by gas. The company targets 50 GW of renewables and a 40% direct emissions cut by 2030 compared with 2017
- **Iberdrola** emitted 110 gCO_2/kWh in 2019, mainly thanks to the reduction of emissions from thermal power plants. This is in line with its objective to reduce emissions intensity by 50% in 2030 compared to 2007, with virtually zero emissions in Europe

Figure 4.9. CO_2 intensity from heat and power generation[1]



1 The chart displays CO2 intensity resulting from scope 1 emissions (meaning from in-house sources: gas transmission, power and heat generation and excluding other greenhouse gases)
2 CAGR 2016-2019 for Uniper for which only 4 years of data have been considered
3 CAGR 2017-2019 for CEZ for which only 3 years of data have been published in annual reports
4 E.ON's scope 1 emissions relate to its network activities (excluding Innogy's Network and Sales businesses) and the related distributed power and heat generation
5 No Scope 1 emission value has been considered for 2019 since Centrica's core business no longer includes power production
Source: Thomson Reuters EIKON data ("Total revenue")

Utilities demonstrated their resilience in facing an external crisis (COVID-19) leveraging a more renewables-oriented asset portfolio and better management of operations

The COVID-19 outbreak had a mitigated impact on H1 2020 financial results for most European utility companies:

- COVID-19 had a slight impact on revenues (-4.2% on average), due to the demand decrease (-8.5% on average). However, there was no apparent drop in revenue generation since most utilities were hedging their energy sales leveraging financial tools like Forwards or Futures, for example.
- Average EBITDA increased during the period under review (+12%) mainly thanks to OPEX reduction programs aiming at protecting companies' cash flow.
- German players kept rebounding, showcasing revenue, EBITDA and stock price increases during the period. Most other companies' stocks are still suffering from the COVID-19 crisis.

European utilities showed signs of revenue slowdown during the COVID-19 outbreak

- On average, revenues have decreased by roughly 4.2% for H1 2020 compared to H1 2019. Revenues have suffered from COVID-19 - related lockdowns and from economic stress around the world having a huge impact on energy (gas and electricity) demand and price. As an example, from March to May 2020, European electricity demand was 8.5% below the same period in 2019 thus resulting in a significant decrease in energy sales' volumes already affected by a warm winter.
- In addition, the COVID-19 crisis had strong impacts on foreign exchange markets and marketable securities, penalizing companies' results even more. The pandemic risk was neither anticipated nor priced within the financial market: investors massively sold their marketable securities to recover liquidity and then face the impending crisis.
- Finally, with the COVID-19 pandemic having a downwards effect on the general economy, most companies saw a significant increase in bad debt, further decreasing revenue.

Cutting operational costs avoided COVID-19 impacting on EBITDA

- Reacting to falling revenues, companies cut operational costs in order to preserve their EBITDA.
- In order to reduce operational costs companies have been using government job retention programs, freezing bonuses and cutting jobs.
- In addition, utilities such as Naturgy and Centrica have been accelerating existing cost cutting plans, or identifying new cost-cutting possibilities such as EDF planning a reduction of €500 million in OPEX over 2019-2022.

Renewables protected revenue and EBITDA

- During H1 2020, power produced by coal, nuclear and gas plants diminished as well as related revenues (i.e. lower demand and lower volumes). However, RWE secured its nuclear and coal related revenues leveraging financial tools (futures, forwards, etc).
- In addition, highly favorable weather conditions enabled remarkably high electricity production from renewable sources during H1 2020. Leveraging a guaranteed energy sale price, renewables contained the fall, ensuring regular revenues.
- Using the same principle, companies developing Corporate Power Purchase Agreements had even less negative impact on their results.
- Finally, increased utilization of companies' renewables plants enabled OPEX reductions, especially regarding maintenance and cost of operations.

Figure 4.10. COVID-19 impacts on utilities' H1 2020 financial results

	Companies	H1 2019-H1 2020 revenue evolution	H1 2019-H1 2020 EBITDA evolution	Expected DPS (€)	Realized DPS (€)	Dividend trends	Share prices (€) 3/01/20	3/15/20	4/15/20	5/15/20	6/15/20	Average variation per group	Curve type	Comments
Leading performance	RWE	0.5%	59.9%	0.8	0.8	→	29.76	20.38	22.87	26.09	27.90	5%	U	The members of the leading group: - performed well despite the COVID-19 crisis, mitigating its impact on both revenues and EBITDA. - Maintained the expected dividends for the shareholders. - Saw their share price return to pre-COVID-19 levels or even increase.
	E.ON	90.5%	34.9%	0.46	0.46	→	10.07	8.09	8.25	8.57	9.67		U	
	EnBW	-2.9%	24.3%	0.7	0.7	→	42.37	35.08	48.29	47.46	50.14		V	
	CEZ	6.2%	11.2%	1.28	1.28	→	17.40	13.15	16.96	17.40	17.54		V	
	Uniper[1]	-40.8%	54.0%	1.15	1.15	→	26.82	21.02	21.91	23.59	27.52		U	
Average performance	Ørsted	-19.8%	11.5%	1.41	1.41	→	93.87	77.72	91.29	94.68	101.10	-8%	I	The members of the average group: - Saw a slight decrease in revenues and EBITDA - Mostly maintained their expected dividend (except EDF) - Mostly saw their share price slightly decrease or remain flat during the COVID-19 crisis, except for Ørsted which leveraged its renewable assets.
	Fortum[2]	-18.1%	14.9%	1.1	1.1	→	16.52	11.27	13.77	14.92	16.65		U	
	EDP	2.2%	-2.6%	0.2	0.2	→	4.12	3.24	3.52	3.89	4.07		V	
	EDF	-4.9%	-2.0%	0.46	0.15	↓	12.25	7.82	7.28	7.20	8.17		L	
	Iberdrola	-9.9%	-1.4%	0.4	0.4	→	10.50	8.06	8.71	8.32	9.50		U	
	Enel	-18.5%	-2.9%	0.33	0.33	→	7.49	5.38	6.08	5.65	7.22		U	
Lagging performance	Centrica	-7.5%	-19.2%	0.06	0.02	↓	73.48	42.44	31.59	39.84	46.88	-31%	L	The members of the lagging group: - saw revenues and EBITDA strongly negatively affected by the COVID-19 crisis, due to higher exposure to the drop in thermal plant production - Mostly maintained their dividend except Centrica and Engie which reduced or cancelled them - Had their share prices more exposed.
	Engie	-9.3%	-15.1%	0.8	0	↓	13.84	9.13	8.54	8.58	10.81		L	
	Naturgy	-24.2%	-14.1%	1.37	1.37	→	20.20	14.71	15.11	15.59	16.19		L	
	SSE	H1 2020 results unavailable		0.89	0.89	→	16.99	13.12	13.30	13.26	13.76		L	

1 The evolution of Uniper's year-on-year results is partly due to a change of scope and a decrease in OPEX
2 Fortum's H1 2020 revenues have been prorated in order to compare them with the equivalent scope as the previous year
Disclaimer: Vattenfall being a non-listed company, it has not been included in this table.
Source: Companies' reports, Bloomberg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WEMO 2020 China Editorial

Philippe Vié

In 2020, during the isolation period related to the COVID-19 pandemic, total electricity demand in China fell by 7.8 percent during January and February, as compared to the same period in 2019. All high-consuming sectors, except residential and telecom and web services, experienced a decrease. But, as the world emerges from the COVID-19 crisis, we recognize this dip as temporary. In fact, there is evidence that pandemic has spurred a revival in the use of fossil fuels in order to boost the national economy.

2020: Shifting back to coal, despite new interest in renewables

As part of the country's economic recovery efforts, the Chinese government has aimed to create employment opportunities through an increase in coal power plant construction. However, due to low operational costs, renewables maintain an edge in China's power market. As a result, renewables generation increased year over year, with solar and wind growing by 12 percent and 1 percent, respectively. Meanwhile, thermal sources decreased by almost 9 percent compared to the previous year.

Meeting rapidly increasing demand through new generation sources

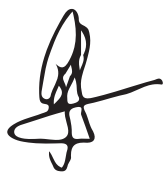
China is on a path to becoming a nuclear power giant. About 45 nuclear power reactors are in operation, representing some 48 GW of capacity and around 5 percent of the country's electricity generation. An additional twelve reactors are under construction. According to the country's 13th Five-Year Plan, a national framework for government policies from 2016-2020 focused on boosting economic development, six to eight nuclear reactors were to be approved each year. Under this plan, China's nuclear installed capacity is expected to catch up with that of the U.S. and France within the next decade.

China is the world's largest Hydrogen producer—but challenges for embracing green Hydrogen remain

Hydrogen does not mean greener energy in China. In China, most Hydrogen is produced from fossil sources such as coal gasification (40%), industry by-product (32%), petroleum (12%) and steam methane reforming of natural gas (12%). Only 4% of the production comes from water-electrolysis.

However, China is attempting to drive down the cost of electrolysis, which could make green Hydrogen more cost competitive. In June 2019, China released a white paper stating that the country is targeting 70% Hydrogen production from renewables by 2050. The growing use of biomass as feedstock to produce Hydrogen is another method being explored, however technical and economic challenges remain.

China maintains a dominant position in the energy equipment supply market. Eighty-eight of the 115 battery megafactories are located in China, as are seven out of ten of the largest equipment managers. The country also leads in terms of Hydrogen and third-generation nuclear reactors (along with France), as well as mining of rare earth materials with a refining market share of 60-100 percent on major metals. However, even with the largest global share in renewables investments (38% for wind and 18% for solar in 2019), China has yet to commit to a mid-2020 carbon neutrality roadmap. Instead, the government announced in September 2020 that the country will be carbon neutral by 2060, with an emission peak in 2030.



Philippe Vié

Energy Utilities and Chemicals sector head

WEMO 2020 India Editorial

Philippe Vié

While not entirely comparable, India shows some similarities with China as it relates to fossil fuels. India's energy-related CO_2 emissions continued to rise to 2,480 million tons[1] of CO_2 ($MtCO_2$) in 2019. However, the government has adopted several initiatives to address this issue. For example, in 2019, the Ministry of Environment, Forest and Climate Change (MoEFCC) announced the National Clean Air Program (NCAP), which aims to reduce particulate matter (PM2.5 and PM10) by 20–30 percent by 2024.

Coal continues to dominate the Indian energy system in 2019, despite a steady increase in the share of renewables

Coal is expected to represent 57 percent of total electricity generation in India by 2040 — a substantial drop as compared to the 73 percent share in 2019. Grid connected renewable electricity capacity reached 84 GW in 2019, as driven by onshore wind (~38 GW), solar (~35 GW), and the remainder coming from small hydro and bio-power. If large hydro is also considered, the figure reaches almost 130 GW—more than twice the 2010 renewable capacity.

Similar to many other parts of a world, lower energy consumption during the lockdown period related to COVID-19 as well as a decreased share of coal in the electricity mix led to the first decrease in CO_2 emissions in four decades in India. Though temporary, India experienced a 15 percent decrease in March and a 30 percent decrease in April 2020.

Enhancing oil security becomes a priority

Demand for oil in India continued to grow as falling domestic production and limited oil reserves highlighted the country's strong dependence on imports. In 2018-19, imports accounted for 83.8% of the oil supply in India; that figure rose to 85% in 2020 and is expected to increase further in the future.

COVID-19 impact on energy transition plans

In 2020, energy demand is expected to see a 4 percent decrease compared to 2019. Retail tariffs, which are structured on a variable cost basis, have since fallen as power demand plummeted during the lockdown. In the private sector, companies face huge working capital issues with annual losses expected to reach US$15 billion.

Considering these circumstances and the general uncertainty of the market, it remains to be seen how new energy investments, including that in renewables, are affected by companies' liquidity issues in the changed scenario. We are hopeful that with strong government support, the impact may be minimized.

Philippe Vié

Energy Utilities and Chemicals sector head

1 BP Stats

WEMO 2020 Southeast Asia Editorial

Gaurav Modi

Climate change is one of the greatest threats to long-term stability in Southeast Asia

With the constant increase in global temperatures, sea levels are expected to rise by 50-70 centimeters by the end of the century. This development could threaten the lives and livelihoods of the 77 percent of Southeast Asians who live along the coast or in low lying river deltas. According to the latest Global Climate Risk Index, the Philippines and Vietnam rank fourth and sixth respectively in terms of susceptibility to the effects of climatic change.

While SEA is not the main global carbon dioxide (CO_2) producer, its emissions will become significant if action is not taken. The electricity and transportation sectors contribute to the maximum share of CO_2 in Southeast Asia.

Countries are adopting measures to reduce carbon emissions on the regional level. Expanding the use of clean and renewable energy, climate-resilient development and strengthening policies are among the major mitigation plans taken to combat climate change and reduce CO_2 levels.

Southeast Asian countries are still dependent on coal to meet energy demand

Taiwan and Vietnam leading the way in active coal projects, according to the 2020 Global Energy Monitor report.

Fortunately, the region show signs of positive change with respect to coal. Between 2016 and 2019, the pipeline for commissioning new coal plants has decelerated and the construction of new plants has fallen over 85 percent. Limiting the use of coal is one of the strategies identified in the Paris agreement to keep global warming below the criticial 2°C threshold.

To encourage clean energy investments and ensure security, many governments are adopting new policies

Southeast Asia is becoming one of the fastest-growing solar energy markets in the world and one of the most promising regions for expansion of the solar energy industry.

For example, Malaysia is developing a new roadmap for energy transition—the Renewable Energy Transition Roadmap (RETR) 2035, which aims to boost the country's renewables share to 20 per cent by 2025. In 2019, Vietnam installed an impressive amount of solar capacity and was recognized on a global level for its Feed-in Tariff (FiT) incentive offered by the government.

1 https://www.germanwatch.org/sites/germanwatch.org/files/20-2-01e%20Global%20Climate%20Risk%20Index%202020_14.pdf

Demand for electricity in the region is growing at an average rate of 6 percent annually. However, there is not enough financial support to invest in energy transmission and generation infrastructure to accommodate this growth rate

Government will need to play a more active role in helping energy players access more financing in order to improve overall supply. Mobilizing investment requires broad participation from the private sector, as well as the targeted use of public funds.

In 2019, Electricity bills in Singapore and the Philippines were amongst the highest in Southeast Asia due to heavy reliance on energy imports

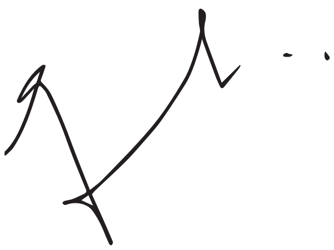
Improving energy efficiency is an essential component of Southeast Asia's energy transition strategy. Effective efficiency measures can decrease CO_2 emissions by as much as 30 percent, according to the Sustainable Development Scenario. Improved energy efficiency also eases energy security concerns by curbing import growth, while keeping consumer bills in check.

COVID-19 poses great challenges for the economic integration of East and Southeast Asia

In addition to the pandemic's economic devastation, electricity demand is undergoing several key changes. Consumption has dropped and largely shifted to the residential sector, creating an overall change in the shape of daily load profiles. These changes have consequences for all entities along the electricity value chain.

However, according to the pre-pandemic projections of the International Energy Agency, cooling is expected to account for 30 percent of the peak electricity demand for 2040. This will require around 200 GW of additional generation capacity in the region.

To meet the increased energy demand in SEA-creditworthiness, the region's policy and regulatory environment, project bankability, and overall economic health will all factor into securing the necessary public and private financial flows that will allow the power sector to advance.



Gaurav Modi

Chief Executive Officer
Capgemini Southeast Asia, Hong Kong & Taïwan

2 https://www.iea.org/reports/southeast-asia-energy-outlook-2019

China

Country description

- Country: **China**
- Population: **1.40 bn**
- GDP: **$14.3 trillion**

CO_2 footprint
- Total 2019 CO_2 emissions: **9,825 Mt**
- 2020 CO_2/capita emissions: **6.59 tons**

Energy demand
- In 2020, the industrial energy demand may decline by 73 billion kWh
- Energy demand expected to be 3.91 Btoe by 2035

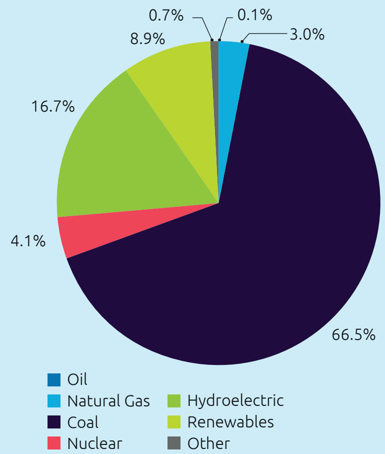
Renewable energy
- Investments in clean energy: **US$83.4 bn** (2019); (-8% from 2018)

Gas
- Total natural gas production: **6.39 EJ**
- Total natural gas consumption: **307.3 bcm**
- LNG imports : **84.8 bcm,** largest importer of LNG

Coal
- Total coal production: 79.82 EJ, 48% of the world's total, up 4.2% from 2018
- Coal consumption: 81.67 EJ, 51.7% of the world's total, up 2.3% from 2018

Electricity
- Total electricity generation capacity: **2,010 GW**
- Total electricity consumption 2018: **6,510 TWh**
- Average electricity price (in $US cents): **8.4/kWh**
- Electrification rate: **100%**

Electricity generation by Fuel, 2019



Source: BPstats

Sources: World Bank, UN, IEA, BEF, CEIC, BP Statistical Review, JRC, Enerdata, UNEP

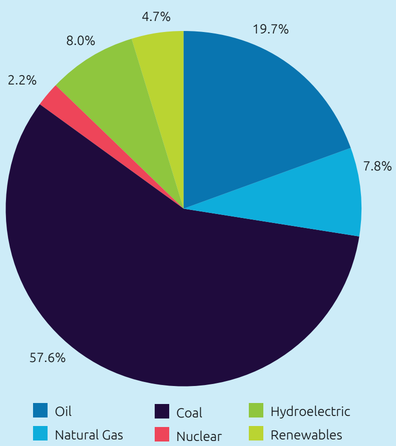
"China is the giant world energy leader, in almost all dimensions", Philippe Vié, Energy, Utilities and Chemicals sector head

Oil
- Total oil production: **3,836 thousand** barrels daily (4% of the world's total production)
- Total oil consumption: **14,056 thousands barrels** daily (14% of the world's total)
- Oil refining capacity: **16,199 thousand barrels/day** (16% of the world's total)

Electric mobility
- Number of electricity charging stations: 1.245 million units; 531,000 public and 714,000 privately-owned charging stations
- Number of electric vehicles (2019): 2.3 million
- PEV is a subset of electric vehicles that includes all-electric, or battery electric vehicles (BEVs), and plug-in hybrid vehicles (PHEVs)
- Market growth: 5% of new car sales

Nuclear
- Total generation: **348.7 TWh**
- Consumption: **3.11 EJ,** 17.8% increase from 2018
- 45 nuclear power reactors in operation, 12 under construction, 2 EPR reactors built

Primary Energy Consumption by Fuel, 2019



Source: BPstats

Network
Regional sources
Length: 3.3 million km (transmission lines of 1,100kV and above, end 2019)

Country highlights
- **Key policies :** Renewable portfolio standard (RPS), The 14th Five-Year Plan
- **Key facts :**
  - China is the world leader in wind energy production with an installed capacity of 211.4 GW
  - China's energy demand growth slowed to 1.1% p.a. in 2019, less than one fifth of its pace in the last 22 years (5.9% p.a.)
  - China to optimize subsidy policies on renewable energy generation

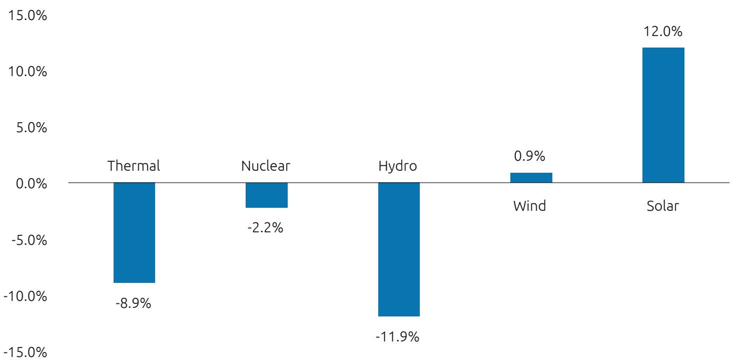
Sources: World Bank, UN, IEA, BNEF, CEIC, Enerdata, JRC, World Nuclear Association, Mckinsey, RenewableEnergyworld

China's energy mix has been impacted by the lockdown period...

Renewables proved to be resilient during the lockdown period: solar PV is the big winner of the crisis

- As in most countries, China has seen its energy landscape transformed by the COVID-19 crisis. The lockdown that started in late January had an immediate effect on both electricity supply and demand.
- Total electricity demand fell by 7.8% in January-February compared to the same period in 2019, with a decrease in all high-consuming sectors except residential and telecom & webservices.
- Lower demand has caused an increased competition between the different energy sources. Thanks to low operational costs, renewables had a leading advantage on China's power market: this resulted in an increase of power generation by 12% for solar and 1% for wind, and a decrease of thermal sources by almost 9% compared to the previous year.

Figure 1. Year-on-year changes in generation volume (Jan & Feb 2020 vs 2019)

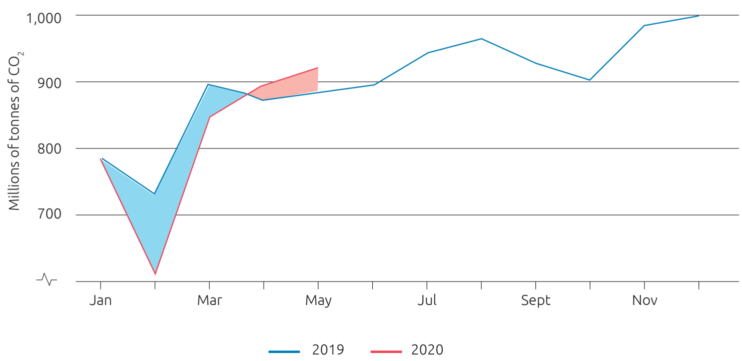


Source: ihsmarkit

The post-lockdown rebound increased carbon emissions

- After a 25% drop in CO_2 emissions during the crisis, activity rebounded after the easing of lockdown in early March, and with it, carbon emissions.
- Data shows that CO_2 emissions in May 2020 have risen by 4-5% year on year, mostly driven by the fast recovery of coal power, cement and heavy industries. Bad weather conditions for hydropower also explain the surge of coal to compensate for the missing power.
- The rebound, both in electricity demand and in carbon emissions, gives a false sense of "back to normal". However, the decisions made by the Chinese government during and after the lockdown will have significant mid- and long-term consequences for the Chinese energy landscape.

Figure 2. Carbon emissions in China – Comparison between 2019-2020



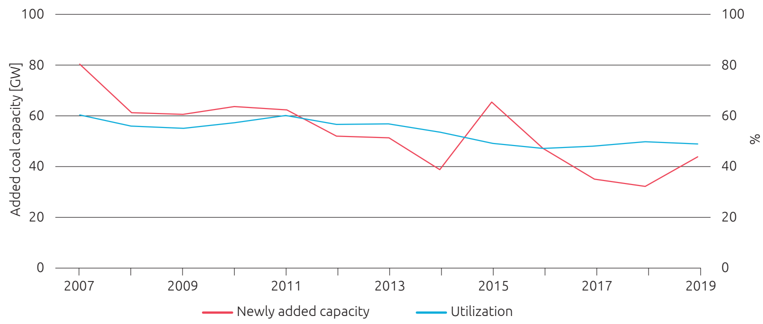
Source: CarbonBrief

...and it will have long-term consequences for its previously anticipated evolution

Stimulus measures create a new coal boom

- In the first five months of 2020, in addition to 46 GW of coal-fired power plants already under construction, an additional 48 GW were approved after the central government eased environmental constraints.
- In comparison, 43.8 GW of new capacity was commissioned in 2019, already a record year for coal plants installations.
- China has traditionally resorted to large infrastructure projects to create local employment and mitigate economic or employment crisis. After the lockdown, environmental restrictions were eased to boost approval for construction of many more coal plants to support local economies.
- The coal boom raises two issues: as coal is the most carbon intensive energy source, climate goals might be in jeopardy. In addition, as existing coal plants are already running with a low utilization rate, adding capacity will limit the ROI of new assets.

Figure 3. Newly added coal capacity and utilization rate



Source: Carbonbrief

The post-COVID recovery plan : energy as a key focus

- **Environmental challenges**
  Climate change motivated Beijing to decouple economic growth and fossil fuel consumption in 2015. The government then pledged to cut energy intensity by 15% from 2016 to 2020. The country was on track until 2018, when the target was lowered to 13%. In late 2019, the economic slowdown created room to lift environmental restrictions and the COVID-19 crisis accelerated this trend. Although air pollution and climate change still remain on the agenda, it is unclear whether strong objectives will be set for the 15th five-year plan.

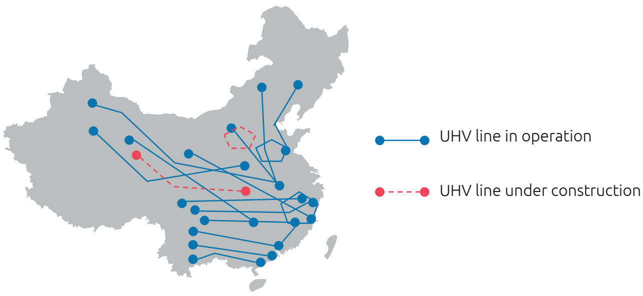
- **Energy security**
  Although clear measures have not been announced yet, the NDRC (National Development and Reform Commission) 2020 working report emphasizes the importance of energy security, in a context of souring relations with the US. The country aims at reducing its dependence on oil and gas imports, to reduce its reliance on foreign states. Upstream development, particularly gas, to reduce imports from foreign countries will be key in future years.

- **Electrification**
  The post-COVID-19 recovery program emphasizes new infrastructure and new urbanization. It will drive the electrification of the country which is mostly seen as a growth mechanism to help the country recover from the crisis, while supporting the goal of energy independence. Seven areas will be promoted in the infrastructure plan, including ultra-high voltage power transmission and electric vehicle charging infrastructure. In total, the infrastructure plan is expected to represent an investment 10 trillion Yuan (US$1.4 trillion) over 2020-2025. Electrification of the cities and a boost in electric vehicles will drive the power demand.

To sustain China’s long-term economic development, the national utility SGCC is securing the territory’s electrification through a vast network of Ultra High Voltage transmission lines

SGCC company overview	
Name	State Grid Corporation of China (SGCC)
Founded	2002
Headquarters	Xicheng District, Beijing City
Revenue (2018)	US$ 387,056 million
Employees	917,717
Clean energy capacity (2018)	569 GW
Ultra-high voltage transmission lines	30,400 km
National coverage	88% of the national territory, accounting for 1.1 bn people

Figure 4. China’s main UHV transmission lines



Main facts

- SGCC’s core business is the construction and operation of power grids. As a super-large state-owned enterprise crucial to national energy security and an economic lifeline, its mission is to provide safer, cleaner, and more economical power supply.
- In early 2020, China had 24 UHV (800 or 1000 kV) transmission lines in operation, covering more than 37,000 km; 21 of those are operated by SGCC.
- An additional 9 lines (for a total of close to 12,000 km) are currently under construction or planned.
- These lines will put an end to the previously unavoidable necessity of having electricity generation close to demand centers, and therefore unlock the potential of remote areas for renewable generation, as well as reduce plant-related pollution in major cities.
- Using the successful national example, SGCC also heads China’s effort to create a global energy interconnection (GEI) system, which aims to achieve a sustainable, secure, and affordable supply of energy for both developing and developed countries. The goal is to promote a worldwide interconnection of UHV-powered energy grids by 2050 to distribute electricity coming from every sustainable power source in the world.

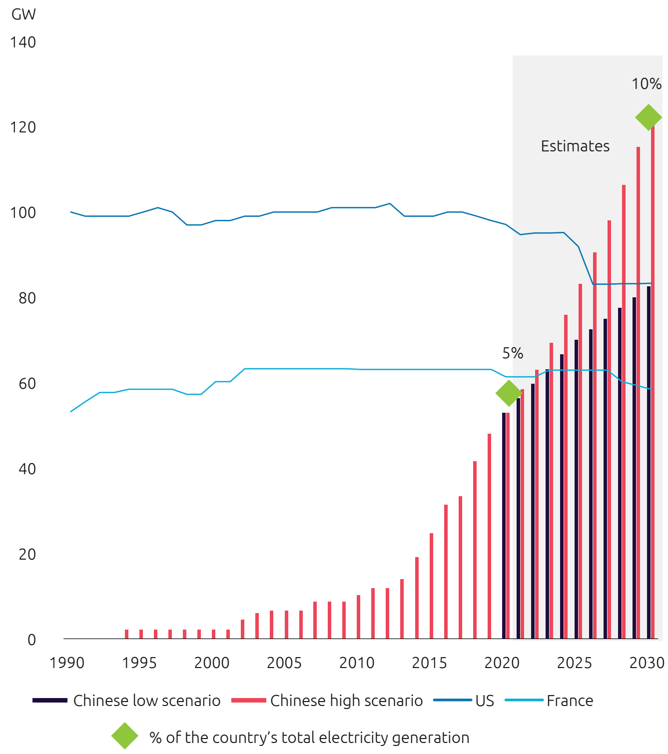
Sources: Bloomberg, Fortune, State Grid website, Global Electricity, EIA, China National Statistics Bureau

At the same time, China is ensuring that power demand is met through the development of new generation sources, such as nuclear power

China is rapidly becoming one of the world’s nuclear giants

- China began its civil nuclear power story in the mid-1980s with the construction of its first two nuclear power plants at Daya Bay near Hong Kong and Qinshan, south of Shanghai (operational in 1994).
- Less than 30 years later, about 45 nuclear power reactors are in operation (representing some 48 GW and around 5% of the country’s electricity generation) and 12 are under construction.
- In 2014, the government's Energy Development Strategy Action Plan set a target of 58 GW capacity by 2020, likely to be missed despite 30 GW under construction. Under the 13th Five-Year Plan (2016-2020), six to eight nuclear reactors were to be approved each year and their construction significantly ramped up. China’s nuclear installed capacity is expected to catch up with the US and France’s in the next decade.
- In 2018 the NDRC's Energy Research Institute emphasized again the crucial role of nuclear power with a different perspective: it revealed that China's nuclear generating capacity must increase to 554 GW (28% of the country’s energy mix) by 2050 to comply with a climate scenario limiting global temperature rise to less than 1.5 °C.
- Characteristically, China is leveraging its large demand for nuclear reactors to create a strong national nuclear industry: Chinese players can now produce 10 nuclear reactors a year and provide 85% of the necessary components. The objective is to go beyond 90% of local production and rapidly develop Chinese standards.

Figure 5. Installed nuclear power capacity of China vs the US and France, 1990-2030

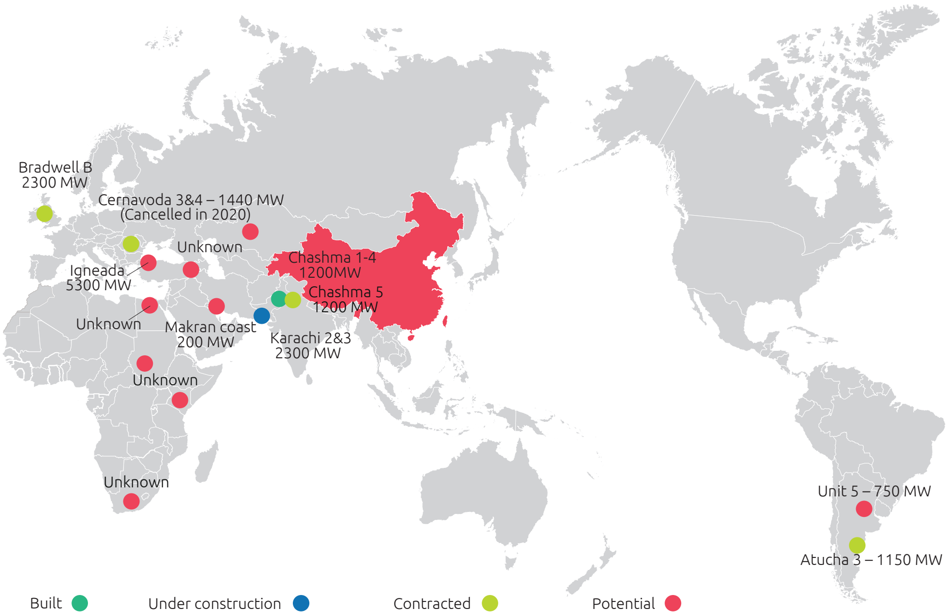


Sources: World Nuclear Association, IAEA, Bloomberg, Reuters, Le Monde de l’Energie, EIA

As seen before, China uses the expertise gained domestically to later strengthen its position on the global energy markets

After years of relying on foreign technology sharing, China has now developped its own nuclear technology with the aim of exporting it

Figure 6. Chinese nuclear presence abroad



Sources: World Nuclear Association, IAEA, Bloomberg, Reuters, Le Monde de l'Energie

China's nuclear development follows a pattern already observed in the expansion of other industries in which it is a leader:

1. A learning phase supported by technology sharing from international players
2. Appropriation of acquired technologies and deployment of mass production supported by government policies and advantageous credit lines, generating economies of scale
3. Large-scale deployment within the Chinese market
4. Massive exports once the technology is mastered and competitive:
   - In June 2019, the Chinese People's Political Consultative Conference (CPPCC) suggested that as many as 30 Chinese reactors could be built overseas by 2030 as part of the Belt and Road Initiative.
   - China mainly exports the Hualong-1 (HPR1000) which passed the IAEA tests in 2014 and was submitted in 2015 for certification of compliance with the European Utility Requirements (EUR). The first Hualong-1 reactor built outside of China started operations in Karachi, Pakistan, in December 2019.

- China is the home of the first two (and only) EPRs in operation, which came online in 2018 and 2019 after nine years of construction, while several other EPRs in Europe face significant construction delays and cost overruns.
- The world's first nuclear reactor exporter remains Russia, but China has joined it on most of the global bids.
- The development of Small Modular Reactors (SMRs, especially the ACP100) mainly targets foreign markets, following demonstration units at home.

China is the world's largest Hydrogen producer, mainly from fossil fuels

Hydrogen : state of the art in China

- China supplies a third (22 million tons in 2019) of the 70 million tons of global Hydrogen demand. This production is particularly driven by chemicals production such as ammonia (40% of which is produced in China) and oil refining.
- Hydrogen demand in China alone is expected to hit 35 million tons in 2030.
- Most Chinese Hydrogen is produced from fossil sources: coal gasification (40%), by-product from the industry (32%), petroleum (12%) and steam methane reforming of natural gas (12%). Only 4% of the production comes from water-electrolysis.
- Nevertheless, China has the ambition to green its methods to produce Hydrogen by driving down the cost of electrolysis, which remains uncompetitive so far.

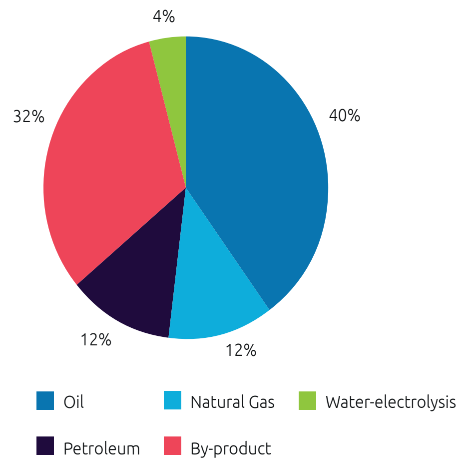
Hydrogen production from renewables and biomass on the rise

- Hydrogen production from coal produces 19 tCO_2/tH_2, twice as much as natural gas. In June 2019, China released a white paper targeting 70% Hydrogen production from renewables by 2050 to comply with CO_2 emissions reduction objectives, compared to just 3% in 2018.
- The rise of biomass as feedstock to produce Hydrogen from 2030 is also a method explored to produce green Hydrogen, however technical and economic challenges remain.

Source: IEA, The future of Hydrogen

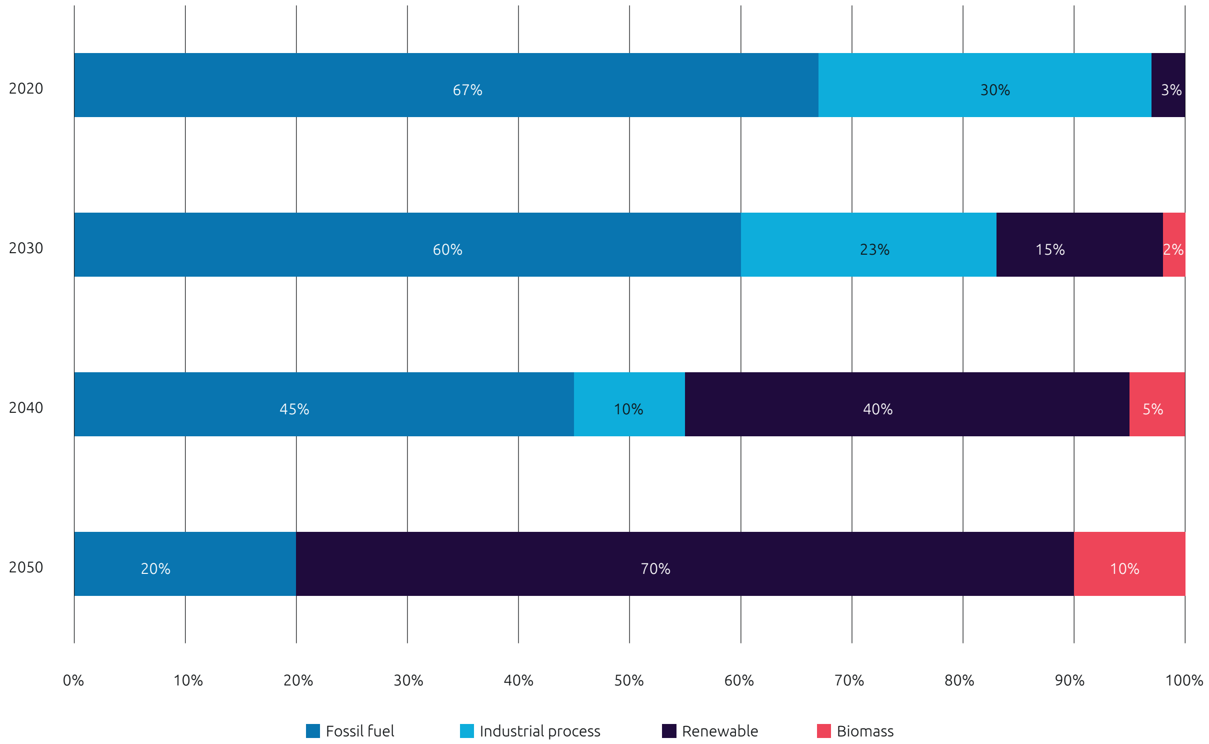
- That means, according to the Hydrogen production mix targeted, a market of 5.25 million tons of green Hydrogen or 262.5 TWh renewable generation. China's renewable power capacity is more than sufficient to support that demand. But the critical factor behind commercialization is the electricity price from renewables.

Figure 7. Hydrogen production technology mix in 2018



Source: China Hydrogen Alliance

Figure 8. Hydrogen production mix evolution from 2020 to 2050



Source: China Hydrogen Alliance

Asia

In the mid-term, coal-based Hydrogen equipped with CCUS is likely to be the cheapest option for clean Hydrogen production

Green Hydrogen in China is increasingly competitive

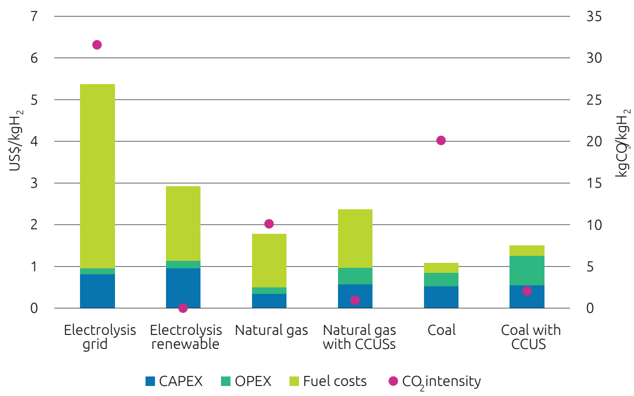
- Coal is the cheapest way of producing Hydrogen in China, with costs around US$1/kg$H_2$. It is 20% cheaper than Hydrogen from natural gas production and is three times less than Hydrogen production via water electrolysis after pressurization and storage.
- The cost of electrolysis is strongly linked to electrolysers and electricity costs. A detailed economic assessment by the IEA, suggests Hydrogen from renewables could be produced at a cost of US$ 2-2.3/kgH2 depending on location.
- Average solar and wind grid prices are around US$0.04-0.09/kWh. Still, it estimated that renewable-to-Hydrogen needs US$0.01/kWh (or $10/MWh) to become competitive in comparison with coal gasification.

Despite CCUS, fossil fuel-based Hydrogen remains cheaper than green Hydrogen in the mid-term

- Renewable curtailment pushes down renewable electricity prices (even going negative) in China. That means electrolysis based on renewable sources could be a very economical option for the country. In 2017, 100 TWh of solar, wind and hydro were curtailed in China.
- However, if surplus electricity is only available on an occasional basis it is not profitable. Running the electrolyser at high full load hours and paying for the additional electricity can actually be cheaper than just relying on surplus electricity with low full load hours. Very low-cost electricity is generally available only for a very few hours within a year, which implies a low utilization of the electrolyzer and high Hydrogen costs that reflect CAPEX costs.
- In the mid-term, the cheapest source of Hydrogen production respecting CO_2 emissions reduction objectives is likely to be coal with CCUS followed by natural gas with CCUS. Renewables are not sufficiently competitive to replace coal or natural gas even if China expects that the cost of electrolysis Hydrogen production will decrease by 50% by 2050.

Sources: IEA, The future of Hydrogen, 2019 and Cleantech report, 2019

Figure 9. Hydrogen production costs in China in 2019



Sources: IEA, The future of Hydrogen, 2019

China is willing to contest Europe's lead in the use of Hydrogen

Transportation is a key sector for Hydrogen in China

- Hydrogen is expected to have applications across sectors including transportation, alternative feedstocks, heat and power in buildings and industrial energy, with a key focus of carbon neutrality and energy independence.
- In 2020, China decided to stop providing purchase subsidies for fuel cell vehicles (FCV). Instead a new pilot program will be set up to encourage innovation and to stimulate the development of Hydrogen and the FCV industry in China. The reason for that change is Hydrogen charging infrastructure and services are identified as the bottlenecks for industry progress.
- In the automotive sector, China expects to have more than 1,000 Hydrogen refueling stations and one million fuel cell vehicles in service by 2050. It will be one of the first fleets in the world (behind Japan). Other announcements on Chinese Hydrogen policy are expected in the 14th five-year plan published in 2021.

Europe is using Hydrogen to take revenge on China for the solar fiasco

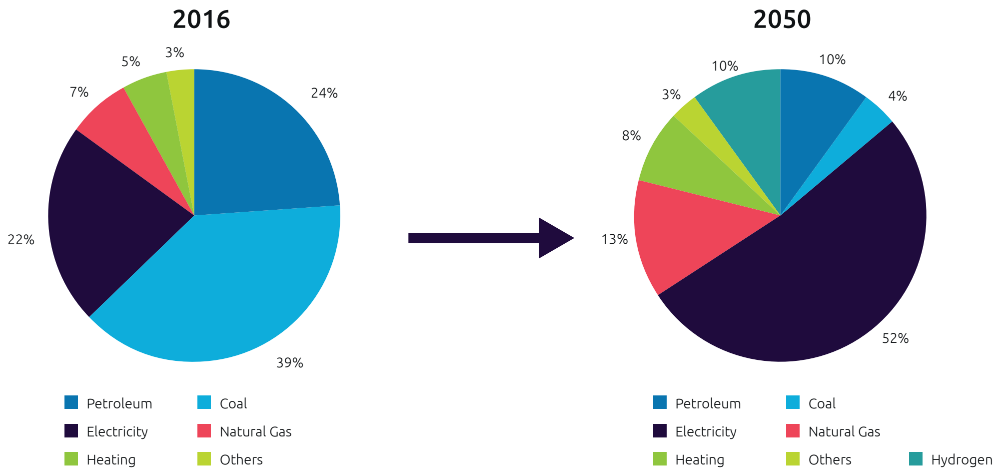
- China's Hydrogen supply is about three times that of the entire continent of Europe, the latter at around 7 Mt/year.
- Europe's strategy is to increase green Hydrogen production capacity to 40 GW and generate up to 10 million tons of renewable Hydrogen in the EU by 2025-2030. At the same time, China's Hydrogen demand is expected to account for 5% of total energy consumption by 2030 (~35 million tons) and 10% by 2050 equivalent to 100 millions ton of Hydrogen. China has a wider market than Europe, benefiting from economies of scale, but it also has more difficulties to overcome before paving the way for green Hydrogen. Coal certainly seems to have a long-term advantage there in terms of its competitiveness.
- Europe wants to lead this technology on a global level and does not want to make the same mistake as it did with solar. This technology began in Europe, especially in Germany, and moved progressively to China where it benefits from a lower production cost. In the Hydrogen race, Europe is in the lead... for the moment.

Sources: IEA, The future of Hydrogen, 2019 – Cleantech report, 2019 China Hydrogen Alliance, 2018 – International Council on Clean Transportation (ICCT), 2020

Year	Hydrogen Refueling Stations	Fuel Cell Vehicles
2020	Over 100 stations	5,000 FCVs in demonstration, among which 60% are FC commercial vehicles and 40% are FC passenger cars
2025	Over 300 stations	50,000 FCVs in service, among which 10,000 units are FC commercial vehicles, and 40,000 units are FC passenger cars
2030	Over 1,000 stations and >50% Hydrogen production from renewable sources	Over one million FCVs in service

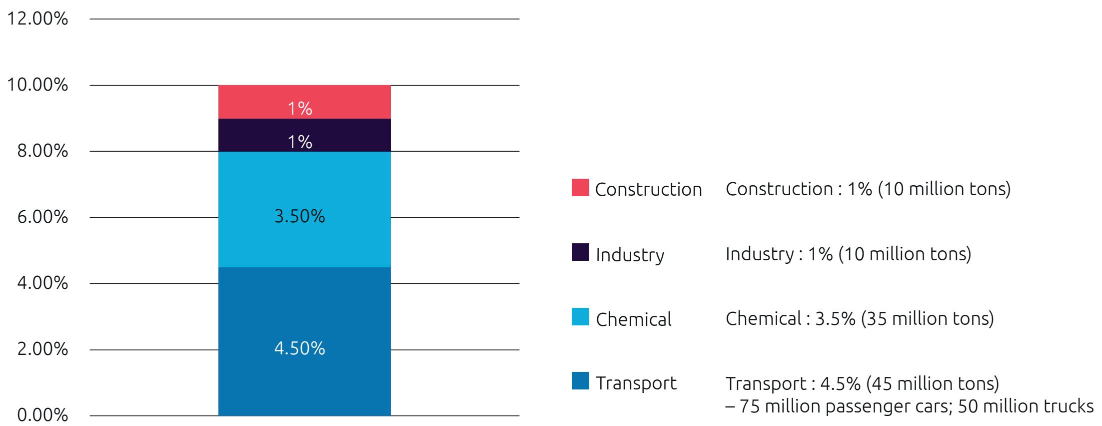
Source: Hydrogen fuel cell vehicle technology roadmap, Strategy Advisory Committee of the Technology Roadmap for Energy Saving and New Energy Vehicles

Figure 10. Hydrogen proportion in the total energy consumption



Source: China Hydrogen Alliance

Figure 11. Hydrogen use in 2050 by sector



Source: China Hydrogen Alliance

India

Country description

- Country: **India**
- Population: **1.35 Bn**
- GDP: **US$2,719 Bn**

CO_2 footprint

- Total CO_2 emissions: **2,480.4 million** tonnes of CO_2 equivalent
- CO_2 intensity per capita: **1.6 tCO_2** (IEA 2017)
- GHG emissions growth rate: **2%(2019)**

Energy

- Evolution of energy demand (last 5 years): **+18%** (from 28.77 EJ to 34.06 EJ) (BP)

Renewable energy

- Share of renewables in final energy consumption: (BP) **3.6%** (excluding hydro)
- Total investments in clean energy: **11.1 billions** (2018)

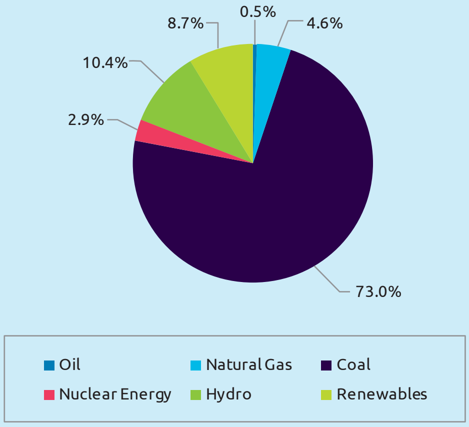
Gas

- Total gas production: **26.9 bcm** (BP)
- Total gas consumption: **59.7 bcm** (BP)
- Average gas price: US$/MWh (regional sources)

Coal

- Total coal production: **12.73 EJ, 8%** of the world's total, **down 0.5% from 2018**
- Coal consumption: **18.62 EJ, 11.8%** of the world's total, **up 0.3% from 2018**

Electricity generation mix by Fuel, 2019



Source: BP statistical review 2020

Source: World Bank, UN, IEA, BEF, CEIC, BP Statistical Review, JRC, Enerdata, UNEP

Electricity

- Total electricity generation (2019): **1,558.7 TWh**
- Total electricity consumption: **1,196 TWh**
- Average electricity price: **0.081 US$/kWh** (Household), **0.111 US$/kWh** (Business)
- Electrification share (average): **95%**

Oil

- Total oil production: **826 thousand barrels** daily (0.9% of the world's total production)
- Total oil consumption: **5,271 thousands barrels** daily (5.4% of the world's total)
- Oil refining capacity: **5,008 thousand barrels/day** (4.9% of the world's total)

Electric mobility

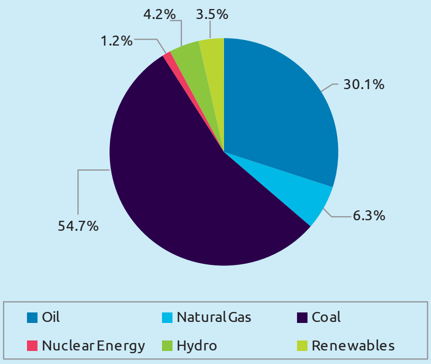
Regional sources

- Electric public charging stations: **150 (2019)**
- Number of electric vehicles: **152 thousand (2019)**
- Type of electric vehicles: BEV, PHEV and HEV
- Market growth: 30% (2018-2030 evolution)

Nuclear

- Total generation: 45.2 TWh
- Consumption: 0.40 EJ, 15.2% increase from 2018
- **22** nuclear power reactors in operation, **21** under construction

Primary Energy Consumption mix by Fuel, 2019



Source: BP statistical review 2020

Transmission network

Length: Total **425,770 ckt. Km(May 2020)** transmission network

Country highlights – Key policies

– **Deen Dayal Upadhyaya Gram Jyoti Yojana** - a Government scheme designed to provide continuous power supply to rural India
– **Bharat Stage (BS) VI** emission standards for motor vehicles - effective in April 2020
– **National Clean Air Programme (NCAP) in 2019** - main goal is "to meet the prescribed annual average ambient air quality standards at all locations in the country in a stipulated timeframe."
– **India Cooling Action Plan (ICAP) in 2019** - provides an integrated vision towards cooling across sectors with a 20-year time horizon

Source: World Bank, UN, IEA, BNEF, CEIC, Enerdata, JRC, World Nuclear Association, Mckinsey, RenewableEnergyworld, BP statistical review, CEA

Will COVID-19 slow down India's energy transition ?

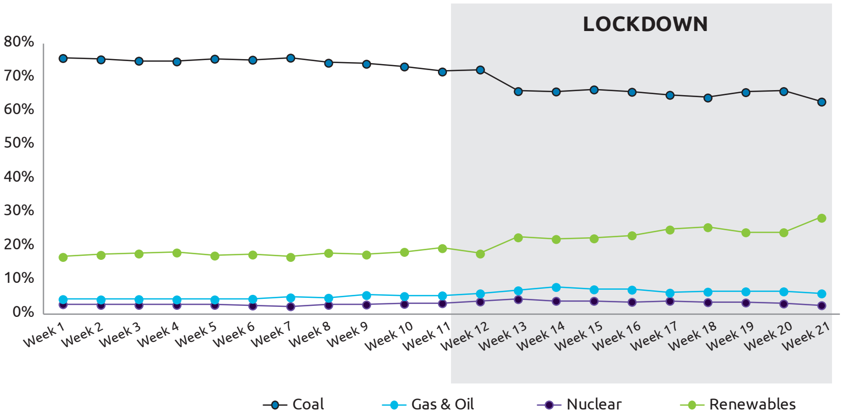
CO_2 emissions fell drastically during India's lockdown due to decreasing energy consumption and an increasing share of renewables in the power mix

- India imposed a strong lockdown that started on March 18, strengthened on March 25 and softened on May 4. In some parts of the country, local lockdowns were then implemented in the following weeks.
- Following the lockdown measures, energy consumption fell by about 25% within 10 days due to demand reduction from industries linked to supply chain disruptions and slowdown in demand. The Western industrial regional (Gujarat and Maharashtra) recorded the steepest decline in consumption, where it fell by 35%.
- Most of the drop in total power demand was borne by coal-based generation, which fell by 15% in March and 31% in the first three weeks of April. The share of coal in the electricity mix decreased from about 75% pre-lockdown to 65%.
- On the other hand, the share of renewables in the power mix increased from about 17% to above 25%, especially due to low operating costs and priority access to the grid through regulation.
- As a result of decreasing energy consumption and the smaller share of coal in the electricity mix, CO_2 emissions fell for the first time in four decades: a 15% decrease was recorded in March and about 30% in April.
- In 2020, energy demand is expected to see a 4% decrease compared to 2019.

The economic crisis put renewable energy investments at risk

- Recovering from the economic crisis is going to be a real challenge for distribution companies. As retail tariffs are structured on a variable cost basis, and since power demand plummeted during the lockdown, they will face huge working capital issues. Their annual losses are expected to reach US$15 billion.
- New energy projects will face energy companies' financial liquidity issues, which could be a serious threat to new energy investments, including in renewables.
- In addition, India will face supply chain and strategic capability issues, with 88% of solar modules coming from China.
- On the other hand, the renewed push for the "Make in India" initiative may boost coal-based generation, which is mostly domestic.

Figure 1. Electricity mix in India, January – May 2020



Source: IEA, 2020 COVID-19 Impact on electricity

With government support, the crisis may have a limited impact on India's energy transition

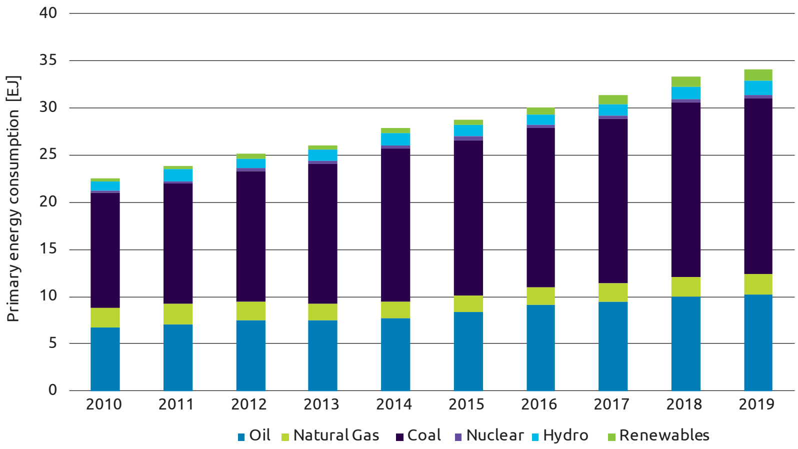
- Support for renewable energy is part of the Government's initiative to revive the Indian economy :
  - Renewables auctions were maintained during the lockdown, despite strong market and financial situation uncertainties : for instance 2,000 MW of new solar capacity were secured at an average cost of US$34/MWh, which is cheaper than the average cost of a unit of electricity from India's biggest coal generator (US$45/MWh).
  - Timelines for renewable energy projects to be completed for the period of the lockdown were also extended, safeguarding renewable energy developers from penalties linked to delays from the committed schedules.
  - In April 2020, while renewable energy manufacturers were looking to diversify their supply chains and shift their base from China, the Ministry for New and Renewable Energy urged states to provide incentives to develop manufacturing hubs in India, for equipment such as solar cells and modules, wind equipment or batteries.
- In addition, the experience of exceptional air quality could lead to strengthened efforts to reduce air pollution by accelerating the shift to a cleaner energy landscape.

Global overview of the energy mix

Some key figures to understand India's specific context

- India's population is expected to grow by more than 267 million by 2040[1].
- India has one of the G20's highest growth rates in energy use per capita (+36%, 2010–2019[2]), even though it is still below the global average.
- A 156% increase in primary energy consumption is expected by 2040. In that scenario, India could represent 11% of global primary energy demand (6% today)[1].
- To meet this demand, power generation may increase by 207% by 2040[1].
- Two-thirds of the population still live in rural areas, but the urbanization rate is around 2.4% per year.

Figure 2. Primary energy consumption by fuel in EJ (2010-2019)



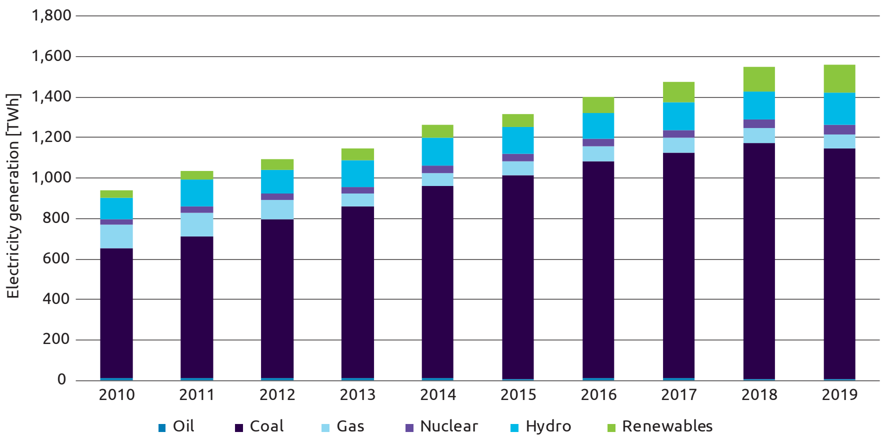
Source: BP statistical review 2020

Brief overview of each energy source

- **Coal:** This is hugely dominant in India's energy system even though its predominance may decline. It will still represent 57% of total electricity generation in 2040 against 73% in 2019. For the first time in 2019, electricity generation from coal decreased (down 2.6%).
- **Oil:** The oil share will remain more or less stable in the next decade (from 30% of primary energy consumption in 2019 to 23% in 2040[1]), following the growth in personal mobility, the industrial economy, and petrochemicals demand. Oil supply security is a major challenge to be tackled (80% is imported).

- **Natural gas:** Demand is expected to rise by 240% by 2040 to 185 Bcm[3] to represent 8% of energy consumption. This dynamic is driven by the increase in residential and industrial gas consumption and promotion of gas vehicles. Regarding electricity generation, gas usage is decreasing (-3.9% in 2019) as new gas power plants are under utilized.
- **Nuclear:** Its part in total energy consumption may only be rising slowly, going from 1.2% in 2019 to 2% in 2040, but it represents a 7.4% CAGR over the period[1]. The initial objective was to reach 63 GW of nuclear capacity in 2032 (against 7 GW in 2019) but the government has stated it may only be 23 GW (21 reactors of 15 GW total capacity to be operational in 2032).
- **Hydropower:** This is the second most important source for electricity generation (10.4% in 2019). 21 GW of new hydropower projects are expected to be developed by 2030 with necessary investment of US$31 billion[3].

Figure 3. Electricity generation by fuel in TWh (2010-2019)



Source: BP statistical review 2020

- **Renewables:** These accounted for 3.5% of primary energy consumption in 2019 and almost 9% of electricity generation, representing a 300% increase since 2010. In 2040, renewables may represent 16% of primary energy consumption[1].

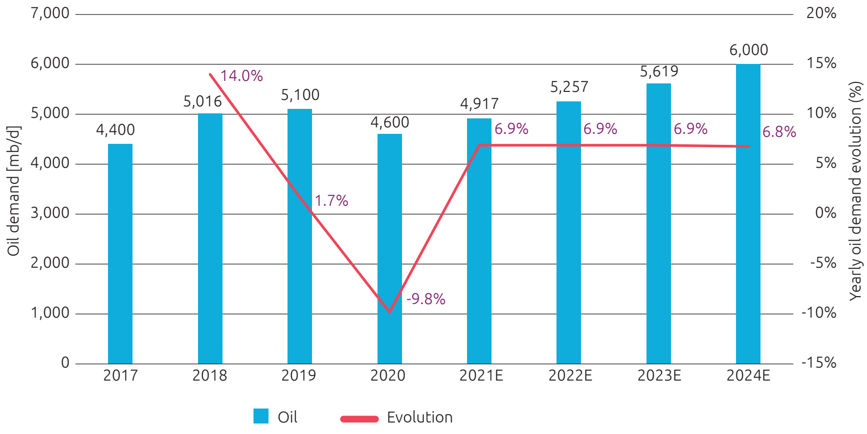
[1] BP Energy Outlook 2019
[2] BP Statistical Review 2020
[3] IEA, India 2020, Energy Policy review

Focus on oil - Facing strong growth in oil demand, India struggles to enhance its security of supply

Overview of the oil situation

- Currently the world's 3rd largest oil consumer (behind China and the USA), oil is the second-largest source in India's total primary energy supply (25% of TPES in 2017, IAE) and the largest in its total final consumption (30% of TFC in 2019[1]).
- India's domestic oil production has remained relatively stable over the last decade, with an average of 862 thousand barrels per day (kb/d), but the 2019 production stood at 826 kdB (thousand barrel per day) which is an 8% drop from its peak of 937 kd/b in 2011 (BPstats 2020).
- Over the same period, the country's oil demand has grown by more than 50%. This is led by the transport sector, the largest oil-consuming sector accounting for 41% of total consumption in 2017 (mainly road transport fueled by diesel and gasoline). The rising demand is also linked to increased usage of liquefied petroleum gas (LPG) as a cleaner cooking fuel, which is heavily subsidized and has made India one of the world's largest LPG importers.

Figure 4. Total Oil Demand Growth (Million barrels per day) (2017-2024E)



Sources: IEA, 2020, Reuters

- The growth of oil consumption in India is expected to surpass that of China in the mid-2020s. Its oil consumption of 4.4 mb/d in 2017 (representing 5% of global consumption) is set to reach around 6 mb/d by 2024 increasing by 3.9% per year, well ahead of the global average of 1.2%[2].

[1] BP Statistical Review 2020
[2] IEA 2019

Enhancing oil security has become a priority

- With continued strong growth in oil demand against falling domestic production and limited oil reserves, India's strong dependence on oil imports, already at 83.8% in 2018-2019, has risen to 85% and is expected to increase. At the same time, India's import bill for crude oil has increased by 27% from US$ 88 billion in 2017 to US$ 112 billion in 2018. The 9% fall in its bill to US$102 billion in 2019-2020, is mainly due to prices crashing with the coronavirus pandemic.
- With an oil import bill of around 4% of GDP in 2019, the Indian government is focusing on enhancing oil security through different levers:
  - **The promotion of domestic production** through major upstream support, the Hydrocarbon Exploration & Licensing Policy (HELP) marks an important transition from regulation to liberalization of India's E&P sector.
  - **The diversification of sources and supply routes:** the historic main suppliers are Iraq (21% in 2018) and Saudi Arabia (18%). Nigeria replaced Iran as the 3rd suppliers following the US sanctions. The new player amongst suppliers is the US, which began selling crude oil to India in 2017 and is fast becoming a major source. Supplies from the US jumped more than four-fold to 6.4 million tones in the 2018-19 fiscal year (DGCI&S) and the country has committed to purchase US$5 billion worth of oil and gas from the US every year.
  - The increase of Indian investments in overseas oil fields in the Middle East and Africa.
  - **The building up of oil emergency stock** by creating the Indian Strategic Petroleum Reserves Ltd (ISPRL) to supplements the commercial storage available at refineries. Given the expected growth in oil consumption, India's strategic reserve capacity of 40 million barrels, which can currently cover 10 days of current net imports, may cover only four days in 2040. The government aims to add an additional 50 million barrels (phase II of the SPR program).

Highly ambitious to remain a refinery hub

- Despite being a net importer of crude oil, India is a net exporter of refined oil products and the fourth-largest oil refiner in the world.
- Most of the exported oil products in 2018 (1,306 kb/d) were road transport fuels: 43% diesel and 23% gasoline. The top five countries that imported India's petroleum products were the United Arab Emirates, Singapore, the Netherlands, China and Turkey[1].
- For 2020, India's oil refining capacity stood at 249.9 million tonnes (Mt), making it the second largest refiner in Asia after China. To maintain India's position as a refining hub, the government aims at nearly doubling its oil refining capacity and reaching 443 Mt by 2030, exceeding its estimated domestic demand level.

Sources: IEA (2019b), Oil Information 2019, https://www.iea.org/statistics/; IEA (2019d), Monthly Oil Data Service, https://www.iea.org/statistics/mods/.

Coal will remain a pillar in electricity production in the next decades, but the sector needs to evolve to face new requirements

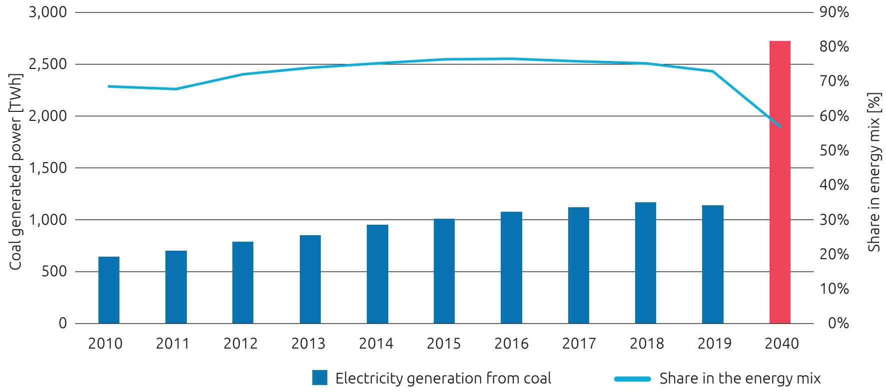
Even though its share in electricity generation may decline from 73% today to 57% in 2040, coal will continue to play a major role in India's energy landscape

- Coal power generation has seen a major increase in the past decade (8% per year), faster than the significant growth in power demand (6.5% per year).
- This strong dependence on coal is explained by several factors:
  - Weakness of coal's relative price compared to other energy sources.
  - Coal is the main energy source available in the national territory (globally, the 5th largest coal reserve) and the sector can represent almost half of local revenues in some states in India.
  - From a practical perspective, coal plants can be built quickly and offer large capacities with important flexibility to respond to the country's growing energy needs.

Coal power plants are suffering from a poor financial situation that may slow down its evolution

- Around 55 GW of coal power plants are in financial trouble with revenues that very often do not compensate for generation costs. It is mainly due to coal supply issues, a growth in power demand slower than expected leaving a part of the fleet underutilized, and some delays in payments by the Bureau of Energy Efficiency (DISCOMS) in poor financial health themselves. This situation has led to the inability of project owners to pay off their debt or get fresh equity.

Figure 5. Electricity generation from coal in TWh and share in the energy mix (2010-2019 & prediction for 2040)



Sources: BP statistical review 2020, BP Energy Outlook 2019

The coal sector is evolving to meet environmental challenges

Having more efficient coal plants and closing old ones

- Among the 50 GW of capacity under construction, 50% are supercritical (less than one-third among existing installed capacity). Through supercritical technology, CO_2 emissions may drop by 23% per unit of electricity generated (compared to subcritical plants).
- The objective is to close almost 50 GW of end-of-life coal plants before 2027 as announced in the 2018 National Electricity Plan.

Adapting the coal fleet to an energy system with more renewables:

- In the future, generation from each coal plant may decrease with the increase in renewables, leading to more financial difficulties for producers.
- More renewables means more flexibility in the electricity system whereas most coal plants were designed to provide baseload power. The government is working on defining the plants that could provide such flexibility.

Promoting better efficiency in coal rail transportation:

- 60% of coal is transported through the rail network, with frequent congestion resulting in delays in delivery. Thus rail transportation represents a large part of coal delivery costs.
- Rationalization along the coal supply chain is underway to cut costs and reduce transportation distances: more coal power plants are being built in the eastern part of the country (where most of the coal mines are) and near the coast (where most coal is imported).

Increasing R&D in carbon capture

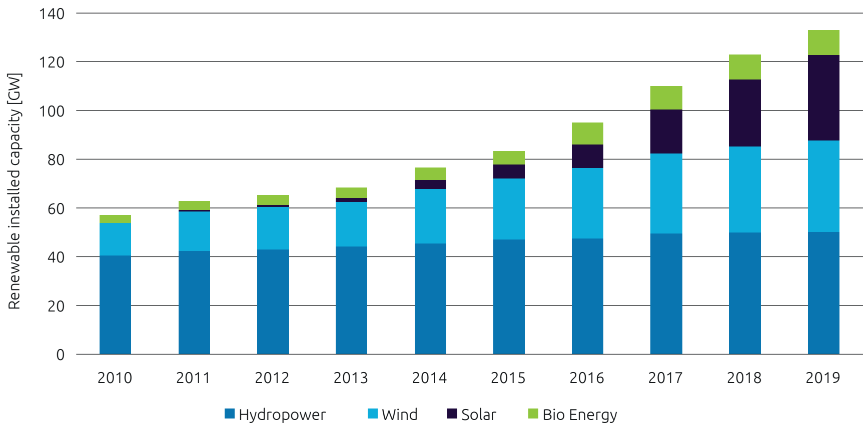
- A national research program dedicated to carbon sequestration was launched in 2007 by the Department of Science and Technology.
- NTPC-NETRA and India's Oil and Natural Gas Corporation (ONGC) signed a memorandum of understanding to build a carbon capture facility at the gas-fired power plant Jhanor Gandhar and aim to use the CO_2 in enhanced oil recovery.

Modern renewable energies are steadily increasing, even though the traditional use of biomass remains the largest renewable source

Renewable electricity capacity keeps increasing, despite a relatively flat share of renewables in the total power mix

- Grid connected renewable electricity capacity reached 84 GW in 2019 (with onshore wind accounting for ~38 GW, solar ~35 GW, and the remainder coming from small hydro and bio-power). If large hydro is also taken into account, the figure reaches almost 130 GW, more than twice 2010 renewable capacity.
- Despite a steady increase in total renewables installed capacity, the share of renewables in electricity generation has remained stable at around 16% over the last decade, due to a strong rise in electricity consumption and the growing share of fossil fuels in the total primary energy supply (TPES) and total final consumption (TFC).
- In 2018, the Government of India increased its initial target from 175 GW to 227 GW of installed renewable capacity by the year 2022, and 275 GW by 2027 (excluding large hydro). In September 2019, the Prime Minister of India announced at the United Nations' Climate Summit in New York an additional target of 450 GW, to achieve 40% of non-fossil fuel base capacity by 2030.

Figure 6. Renewable Installed Capacity, 2010-2019 (GW)



Source: IRENA, Renewable Capacity Statistics 2020

Renewables capacity development is supported by government policies

- To achieve renewable targets, 30 GW of solar energy and 10 GW of wind energy have to be auctioned every year.
- The development of renewable capacity is encouraged by national competitive auctions introduced for solar PV in 2010 and in 2017 for wind.
- In June 2020 Adani Green Energy won the world's largest solar bid to build 8 GW of projects. It becomes the largest renewable power generator in India, with 15 GW of renewable capacity under various stages of development.
- However, COVID-19 impacts may slow down renewables' development, especially due to delays in construction activity and deferred payments across the value chain. In this context, India is at risk of not reaching its renewable targets and increasing support from the government will be required.

Biomass is the largest renewable energy source in India, but efforts are being made to replace it with renewable and non-renewable alternatives

- With more than 60% of the country's population depending on it for its energy needs, biomass is by far the largest source of renewable energy in India.
- In 2017, bioenergy and renewable waste accounted for 186.8 Mtoe (21.2%) of total primary energy supply, making it the third-largest energy source in the country.
- The traditional use of biomass for heating and cooking in households has, however, proven to be hazardous for health (500,000 related deaths every year), especially affecting women.
- From an environmental perspective, about 23% of wood fuel harvested in India is unsustainable, and the burning of fuels such as wood or charcoal implies high greenhouse gases emissions.
- Policies have been introduced to replace the traditional use of biomass with cleaner alternative cooking and heating fuels, both renewable (solar thermal and solar PV cooking applications) and non-renewable (LPG).
- Mostly used for cooking, and heavily subsidised, LPG became the second-largest oil product consumed in India. In 2019, India became the second-largest LPG consumer after China.

The challenges for the Indian Power market and the ongoing reforms

Continued efforts for electrification

- Between 2000 and 2019, around 750 million people obtained access to electricity thanks to efficient policy implementation (rate of national access went from 43% to 95%). Nevertheless, there are still 100 million people without access.
- Renewables may increase their role in providing electricity access through mini-grid developments, above all in isolated areas: A draft national policy on mini-grid (published in 2016) aims to develop 10,000 micro and mini grids (total capacity of 500 MW).
- Solar technologies may play a major role in electrification. For example, the Atal Jyoti Yojana (AJAY) Phase II program aims to install over 3 million solar streetlights.

Facing the system integration challenges with the development of renewables energies

Better forecasting of wind and solar generation to maximize the contribution of existing assets and ensure security of supply

- In 2015 the Framework on Forecasting, Scheduling and Imbalance Handling was published, dedicated to wind and solar generators connected to the interstate transmission system. The objective is to make generators accountable of their generation schedule since the commercial effect due to deviation is fully supported by generators.
- Also, India is starting to deploy REMCs (Renewable Energy Management Centres) to support renewables integration (around 10 in the country). REMCs will be in charge of monitoring in real-time and forecasting renewable generation, analyzing collected data and working with load dispatch centers to ensure the stability of the system.

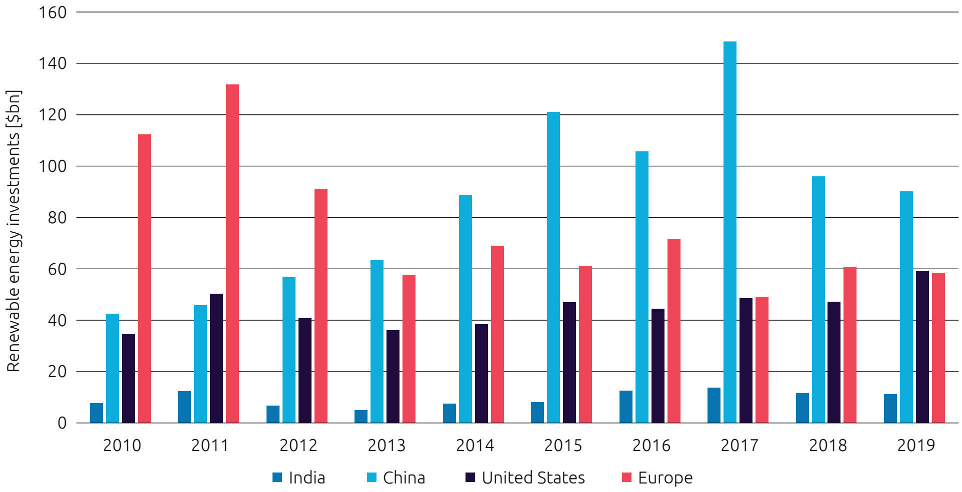
The need for flexible production assets to compensate for renewables irregularity

- The Government aims to facilitate the development of solar–wind hybrid plants, that may integrate battery storage.
- The thermal fleet is under analysis to enhance its flexibility.
- Extension of electricity networks and improved interconnections are crucial as they allow flexible resources to be shared between different geographical areas. Today, the system suffers from interconnection bottlenecks despite major investment in the interstate grid, a situation that may get worse with huge renewables deployment (450GW) exceeding transmission and interconnection capacity. It takes around 10 years to develop an interconnector infrastructure whereas installation of renewables can last less than one year. To solve this issue, the Ministry of Power launched in 2015-2016 the Green Energy Corridor project which aims to develop quickly both the intra- and interstate transmission systems.
- India has an historic experience in the area of demand response to balance the system when available generation capacity was insufficient to meet the demand. Time-of-day (TOD) tariffs are already implemented in the industrial sector and are starting to be introduced in the commercial sector. Nevertheless, the increase in demand flexibility is slowed down by the tariff system in place since the high level of subsidies is mainly financed by industrial consumers, which drives them to self-generate their electricity instead.
- The development of storage solutions is a promising area for the future. PSH (Pumped Storage Hydropower) is the most used storage option although its huge potential (around 90GW) is unexploited (only 4.8 GW able to operate). Until now, battery projects have been limited but the Energy Storage System Roadmap for India (2019-2032) expects to have 62 GWh of battery storage connected to the grid by 2027. India also aims to increase its independence becoming an important battery manufacturer on the all value chain as expressed in 2019 in the five-year manufacturing program established by India's National Mission on Transformative Mobility and Battery Storage.

Removing barriers to investment in renewable energy projects

- In 2019, India was the fourth country in the world in term of investment in renewables capacities (behind the US, China and Japan) and these investments grew with a 10% CAGR between 2004 and 2019. Nevertheless, the gap is huge with the US and China and these investments are reduced due to several barriers.
- Being major investors in solar PV, the poor financial health of DISCOMs is problematic. More than 40% of planned capacity additions in solar PV are allocated to states where DISCOMS have often low financial performance, according to government ratings. The government announced it plans to reinforce the UDAY scheme, adopted in 2015, which aims to improve the financial situation of DISCOMs by reducing their high debts and interest cost.
- Non-compliance with power purchase terms of contract:
  - Payment for power purchase is often delayed by off-takers.
  - The recent price decrease for solar panels has motivated some states to renegotiate or cancel their previously signed purchase contracts. A unilateral cancellation of all planned PPAs was made by the government of Andra Pradesh in July 2019.
- Land acquisition: Investments are impacted by the lack of clarity in land titles, with numerous properties and some outdated records.
- Investment in small-scale projects (such as solar irrigation pumps, minigrids and solar rooftop): These investments suffer from the lack of financing from local banks that often turn to bigger projects and the difficulty in assessing the solvency of small local companies.

Figure 7. Total renewable energy investment in $bn in India, China, Europe and the United States (2010-2018)



Source: UN Environment, Frankfurt School-UNEP Centre, BloombergNEF

Highly vulnerable to climate change, the government is taking action with a strong stance to tackle air pollution

India is the fifth most vulnerable country to climate change

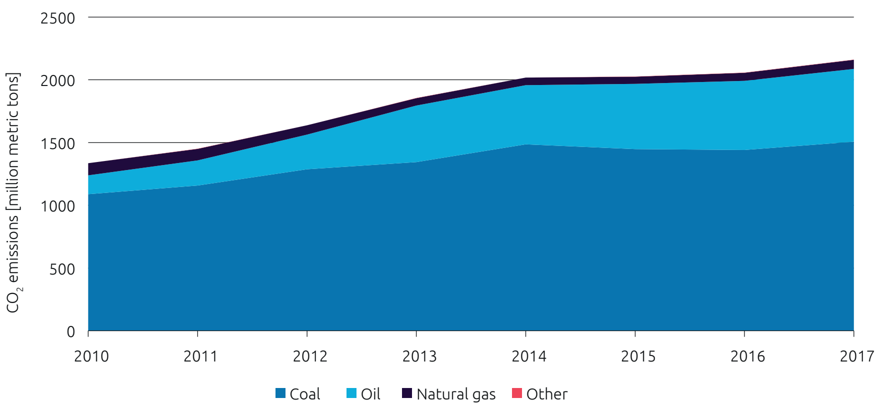
- India recorded the highest number of fatalities due to climate change and the second highest monetary losses from its impact last year. In the Climate Risk Index 2020 (Germanwatch), India's rank rose from the 14th spot in 2017 to 5th in 2018 in the global vulnerability ladder.
- India is exposed to growing water stress, storms, floods and other extreme weather events. The country suffered from one of the longest ever recorded heatwaves in 2018, with hundreds of deaths and temperatures to up to 48°C. The country is particularly vulnerable to extreme heat due to low per capita income, social inequality and a heavy reliance on agriculture.
- Climate change damages amounted to US$ 2.8 billion in 2018[1].
- India also has some of the world's worst air pollution: 10 of the top 20 most polluted cities in the world are located in India. And in 2017 air pollution caused around 1.2 million premature deaths in India (12.5% of the total).

CO_2 emissions

- In 2017, CO_2 emissions from fuel combustion were 2,162 Mt CO_2, 6.6% of the global total, up 71.4% since 2007, when it represented 4.4% of the global total[2].
- Coal is responsible for 69.7% of CO_2 emissions, oil 26.8% and natural gas 3.4% (see figure 8).
- According to BPstats, India's energy-related CO_2 emissions continued to rise to 2,480 million tonnes of CO_2 ($MtCO_2$) in 2019. However, in the fiscal year ending March 2020, CO_2 emissions fell by 30m tonnes (1.4%) in what seems like the first annual decline in four decades.
- In 2019, India's coal-fired electricity generation fell for the first time since 1973, which led to a slight decline in CO_2 emissions from the power sector during the year[3].
- If the decline in emissions reflects different tendencies of the Indian economy since early 2019 (economic slowdown, renewable energy growth), it is likely the impact of Covid-19 is behind this first year-on-year reduction in India's CO_2 emissions.
- The fall in emissions sped up in March, due to the impact of the coronavirus pandemic. The country's CO_2 emissions fell by an estimated 15% during the month of March and are likely to have fallen by 30% in April. Coronavirus has cut India's electricity demand, mostly at the expense of coal (coal-fired power generation fell 15% in March and 31% in the first three weeks of April, based on daily data from the national grid).

[1] Climate Risk Index 2020
[2] IEA 2020
[3] IEA, Global CO_2 emission 2019 report

Figure 8. CO_2 Emissions by energy source (2010-2017) (million metric tons CO_2)



Source: India IEA, 2020

Government initiatives towards climate change

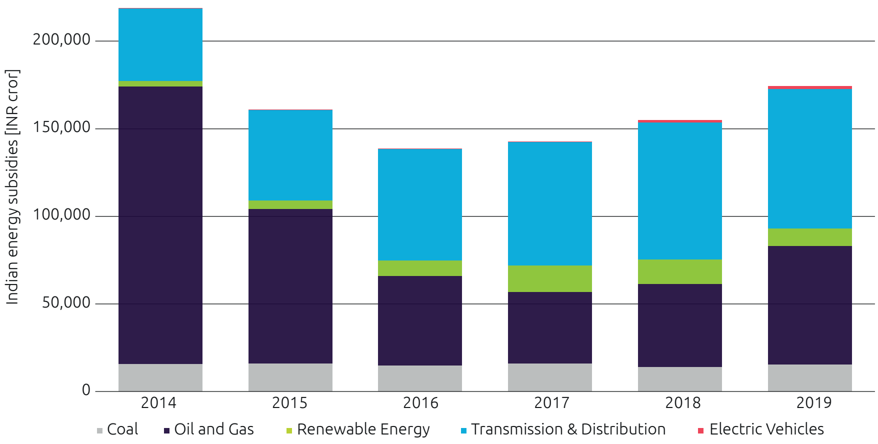
- The Indian government has made a priority of tackling air pollution, which should have significant effects on emissions. It has taken a number of initiatives to combat the challenge of climate change, including the National Action Plan on Climate Change (NAPCC), National Adaptation Fund on Climate Change (NAFCC), Climate Change Action Programme (CCAP) and State Action Plan on Climate Change (SAPCC).
- The Ministry of Environment, Forest and Climate Change (MoEFCC) announced in 2019 the National Clean Air Program (NCAP), which aims to reduce particulate matter (PM2.5 and PM10) by 20–30% by 2024, compared to 2017, including a program in 43 cities with the highest pollution.
- The government initiatives towards combating climate change has made India the only G20 country whose pledge is considered sufficient by the Carbon Tracker Initiative.
- India, for the first time, has ranked among the top 10 in the 2020 Climate Change Performance Index (CCPI), ranking 9th. India's 2030 renewable energy target is rated very highly for its well-below-2°C compatibility. The country pledged an additional carbon sink equivalent of 2.5-3 billion tonnes of CO_2 by 2030 through forest and tree cover.

A significant shift in subsidies has been enhancing efforts towards a clean energy transition since 2014

Overview of India's latest energy subsidy policies

- If the general trend since 2014 is a net shift of support away from fossil fuels and toward clean energy, India's subsidies to oil, gas and coal (INR 83,134 crore or US$ 12.4 billion in FY 2019) remain more than seven times the value of subsidies to renewables and EVs (INR 11,603 crore or US$ 1.7 billion in FY 2019).
- Renewable energy (RE) subsidies fell by 35% from FY 2017 to FY 2019 (from a high of INR 15,313 crore (US$ 2.3 billion) to only INR 9,930 (US$ 1.5 billion) in FY 2019), mainly due to falling RE costs. Several new policies confirmed since 2019 should increase RE subsidies.
- The increase of electric vehicle (EV) subsidies in the past two years is striking: EV subsidies have grown over 440 times since FY 2014 and over 11 times since FY 2017 to INR 1,673 crore (US$ 249 million) in FY 2019, with growth expected to continue.
- Consumption subsidies are also rising due to the increased government efforts towards energy access. The state-level underpriced electricity is the costliest individual subsidy policy in India, estimated at INR 63,778 crore (US$ 9.5 billion).

Figure 9. Total quantified energy subsidies in India, FY 2014–FY 2019 (INR crore)



Source: IISD-CEEW energy subsidies inventory 2020

- Coal subsidies remain largely unchanged, from INR 15,660 crore (US$ 2.6 billion) in FY 2014 to INR 15,456 crore (US$2.3 billion) in FY 2019 and are largely provided by tax breaks (around 90% of subsidies).

Impact of the COVID-19 crisis on energy subsidies

- Due to the severity of the COVID-19 crisis in India, the government is likely to shift its subsidies to prioritize health and economic recovery. It is critical that the state measures implemented should not disregard clean energy transition:
  - The crash in oil prices should free up revenue to help tackle the crisis by temporarily eliminating petroleum.
  - The demand to support energy producers should increase as profits decline and the perception of risk widens. The choice of which energy producers to support will need to be carefully reviewed not to undermine clean energy transition.
  - The expected increased demand for social protection and effective and efficient public services can be an opportunity to better target energy access subsidies towards those most in need.

Focus on oil – A shift in oil subsidies to tackle indoor air pollution issues

- Subsidies for oil and gas decreased by 76 per cent between FY2014 to FY2017, from INR 1,57,678 crore (US$ 26.1 billion) to INR 36,991 crore (US$ 5.5 billion), driven by the decline in global oil prices as well as by major subsidy reforms for petrol, diesel (diesel subsidies ended in 2014/15), LPG and kerosene (IISD and CEEW, 2018).
- However since 2017, oil and gas subsidies have increased again, by over 65% from INR 40,762 crore (US$ 6.1 billion) in FY 2017 to INR 67,679 crore (US$ 10.07 billion) in FY 2019. The main reasons for this resurgence are
  - higher oil prices.
  - growing use of subsidized liquefied petroleum gas (LPG): the largest individual subsidy is for LPG cooking, worth INR 31,447 crore (US$ 4.7 billion) or 17.9% of all energy subsidies (37% of all O&G subsidies). To reduce women's and children's exposure to household pollution, the government launched the Ujjwala scheme in 2017, targeting 50 million new LPG users by providing a subsidy of INR 1,600 to women in households classified as below the poverty line. It is however believed that LPG subsidies are not well targeted, a large portion of LPG subsidies going to higher-income households.
- Kerosene and cooking gas (LPG) were the only oil products subsidised by the government in 2019, but the government of India is increasing their price gradually to phase out the subsidies. The reduction of kerosene subsidies is also linked to clean energy access, as kerosene is a source of indoor air pollution.

India's energy RD&D landscape is largely dominated by the public sector

Energy RD&D supports India's national policies

- Energy research, development and deployment (RD&D) can support India's energy policy goals such as enabling country-wide energy access or containing air pollution and meeting climate targets.
- At the same time, it can contribute to broader national policy such as the"Make in India"manufacturing initiative, launched in 2014 to transform India into a global design and manufacturing hub.

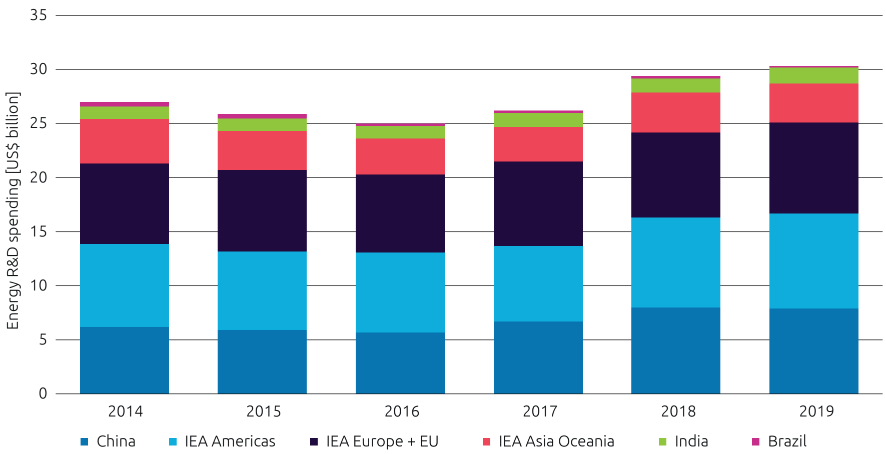
Public clean energy RD&D funding has been increasing but remains much smaller than funding allocated to fossil-fuel RD&D

- Unlike most countries where the private sector drives market-led technology innovation activities, India's energy RD&D landscape has historically been largely dominated by the public sector and involves a broad range of ministries and related agencies.
- Government clean energy RD&D funding has strongly increased in recent years, from US$ 72 million in 2015 to US$ 1,10.61 million in 2018. As a comparison, total public energy RD&D spending amounted to US$ 652.8 million that same year, including US$ 370 million on nuclear power and US$ 180 million on fossil fuel energy.
- Besides public funding, the government initiated a wide range of energy-related National Missions such as the National Smart Grid Mission (2015) or the National Mission on Transformative Mobility and Battery Storage (2019).

The importance of the private sector in the Indian energy RD&D landscape is rising

- In 2018, total private energy RD&D spending amounted to USD 418 million. Indian car makers spent an additional USD 900 million on R&D, significantly directed to more efficient and alternative fuel vehicle technologies.
- The role of the private sector in energy technology innovation is expected to increase in the coming years. The"Make in India"initiative intends to focus on public-private collaboration to scale up domestic technology development and deployment.
- As a result, international energy companies are opening research institutes in India, such as Shell's Technology Centre in Bangalore, one of the company's three global technology hubs, alongside those in the Netherlands and the USA.

Figure 10. Spending on energy R&D by national governments, 2014-2019



Source: Niti.gov.in 2020

India is a key multilateral international collaboration stakeholder, even though its energy RD&D spending is way smaller compared to other emerging economies

- India is a leader in multilateral collaborations such as the IEA Technology Collaboration Programmes, where it contributes to 11 Programmes, the second largest involvement among IEA partner countries.
- India is also a founding and leading member of Mission Innovation, a global initiative working to accelerate clean energy innovation.
- It has established strong bilateral collaborations with other governments to support energy RD&D cooperation and attract foreign investment and human capital, for instance with the UK (e.g. Joint UK-India Clean Energy Centre) or the US (e.g. Indo-US Joint Clean Energy Research and Development Centre in smart grids and energy storage).
- However by global comparison, India's total expenditure in energy RD&D is rather small, especially compared to China, the United States or Europe. At 0.23 per thousand GDP units (flat share over the last two decades), it is way below the IEA mean of 0.36 per thousand GDP units.

Over the last decade India has been strengthening its innovation efforts using a wide range of new technologies

India is a global pioneer in advanced biofuels innovation

- India is co-leader of Mission Innovation's challenge on sustainable biofuels, as well as a member of the IEA Bioenergy task.
- The 2018 National Policy on Biofuels set ambitious biofuels targets of 20% ethanol and 5% biodiesel blending by 2030, aiming at sourcing these biofuels only from sustainable feedstocks that do not compete with food security.
- Advanced biofuel is a representative example of public-private innovation partnerships. For instance, the Department of Biotechnology (DBT) and the Indian Oil Corporation Limited (IOCL) launched in 2012 the Advanced Bioenergy Research Centre that notably conducted research on lignocellulosic ethanol (biofuel produced from non-food crop biomass such as residues from cotton or rice), with demonstration plants for processing 1 to 30 ton/day of bio-waste planned for 2020.
- However, advanced biofuels are still in the early stages of development. Even though the potential feedstock availability is sufficient to meet the 2030 targets, the high upfront costs and the slow pace of deployment of large commercial-scale advanced biorefineries put the ambitious target at risk.

A world leader in sustainable cooling

- Developing cleaner cooling technologies is a key challenge for India, as demand for highly polluting air conditioning and refrigeration is strongly increasing in the country.
- It is a global leader on the subject, and one of the first countries to have released its national Cooling Action Plan in 2019, establishing a plan for robust R&D on alternative cooling technologies.
- In 2018, the Indian Government and the Rocky Mountain Institute launched the Global Cooling Prize, an international innovation competition aiming at developing breakthrough super-efficient and climate-friendly residential cooling solutions. The winner will be announced in November 2020 and be awarded US$1 million to develop its prototype, that must have 5x lower climate impact than the baseline AC unit, while remaining affordable to consumers.

The electric vehicles market is dominated by two and three wheelers

- The Indian Electric Vehicles (EVs) market is by far dominated by two wheelers (98% of EV sales). The sale of electric two-wheelers increased from 54,800 units in 2018 to 126,000 in 2019. Electric three-wheelers/e-rickshaw fleets are also growing, with around 1.5 million functioning units transporting 60 million people every day.
- In 2019, electric cars accounted for only 0.1% of the market share, far below the 4.9% market share achieved in China.
- The government set a target of 15% of vehicle sales to be electric by 2022. An incentive program, the Faster Adoption and Manufacturing of Hybrid and EV (FAME) scheme, provides subsidies worth ~60% of the purchase price of EVs.

Progress under the ambitious Smart Cities Mission remains to be assessed

- In 2015, the Indian government launched its Smart Cities Mission, an initiative to develop 100 smart cities by improving infrastructure and services such as water, energy or mobility,using new technologies.
- Around 5,000 smart projects have been proposed and more than 1,000 have already been implemented in the selected cities, in areas such as smart roads, smart solar or wastewater.
- The government will shortly publish a report assessing the progress made under this initiative.

Hydrogen has a high potential in India but needs to be scaled-up

- Hydrogen in India is currently mostly produced through reforming methane, resulting in significant CO_2 emissions. The potential to capture these emissions through carbon capture and storage (CCS) technology is relatively underdeveloped in India.
- Low Carbon Hydrogen technologies relying on electrolyser facilities and renewable electricity are yet to be deployed at scale, but have a strong potential in India due to the decreasing cost and increasing availability of renewable electricity. Significant research activities are being conducted.
- Markets for Hydrogen include balancing supply and demand in the power sector, replacing fossil fuels in industry, and the carbon-intensive and quickly expanding heavy duty transport market.
- It is estimated that Hydrogen use in India's energy mix could grow up to 10 times by 2050. However, the use of Hydrogen in vehicles has for now been limited to research and test runs, especially due to its extremely high cost.

Southeast Asia

Region description

Country: Southeast Asia
(Hong Kong, Singapore, Malaysia, Philippines, Vietnam and Taiwan)

Population: 246,922,296
GDP: US$ 2,327,614 Million

Electricity
- Total electricity generation (2019) : 869 TWh
- Average electricity price:12 US Cents /kWh
- Access to electricity (average % of population): (2018): 98-100%%

Energy
Regulatory model:
Regulated market in Hongkong and Malaysia, partly Deregulated in Singapore, Philippines and Vietnam, while subsidized, quasi monopolized in Taiwan

Environment
Energy-related CO_2 Emissions:
Hong Kong: 95 Mt CO_2
Singapore: 219 Mt CO_2
Malaysia: 245 Mt CO_2
Vietnam: 286 Mt CO_2
Taiwan: 279 Mt CO_2
Philippines: 140 Mt CO_2

Renewable Energy
Renewable energy consumption (% of total final energy consumption): 69.7

Region description

Energy Players
Hong Kong: CLP Group (US$10,934 Million), The Hong Kong and China Gas Company (US$5190 Million), Hong Kong Electric Company (US$1,584 Million)
Singapore: Singapore Power(US$3,072 Million)
Malaysia: Tenaga Nasional Berhad (TNB) (US$ 12,994 million)
Philippines: Manila Electric (US$ 5788 million)

Recent Developments
- Singapore: Introduced Solar Nova initiative to accelerate solar deployment through promoting and aggregating solar demand across government agencies
- Malaysia: Developing a new roadmap for energy transition called the Renewable Energy Transition Roadmap (RETR) 2035
- Vietnam: In 2019, Vietnam's solar energy achieved an impressive amount of installed capacity – recognized as one of the world records
- Taiwan: The government has set ambitious targets to change the underlying fuel that would see 20 per cent of Taiwan's power generated by renewable sources through 2025
- Philippines: Plans to introduce The Green Energy Tariff Program (GETP)

Southeast Asia is susceptible to the effects of climate change due to extreme weathers and rising sea levels

According to the Intergovernmental Panel on Climate Change (IPCC) 2019 report on global warming, "Countries in the tropics and Southern Hemisphere subtropics are projected to experience the largest impacts on economic growth due to climate change, which should cause global warming increase from 1.5°C to 2°C"

According to the Global Climate Risk Index (CRI) 2020 by Germanwatch (the index scrutinized both absolute and relative impacts of the climate to create an average ranking of countries and also depicted the exposure and vulnerability to extreme events of South Asian countries):

- Due to recurrent catastrophes such as earthquakes and volcanic eruptions, the Philippines ranks fourth out of 181 countries most affected by climate-related disasters.
- Vietnam ranks sixth in the index due to recurrence of floods and its carbon emissions. To reduce emissions Vietnam is focusing on reforestation and increased use of renewables.

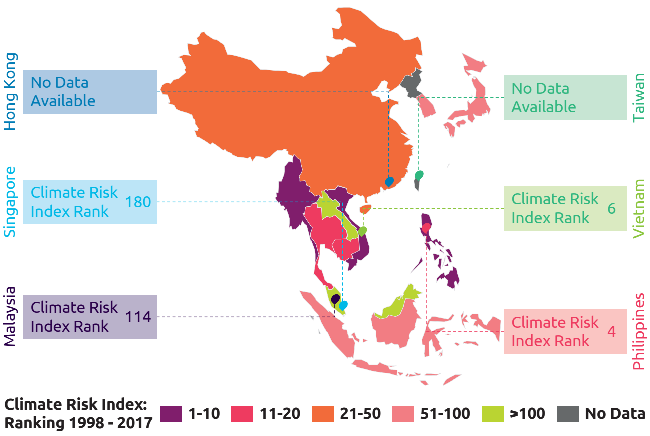
Due to climate changes, countries are facing extreme weather events and rising sea levels

- Typhoons and floods are becoming more intense and frequent in Southeast Asian countries especially Vietnam.
- In the Philippines, extreme weather events like Typhoon Mangkhut and torrential rainfall have exposed the country to the vulnerabilities of climate change.

Some SEA countries, not in the top 10 in the CRI, are nevertheless acting to mitigate the impact of climate change:

- Singapore is investing S$100 billion to safeguard the city against rising temperatures and flooding caused by climate change.
- Malaysia's CCI ranking has moved from 116 to 114 due to tropical floods. To combat climate change, the country is implementing policies particularly for energy, water resources, agriculture, and biodiversity.
- As announced in 2019, the Taiwan government is actively implementing carbon reduction policies and plans to move the city of Taipei to higher ground.

Figure 1. Risk of Southeast Asian Countries in Global Climate Risk Index, 1999–2018



CRI Rank (1999-2018)	Country	CRI Score	Fatalities (annual average)	Fatalities per 100,000 Inhabitants (annual average)	Losses in US$ million (PPP) (annual average)	Losses per unit GDP (annual average)
1	Puerto Rico	6.67	149.90	4.09	4567.06	3.76
2	Myanmar	10.33	7052.40	14.29	1630.06	0.83
3	Haiti	13.83	274.15	2.81	388.93	2.38
4	Philippines	17.67	869.80	0.96	3118.93	0.57
5	Pakistan	28.83	499.45	0.30	3792.52	0.53
6	Vietnam	29.83	285.80	0.33	2108.77	0.47
7	Bangladesh	30.00	577.45	0.39	1686.33	0.41
8	Thailand	31.00	140.00	0.21	7764.06	0.87
9	Nepal	31.50	228.00	0.87	225.86	0.40
10	Dominica	32.33	3.35	4.72	133.02	20.80
114	Malaysia	103.33	64	102	66	143
180	Singapore	172.17	172	172	163	177

Notes:

1) CRI evaluates countries that have been affected by impacts of weather-related loss events (storms, floods, heat waves etc.). Taking into account data from 1999-2018, the index quantifies impacts of such extreme weather events – both in terms of fatalities as well as economic loss – and ranks the countries accordingly.

2) Each country's index score has been derived from a country's average ranking in all four indicating categories, according to the following weighting: death toll, 1/6; deaths per 100,000 inhabitants, 1/3; absolute losses in PPP, 1/6; losses per GDP unit, 1/3.

3) GDP = gross domestic product; PPP = purchasing power parity

Source: Germanwatch and Munich Re's NatCatSERVICE (Report last updated in Dec 2019)

Southeast Asia is highly vulnerable to climate change as a large proportion of the population uses coal as a source of energy and power, leading to high GHG emissions

Power sector of Southeast Asian countries is responsible for almost half of CO_2 emissions in 2040. For example:

- Vietnam's economy has seen huge growth by increasing its global trading. However, this has required greater use of fossil fuels and transportation, increasing carbon emissions by 20 per cent in 2019.

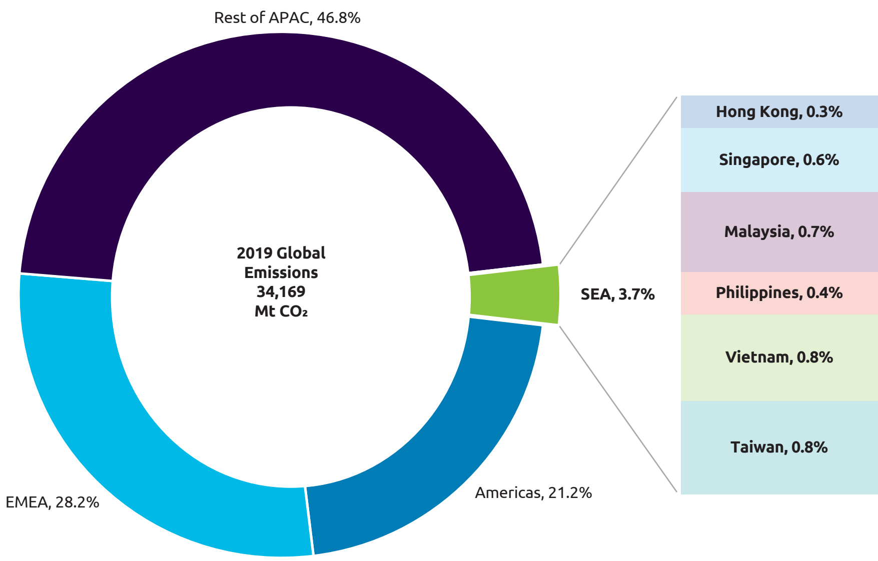
According to BP's Statistical Review of World Energy 2020, Hong Kong and Singapore have shown a decline in carbon emissions of 4.8 per cent and 2.8 per cent respectively.

- Singapore contributes around 0.11 per cent of global GHG emissions. In 2019, these fell by 2.8 per cent year-on-year due to increased use of solar energy.
  - The government plans to phase out internal combustion engines (ICEs) by 2040. In the refining and petrochemical sector, the biggest players are working to reduce their carbon contribution.
- Hong Kong witnessed a decline of 4.8 per cent in carbon emissions by replacing coal with natural gas for electricity generation and developing renewable sources of energy.

Figure 2. Energy-related CO_2 Emissions Growth, 2019 (Million Metric Tons)

Source: BP Statistical Review of World Energy (Report published, June 2020)

Figure 3. Southeast Asia's Share in Global Emissions, 2019 (Million Tons CO_2)



Source: BP Statistical Review of World Energy, June 2020

Coal is a distinct key contributor to the increased carbon emissions over the last decade

- In 2019, global CO_2 emissions from coal declined by 200 million tonnes (Mt), or 1.3 per cent, from 2018 levels, offsetting increases in emissions from oil and natural gas. In 2018, coal-fired power plants were the chief contributor to the growth in emissions with an increase of 2.9 per cent, or 280 Mt, compared with 2017 levels.

At the Paris agreement, all relevant Southeast Asian countries undertook to keep global warming below 2°C and have been limiting coal plants to reduce carbon emissions

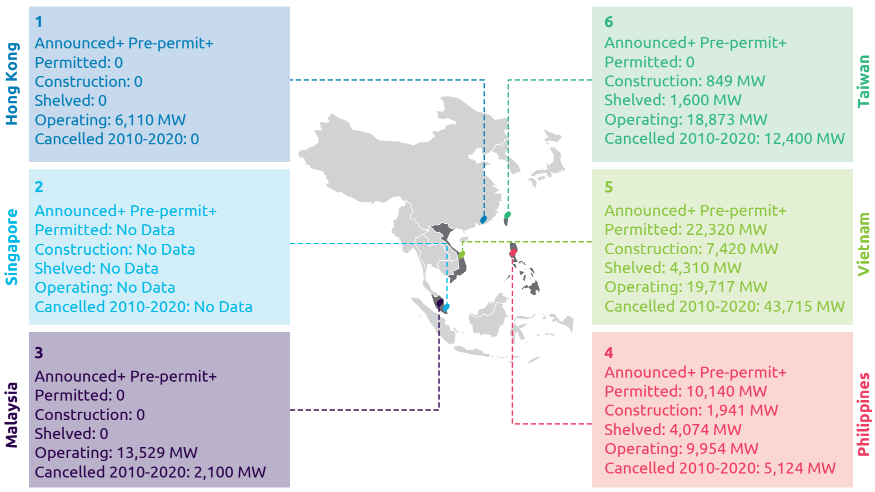
The pace of new commissioning has decelerated, and construction of new plants fell by more than 85 per cent from 2016 to 2019. However, countries are still dependent on coal and are commissioning new projects. For example:

- In Vietnam, the coal fleet has grown faster than other Southeast Asian countries, adding 76 per cent (14 GW) of its 18.4 GW of coal-fired capacity in the past six years. In 2020, an additional 8.7 GW plant is under construction, and 22.3 GW is at the pre-construction stage.
- Malaysia is embracing renewable energy in the next decade. However, it will continue to develop thermal power capacity which will lead to an increase of 5 GW in coal and gas capacity.
- In the Philippines, it is expected that coal expansion by its biggest energy company, Meralco, could lead to the fossil fuel share of the energy mix increasing hugely from 52 per cent in 2019 to 75 per cent by 2025.
- However, the Ayala Corporation (the Philippines' oldest conglomerate) has announced that it plans to exit coal plant construction by 2025.

By shifting towards renewables, Southeast Asia is trying to adapt to the trend of reducing its carbon footprint

- To meet both sustainable development goals and the goals of the Paris Agreement, Southeast Asia plans to decarbonize its energy systems by 2050, mainly through the rapid increase in renewable energy.
- In 2019, major financial players United Overseas Bank (UOB), DBS Bank, and Oversea-Chinese Banking Corporation (OCBC) all exited coal to invest more in renewables.
- New renewable technologies like carbon capture and storage offer an opportunity for balancing economic growth and continued usage of fossil fuels.

Figure 4. Coal Plants in Southeast Asia, July 2020



Note: Includes coal plants of 30 MW or larger, as well as every plant proposed since January 1, 2010.

Source: Global Energy Monitor (Report published, July 2020)

Asia

In Southeast Asia, technological innovations and favorable government policies are key factors driving the clean energy transition

According to the International Renewable Energy Agency (IRENA) 2019 report, increased energy requirements and changing supply-demand dynamics are creating new challenges in the energy sector

Continued use of coal for electricity and power generation in Southeast Asia and increased commodity prices have contributed to slow progress in energy transition.

Southeast Asia Energy Transition

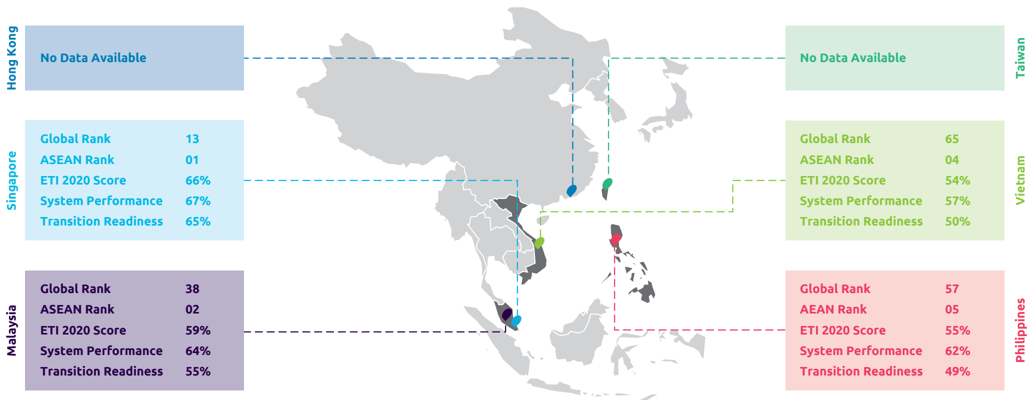
According to the Energy Transition Index (ETI) 2020:

- Singapore has a high ETI ranking of 13, due to its stable guidelines and establishments, a governance framework and transparency along with a culture of innovation and contemporary infrastructure.
- Malaysia has an ETI ranking of 38, due to its high electrification rate, low usage of solid fuels, diversity of its fuel mix and high quality of electricity supply.
- The Philippines has a low ETI rank of 57 but improved from the previous year due to the decline in coal power generation.
- Vietnam has a low ETI rank of 65, due to weaker institutions and a low quality of transportation infrastructure.
  - Vietnam had suffered from a long-term drought that caused a significant shortage of electricity, because of reliance on electricity generated from hydropower.
  - Hence, adequate policies and innovative solutions such as floating solar PV on reservoirs to reduce evaporation should be adopted to diversify the generation sources.

Urbanization, industrialization, and rising living standards continue to drive energy demand and will lead to the emergence of technologies. The dominance of fossil fuels is impacting on the degree of environmental sustainability.

To meet the sustainable goals of Southeast Asia's energy transition, countries are relying on bioenergy, development of biofuels, and renewable technologies

Figure 5. Energy Transition Index Ranking in Southeast Asia, 2020



Definitions:

1. **The Energy Transition Index (ETI), 2020:** Benchmarks countries on the performance of their energy system, as well as their readiness for transition to a secure and sustainable energy future. The Global ETI aggregates indicators from 40 different energy, economic and environmental datasets in order to provide a comprehensive, data-driven picture of the world's energy system. The ETI 2020 score on a scale from 0% - 100%, with 100% being the highest and 0% being the lowest.

2. **Association of Southeast Asian Nations (ASEAN) Rank:** Benchmarks the six Asian countries: Thailand, Singapore, Malaysia, Indonesia, Vietnam and the Philippines on the performance of their energy system, as well as their readiness for transition to a secure and sustainable energy future.

3. **System performance** provides an assessment of countries' energy system related to their delivery in three key priorities: the ability to support economic development and growth, universal access to a secure and reliable energy supply, and environmental sustainability across the energy value chain

4. **Energy transition readiness** is captured by the stability of the policy environment and the level of political commitment, the investment climate and access to capital, the level of consumer engagement, the development and adoption of new technologies, etc

Source: BP Statistical Review of World Energy, 2019

The Energy Trilemma: Hong Kong and Singapore rank highly due to government initiatives towards the energy and environment; Taiwan remains vulnerable

The Energy Trilemma: Energy transition is a policy challenge that involves managing the three core dimensions of energy security, energy equity and environmental sustainability.

According to the 2019 World Energy Trilemma Index for the SEA region:

Country	2019 Rank	2018 Rank	Rank changes
Hong Kong	34	34	No change
Singapore	43	19	▼
Malaysia	51	37	▼
Philippines	94	74	▼
Vietnam	91	83	▼

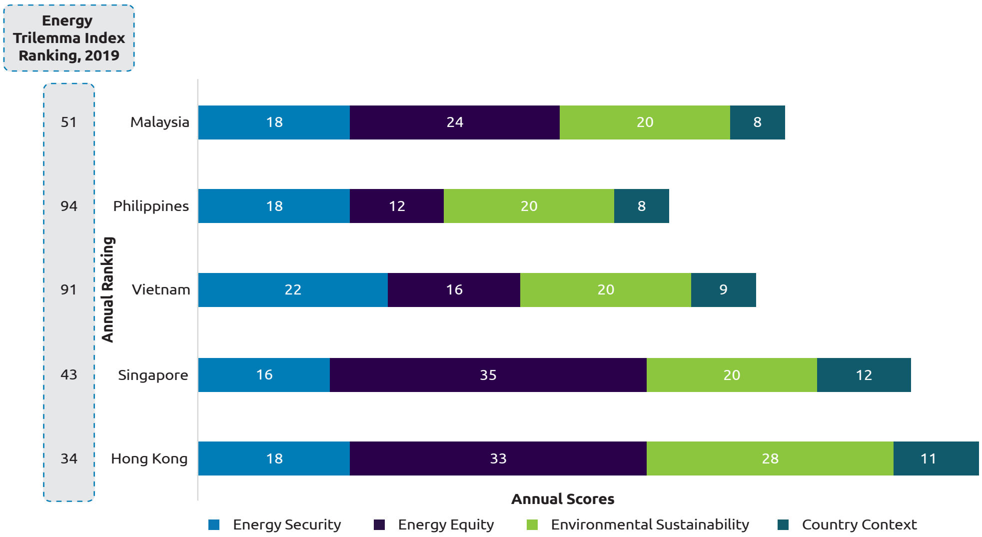
- **Hong Kong** saw no change in its Trilemma Index ranking, due to reliance on energy imports and improved environmental sustainability.
- **Singapore** is ranked at 43, due to low energy security and high energy equity as over 90 per cent of electricity was produced from imported natural gas. To combat this, the country has launched an initiative to consolidate gas, solar and thermal energy into a single intelligent network.
- **The Philippines'** rank fell again due to its low electrification, which is needed to improve energy security and equity.
- **Vietnam** stands at 91, due to its weak environmental sustainability as it ranks low in clean energy adoption; in addition, the country is vulnerable to typhoons and floods.
- **Malaysia's** ranking has fluctuated recently due to global prices changes that have affected its energy security.

Taiwan isn't included in the Energy Trilemma's list of 125 countries due to its own energy challenges

The government is focusing on energy policies to shift the country towards decarbonization, which include:

- **Energy security:** Due to obstruction in opportunities for international cooperation, including global supply and price shocks, Taiwan's energy security is at risk.
- **Equitable and affordable:** Fiscal and investment obstacles have impeded the creation of a more efficient energy market in Taiwan.
- **Environmental sustainability:** Enhanced international cooperation could be essential in Taiwan's journey to environmentally sustainable energy.

Figure 6. Southeast Asia Trilemma Index, 2019



Definitions

1. World Energy Trilemma Index: Provides an objective rating of national energy system performance across these three Trilemma dimensions which involves three core dimensions: Energy Security, Energy Equity and the Environmental Sustainability of Energy Systems throughout the transition process

The Trilemma Index presents two sets of results: **Annual scores and Index trends.** Annual scores are calculated from each dataset and rescaled from 0 to 100, with higher scores representing better performance and a higher annual rankings. Individual indicator scores are combined into annual dimension scores using relative weights.

Dimension Index trends, or dimension indices, are calculated to show improved dimension performance from a baseline year, set as 2000. Each dimension score in the year 2000 is assumed to represent an Index value of 100

2. Energy Security: Reflects a nation's capacity to meet current and future energy demand reliably, withstand and bounce back swiftly from system shocks with minimal disruption to supplies

3. Energy Equity: Assesses a country's ability to provide universal access to affordable, fairly priced and abundant energy for domestic and commercial use

4. Environmental Sustainability of Energy Systems: Represents the transition of a country's energy system towards mitigating and avoiding potential environmental harm and climate change impacts

5. Country Context: Focuses on elements that enable countries to effectively develop and implement energy policy and achieve energy goals.

Source: World Energy.org, May 2020

Southeast Asian countries are continuously improving their equity score through access to modern energy that has gained momentum across the region and in many Asian countries.

Southeast Asia is set to make its mark on global energy demand and clean energy transition by focusing on new policies

According to a 2019 International Energy Agency (IEA) report, it is expected that the share of renewables will triple to 70 per cent in the energy mix by 2040

As the economy expands, more energy will be required to boost it. In addition, the population of Southeast Asia is expected to expand by 20 per cent, with the urban population alone growing by over 150 million people in the next 10 years. These factors will drive energy demand in Southeast Asia.

Therefore, to boost clean energy and ensure security of supply, governments are formulating new policies.

Malaysia: A paradigm shift towards clean energy:

According to the Energy Transition Index (ETI) 2020,

- Malaysia is developing a new roadmap for energy transition called the Renewable Energy Transition Roadmap (RETR) 2035 that aims to boost renewables share to 20 per cent of the country's energy mix by 2025.
- The government is focusing on ways to promote the growth of sustainable energy (SE) in the form of renewable energy (RE) and energy efficiency.
- Potential strategies in the roadmap include peer-to-peer energy trading, where prosumers (producer-consumers) will be able to sell their excess electricity to consumers through net energy metering (NEM).
- In 2020, Malaysia launched a new round of solar auctions with a targeted capacity of 1 GW. It also plans to add about 800 MW net capacity between the end of 2019 and 2029.

Singapore: To meet the demand for clean energy, it has included regional power grids as one measure to help decarbonize its power sector, which is based on imported natural gas.
Vietnam: In 2019, Vietnam's solar energy achieved an impressive amount of installed capacity – recognized as one of the world records due to its feed-in tariff **(FiT)** incentive from the government.

To further encourage development of solar power projects, the government has introduced feed-in tariff 2 (FiT2), applicable for solar projects from 1 July 2019 to 31 December 2021.

- This new FiT2 program has increased tariffs for floating solar energy projects in order to compensate for their high technology costs, removed tariffs for solar power projects with integrated storage systems as there is low interest in them, and set a single commercial operation date (COD) deadline of 31 December 2021.

According to the 2019 International Energy Agency report, demand for energy in Southeast Asia is expected to grow at a rate twice the global average over the next 20 years

In 2019, growth in renewables was driven by solar, wind, hydropower and natural gas, which together contributed over three-quarters of the net increase. Southeast Asia is becoming one of the fastest-growing solar energy markets and one of the most promising regions in the global expansion of the solar energy industry.

Southeast Asia's growth in electricity demand averages 6 per cent per year, the fastest in the world. However, several power systems are facing a financial crisis.

- Southeast Asia's energy demand will require enormous investment in energy generation and transmission infrastructure.

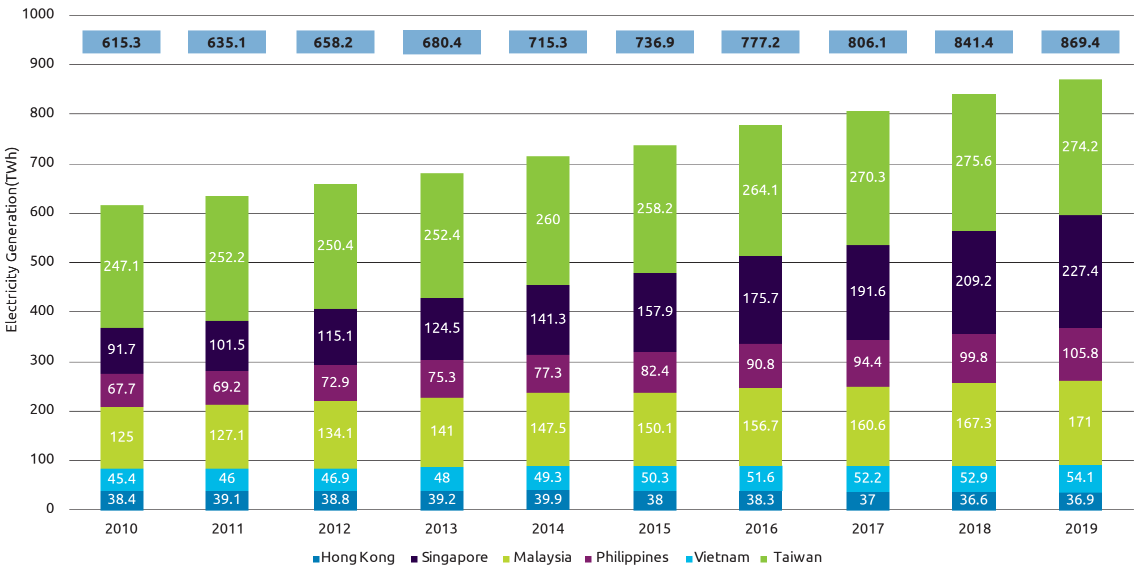
– Government policies will play a critical role in moderating the impact of this demand; over 95 per cent of energy investment is incentivized by regulations and contracts.

– According to the 2020 National Renewable Energy Laboratory (NREL) report, SE Asia's energy generation capacity needs to double by 2035; to meet the growing demand it requires investment of US$500 billion in power generation assets.

To meet the demand for clean energy, Southeast Asia is focusing on the latest trends, which include:

- Micro grids or mini grids that provide energy to remote communities.
- Investment from development banks and green funds for infrastructure projects.
- Blockchain solutions for peer-to-peer (P2P) energy trading.

Figure 7. SEA - Electricity Generation by Country (Terawatt Hours), 2010-2019



Source: BP Statistical Review of World Energy, June 2020

Shifting to renewables at a measured pace:

- In most Southeast Asian countries, coal is and will remain a major energy contributor for some time. However, recent investment in coal infrastructure development has slowed abruptly to combat carbon emissions.
- Policymakers have been intensifying efforts to ensure a secure, affordable, and sustainable pathway for the energy sector, which includes activities to facilitate investment in solar power generation and infrastructure.

In 2019, Electricity bills in Singapore and the Philippines were amongst the highest in Southeast Asia due to heavy reliance on energy imports

- **Philippines:** In 2019, the Philippines had the highest electricity rates in Southeast Asia at US$0.20 per kWh for households and US$0.134 per kWh for businesses.
  – The high prices reflect the country's dependence on imported fossil fuels and its uncompetitive market structures.
  – According to the 2019 Institute for Energy Economics and Financial Analysis (IEEFA) report, the introduction of renewables to the Philippines energy market should lead to a decline in wholesale energy prices of 30 percent.

- **Singapore:** In 2019, the price of electricity was US$0.180 per kWh for households and US$0.144 per kWh for businesses. Prices varied due to changes in commercial oil contracts according to global conditions.
  – The government is planning to reduce electricity tariffs for the period July 1, 2020 to September 30, 2020 due to the changes in the cost of fuel and power generation. Prices will decrease by an average of 15 per cent or 3.42 cents per kWh compared with the previous quarter.

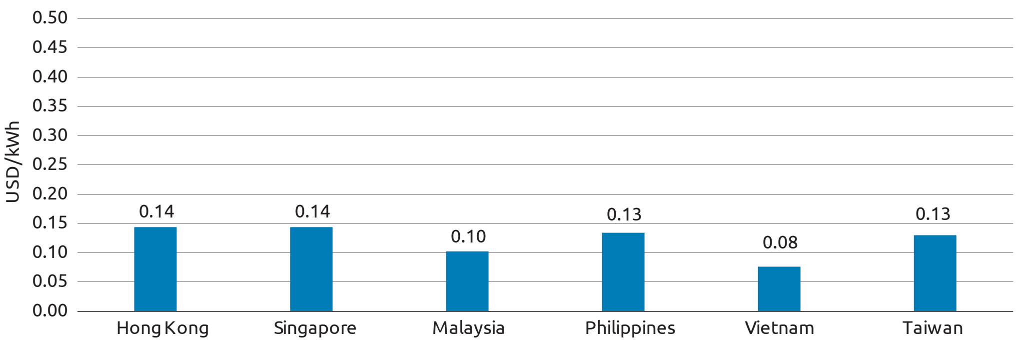
- **Malaysia:** In 2019, the price of electricity was US$0.057 per kWh for households and US$0.102 per kWh for businesses. Electricity prices will rise because the government has set the base tariff at 39.45 sen per kWh.

- **Hong Kong:** In 2019, the price of electricity was US$0.144 per kWh for households and US$0.142 per kWh for businesses. Prices rose due to the growth in natural gas generation leading to higher capital expenditure and increased fuel costs.

- **Vietnam:** In 2019, the price of electricity was US$0.081 per kWh for households and US$0.077 for businesses. In the last decade, Vietnam's electricity prices have almost doubled, although no price rises are evident since 2017. The electricity price is on the low side as foreign investors are not attracted to Vietnam's electricity projects.

- **Taiwan:** The price of electricity was US$0.096 per kWh for households and US$0.130 for businesses in 2019. Energy markets across the world are observing some fluctuations but Taiwan continues to maintain its current price.

Figure 8. Southeast Asia Average Retail Electricity Tariffs(USD/Kilowatt Hour), 2019



Note: US$/kWh excluding VAT but including all other applicable taxes and charges
Source: GlobalPetrolPrices.com, June 2020

COVID-19 has had a pronounced impact in Malaysia, the Philippines, Singapore, and Vietnam due to the relatively larger demand for power by the industrial sector and the export orientation of the economies

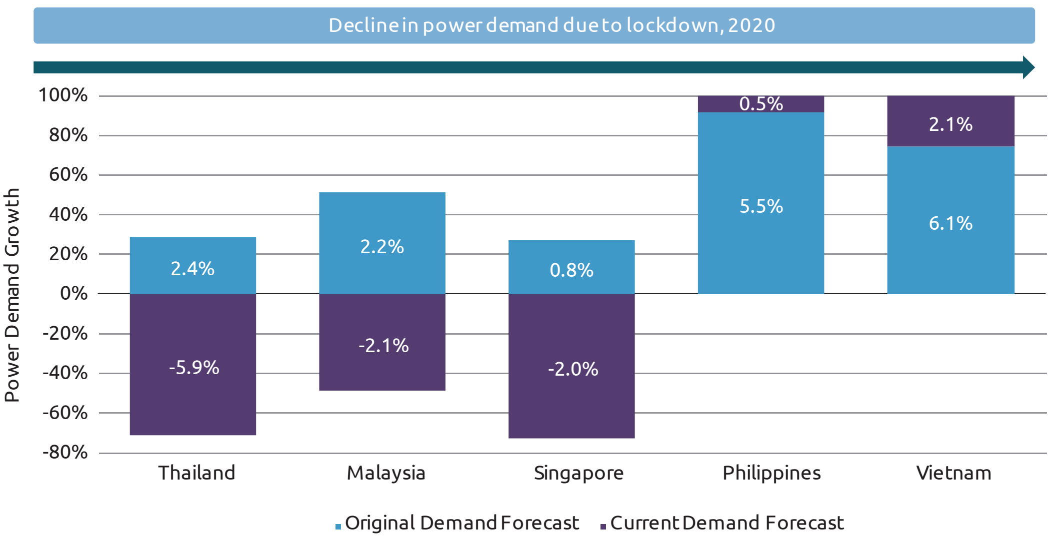
Declining rates of fossil fuel combustion have shown temporary improvements in air quality and reductions in emissions and pollutants.

Countries will take one or two years to return to their original growth trajectory. Although the project delays may not affect the overall system stability and reliability, the scheduled power development plans and renewable targets in Southeast Asia countries will be affected.

Country	Number of lockdown days (start date, end date)*	Estimated decline during lockdown	Estimated decline vs 2019 annual power demand
Philippines	46(16 March 2020, 30 April 2020	2.7TWh	2.6%
Malaysia	56(18 March 2020, 28 April 2020	5.7 TWh	3.5%
Singapore	56 (7 April 2020, 1 June 2020	0.7 TWh	1.2%
Vietnam	23(1 April 2020, 22 April 2020)	1.5 TWh	0.6%

*Indicative end date of lockdown as of 24 April 2020

Figure 9. SEA - COVID-19 Impact on Power Sector, 2020



Source: IHSMarkit, May 2020

Asia

Impact on Power Demand:

- Pandemic responses have decreased overall electricity system demand, lowering commercial and industrial usage while increasing residential consumption—shifting and changing the shape of load curves. Residential utility bills have increased for much of the population, adding additional strain to consumer financial health that has been impacted by economic disruption.

New policies and regulations aim to combat fluctuating electricity tariffs and accelerate the use of solar energy

Countries	Description
Hong Kong	• **Scheme of Control Agreement (SCA)** The SCA provides a framework for the government to monitor HK Electric's financial affairs and operating performance. It is effective for 15 years from January 1, 2019 until December 31, 2033. HK Electric is entitled to a return of 8 per cent on average net fixed assets. This agreement provides long-term security for HK Electric while it's replacing coal-fired units by gas-fired ones. With a strong emphasis on energy efficiency, customer services, promotion of renewable energy and operational transparency, the SCA effectively balances the interests of various stakeholders. • **Feed-in Tariffs (FiTs)** The FiT scheme is an important new initiative to promote development of renewable energy (RE) under the current SCAs, which were ratified by the government and two power companies in April 2017. The FiT scheme will help encourage the private sector to invest in RE as the energy generated can be sold to power companies at a rate higher than the normal electricity tariff, to help recover the cost of investment in RE systems and generation.
Singapore	• SolarNova This initiative, led by the **Economic Development Board (EDB)**, aims to accelerate solar deployment in Singapore through promoting and aggregating solar demand across government agencies. SolarNova will encourage private sector adoption of solar as various players in the ecosystem, such as engineering contractors, project developers and financial institutions, become more familiar with solar projects.
Malaysia	• **Sustainable Energy Development Authority (SEDA)** By November 2019, Malaysia had approved a cumulative net energy metering (NEM) program quota of 108 MW. – In Q4 2018, SEDA Malaysia introduced e-bidding for biogas, with the second e-bidding in July 2019. Also in 2019, it extended e-bidding to small hydro in applications under the Feed-in Tariff (FiT) scheme to facilitate price discovery for RE generated from resources and promote healthier competition.

Countries	Description
Vietnam	• **Decision 13** – In April 2020, "Decision 13" was announced, detailing mechanisms to encourage development of solar energy projects in Vietnam. Decision 13 draws a clear distinction between grid-connected solar power projects and rooftop ones, each having different regimes and feed-in tariffs. It has provided better clarity by further classifying grid-connected solar power projects into two types –floating and ground-based. – Floating power projects are new to Vietnam's solar sector, and are defined as grid-connected solar ventures with photovoltaic panels installed on a floating structure on the water surface. Grid-connected solar power projects that are not floating are considered to be ground-based.
Taiwan	• The government has set ambitious targets to change its basic fuel mix – a "20-30-50" formula that would see 20 per cent of Taiwan's power generated from renewable sources, just 30 per cent from coal, and 50 per cent from natural gas by 2025. To add some 27 GW of generation capacity from renewables, the government aims to attract as much as US$59 billion in foreign investment. • Taiwan is closely connected with the global manufacturing supply chain. With tech giants such as Google and Apple joining the RE100 initiative, the pressure is on for suppliers in Taiwan and elsewhere to use green energy. • In 2019, Taiwan's Renewable Energy Development Act ("RED Act") was updated, so that renewable energy generation facilities over 500 kW but below 2,000 kW are no longer obliged to obtain an electricity business license, and only need to register the facilities under the Regulation Governing the Establishment of Renewable Energy Facilities before commencing operation.
Philippines	• In 2020, the Philippines plans to introduce its **Green Energy Tariff Program (GETP)**, which targets 2,000 megawatts (MW) of new installed capacity, an investment value equivalent to US$2 billion (generation only, excluding transmission, distribution and storage). The policy will be designed around a price cap and a renewable energy auction administered by the Department of Energy and a Green Energy Allocation Committee appointed by the Secretary of Energy. • Green strategies now have the potential to unlock new sources of donor-backed funding that could meaningfully reduce the Philippines' long-term power costs by ending its dependence on imported fossil fuels.

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WEMO 2020 Australia Editorial

Jan Lindhaus & Anastasia Klingberg

2019 saw Australia experiencing one of the longest and most intensive bushfire seasons on record as well as recording the driest year in 119 years. Mean surface temperatures have risen more steeply in Australia than in the rest of the world. Climate change and therefore energy policy and energy transition has been front and centre in everyone's minds over 2019/2020.

This is our fourth edition of the Australian section of the World Energy Market Observatory and we continue to monitor the evolving nature of Australia's Energy transition.

Investment in renewable energy has again increased over the last year, contributing to a continuing shift in the energy generation mix away from traditional fossil fuel sources.

- At the end of 2019, 11.1 GW of new generation was under construction or financially committed, representing A$20.4 billion in investment and more than 14,500 jobs. 34 renewable energy projects were completed.
- In 2019, renewable energy was responsible for 21 per cent of Australia's total electricity generation, an increase of 2 percentage points on 2018.
- In 2019, the amount of new clean energy capacity additions were evenly split between the large-scale and small-scale sectors, each setting new records and contributing half of the 4,400MW.

Australia will meet its 2020 renewable energy target of 23.5 per cent and 33 terawatt hours and according to government sources it will surpass the emissions reductions required to meet its 2020 Kyoto Protocol target by 264 MT CO_2-e.

The ability to meet the 2030 Paris Agreement target of 26-28 per cent below 2005 levels is still uncertain with current government calculations suggesting it will need to use its carry-over credits from the Kyoto Protocol to meet this target. To date, Australia is the only country to indicate it will use carry-over credits to meet the Paris Agreement targets.

In 2020, the Australian Energy Market Operator (AEMO) released its Draft 2020 Integrated System Plan (ISP). The ISP identified investment choices and recommended essential actions to optimise consumer benefits in response to Australia experiencing what is acknowledged to be the world's fastest energy transition. The ISP identified the least cost and least regret transition pathway. This 20-year pathway requires an increase in renewable energy generation across the country, as well as the increased use of virtual power plants (VPPs) as well as an increase in demand-side participation. AEMO highlighted the need for significant investment in the grid in order to cater for the new renewable resources, and up to 21GW in new flexible dispatchable resources.

Government Policies in previous years have focused on funding investment in new renewable technologies (e.g. solar, wind, biomass, and wave). In 2020, a new investment roadmap was introduced by the Minister for Energy and Emissions Reduction expanding the investment focus from investment in renewables to investment in low emission technologies. The statement outlines five priority technologies and economic stretch goals to make the new technologies as cost effective as existing technologies. The top four are:

- Hydrogen production under A$2 per kilogram
- Long duration energy storage (6-8 hours or more) dispatched at less than A$100 per MWh – this will enable reliable, firmed wind and solar at prices around the average wholesale electricity price of today
- Low carbon materials – low emissions steel production under A$900 per tonne, low emissions aluminum under A$2,700 per tonne
- CCS – CO_2 compression, hub transport, and storage under A$20 per tonne of CO_2

The challenge of energy policy is to maintain affordable, reliable, and sustainable energy whilst enabling the transition to new generation technologies. Technologies such as Hydrogen production and carbon capture are in their infancy and will require more investment before they can be economically competitive. In the interim, with the estimate of up to 14 coal power stations to close over the next 30 years, the Australian government introduced a policy to use gas as the power generation transition fuel. This policy, introduced in the middle of 2020, has been received with mixed reviews.

In 2019, the cost of electricity continued to rise with Australia experiencing record highs in wholesale prices, averaging close to A$100 per MWh up from A$90 per MWh in 2018. This was coupled with higher consumer demand due to rising temperatures and higher investment in network assets, mainly to replace and refurbish old assets. Household electricity bills had risen more than general inflation in the last decade.

On a positive note, it is estimated that over the next three-year reporting period, annual residential bills are expected to decrease by 7.1 per cent (2019/2020 to 2021/2022)

- Wholesale costs are expected to go down by 11.6 per cent (or A$62) over the reporting period contributing -4.6 percentage points. This is driven by the influx of new generation of 8,594 MW. Committed projects make up 60 per cent of the total new generation and the rest of this is modelled by the AEMC.
- Regulated network costs are expected to decrease by 1.8 per cent (or A$11) over the reporting period contributing -0.8 percentage points. This is driven by a reduction in distribution and metering costs, mainly in South East Queensland.
- Environmental costs are expected to go down by 23.9 per cent (or A$21) over the reporting period contributing -1.6 percentage points. This is driven by a decrease in Large-scale Renewable Energy Target (LRET) costs stemming from a reduction in the cost of large-scale generation certificates (LGCs)

We cannot finish this editorial without mentioning the disruption of Covid-19 into the Australian energy market. Demand for electricity dropped during the second quarter of 2020, reducing wholesale electricity prices by 46-68 per cent compared to 2019. The Covid-19 pandemic has also increased the risk that multiple power retailers could default during the crisis because of an increase in costs and non-payment by customers. Large retailers such as AGL have witnessed up to A$38 million dollars of increased costs - A$20 million from increased net bad debt and A$18 million from increased on-site operating costs. The Council of Australian Governments Energy Council (COAG Energy Council) have met to agree on a coordinated response to manage the impacts on the energy sector. As we are writing this editorial, the crisis in Australia is not over and the extent of the impact on the energy sector is still unknown.

We hope you enjoy the fourth Australian edition of our Energy Markets Observatory and look forward to watching the next year unfold in our Energy and Utilities Sector. Areas we will be monitoring with interest during 2020/2021 will include

- The uptake of electric vehicles
- The evolving Hydrogen industry
- The impact of Covid-19
- Electricity prices- are the forecasts correct?

Jan Lindhaus

Vice President, Head of Energy & Utilities Australia

Anastasia Klingberg

Industry Practice Lead Energy & Utilities, Australia

Region description (AUS)

Quick introduction

Region: Australia
Population: 25,710,610 (Oct. 2020)
GDP: US$1,392.7 billion (2018-2019)

Electricity

Total electricity generation (2019) : 265.11 TWh
Average electricity price: 21.89 US Cents/KWh (residential price)
Electrification share (average): 100 per cent

Gas

Total Natural gas production : 153.5 bcm
Total Natural gas consumption : 53.7 bcm

Energy

- Energy mix: Renewables 55.4TWh vs Fossil Fuels 155.2TWh vs Gas 54.3TWh
- Regulatory model: Australian Energy Regulator (AER) regulates the wholesale electricity and gas markets, and is part of the Australian Competition and Consumer Commission (ACCC). ACCC enforces the rules established by the Australian Energy Market Commission
- Regulated: 7/7 (7 states of Australia)

Renewable energy

In 2019, renewable energy was responsible for 21 per cent of Australia's total electricity generation, an increase of 2 percentage points on 2018.
In 2019, Australia met its 2020 renewable energy target of 23.5 per cent and 33 terawatt-hours

Environment

Total CO_2 emissions: 532 $MtCO_2$ -e
CO_2 intensity per capita: 21.5 tCO_2 -e per person
GHG emission growth rate: 0.4 per cent

Electric mobility

- Electric charging stations: 1,930
- Number of electric vehicles: 6,718
- EV Market growth (2014-19): 408.16 per cent

Network (Regional sources)

- Length: 850,000 km of distribution grid and 45,000 km of transmission grid
- Tension: 216 - 253 V (households)
- Age: Electricity supply began during colonial era of 1880s and can be marked as an ~140 years old network
- Average cut-off time per year (2019): 130 min/customer

Energy players

- Generation and Retail: “Big Three” AGL, Origin Energy and Energy Australia
- Market share: Big Three holds 63 per cent of small electricity and 75 per cent of small gas market
- Second tier’ retailers have built significant market share in some regions - Snowy Hydro, Alinta Energy and Simply Energy have emerged as strong ‘gentailers’

Country highlights

Key policies

- In Sep 2020, Technology Investment Roadmap released with a primary focus on Low Emissions Technology
- Electricity Retail Code revision launched on July 1, 2019 after the finalization of the ‘Price Safety Net’ policy
- The Liberal National Government is focusing on multi-pronged policy approach to address energy affordability, reliability and security challenges faced by NEM:
  - The A$1 billion Grid Reliability Fund
  - Underwriting the New South Wales-Queensland Interconnector
  - Implementing the Retailer Reliability Obligation
  - Building Snowy 2.0, and
  - Supporting Tasmania's MarinusLink and Battery of the Nation

Key facts

- Due to Covid-19 as of March 2020, there were significant reduction in operational demand in the National Electricity Market (NEM). Overall, demand was down 6.7 per cent, with South Australia experiencing the biggest reduction of 11.1 per cent and a new record low
- Australia has one of the highest rates of adoption of household rooftop solar systems in the world. Uptake of batteries, smart appliances and electric vehicles is likely to continue to grow, as CSIRO forecasts indicate continued decline in the cost of solar panels and battery storage technology.
- Australian Government wants the private sector to step-up and make timely investments in the gas market. If the private sector fails to act, the Government will step in – as it has done for electricity transmission – to back these nation building projects
- The Australian Renewable Energy Agency has identified approximately 22,000 potential pumped hydro energy storage sites around Australia with merit for investigation

1-Climate Change & Energy Transition

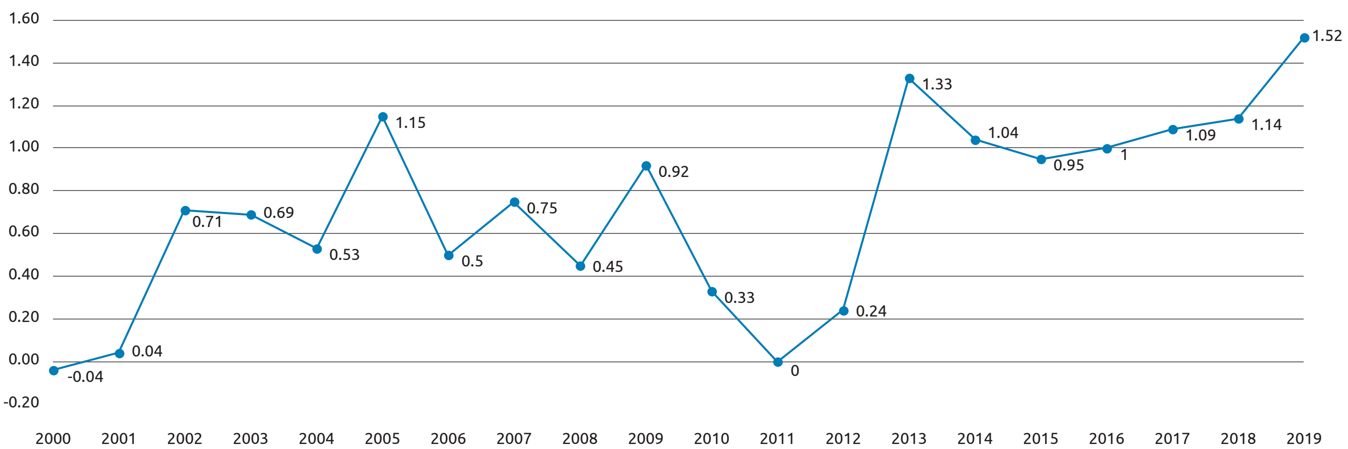
Australia is warming faster than the global average

Given its share of landmass, Australia's annual temperature suffers a stronger divergence than the rest of the world. The weather of Australia is volatile and very vulnerable to climate change.

- In Australia, 2019 was the warmest and driest year on record with the temperature reaching 1.52°C, above the long term average (BoM 2020). The average daytime maximum temperature across Australia in 2019 was 30.7°C , the highest since records began in 1910 and 2.1°C above the usual average. The extreme temperatures were spread across most of the country. On Dec 18, Australia experienced its hottest day on record when the average maximum temperature climbed to 41.9°C in the country.
  - In 2019, the average temperature across global land and ocean surfaces was 1.71°F (0.95°C) above the twentieth-century average of 57.0°F (13.9°C), making it the second-warmest year on record.
  - The global annual temperature has increased at an average rate of 0.07°C (0.13°F) per decade since 1880 and over twice that rate (+0.18°C / +0.32°F) since 1981.

According to data from the Australian Bureau of Meteorology, the rise of mean surface temperatures has been steeper in Australia than in the world on average and this has led to an increased intensity and frequency of extreme heat events, longer fire seasons, warming and acidifying oceans and rising sea levels that amplify the effects of high tides and storm surges on coastal communities and infrastructure.

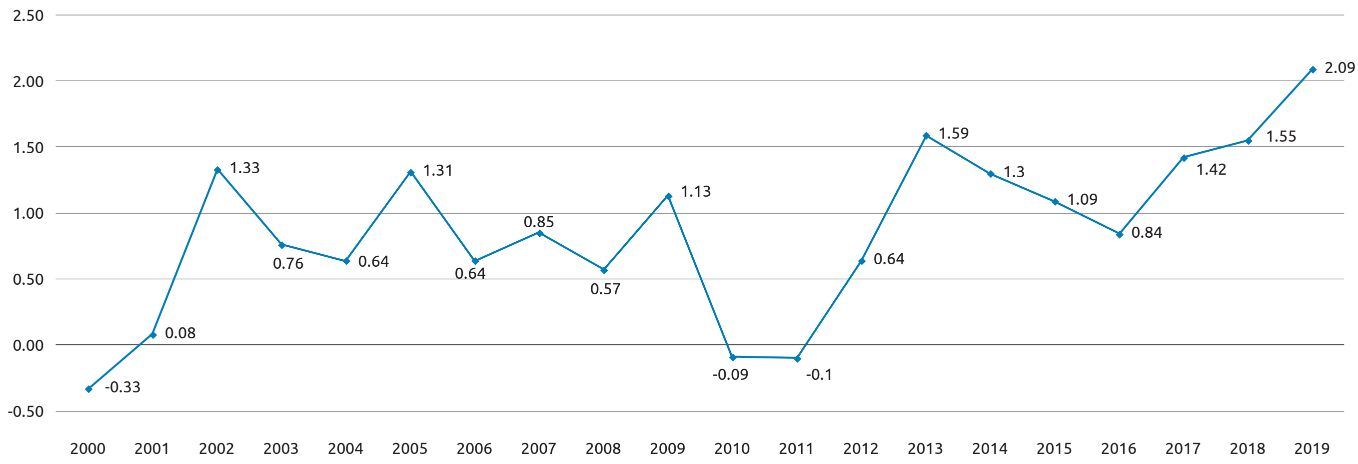
Figure 1.1 ~ Mean Annual Temperature Anomaly in Australia, 2000-2019 (°C)



Source: Australian Government - Bureau of Meteorology (Data available until 2019)

Australia

Figure 1.2 ~ Annual Maximum Temperature Anomaly in Australia (2000-2019) (°C)



Source: Australian Government - Bureau of Meteorology (Data available until 2019)

Australia's weather is vulnerable to the extremes of climate change. Weather historically has been impacted by both the geographic landscape and sea surface temperature changes especially in the Pacific Ocean (La Nino and La Nina) and the Indian Ocean (Indian Ocean Dipole). The increase in air and water temperatures as a result of climate change have been seen to increase the severity of Australia's weather cycles either causing longer drought periods, longer or more intense rainfall as well as an increase in overall temperature above global averages.

Geographic Landscape
Australia, is the smallest continent in the world and is also considered as flattest and driest continent. Australia's landmass is large enough to include climate regions from the tropics in the north to deserts in the middle to temperate regions in the south. The continent is also situated between the Antarctic, Indian, and Pacific oceans. Along Australia's coasts, the oceans act like buffers and help moderate the climate in cities such as Sydney and Perth. As Australia is a continent it also experiences continentality, a phenomenon where inland areas far from water experience a wider temperature range than the coasts. Australia doesn't have a large inland system of lakes and rivers. Some large lakes can form during periods of torrential rain, but those lakes aren't very deep, which means they don't store much heat and can evaporate quickly. This reduces their capacity to cushion surrounding regions against temperature extremes. Australia also doesn't have a large, snow-capped mountain range which is different to other continental landmasses. Melting mountain snow can act as a reservoir for water throughout the year and keep rivers and lakes topped up. For Australia, this makes inland areas more dependent on rainfall and more vulnerable to drying out during droughts.

El Niño and La Niña (Pacific Ocean)

El Niño and La Niña (sea surface temperature phenomena) have perhaps the strongest influence on year-to-year climate variability in Australia. They are a part of a natural cycle known as the El Niño–Southern Oscillation (ENSO) and are associated with a sustained period (many months) of warming (El Niño) or cooling (La Niña) in the central and eastern tropical Pacific.

The ENSO cycle loosely operates over timescales from one to eight years.

- **La Nina:** La Niña events are associated with greater convection over the warmer ocean to Australia's north. La Niña episodes represent periods of below-average sea surface temperatures across the east-central Equatorial Pacific. Typically this leads to higher than average rainfall across much of Australia, particularly inland eastern and northern regions, sometimes causing floods.
- **Neutral:** In the neutral state (neither El Niño nor La Niña) trade winds blow east to west across the surface of the tropical Pacific Ocean, bringing warm moist air and warmer surface waters towards the western Pacific and keeping the central Pacific Ocean relatively cool.
- **El Nino:** The term El Niño refers to the large-scale ocean-atmosphere climate interaction linked to a periodic warming in sea surface temperatures across the central and east-central Equatorial Pacific. During El Niño events, the ocean near Australia is cooler than usual, bringing lower than average winter–spring rainfall over eastern and northern Australia. Although most major Australian droughts have been associated with El Niño events, widespread drought is certainly not guaranteed when an El Niño is present.

Indian Ocean Dipole

The Indian Ocean Dipole - often called the "Indian Niño" is another key driver of Australia's climate. Sustained changes in the difference between sea surface temperatures of the tropical western and eastern Indian Ocean are known as the Indian Ocean Dipole or IOD.

The IOD has three phases mentioned below. Events usually start around May or June, peak between August and October and then rapidly decline when the monsoon arrives in the southern hemisphere around the end of spring.

The strength of the IOD is monitored with the Dipole Mode Index, which is a measure of the surface temperature difference between the western and eastern tropical Indian Ocean.

- **Positive IOD:** The pattern of ocean temperatures is reversed, weakening the winds and reducing the amount of moisture picked up and transported across Australia. The consequence is that rainfall in the south-east is well below average during periods of a positive IOD.
- **Neutral IOD:** Water from the Pacific flows between the islands of Indonesia, keeping seas to Australia's northwest warm. Air rises above this area and falls over the western half of the Indian Ocean basin, blowing westerly winds along the equator. Temperatures are close to normal across the tropical Indian Ocean, and hence the neutral IOD results in little change to Australia's climate.
- **Negative IOD:** Westerly winds intensify along the equator, allowing warmer waters to concentrate near Australia. This sets up a temperature difference across the tropical Indian Ocean, with warmer than normal water in the east and cooler than normal water in the west. It results in above-average winter–spring rainfall over parts of southern Australia as the warmer waters off northwest Australia provide more available moisture to weather systems crossing the country.

Visible impacts of climate change on Australia include:

- The ocean surface around Australia has warmed at a similar rate to the air temperature. Sea surface temperature in the Australian region has warmed by around 1 °C since 1910, with eight of the ten warmest years on record occurring since 2010. (It is considered that 2019 was the warmest year on record for the world's oceans). Part of the East Australian Current now extends further south, creating an area of more rapid warming in the Tasman Sea. This extension is having numerous impacts on marine ecosystems, including many marine species extending their habitat range further south.
- Warming of the ocean has contributed to longer and more frequent marine heatwaves. There were long and intense marine heatwaves in the Tasman Sea and around southeast Australia and Tasmania from September 2015 to May 2016 and from November 2017 to March 2018. These ocean heatwaves impacting the marine ecosystem for last few years.
- Traditional La Nina and El Nino events have continued to get more extreme since recording began in 1900. Researchers say the impacts of El Niño/La Niña events have become more severe over the past 20 years due to a warmer climate.

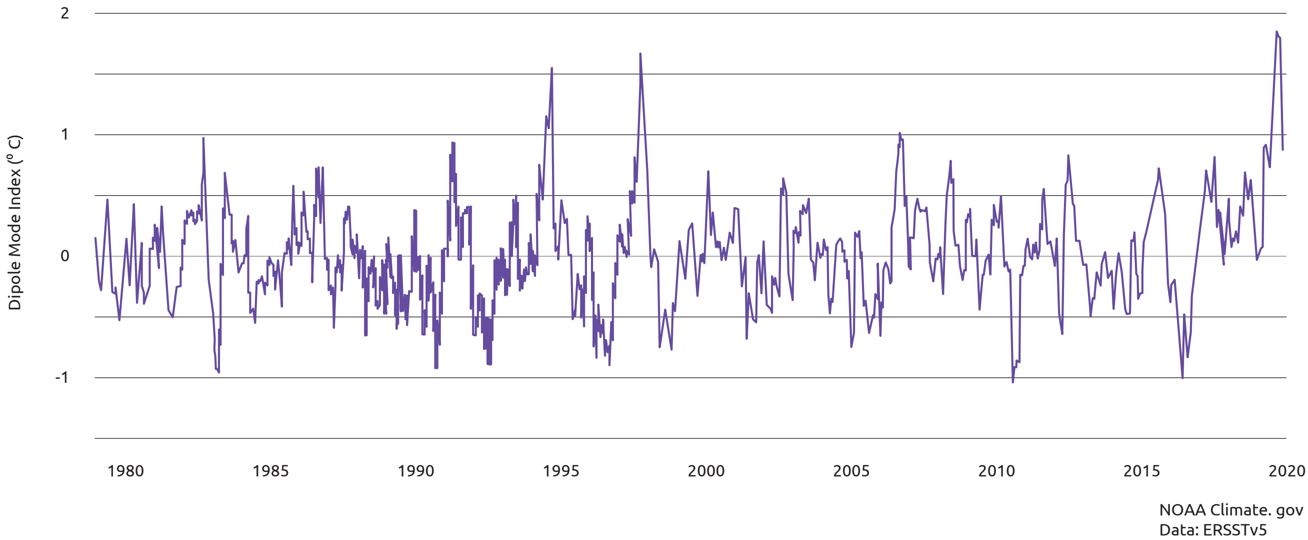
– In 2011, the Bureau of Meteorology recorded the Australian mean rainfall of 699 mm (234 mm above the long-term average of 465 mm), placing the year at the third-wettest since comparable records began in 1900.

– In 2016, an El Nino event was associated with catastrophic coral bleaching on the Great Barrier Reef

– In 2019, both an El Nino event as well as the strongest positive IOD recorded in the last 40 years ensured Australia recorded the hottest year in record as well as one of the driest since 2005.

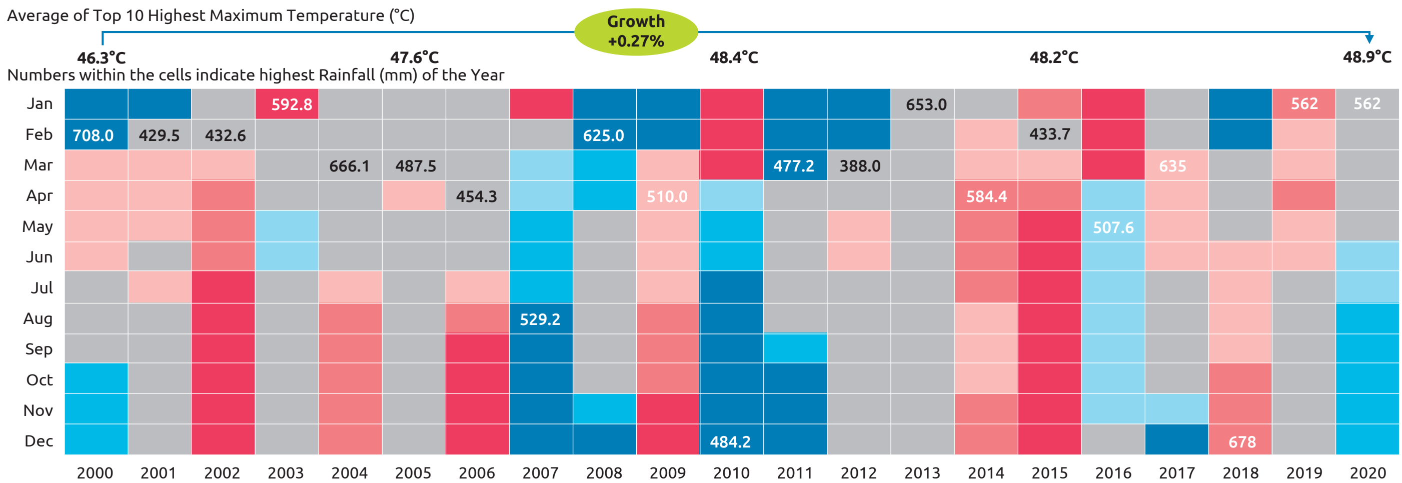
– Temperatures in Australia are expected to increase over the next number of years. "Some cities in Australia will likely hit temperatures in the 50's (Celsius) [more than 122 degrees Fahrenheit] by the end of the century" Said by Sarah Perkins-Kirkpatrick, a senior lecturer at the Climate Change Research Centre at the University of New South Wales, Sydney.

Figure 1.3 ~ Monthly Dipole Index (DMI) from January 1979 to December 2019



Source: NOAA Climate.gov

Figure 1.4 ~ ENSO Pattern in Australia mapped with Highest Rainfall (Millimeter) and Average of Top Ten Maximum Temperatures (Centigrade)



El Niño and La Niña are part of a natural cycle known as the **El Niño-Southern Oscillation (ENSO)** that loosely operates over timescales from one to eight years

Key

- El Niño WATCH
- El Niño ALERT
- El Niño
- La Niña WATCH
- La Niña ALERT
- La Niña
- ENSO Inactive

El Niño occurs when sea surface temperatures in the central and eastern tropical Pacific Ocean become substantially warmer than average, and this causes a shift in atmospheric circulation	Reduced rainfall | Warmer temperatures | Shift in temperature extremes | Increased frost risk | Reduced tropical cyclone numbers | Later monsoon onset | Increased fire danger in southeast Australia | Decreased alpine snow depths
La Niña occurs when equatorial trade winds become stronger, changing ocean surface currents and drawing cooler deep water up from below	Increased rainfall | Cooler maximum temperatures | Shift in temperature extremes | Decreased frost risk | Greater tropical cyclone numbers | Earlier monsoon onset | Deeper relative snow cover

Source: Australian Government - Bureau of Meteorology ENSO Outlook

In 2019 Australia experienced the driest year coming off the back end of an El Nino and IOD event

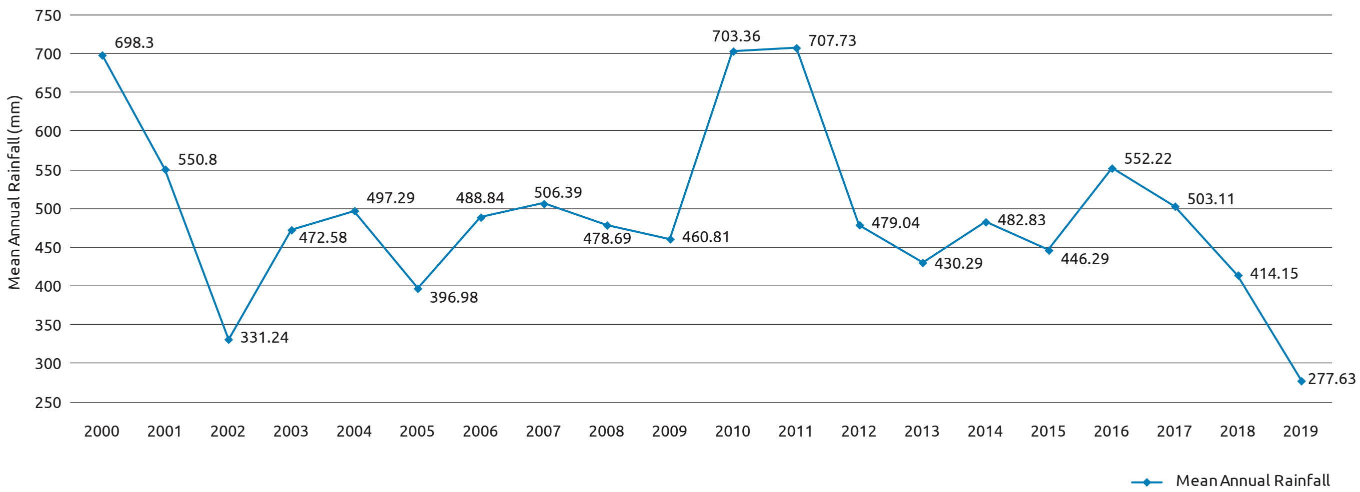
2018-2019 considered to be the driest year due to the impact of El-Nino and positive IOD:

- The national total rainfall for 2019 was 40 per cent below the 1961–1990 average at 277.6 mm (the 1961–1990 average is 465.2 mm). This makes 2019 the driest year in the 119 years since 1900.
  - Australia started 2019 with an extreme heatwave in January that helped make the 2018-19 summer the country's hottest. Throughout the year, rainfall was generally dismal, averaging just 277.63 millimetres across Australia in 2019. That tally was more than one-10th below the previous record low set in 1902.
  - Each city, except Sydney, had rainfall totals within the driest 10 per cent of years recorded. Sydney had many months with below-average rainfall and ended up with its driest year since 2005.
  - Low rainfall during 2019 resulted in severe drought across New South Wales and Queensland, parts of southeastern Australia, and the South West Land Division in Western Australia.
  - Across Australia the effect of low rainfall over 2018 and 2019 continues to be felt in many large water storages.
  - Water storage levels in the northern Murray–Darling Basin remain low despite recent rainfall in the first half of 2020; river flows in the northern Murray–Darling Basin dropped during May 2020, and dried out in the far north.
  - As the 2019–2020 summer brought record heat to Australia, New South Wales appeared to be heading into its third year of severe drought. From January 2017 through October 2019, the eastern Australian state experienced its lowest amount of rainfall in nearly a century.
  - Eleven tropical cyclones were recorded in the broader Australian region during the 2018–19 tropical cyclone season, equaling the long-term average (for all years since 1969–70). Six tropical cyclones reached severe (category 3), the first time since the 2014–15 season.

According to CSIRO, the effects of climate change will be superimposed on natural climate variability, leading to changes in the frequency and intensity of extreme weather events.

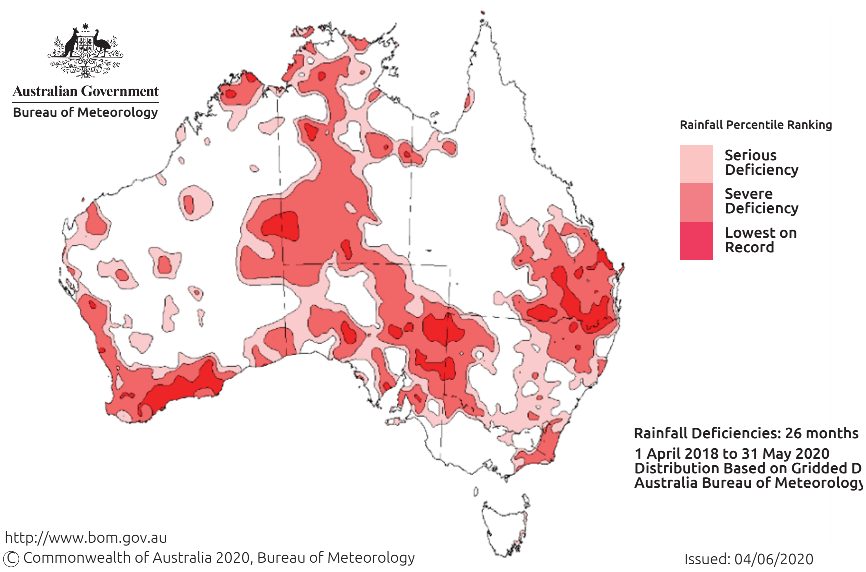
- Tropical cyclone days are projected to decrease in frequency in the Australian region, but it is expected that a greater proportion will be higher intensity.
- Cyclones and other low pressure systems can cause oceanic storm surges. These are projected to become larger, leading to more coastal flooding when superimposed on sea-level rise.
- Rising average sea-level will mean that storm surge effects on our coasts will increase in frequency even if the height of storm surges above mean sea level does not change.
- Heatwaves are likely to occur more often and with greater intensity in future decades. Harsher fire weather is projected. Frosts and snow-storms are likely to occur less often.
- Days with heavy rainfall are projected to become more intense over most areas of Australia.
- The number of days with large hail is projected to increase along the east coast from Fraser Island to Tasmania and decrease along the southern coast of Australia.

Figure 1.5 ~ Mean Annual Rainfall in Australia (millimeter), 2000-2019



Source: Australian Government - Bureau of Meteorology (Data available until 2019)

Figure 1.6 ~ Rainfall Deficiencies: 26 months (1st April 2018 to 31st May 2020)



Source:: Australia Government, Bureau of Meteorology

Australia received good rainfall in 2020 due to the impact of La Nina and Negative IOD

- After more than 34 consecutive months of dry conditions, steady and occasionally heavy rain arrived in New South Wales. From January to May 2020, southeastern Australia received above-average rainfall and even broke records in Victoria.
- An active monsoon pattern across northern Australia in February, combined with several active weather systems that moved through central and eastern parts of the country, brought much needed rain to finally extinguish the fires. Then further heavy rain extended across northern and eastern Australia in early March due to the remnants of tropical cyclone Esther, which helped to replenish catchments and brought rain to drought-affected areas that missed out during February.
- According to the Australian Bureau of Meteorology, April and May 2020 was the first period since 2016 with close to average rainfall in New South Wales and the Murray–Darling Basin. The BOM predicted 2020 to be wetter than average for most of the states including western New South Wales and parts of South Australia.
  - Sydney has been hit by its heaviest rain in 30 years, bringing widespread flooding but also putting out two massive bushfires in New South Wales. Australia's weather agency said 391.6mm of rain had fallen in first week of February in Sydney, more than three times the average rainfall for February.
  - Eastern New South Wales was particularly wet, with the first quarter in the top 10 wettest years.
  - Victoria also experienced record-breaking rain at the beginning of 2020. From January to April, Melbourne received around 400 millimeters (16 inches) of rain—nearly eight times more rainfall than last year during this time period. This is Melbourne's wettest start of the year since 1924. The BOM predicts Victoria may experience drier than normal weather for the upcoming winter.
  - According to Dr Trewin, most of the rest of the country has been average to above average without being too extreme.
- While many areas received more than a month's worth of rainfall in just a few days, and some locations saw more than a year's total rainfall during the same period, the drought in many areas is far from over. Many agricultural areas are still suffering from significant rainfall deficiencies experienced during the past two years.

Comparison of annual average rainfall from 2010 and 2020

Average Rainfall (mm)											
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020* (9 months, Jan to Sept)
Australia	703.36	707.73	479.04	40.29	482.83	446.29	552.22	503.11	414.15	27.63	334.36
Queensland	1113.33	824.36	656.9	485.67	559.14	492.45	626.15	550.11	522.41	483.87	425.82
New South Wales	818.33	665.7	564.7	462.22	468.31	541.73	663.05	456.43	331.68	251.49	465.06
Victoria	852.75	785.68	620.35	604.31	546.67	499.44	778.19	615.39	485.55	467.4	509.86
Tasmania	1359.15	1419.09	1312.95	1507.61	1150.63	1095.5	1762.37	1152.22	1355.05	1306.78	977.68
South Australia	360.71	341.79	171.12	188.88	197.04	191.57	355.56	232.46	166.44	82.31	148.51
Western Australia	333.1	596.12	383.7	402.05	400.85	352.72	411.14	472.55	370.85	177.54	253.12
Northern Territory	881.62	955.86	497.63	445.53	664.04	599.6	587.04	630.61	485.34	265.39	365.17
Murray-Darling Basin	812.22	601.11	499.7	368.59	417.39	429.2	620.51	402.3	290.67	229.85	393.38

Increase in Australia's average temperature has influenced the severity of bushfires that have occurred in Australia

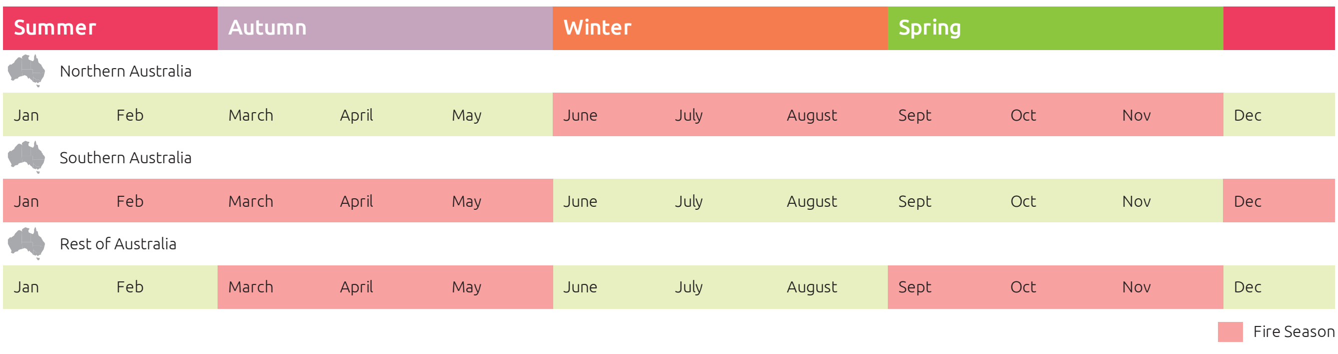
Bushfires and grassfires are common throughout Australia with natural ecosystems evolving with fires.

The increase in temperature and the prolonged droughts caused by climate change is directly affecting the severity of bushfires in Australia, with fire seasons are becoming increasingly longer and more severe.

- The Australian climate is generally hot, dry and prone to drought. At any time of the year, some parts of Australia are prone to bushfires. The widely varied fire seasons are reflected in the continent's different weather patterns. For most of southern Australia, the danger period is summer and autumn. For New South Wales and southern Queensland, the peak risk usually occurs in spring and early summer. The Northern Territory experiences most of its fires in winter and spring.
  - Over the past 150 years the state of Victoria has suffered about half of the country's economic damage from bushfires. The 1983 bushfire disaster claimed 47 lives in Victoria and 28 lives in South Australia.
  - The 2009 Black Saturday fires claimed the most lives, with 173 people. The most destructive event, which happened in 1974 and burned 117 million hectares, is unnamed because most of the land was in central Australia and had little impact on communities.
  - NSW has suffered the majority of bushfires in last five decades. NSW experienced larger fires in 1974 and 1984, but the fires in 2019-2020 were much more powerful as the areas burnt had experienced the lowest rainfall between January and August of 2019.
  - The east coast of Australia experienced a drought for three years in a row up until 2019, creating perfect conditions for the lengthy 2019/20 fire season.

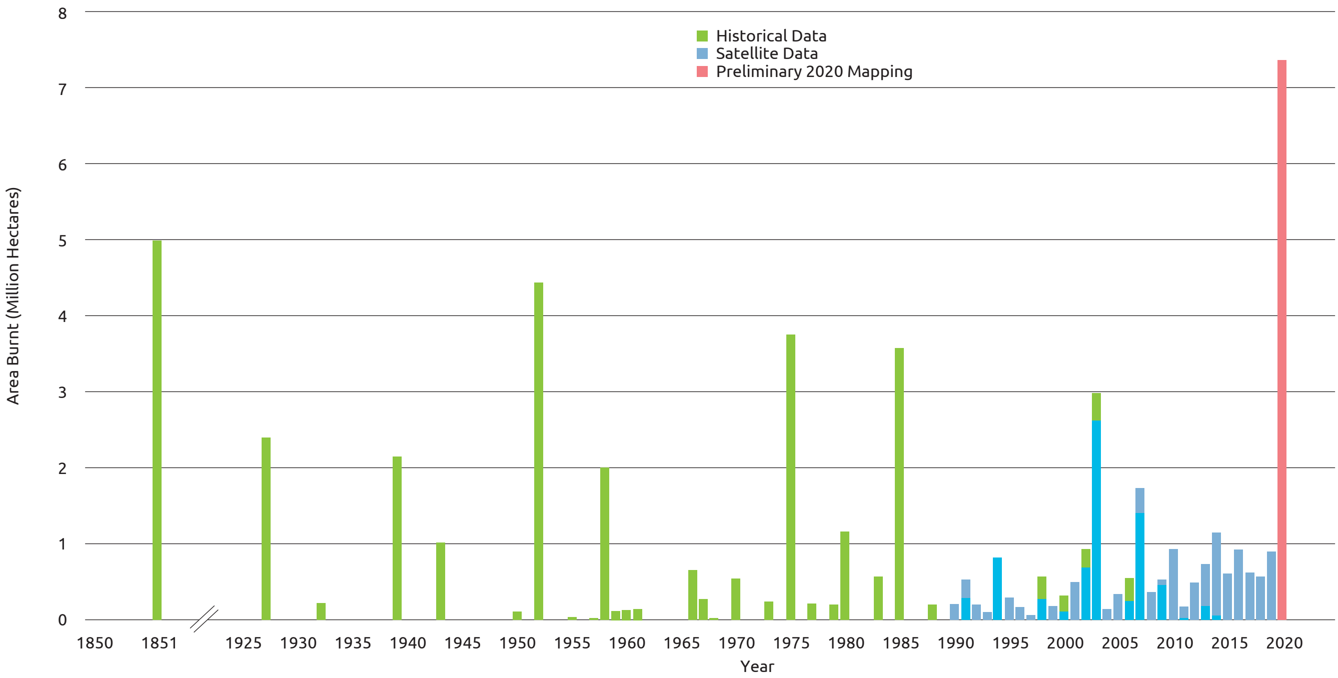
Australia's average temperature in 2019 was already 2.74 degrees (1.52 degrees Celsius) above the long-term average from 1961 to 1990, and the impact on fire season is likely to get worse as the climate becomes hotter and drier — increasing the speed and intensity with which the landscape can burn.

Figure 1.7~ Australia Bushfire Seasons



Source: Guardian.com

Figure 1.8 ~ Total Area Burned in Hectares per Fire Season



Source::Industry.gov.au.

Australia's fire season is getting longer and more dangerous- Do Australia's land clearing policies exacerbate this trend?

- In last few years, state governments have passed legislation to significantly restrict land clearing, especially in environmentally significant areas – the perception that there may have been more fuel to burn during the 2020 bushfires, adding to the intensity experienced is a position strongly held by the Federal National Party.
- While discussing a federal inquiry into the impact of these policies, federal agriculture minister David Littleproud suggested that the strengthening of land clearing regulations may have worsened Queensland's December bushfires.
- The reduction of land clearing in Australia can be attributed to climate policies in state and local governments. The reduction comes from the position that land clearing can affect the regional climate. In parts of eastern Australia, tree cover reductions are estimated to have increased summer surface temperatures by up to 2°c and southwest Western Australia by 0.4–0.8°c, reduced rainfall in southeast Australia, and made droughts hotter which can easily lead to fire.
  - In 2018, the Queensland Labor government strengthened land clearing laws after several years of systematic weakening of these protections on the back of concerns over irreversible environmental damage land clearing can cause.
- A Bushfire inquiry into vegetation management was set up in December 2019 to look at the impact of land management policy on the intensity and frequency of bushfires. This inquiry has since been rolled into the Royal Commission into Natural Disaster Arrangements.

History of Australian Catastrophic Bushfire

Location/Names of Bushfire	Year	Hectors of Land Burnt	Properties Damaged/ Destroyed	Deaths
Black Thursday - Victoria	1851	5,000,000	1300	15
Gippsland and Black Sunday - Victoria	1926	400,000	1000	60
Black Friday - north-eastern Victoria and Gippsland	1939	1,750,000	1300	71
Blue Mountains- NSW	1957	2,000,000	158	5
Summer - Western Australia	1961	1,800,000	160	0
Black Tuesday - south-east Tasmania	1967	270,000	4,000	62
Daylesford – Victoria	1969	250,000	251	23
Ash Wednesday - Victoria and South Australia	1983	250,000	2500	75
Western Division Fire - NSW	1984	3,500,000	NA	NA
Black Christmas - NW	2001	774,000	109	NA
Canberra Bushfire	2003	260,000	816	4
Victorian Bushfire	2009	450,000	2123	173
NSW Bushfire	2013	118,000	248	2
Tasmanian Bushfire	2013	34,900	431	1
Australian Bushfire	2020	4,300,000	5,900	34

2019-2020 Bushfire intensity reignites Climate Change Activism in Australia

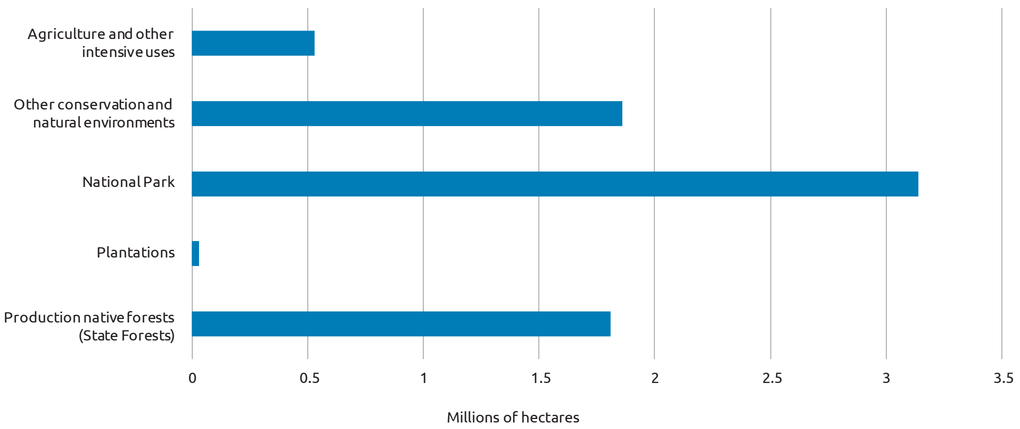
During the 2019-2020 fire season in Australia, record-breaking temperatures and months of severe drought fueled a series of massive bushfires across the country.

- The bushfires experienced in the 2019-20 season have burned more than 10 million hectares of land in southern Australia, greater than the combined area burned in the 2009 and 1983 bushfires.
- As of February 15, 2020, more than 46 million acres (72,000 square miles) of land were burned in thousands of fires since June 2019. At least 80 per cent of the Blue Mountains World Heritage area in NSW and 53 per cent of the Gondwana world heritage rainforests in Queensland (QLD) were burned.
- Approximately 34 people died in the bushfires since October 2019 and it is estimated that more than 1 billion animals have lost their lives.
- The Insurance Council estimated that since November 2019 till February 2020, bushfire losses were approximately $A1.9 billion insured claims. More than 23,362 claims for fires across NSW, QLD, SA and VIC were filed between November 8, 2019 and February 14, 2020.

Australia's fires emitted 830 metric tons of CO_2 impacting the quality of air and overall climate.

- In the beginning in 2020, the Australian capital city of Canberra registered the worst air quality reading in the world. The Canberra Times reported that smoke billowing through the city had raised its air quality index reading to 20 times above the level considered hazardous. The 3 months of fire contributed as much as two-thirds of the nation's annual CO_2 emissions.
- If compared with international emissions, it is suggested that the forest bushfires between September and February would rank Australia sixth on a list of polluting nations, behind only China, the US, India, Russia and Japan.
- Normally, with time and in the absence of new hazards, Australia's eucalypt forests re-absorb carbon to balance the carbon emitted during the fires. Forests burnt this year are expected to continue sequestering carbon over the next decade and beyond as they recover. As an example, more than 98 per cent of forest cover was observed to return within 10 years after the 2002-03 bushfires.
  - 2019 – 2020 bushfire have affected some of Australia's highest-biomass forests with an average aboveground biomass and debris estimated at around 300 tonnes per hectare. The fires are estimated to have burnt an average of around 20 per cent of the above-ground biomass and debris, resulting in average emissions of around 130 tonnes of CO_2-e per hectare of forest burnt.

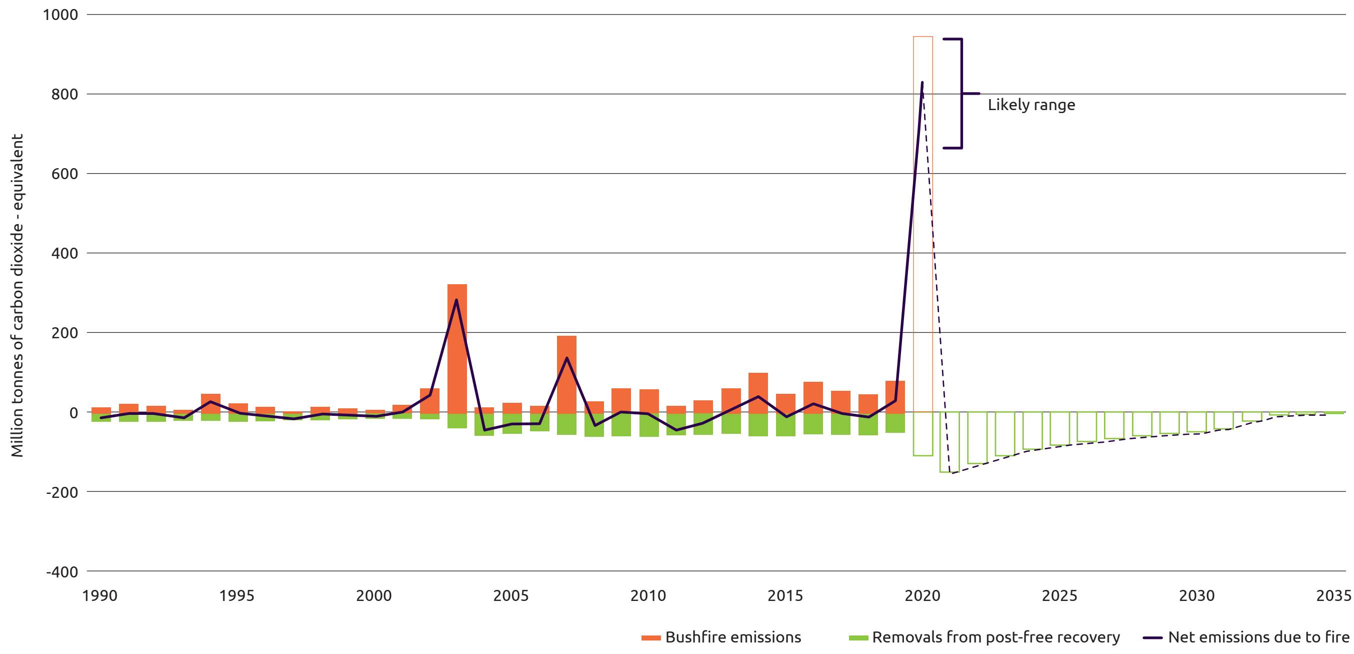
Figure 1.9 ~ Estimated Area Burnt, Australian Temperate Forests, by Land-use, September 2019 to January 2020



Source:: DISER using data supplied by Landgate and mapping by EMSINA, and ABARES Catchment-Scale Land Use Mapping

Australia

Figure 1.10 ~ Bushfire Emissions and Post-Fire Sequestration (removals) in Temperate Forests (Million tonnes CO_2-e)



Source::Industry.gov.au.

Government looking for ways to minimize the effect of bushfire:

- The Australian Government has commenced two significant processes aimed at building Australia's resilience to future climate change impacts:
  - The recent establishment of a National Royal Commission into the 2019-20 unprecedented bushfire season
  - A research report by the CSIRO, in partnership with an expert advisory panel chaired by Australia's Chief Scientist, to provide practical options for Australian governments to support and improve climate and disaster resilience.

The resulting information from these processes should go a long way towards addressing the Authority's recommendations on preparedness and resilience.

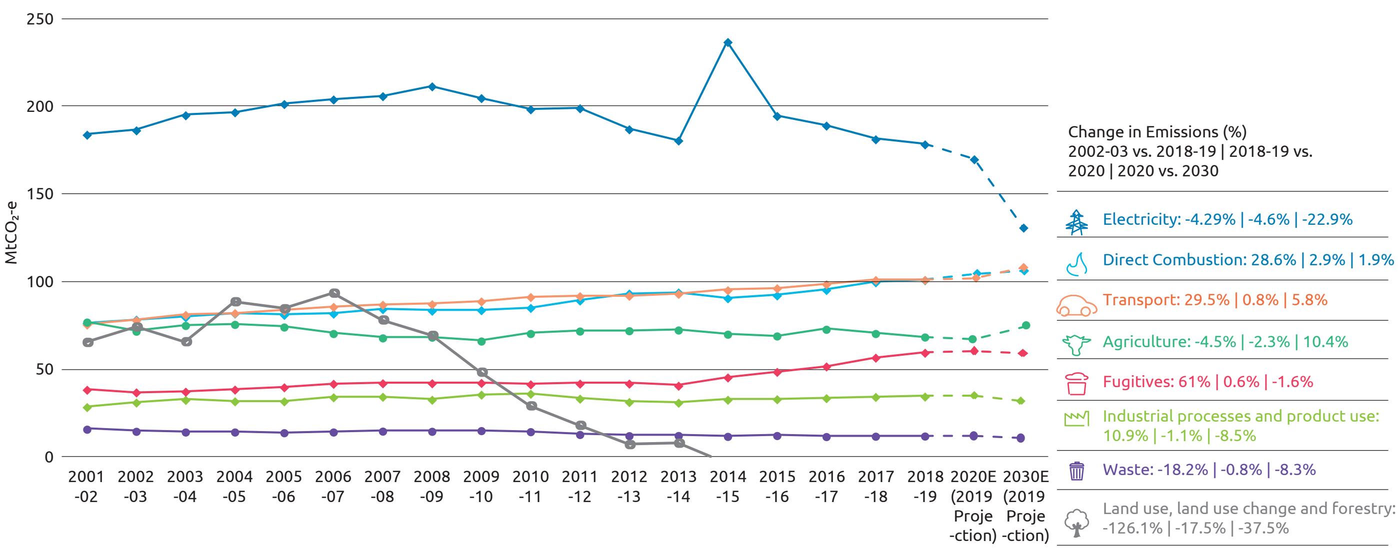
- In the 2019-20 Federal Budget, the Government committed to a four-year program to enhance the modelling of carbon in forests using the Full Carbon Accounting Model (FullCAM).
  - As part of this program, the department has contracted the CSIRO to undertake a work program to improve the modelling of fire emissions using the latest data and science.
  - Recent work by the CSIRO has already contributed to significant advances in FullCAM modelling capability for fires. Since 2018, emissions estimates have been spatially explicit, meaning that the modelling of fire emissions reflects site-specific factors including productivity, fire history and fuel loads at the time of burning. Carbon sequestered in the recovering forest over time is also modelled spatially, reflecting site-specific factors.
  - Over the coming years, the department will focus on further developing the fire model to reflect the latest scientific data relating to fire intensity, frequency and climate impacts on post-fire recovery.

In the year to December 2019 emissions per capita, and the emissions intensity of the economy reached the lowest levels in the last 30 years

Australia generates high levels of greenhouse gas emissions, with its economy ranking in the top 10 in the world for emissions per capita (IEA, 2019a). Australia's emissions are produced primarily by the electricity generation, industry, and transport sectors.

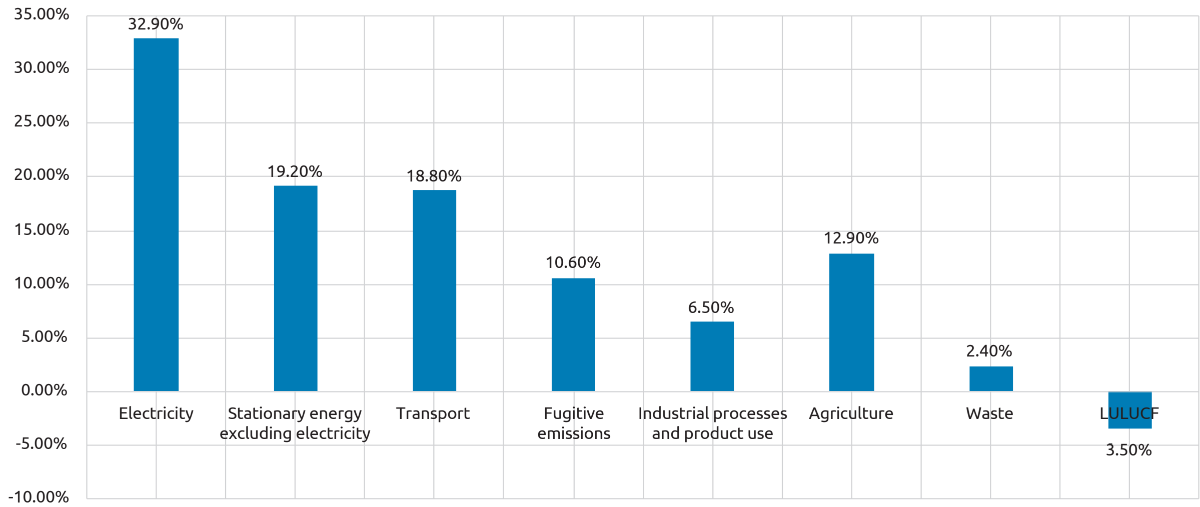
- Over the year to December 2019, there were decreases in emissions from the electricity, transport, agriculture, and industrial processes sectors.
- The 2.9 per cent decrease in emissions from the electricity sector is mainly due to a 4.3 per cent reduction in coal generation, and a corresponding 10.0 per cent increase in supply from renewable sources in the NEM.
- Transport emissions decreased 1.1 per cent over the year to December reflecting a 2.7 per cent decrease in petrol consumption.
- The 5.8 per cent decline in emissions from the agriculture sector reflects the effects of drought which has led to a decline in livestock populations as well as fertilizer use.
- Emissions from total export industries increased by 3.0 per cent (6.1 Mt CO_2-e), mainly reflecting the increases in LNG exports (up 11.0 per cent). The increases in LNG exports contributed to the increase in emissions of approx 1.9Mt Co_2-e over the 2019 year.

Figure 1.11 ~ Energy-related CO_2 Emissions by Sector: Evolution since 2001-02; Outlook till 2030E (million tonnes of carbon dioxide equivalent)



Note: E- Estimated
Source: Quarterly Update of Australia's National Greenhouse Gas Inventory: December 2018, Australia Government Department of the Environment and Energy; Australia's emissions projections 2019, Australia Government Department of the Environment and Energy (Dec 2018)

Figure 1.12 ~ Share of Total Emissions, by Sector, for the year to December 2019 (Million tonnes of carbon dioxide equivalent)



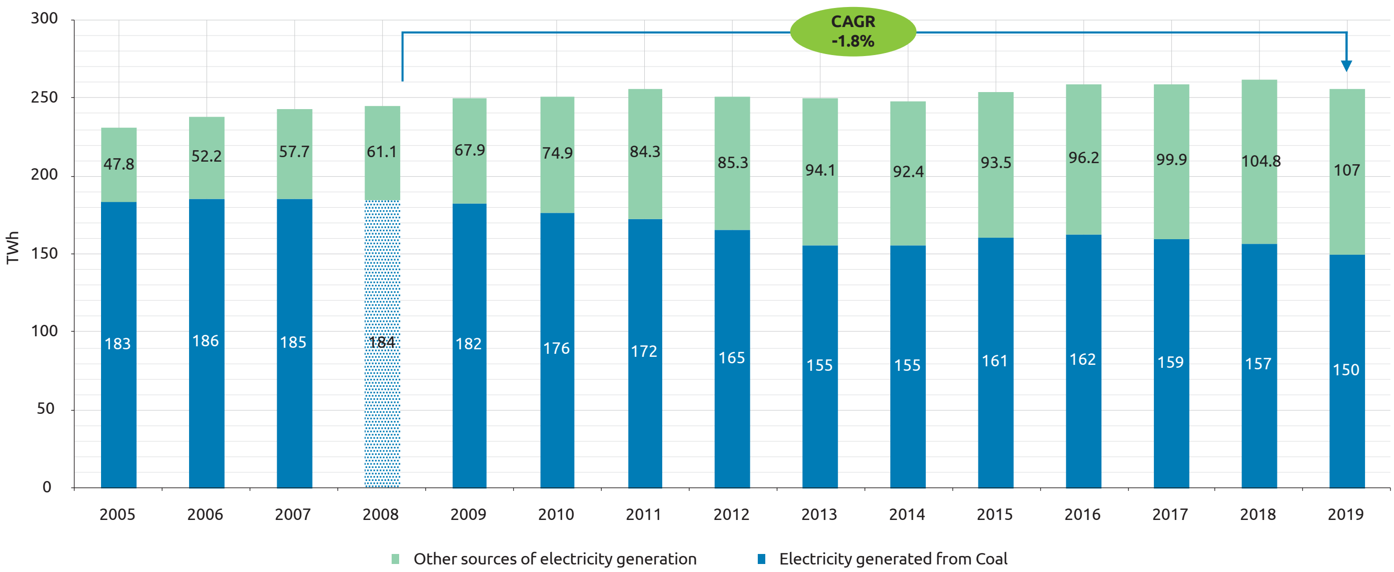
Source: Quarterly Update of Australia's National Greenhouse Gas Inventory: December 2019 – Australian Government Department of Environment and Energy

Electricity generation is Australia's largest emissions source, affecting all downstream sectors of the economy

Electricity generation is Australia's highest emitting sector, accounting for more than one-third of the national total emission(DoEE, 2019f). In order to meets Australia's Paris climate agreement targets the electricity sector is the main focus of decarbonization.

- Electricity emissions have fluctuated over the past 10 years - Peaking in 2009, they declined over the five subsequent years. Several factors led to this decrease, including policies that supported renewable energy and carbon pricing from mid-2012 to mid-2014. After 2014, emissions rose for two years before dropping again between 2017 and 2018.
- The most recent decline in electricity emissions reflects the closure of coal power stations and the increasing deployment of renewable sources. In Australia, coal-fired electricity generation fell to around 60 per cent of the total generation in 2018, decreased from 71 per cent in 2010.
- Australian government is increasingly focusing on other sources of electricity and slowly reducing its dependency on coal.
- The gradual aging of coal plants may be leading towards a greener and cleaner environment, but with this transitioning emerges the question of ensuring overall demand of electricity in Australia can be met.
- Australia needs to progress technology advancements to ensure the stability of energy supply in times when low-cost renewables are not available, before phasing out its current baseload supply via coal.
- While Australia is shutting down aging and polluting coal-fired power plants, it is still one of the largest exporters of coal for power generation purposes in the world.
- In August 2020 the Australian Federal Government has published its Energy Policy stating that Gas will be the intermediate solution to ensure low cost and reliable energy during Australia's energy transition as well as assist Australia to meets its 2030 Paris Agreement targets.

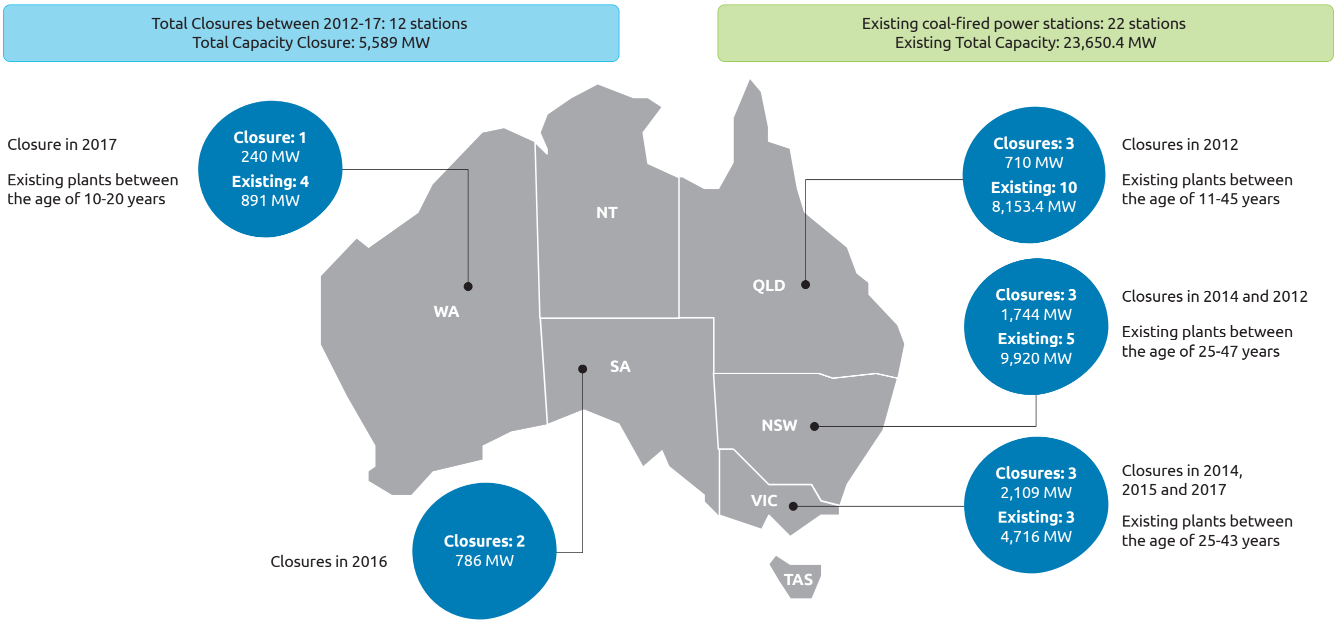
Figure 1.13 ~ Electricity Generation from Coal (Terawatt-hours), 2005-2019



Source: BP Stats Review 2019

Australia

Figure 1.14 ~ Australian Coal Power Station Capacity (megawatt) by State



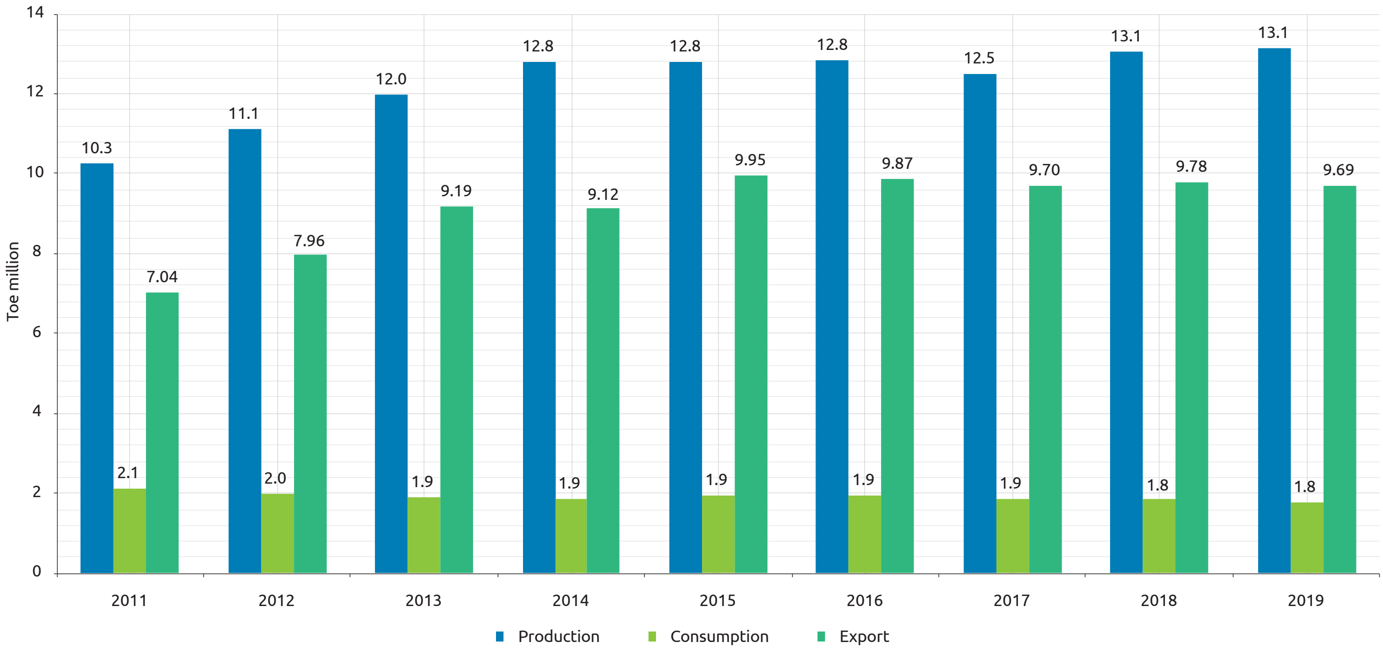
Note: As on until June 2019

Source: Closures of coal-fired power stations in Australia: Local unemployment effects Centre for Climate Economics & Policy, Sep 2018, Coal Transitions in Australia 2018, Australian National University and Melbourne Sustainable Society Institute

The coal industry brings in around A$70 billion in annual export revenue.

- Economically, coal is Australia's most valuable export, with black coal resources occurring in a majority of the country’s states.
- Australia’s export volumes are forecast to grow from 210 million tonnes in 2018–19 to 224 million tonnes by 2024–25, as a number of mines increase production.
- The real value of Australia’s thermal coal exports is projected to decline sharply from A$26 billion in 2018–19 to A$21 billion in 2019–20, as a result of the recent price decline.

Figure 1.15 ~ Australian Coal Production and Utilization (Exajoules) 2011-2019



Source: BP Stats Review 2020

Communities transitioning from coal-fired power:

Latrobe Valley, Victoria

- The Latrobe Valley Authority, supported by A$266 million from the Victorian Government, was developed to support the communities affected by the closure of the Hazelwood power plant and mine in 2017. The Latrobe Valley Authority delivered new jobs by building infrastructure and other facilities that meets community needs. The Latrobe Valley Authority continues to work with government to facilitate investment through policies such as additional renewable energy investment incentives, investment tax incentives and the prioritized construction of new infrastructure. While the Latrobe Valley Authority has been held up as an example of good practice, it was created only five months ahead of the closure, which was the notice period given by Engie.

Hunter Valley, New South Wales

- In the Hunter Valley, the Hunter Energy Transition Alliance has produced a blueprint to manage the closure of both Liddell and Bayswater power plants, in 2023 and 2035 respectively, and diversify the region (HETA 2016). AGL, which owns both power plants, has developed a detailed transition plan for the closure of Liddell seven years in advance, including new investment in renewable generation and storage and a new gas peaking plant (AGL 2017). It also committed to no forced redundancies when Liddell closes and to providing retraining for workers (AGL 2019).

Australia is divided on the introduction of new coal mines.

Topic Box 1.1: While Australia is shutting down aging and polluting coal-fired power plants, it is still one of the largest exporters of coal for power generation purposes in the world. Australia's division over new coal mines is reflected in the journey of the Glencore Coal Mine.

- A giant Glencore Plc coal project in Australia has been fast-tracked as the nation turns to its vast natural resources to lift the economy out of its first recession in almost three-decade. A$1.5 billion Valeria mine in Queensland has been designated a "coordinated project" on 12th June 2020.
- Glencore's proposed mine in the state's Bowen Basin coal heartland will produce around 20 million tons a year of thermal and metallurgical coal, equal to about 4 per cent of the nation's output. That's double the size of Adani's controversial Carmichael project, also in Queensland, which has been targeted by climate activists for potentially opening up a new region to coal mining.
- The government is betting on strong consumption of the fuel in Asia even as critics warn that the falling cost of renewables and global efforts to combat climate change may see the weakening demand in the future.
- Pressure from international investors concerned about the climate impacts of burning coal pushed the company in 2019 to declare it would not increase the production of the fuel. Hence, Glencore coal operations promised to replace production from other Glencore coal operations as they near retirement, including the nearby Clermont mine, to be in line with Glencore's global climate change commitments. Glencore has advised that any thermal coal produced by the new mine will be subject to the company's cap on thermal coal output, to support the global transition to a low-carbon economy.

Expected Benefits:

- It will help to boost up the economy: In 2019, the company's coal operations contributed more than A$4 billion to the Queensland economy.
- **Expected to create up to 2,350 jobs:** 1,400 during construction and 950 ongoing roles once fully operational.
- **Glencore will rebalance its global coal portfolio to take into account new production:** Coal produced by Valeria will be used to support global steelmaking activities, which will be "vital" to the world economy as it recovers from Covid-19. Steel is critical for construction, but it's also used for key elements of a renewable energy future such as solar panels, wind farms, batteries, and electric vehicles.

"This new mine has the potential to create hundreds of new jobs as Queensland recovers from the extraordinary shock of the global coronavirus pandemic. "Coal mining has a long history in Queensland and will continue to be a major industry for many years to come."

said Cameron Dick, Queensland's Treasurer

Expected Damages

- Although the Glencore project passed the State government environmental checklists, environmentalists are still concerned about far-reaching ecological damage, such as:
  - **The potentially damaging effect to threatened ecological communities:** 26 listed threatened species, 12 listed migratory birds, and one nationally significant wetland.
  - **Increased contribution to carbon emissions:** It will impact the carbon emission contribution of the state and climate conditions overall.

"A coal-driven economic recovery only throws us from one crisis into another. Support for major new coal projects eroded the credibility of the state government's commitment to protecting the Great Barrier Reef and reaching net zero carbon-dioxide emissions by 2050."

said Gavan McFadzean, climate and energy program manager at the Australian Conservation Foundation

Queenslanders don't realise we are Australia's biggest carbon emitter and burning coal is the biggest cause of climate change. So to be discussing a new coalmine as a viable option is unbelievable."

said Claire Fryer, a climate and energy campaigner at the Queensland Conservation Council

ADANI Update: In WEMO 2019 edition, it has been reviewed how the controversial Adani Carmichael mine won the final approval on the 13th of June 2019 and received a go-ahead to start operations. The project is designed to produce 60 million tonnes per annum (mtpa) during peak production, and initial production of 40 mtpa every year.

However in 2020 after the extreme bushfires environmentalists expressed strong protest and companies are taking away their support for the coal mine.

After the 2019 -2020 bushfire, activists and other companies again raised their voices against the coal mine with major contractors and insurers retreating as financial institutions shun new coal projects at an increasingly rapid rate.

- Three major insurance groups - AXA XL, Liberty Mutual, and HDI who provided cover for parts of the Adani coal project in Queensland have said they will not provide future policies to the project. In January, the Australian coach company Greyhound cut ties with a contractor building the Adani mine railway.
- Both CommBank and Westpac have ruled out financing the Adani Carmichael project, along with 36 other major banks and bond arrangers. In June 2020, South African bank Investec ruled out while also distancing itself from Adani's Abbot Point coal port, despite arranging a bond issue for the port back in 2017.

The financial viability of Adani's Carmichael coal mine became unstable as banks have refused to finance the project, forcing the Adani group to use their own money. In April 2020, Sydney Morning Herald reported that Adani's losses are nearing A$800 million.

Adani's accounts warn the coronavirus pandemic could have a significant impact on the valuation of the Carmichael mine and increase its dependence on its parent company in India. The rising costs raise questions about the Adani Group's willingness to continue using its own money to finance the much-delayed coal project. To make things even more challenging for Adani its Abbot Point coal port is facing an almost A$1 billion debt burden.

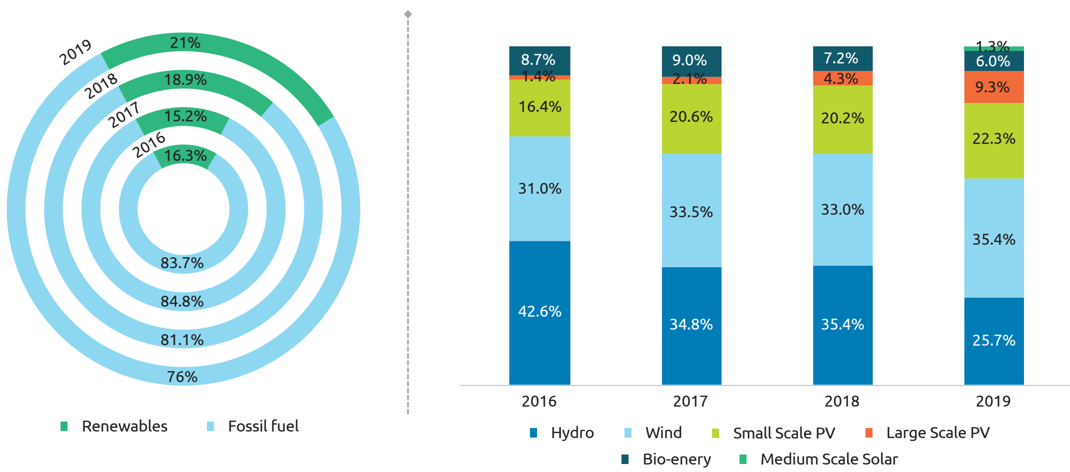
However, in September 2020, Adani Mining confirmed that its Carmichael project in central Queensland has created jobs for more than 1,500 people and awarded over A$1.5 billion in contracts. The company said construction of the railway line and mine was set to continue through into 2021 and it was expecting to generate more direct jobs. Mining has cushioned the Queensland and Western Australian economies from the worst of the devastating economic impact of the COVID-19 lockdowns.

Renewable energy investment has increased significantly in Australia

To combat emissions and reduce pollution, investment in renewable energy has increased significantly in Australia over recent years, contributing to a continuing shift in the energy generation mix away from traditional fossil fuel sources.

- At the end of 2019, 11.1 GW of new generation was under construction or financially committed, representing A$20.4 billion in investment and more than 14,500 jobs. 34 renewable energy projects were completed.
- In 2019, renewable energy was responsible for 21 per cent of Australia's total electricity generation, an increase of 2 percentage points on 2018.

Figure 1.16 ~ Australia Electricity Generation (Gigawatt-hours) and Renewable vs. Fossil share (%)



Source: Australian Energy Statistics by Department of the Environment and Energy, Australian Energy Statistics, Table O, March 2019

In 2019, Australia met its 2020 renewable energy target of 23.5 per cent and 33 terawatt-hours (TWh)

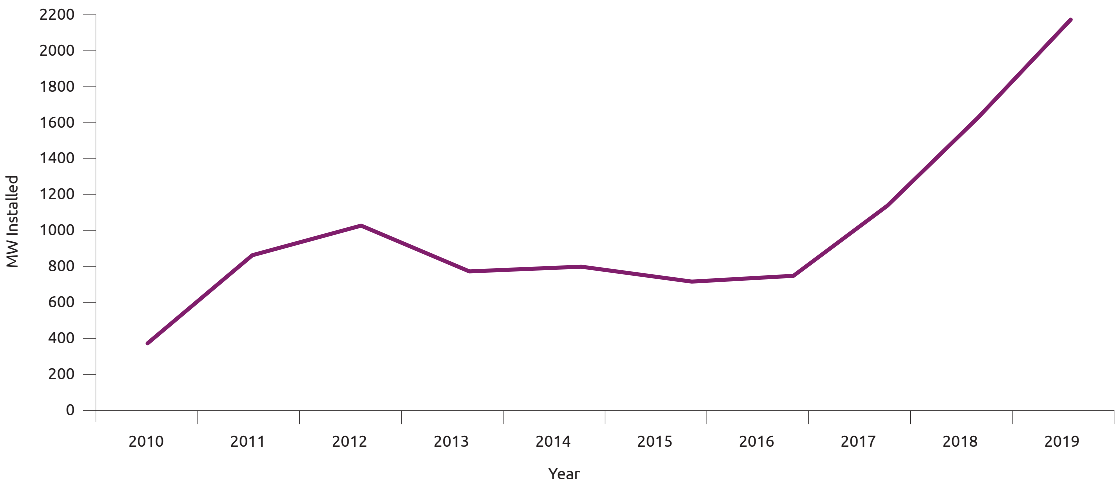
- Australia established new records for renewable energy investment across both the small and large segments in 2019.
  - In 2019, the amount of new clean energy capacity additions were divided evenly between the large-scale and small-scale sectors, each of them setting new records and contributing half of the 4,400MW.
  - More than 2,200MW of additional large-scale wind and solar capacity was added to the Australian grid. Around two-thirds of this capacity was in the form of new large-scale solar projects, adding 1,416MW, with wind generation adding 837MW across eight projects.
  - Renewable energy sources now supply around one-fourth part of Australia's electricity supply, with the amount of wind generation exceeding hydroelectricity generation for the first time.
  - *"A record 2019 saw Australia take a major step towards a clean energy future, with 4.4 GW of renewable energy capacity installed, which is the equivalent to more than two times the capacity of the Liddell Power Station installed in just a single year. Last year saw the construction of 34 new large-scale renewable energy projects, adding 2.2 GW of clean energy to the grid. This represents around A$4.3 billion in investment and the creation of more than 4,000 new jobs."* CEC chief executive Kane Thornton said.
  - The strong performance was also reflected in surging growth of the battery storage market, with more than 22,000 new residential battery systems installed last year. The cumulative installed storage capacity has now passed 1 GWh.
  - From 2016 to 2019, investment in large-scale renewable energy projects increased significantly.
    - Federal Minister for Energy and Emissions Reduction, Angus Taylor, said the increase in renewable generation was driven by record levels of new investment, with 6.3GW of new renewable energy capacity delivered in 2019 and a similar level expected to be delivered in 2020.
    - *"The renewable energy industry is uniquely placed to lead Australia's recovery from the COVID-19 crisis. In addition to providing much-needed stimulus to the Australian economy, we can insulate households and businesses from high electricity costs while also ensuring that we meet our emissions reductions obligations."* said CEC chief executive Kane Thornton.

- Government climate change-related policies have encouraged investment in large-scale renewable electricity generation. One of the main Australian Government policy is the Renewable Energy Target (RET), which targets 33,000 gigawatt hours (GWh) of additional large-scale renewable electricity generation by 2020.
  - The RET incentivizes the development of new renewable energy power stations. It does this by requiring liable entities, predominantly electricity retailers, to source an annually increasing proportion of their electricity requirements from renewable generators. Under the RET, renewable power plants can create large-scale generation certificates (LGCs) for each megawatt hour (MWh) of renewable electricity generated. These certificates can then be sold or transferred to liable entities or other companies looking to surrender certificates voluntarily.
  - The Clean Energy Finance Corporation (CEFC) and the Australian Renewable Energy Agency (ARENA) have also played an important role in helping developers obtain finance by directly financing projects and encouraging private investment. These agencies have directly invested around A$8.5 billion in clean energy-related projects since their inceptions. They estimate that this investment has encouraged a further A$25 billion to A$30 billion of additional private sector investment (ARENA 2019 and CEFC 2019).

Solar:

- Australia receives an average of 58 million PJ of solar radiation per year, approximately 10 000 times larger than its total energy consumption. The most common use of solar energy is solar thermal water heating. Solar PV systems play an important role in off-grid electricity generation in remote areas.
- Australia set its third consecutive annual record for rooftop solar installations, with 2,200MW of new rooftop solar being added in 2019.
- NSW retook the lead in the rooftop solar market for the first time since 2010, with 597MW of new rooftop solar capacity added in the 2019 year, overtaking Queensland with 588MW, with Victoria ranking third with 450MW.

Figure 1.17 ~ Annual Installed Capacity of Solar PV (MW)



Source: Clear Energy

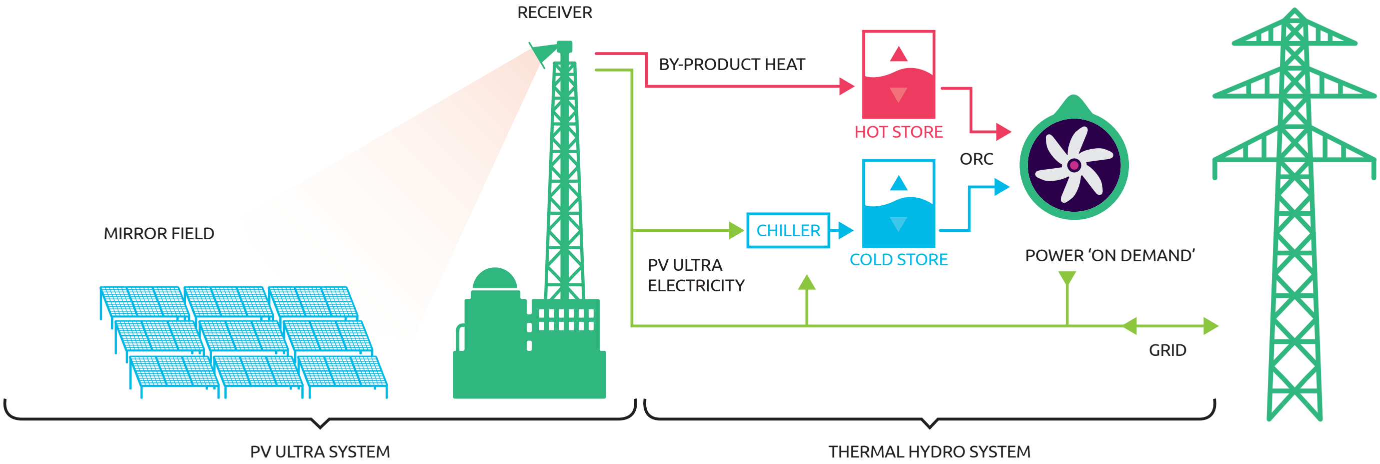
In March 2020, The Australian Renewable Agency (ARENA) funded A$3 million in RayGen Resources Pty Ltd (RayGen) to conduct a technical and commercial feasibility study for a 4 MW "solar hydro" power plant to be built in north-western Victoria.

RayGen proposed to build a fully dispatchable renewable energy facility that will use their concentrated solar PV technology known as PV Ultra. This technology will be combined with Thermal Hydro technology to generate renewable energy and provide large scale energy storage. The grid-scale power plant is proposed to be built in Carwarp near Mildura capable of providing 4 MW of solar generation and 17 hours of storage. RayGen will be working with AGL and GHD on this initial phase which will include technical and commercial feasibility studies, commercial assessment, a connection agreement, offtake agreements, capital raising, and a planning permit for a preferred site.

Technology Used:

PV technology combines low-cost solar collection heliostats and high-efficiency solar conversion via PV cells, creating the ability to co-generate electricity and heat. The heat by-product is captured and used to boost the efficiency of the thermal storage element.
The thermal storage technology stores energy as a temperature difference between two water reservoirs. The heat generated from the PV Ultra is used to charge the hot reservoir, whilst the cold reservoir is cooled using an electric chiller supplied with electricity from PV Ultra and the grid.

Figure 1.18 ~ Solar Hydro Power Plant



Source: :https://raygen.com/technology/

Australia has set new records for renewable energy investment and deployment across both the small and large segments in 2019

Wind:

In 2019, 837 MW of capacity was added across eight new wind farms. For the first time, wind overtook hydro as Australia's leading clean energy source, accounting for more than 35 per cent of Australia's renewable energy generation.

Of the eight new wind farms commissioned in 2019, the largest was AGL's 200 MW Silverton Wind Farm in north-western NSW.

Other notable projects completed in 2019 include the 180 MW Mount Emerald Wind Farm in Queensland and APA Group's 130 MW wind farm that is part of the Badgingarra Renewable Facility. At the end of 2019, 30 wind farms with a combined capacity of more than 5.5 GW were under construction or financially committed nationally.

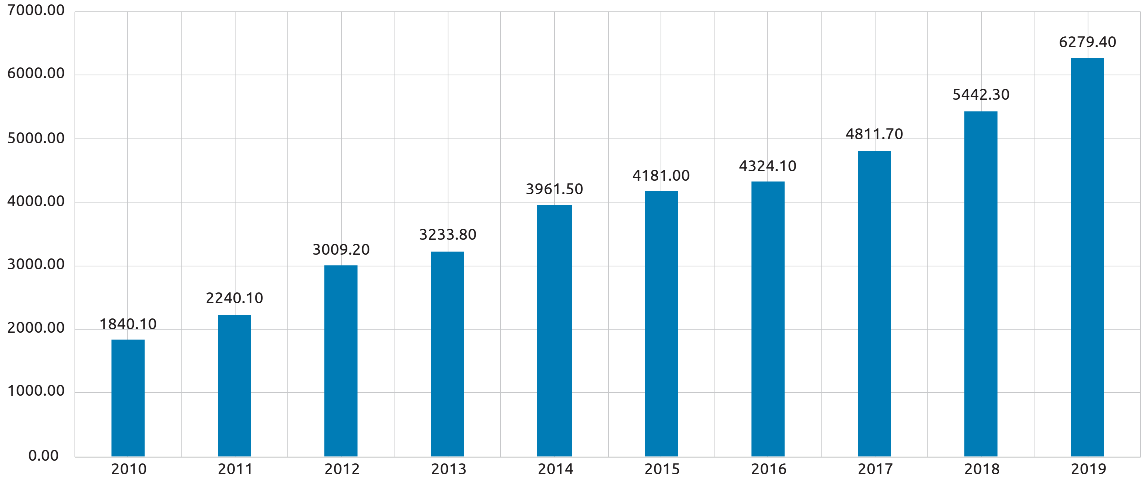
Australia's First Offshore Wind Farm is scheduled to come alive!

As of March 2020, Star of the South project is working on a feasibility study to launch an offshore wind farm. Planned for the south coast of Gippsland, the A$8 billion project will provide 2200 MW of clean energy to homes across Victoria and bring jobs to the area.

Capturing offshore wind for energy needs is common in the UK and Germany, but this project is the first of its kind in Australia. Offshore wind projects have a major advantage over onshore wind farms – they can be developed at a much larger scale, because there's a lot more ocean than land.

Site exploration to identify the best sites for the wind turbines began in March 2019, alongside local community engagement. While some way off final approvals and build, it's another exciting development for Australia's renewable energy industry and a welcome new source of clean energy for its electricity grid.

Figure 1.19 ~ Cumulative Wind Capacity in Australia (MW)



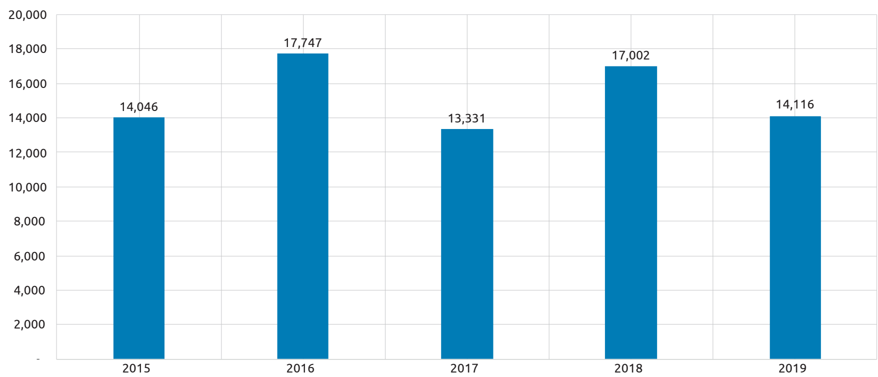
Source: Clean Energy Council

Hydro:

Hydropower accounted for 25.7 per cent of total clean energy generated and 6.2 per cent of Australia's overall electricity in 2019.

Hydro had a difficult year in 2019, with the impact of the drought in eastern Australia resulting in it making its lowest ever contribution to Australia's renewable energy generation. However, hydro was still the second-largest generator of renewable electricity in 2019, providing 14,166 GWh of clean energy into the grid.

Figure 1.20 ~ Hydroelectricity Generation in Australia (GWh)



Source: Clean Energy Council

Hydro energy is particularly important in Tasmania where it provides much of the state's electricity. The Tasmanian integrated hydropower scheme harnesses hydro energy from six major water catchments and involves 50 major dams, numerous lakes, and 29 power stations with a total capacity of over 2600MW. The scheme provides base and peak load power to the National Electricity Market, firstly to Tasmania and then to the Australian network through Basslink, the undersea interconnector which runs under Bass Strait. There are also hydroelectricity schemes in north-east Victoria, Queensland, Western Australia, and a mini-hydro electricity project in South Australia.

There are more than 120 working hydropower stations in Australia, with most of the nation's hydroelectricity generated by Hydro Tasmania's network of power plants and the Snowy Mountains Hydro Scheme in New South Wales.

Bioenergy:

Biogas production and utilization can contribute to Australia's national greenhouse gas emission reduction target by providing a renewable energy source and capturing emissions from animal waste storage and landfill sites. These emissions would otherwise be released into the atmosphere.

- Bioenergy generated approximately 3314 GWh of electricity in Australia in 2019. This equated to 1.4 per cent of total electricity generation, and 6.0 per cent of total clean energy generation.
- *"Bioenergy and energy from waste technologies are well-developed worldwide, with the International Energy Agency's forecasted renewables report identifying this area as an 'overlooked giant' within the renewables space. There is also significant potential for biofuels to decarbonise the industrial and transport sectors in Australia. Much like with Hydrogen, we're hoping that this will lead to further uptake and unlock new opportunities for bioenergy in Australia, and will enable bioenergy to play a considerable role in helping us to reduce emissions while also providing secure, reliable and affordable energy supply."* said by ARENA CEO, Darren Miller.
- ARENA has appointed a consortium of ENEA Consulting and Deloitte Touche Tohmatsu to assist in delivering the Bioenergy Roadmap, and on April 2020 commenced public consultation on the roadmap. The Bioenergy Roadmap is expected to be completed in the second half of 2020. The Government, through ARENA, has already provided more than A$118 million to help fund Australian bioenergy projects from areas such as waste, biogas, biomass and biofuels.
- Australia has a total of 222 operating bioenergy plants and there are an additional 55 projects that are under feasibility assessment stage or are under construction forming the third largest energy generating technology.

The Goulburn Bioenergy Project at the Southern Meats abattoir in NSW commenced operation in February 2018.

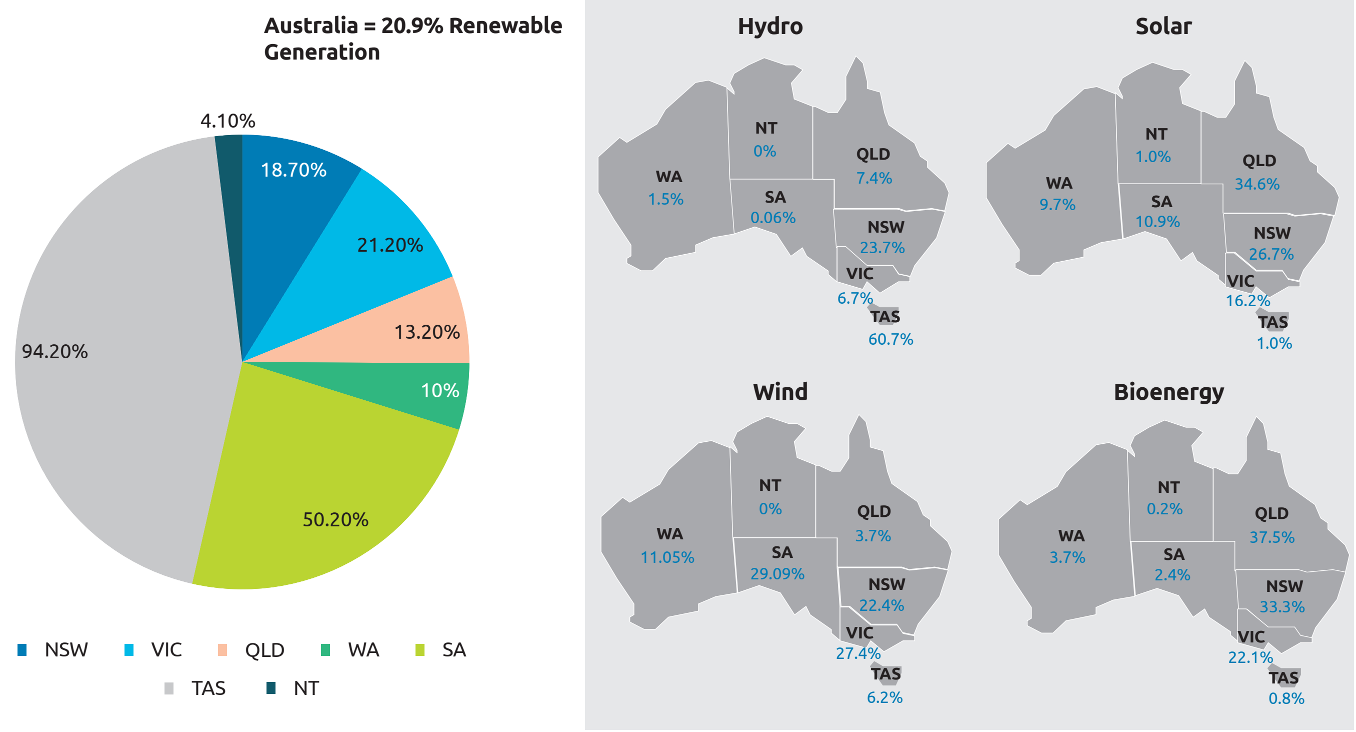
- Plant capacity: The bioenergy plant includes a covered anaerobic lagoon for the treatment of wastewater from the abattoir, followed by a biogas treatment process.
- Produced biogas is then fed into 2 x 800 kW dual fuel Caterpillar generators that can run on dual fuel, blending biogas and natural gas. Capital investment: A$5.75 million
- GHG savings: The plant is estimated to contribute to approximately 18,000 tonnes CO_2e emission savings

In May 2020, the state government of New South Wales (NSW) provided approval for the Snowy Hydro 2.0 hydropower project which is a 2GW expansion.

In May 2020, the state government of New South Wales (NSW) in Australia issued planning approval for the main works of the Snowy Hydro 2.0 hydropower project. Estimated to cost A$4.6bn ($3bn), the Snowy Hydro 2.0 project involves a 2GW expansion of the existing Snowy Hydro-operated 4.1GW Snowy Mountains Scheme. It will generate approximately 10 per cent of Australia's energy needs at peak times. "Snowy 2.0 will provide the storage and on-demand generation needed to balance the growth of wind and solar power and the retirement of Australia's aging fleet of thermal power stations" says Snowy Hydro Chief Executive Paul Broad.

The Snowy Mountains scheme or Snowy scheme is a hydroelectricity and irrigation complex in south-east Australia, consisting of sixteen major dams; seven power stations; one pumping station; and 225 kilometers of tunnels, pipelines, and aqueducts that were constructed between 1949 and 1974.

Figure 1.21 ~ Renewable Electricity Generation – Australia State-level 2019 (%)



Source: Australian Energy Statistics by Department of the Environment and Energy, Australian Energy Statistics, 2019

Figure 1.22 ~ Australian Electricity Generation Year on Year Change By Fuel Type, 2019

	NSW	VIC	QLD	WA	SA	TAS	NT	AUST
Coal	▼ 1%	▼ 8%	▼ 6%	▼ 4%	na	na	na	▼ 5%
Gas	▲ 31%	▲ 31%	▲ 1%	▲ 2%	▲ 11%	▼ 4%	▲ 2%	▲ 6%
Wind	▲ 40%	▲ 16%	▲ 194%	▲ 33%	no change	▲ 10%	na	▲ 19%
Hydro	▼ 31%	▼ 16%	▲ 29%	no change	▲ 16%	▼ 15%	no change	▼ 18%
Solar	▲ 39%	▲ 56%	▲ 62%	▲ 25%	▲ 36%	▲ 15%	▲ 32%	▲ 46%

Year on year change from 2018

Source: Australian Energy Statistics by Department of the Environment and Energy, Australian Energy Statistics, Table O, March 2019

Renewable Energy Projects Completed in 2019

NSW Total Capacity: 568 MW

Tech	Owner	Project	Capacity (MW)
Wind	AGL PARF	Silverton Wind Farm	200
Solar	John Laing	Finley Solar Farm	133
Wind	Bodangora Wind Farm	Bodangora Wind Farm	113
Solar	New Energy Solar	Beryl Solar Farm	87
Solar	ARENA	White Rock Solar Farm	20
Solar	City of Newcastle	Summerhill Solar Farm	5
Solar	Kanowna Solar	Bullarah Solar Farm	5
Solar	Meralli Solar	Kanowna Solar Farm	5

SA   Total Capacity: 229 MW

Tech	Owner	Project	Capacity (MW)
Wind	ENGIE	Willogoleche Wind Farm	119
Solar	Arcadia Energy Trading	Tailem Bend Solar Farm	95
Solar	Pirie Solar Farm	Pirie Solar Farm	5
Solar	Terregra Renewables	Mobilong Solar Farm	5
Solar	Canadian Solar	Mannum Solar Farm- Stage 1	5

WA Total Capacity: 164.8 MW

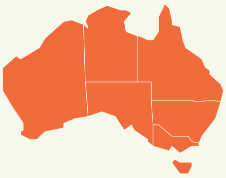
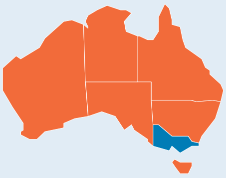
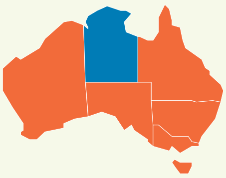
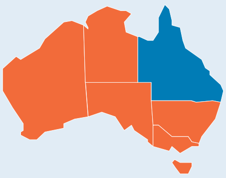
Tech	Owner	Project	Capacity (MW)
Hybrid	APA Power Holdings	Badgingarra Renewable Facility	147.5
Solar	Bookitja/IBA Northam Solar	Northam Solar Farm	10
Solar	Aggreko	Granny Smith Mine Hybrid Power Station	7.3

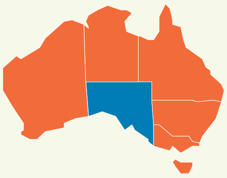
QLD Total Capacity: 991 MW

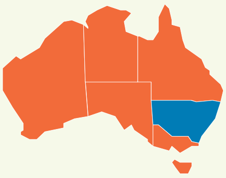
Tech	Owner	Project	Capacity (MW)
Wind	Mount Emerald Wind Farm	Mount Emerald Wind Farm	180
Solar	Edify Energy	Daydream Solar Farm	150
Solar	Palisade Investment Partners	Ross River Solar Farm	116
Solar	APA Group	Darling Downs Solar Farm	110
Solar	Lilyvale Asset Co	Lilyvale Solar Farm	100
Solar	Pacific Hydro	Haughton Solar Farm	100
Solar	Clermont Asset Co	Clermont Solar Farm	75
Solar	Adani	Rugby Run Solar Farm - Stage 1	65
Solar	Edify Energy	Hayman Solar Farm	50
Solar	Diamond Energy	Oakey Solar Farm - Stage 1	25
Solar	Chinchilla Solar	Chinchilla Solar Farm (Baking Board)	20

VIC Total Capacity: 299.7 MW

Tech	Owner	Project	Capacity (MW)
Solar	Neoen	Numurkah Solar Farm	100
Solar	BayWa r.e	Karadoc Solar Farm	90
Wind	Pacific Hydro	Crowlands Wind Farm	80
Solar	Diamond Energy	Girgarre Solar Project	8
Solar	Deakin University/AusNet Services	Waurn Ponds Microgrid Project	7.3
Wind	Epic Energy	Timboon West Wind Farm	7.2
Wind	Epic Energy	Yawong Wind Farm	7.2

	Target	Mechanisms to deliver the Renewable Energy Target
Australia Capital Territory 	• 2045 zero net emissions target • Reached 100 per cent renewable energy target	• To maintain its 100 percent renewables position, the ACT launched an additional reverse auction for largescale renewable technology in 2019. The reverse auction is open to all types of renewable energy projects, with capacities starting at 200 MW for wind and 250 MW for solar. • To move towards its target of zero net emissions by 2045, the two largest sources of emissions: transport (60 per cent) and gas usage (22 per cent) are the top focus area. • Prioritising investment in long-term emissions reduction measures rather than purchasing carbon offsets.
Victoria 	• By 2020, 15-20% below 2005 level • Committed in 2017: Net zero by 2050 • Victoria's 50 per cent renewable energy target by 2030 became law in October 2019 • Renewable Small-scale - 3,000 MW installation or 1 million solar photovoltaics by 2020	Key initiatives include : Focusing on investing in renewable energy capacity, increasing total electricity generation in Victoria by 9 per cent by 2030, improving the reliability of Victoria's supply. • A$48.1 million for renewable energy certificate purchasing, including powering Victoria's tram fleet. This has also brought forward the development of two new wind farms totaling 100MW and a new 75MW solar farm, resulting in over A$350 million of investment and 500 new regional jobs. • As at 30 June 2019, there were 16 new renewable energy projects under construction or undergoing the final stages of commissioning in Victoria. These projects are expected to add 2,960 MW to Victoria's renewable energy generation capacity.
Northern Territory 	• 2050 zero net emissions target • Despite committing to source 50 per cent of its power from renewables by 2030, progress has been slow in the Northern Territory (NT), with just 4 per cent of the state's electricity sourced from renewable energy sources	• Construction has begun on the NT's largest solar farm with battery storage. The 25 MW Katherine Solar Farm will include 100,000 panels and be able to generate approximately 700,000 MWh of power each year. The A$40 million project has a power purchase agreement with Jacana Energy. • Sun Cable's Australia/Singapore power link - this A$20 billion project near Tennant Creek includes provisions for a 10 GW solar farm and 20-30 GWh storage facility. It's the largest solar farm under development in the world.
Queensland 	• Emission Target: – Announced in 2017: By 2030, 30% below 2005 level – Announced in 2017: Net zero by 2050 • Renewable Target: – Large-scale - Announced in 2015: 50% by 2030 – Small-scale - Announced in 2015: 3,000 MW installation or 1 million solar photovoltaics by 2020 – Government mandate to support 1000 MW of new renewable generation by 2025	• The target for 1 million rooftops or 3,000 megawatts of solar photovoltaics (PV) in Queensland by 2020. This goal was reached in October 2018. There is now more than 4,000 megawatts of small and large-scale solar power, effectively making solar power the largest power station in the state. • Electricity supply well above demand resulted in Queensland experiencing negative electricity prices several times towards the end of 2019. This was attributed to strong solar generation and an outage of the interconnector with New South Wales. • Queensland's newest publicly-owned energy company, CleanCo, started trading on the National Electricity Market on 31 October 2019. • CleanCo is part of a government mandate to support 1000 MW of new renewable generation by 2025. • In April 2020, Coopers Gap Wind Farm started its operation, with 50 out of 123 planned turbines feeding into the NEM.

	Target	Mechanisms to deliver the Renewable Energy Target
South Australia 	• Net zero emission by 2050 • 100 per cent renewable energy target by 2030	• South Australia is focusing on wind and solar generation to boost reliability of supply for the state. • Project EnergyConnect, the new interconnector planned to deliver benefits to South Australia, including cheaper power prices, improved reliability and opportunities to export renewable energy. – Project EnergyConnect is a proposed high voltage transmission line connection between the South Australian and New South Wales power grids. The SA-NSW interconnector involves the construction of a new 330 kV, above-ground transmission line between Robertstown in South Australia and Wagga Wagga in New South Wales. – The 900-kilometer transmission line built by ElectraNet and Transgrid is expected to unlock up to 30 new wind and solar projects totaling nearly 5.3 GW planned for South Australia, New South Wales, and Victoria. – Construction of Project EnergyConnect is due to commence in mid-2021 and be fully commissioned by 2023. It will provide 800 regional jobs during construction and 700 ongoing jobs.
Tasmania 	• Renewable energy : Announced in 2017: 100 per cent by 2022 • Announced in 2020: 200 per cent renewable energy action plan i.e Tasmania will effectively double its output of renewable energy from around 10,500GWh a year to 21,000GWh by 2040, with an interim target of 15,750GWh per year, or 150 per cent renewables. • It expects $7 billion to be invested in new renewables projects by 2030.	• Tasmania is on track to be self-sufficient in renewables by 2022, making it the first state in Australia with 100 per cent renewable power generation. • The Granville Harbour Wind Farm (A$280 million project), with 31 turbines completed in Feb 2020 which boosted 30 per cent increase to wind power capacity. The project was supported by a A$59 million investment by the Clean Energy Finance Corporation and secured by a long-term power purchase agreement with Hydro Tasmania. • UPC Renewables has proposed the construction of two massive wind farms at Jim's Plain and Robbins Island in Northern Tasmania that together could provide up to 1 GW of new renewable generation. The two wind farms, which may also include solar, received go-ahead approval from the state's Environment Protection Authority in May 2020 with the goal of starting construction by the end of 2021.

New South Wales 	• Net Zero emissions target by 2050 • By failing to set a renewable energy target, New South Wales could fall short of its 2050 zero net emissions target • Only 17.1 per cent of the state's energy coming from renewable sources, NSW is falling well behind most other States	• The NSW Government released its Electricity Strategy in late 2019, with a focus on affordable electricity and a secure energy supply. It included a plan to create a renewable energy zone – with 3000 MW of renewables investment – which could start to close the gap on the state's emissions target. • The NSW and Federal Governments have agreed to share the financial responsibility – up to A$102 million – to upgrade the Queensland-NSW interconnector. This project is a priority under the NSW Government's Transmission Infrastructure Strategy, with plans to kick off construction in 2021 following regulatory approval. • ElectraNet and Transgrid are working together on the SA, NSW and Vic interconnector, called Project EnergyConnect, to deliver energy security, reduced prices and economic benefits for the states. • On 31 January 2020, the Honourable Prime Minister of Australia, Scott Morrison, and the Honourable New South Wales Premier, Gladys Berejiklian, signed an agreement, worth more than A$2 billion, committing both governments to collaborate on a number of initiatives that will: – Increase gas and electricity supply in New South Wales by encouraging investment – Improve grid security by supporting transmission interconnection and network access – Support emissions reduction projects that deliver genuine abatement

The City of Sydney, the central borough of the larger Australian metropolis, entirely transitioned itself to green energy.

As of 1st July 2020, Sydney, the largest city in Australia, will power all its operations with 100 per cent renewable energy via power purchase agreements now flowing from wind and solar projects from across regional New South Wales. It will help to lower CO_2 emissions by around 20,000 tonnes each year. Sydney began working to reduce its carbon footprint in 2016 when it adopted a plan to cut its carbon emissions by 70 per cent by 2030.

The Power purchase agreement, put together by Flow Power is projected to save the city more than a half-million dollars on its electricity bills every year for the next 10 years. It will reduce carbon emissions by around 20,000 tonnes a year, which is equivalent to the power used by 6,000 average households. It is also expected to generate jobs, support communities impacted by the COVID-19 pandemic, and create new opportunities in the drought-affected NSW area.

Power will be sourced from wind and solar farms in Glen Innes, Wagga Wagga, and the Shoalhaven region in a deal worth around A$60 million.

Hydrogen is gaining importance in Australia with a plan for it to become part of Australia's renewable energy mix

Several Australian and global institutes and agencies, including CSIRO, the International Energy Agency and the World Energy Council, have identified Australia's potential to be one of the world's largest Hydrogen producers.

To realise this potential, the COAG Energy Council agreed in December 2018 to establish a dedicated Working Group, chaired by the Chief Scientist, to support the development of a clean, innovative and competitive Hydrogen industry that establishes Australia as a major global player by 2030.

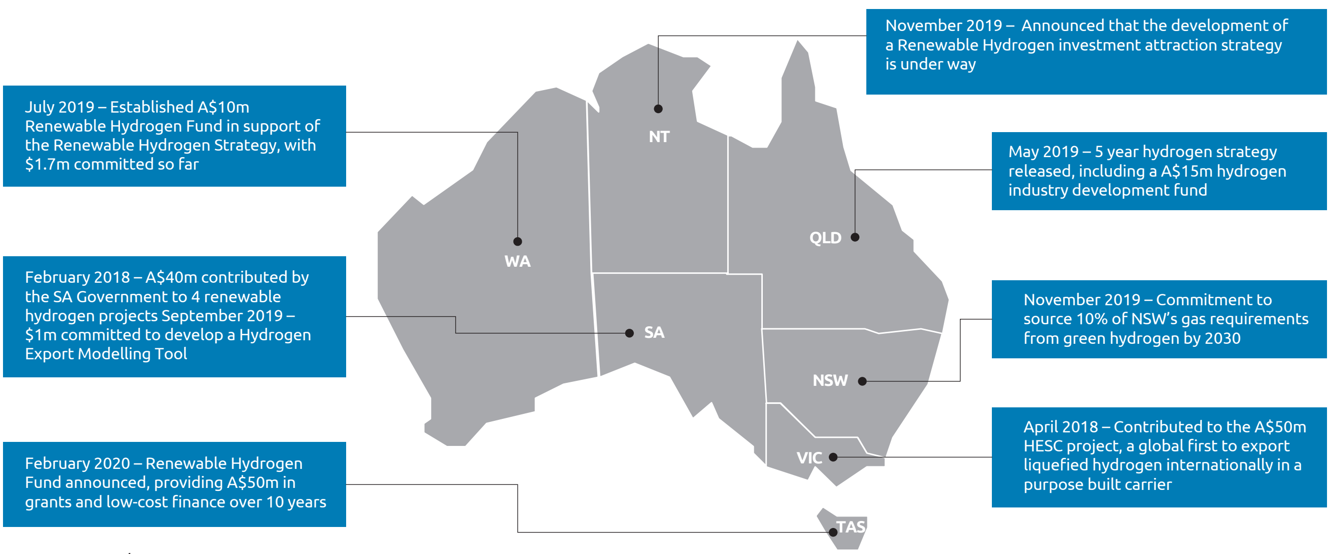
The Working Group has six work streams: Hydrogen exports; Hydrogen for Transport; Hydrogen in the gas network; Hydrogen for industrial users; Hydrogen to support electricity systems; and cross-cutting issues.

The Federal Government is focusing on to restoring the national economy and encourage private investment in a number of sectors – including in new Hydrogen technologies. The long-term goal is to create a competitive and leading Hydrogen industry, with the government setting an economic 'stretch' goal of 'H2 under 2' (ie Hydrogen production under A$2 per kilogram).

On May 2020, Federal government announced A$300 million in the Advancing Hydrogen Fund to help Australia to become a world leader in Hydrogen production and exports.

- The Advancing Hydrogen Fund will be dedicated to providing concessional finance for projects that boost Australia's Hydrogen production. It will develop export and domestic supply chains, establish Hydrogen hubs and build domestic demand for this alternative energy.
- The Fund, along with the A$70 million in funding from the Australian Renewable Energy Agency (ARENA) through the Renewable Hydrogen Deployment Funding Round, constitutes one of the largest government commitments to the Hydrogen sector in the world.
- In July 2020, seven companies have been shortlisted and invited to submit a full application for the next stage of the Hydrogen funding round:
  - APT Management Services Pty Limited
  - ATCO Australia Pty Ltd
  - Australian Gas Networks Limited
  - BHP Billiton Nickel West Pty Ltd
  - Engie Renewables Australia Pty Ltd
  - Macquarie Corporate Holdings Pty Limited
  - Woodside Energy Ltd

Figure 1.23 ~ State-wise Policy to Support the Development of Hydrogen as a Fuel



Note: As on March 2020

Source: PwC, Embracing clean Hydrogen for Australia

Understanding Hydrogen Terminology	
Grey Hydrogen	Hydrogen derived from fossil fuels, typically involving the combustion of gas or coal in steam methane reforming (SMR), with little to no Carbon Capture, Utilisation and Storage (CCUS) involved.
Clean Hydrogen	Hydrogen with little to no carbon emissions directly resulting from the production process. Comprising both Blue and Green Hydrogen.
Blue Hydrogen	Hydrogen derived from fossil fuels but considered carbon-neutral due to substantial use of CCUS technology.
Green Hydrogen	Hydrogen derived from renewable electricity, produced from electrolysis of water, with effectively zero carbon emissions.

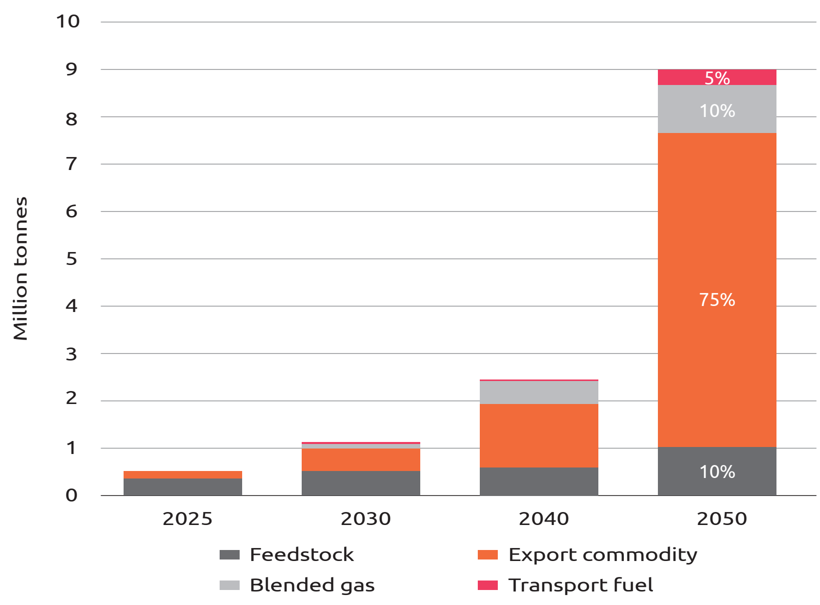
Emerging Role for Hydrogen: Hydrogen is expected to play a major role as a blended gas and as a transport fuel in the future of Australia's domestic energy system, but its growth will also present many investment opportunities across numerous sectors.

- **Hydrogen in the gas network:**
  - Hydrogen may be blended into the gas network to reduce overall carbon emissions from domestic, commercial and industrial heating and power.
    - Adding Hydrogen to natural gas can significantly reduce greenhouse gas emissions if the Hydrogen is produced from low-carbon energy sources such as biomass, solar, wind, nuclear, or fossil resources with carbon capture and storage (CCS).
  - Many existing gas distribution networks can support between 10per cent and 20per cent Hydrogen-blending before the effects of pipe embrittlement are encountered, depending on the composition of the pipes.
  - Within Australia, the progressive replacement of existing cast-iron distribution pipelines with 'Hydrogen ready' high density polyethylene (HDPE) is already underway, with ACT and Tasmania largely already Hydrogen-ready and Victoria set to join by 2035.

- **Hydrogen for transportation:**
  - The Australian transport sector is under increasing pressure to reduce carbon emissions. Due to ongoing population growth, these emissions have been steadily rising with the increase of cars on roads and freight trucks in transit. Hydrogen is one technology that has the potential to provide a reduction in greenhouse gas emissions as well as a more reliable, domestic fuel supply. Hydrogen fuel cell electric vehicles (FCEVs) are an emerging zero-emission alternative for the transport sector, which offer a variety of benefits.
  - Hydrogen contains approximately three times the energy per unit mass when compared to gasoline, making it very attractive for use as a transport fuel.
  - Hydrogen fuel cells, while still at a nascent stage of development for mine vehicles, could offer a viable alternative to traditional style and lithium-based batteries. On a larger scale, they also provide an alternative energy-storage mechanism for off-grid mine sites, and can be applied alongside advanced battery systems and gas or renewable energy sources in order to secure sites a reliable source of low-cost power for those sites.

- **Hydrogen is expected to play a key role in a decarbonised energy system including:**
  - Providing a stock-based energy supply to ensure grid stability by firming electricity generation.
  - As a zero-carbon feedstock for industrial processes, including the production of ammonia, hydrocarbons and steel.
  - As a fuel for heavy machinery used in industry, particularly fleet vehicles requiring rapid refuelling, such as mining and warehouse operations.

Figure 1.24 ~ Australia's Hydrogen end uses



Source: COAG Energy Council, Hydrogen for Transport, 2019

- Kawasaki Heavy Industries has partnered with the Australian Federal and Victorian State Governments for the development of a grey Hydrogen production facility in the Latrobe Valley, as part of a greater trial project to export Hydrogen from Australia to Japan.
- In December 2019 Kawasaki debuted the world's first liquefied Hydrogen carrier, which will have storage capacity for 1,250 cubic meters of Hydrogen at 1/800 of its original gaseous volume, having been cooled to -253 degrees Celsius.
- In combination, these two projects are laying the groundwork for future mass production and export of green Hydrogen from Australia.

- **Hydrogen as an export commodity:**
    - Japan and South Korea have clearly declared their ambitions to transform themselves into Hydrogen fueled societies by 2050 through their national Hydrogen strategies. They are substantiating these ambitions through significant investments into research, development and commercialisation of green Hydrogen technologies, and by developing international supply chains.
    - The Australian Government has already signed a cooperation agreement with Japan and a letter of intent with South Korea to underpin future Hydrogen exports, with a plan to lead the development of international certification standards. Australia has the opportunity to export over 500kt of Hydrogen to East Asia by 2030, worth an estimated A$2.2billion, which may grow further to over A$5.7billion by 2040.

While Hydrogen is often described as "zero-emission fuel" and "green energy carrier", however, its environmental impact differs dramatically depending upon the method by which it was produced.

- Hydrogen emits zero carbon at the time of consumption in fuel cells, where the by-products are mostly water vapour and small amounts of nitrogen oxides. However, Hydrogen is not necessarily zero carbon during production. There are a range of methods available for producing Hydrogen. Some use fossil fuels as a feedstock. These methods produce greenhouse gas emissions.
- Currently, the leading extraction methods are coal gasification and steam methane reforming (SMR). These are significantly cheaper per unit of output than electrolysis from renewable energy sources.
- The Latrobe Valley project plans to use brown coal to produce Hydrogen through coal gasification. Hydrogen made via this method is known as "brown Hydrogen". This method of producing Hydrogen is highly inefficient and polluting. The pilot project in the Latrobe Valley estimates that it will produce over thirty times more carbon dioxide than Hydrogen in weight. The most common method of extraction is the process of steam methane reforming. In contrast to brown Hydrogen sourced from coal, this method utilises 'natural gas' or methane. The gas industry is now marketing this as "blue Hydrogen" when carbon emissions are abated (eg, through CCS).

- Emissions from methane are lower than emissions associated with Hydrogen production from coal. The Energy Transition Hub estimates emissions of 54 kilograms of carbon dioxide per gigajoule of Hydrogen using SMR, compared to 107 kilograms per gigajoule using coal gasification. The amount of carbon dioxide by-product from blue Hydrogen is significant, despite being lower than those from brown Hydrogen.
- Electrolysis is currently more expensive than the previous two methods of Hydrogen production but produces truly zero-carbon Hydrogen known as "green Hydrogen". In this process, oxygen is the only by-product of production. Currently this is a higher cost method of producing Hydrogen than through coal gasification and SMR. However, technology costs are falling rapidly, both for electrolysis and for renewable energy, and the combination is being explored for future large-scale deployment.
- Recent analysis by Bloomberg New Energy Finance projected green Hydrogen costs to fall by 80 per cent by 2030. Connecting electrolysis to renewable sources such as wind farms and solar plants would allow for low price, excess energy to be stored as Hydrogen, which could in turn reduce volatility in renewable energy supply.

CSIRO has two technologies currently under development: Catalytic Membrane Reactor; and Direct Ammonia Engine technologies.

- The Catalytic Membrane Reactor can extract pure Hydrogen from ammonia and there is an opportunity for this technology to be a key component of equipment and devices in ammonia-Hydrogen distribution and fueling systems.
- Direct Ammonia Engine technology entails modifying standard diesel 4-stroke engines to accommodate ammonia's higher ignition temperature and low flame speed. This means ammonia can be readily used as a fuel for stationary power generation.
- When combined, these technologies could enable multiple energy business models to deliver electrical power into a grid or electric vehicle charging points, and Hydrogen for fuel cell vehicle refueling. There are also potential benefits in waste heat recovery, integration of control systems, and balancing the relative electricity and Hydrogen production rates in response to fluid local demands.

The Australian Government has supported nine Hydrogen projects in the past two years. The state and territory governments have also made early moves by supporting specific projects and in some cases, releasing their own Hydrogen project strategies.

Region	Priorities	Actions
NSW	• Looking for ways to encourage the development of domestic Hydrogen production capabilities for domestic or export purposes. • Focusing on development of supporting infrastructure and capabilities which would eventually underpin a larger scale Hydrogen sector, including an export market for North Asia and beyond.	• Coal Innovation NSW is leading the NSW CO_2 Storage Assessment Program to identify opportunities across the state for the safe and secure geological storage of CO_2, which could potentially be used to support fossil-fuel-based Hydrogen production. • Jemena Western Sydney Green Gas Project: The Western Sydney Green Gas Project involves designing and constructing a Power-to-Gas facility which will convert solar and wind power into Hydrogen via electrolysis. It's a A$15 million project, co-funded by ARENA. • In July 2020, a draft plan released for the Wagga Wagga Special Activation Precinct which could be Australia's first Hydrogen powered precinct. *"Our plans for the Wagga Wagga precinct include big ideas such as creating a circular economy – where one business's waste becomes another's resource – and Australia's first green Hydrogen hub, powered by sustainable energy"* - said by Deputy Premier and Minister for Regional NSW John Barilaro.
Victoria	• The Victorian Hydrogen Investment Program (VHIP) is supporting the development of a green Hydrogen industry through market testing, policy development, and a targeted investment program.	• Victoria is actively pursuing opportunities to use its brown coal resource in new ways, consistent with the Statement on Future Uses of Brown Coal. The production of Hydrogen from brown coal, when coupled with CCS (Carbon capture and storage)presents a significant opportunity and comparative advantage for Victoria. • Victoria has 23 trade and investment offices around the world that are focused on building international partnerships and investment. Hydrogen opportunities are being pursued as part of the overarching work program. • The four years (2018–2021) HESC (The Hydrogen Energy Supply Chain) Pilot Project comprises multiple stages to produce and export Hydrogen to Japan from the Latrobe Valley, using established and scientifically proven technologies. The Pilot Project is the world's largest Hydrogen demonstration project and includes the transportation of liquefied Hydrogen in a world-first, purpose-built liquefied Hydrogen carrier. • A commercial Hydrogen supply chain from Victoria to Japan would be in operation by the 2030s. Any commercial HESC project is dependent on a successful pilot, and a commercial decision by the project consortium.

Region	Priorities	Actions
Queensland	• The Queensland Hydrogen Industry Strategy 2019–2024 (Queensland Hydrogen Strategy) sets a vision that 'by 2030, Queensland is at the forefront of renewable Hydrogen production in Australia, supplying an established domestic market and export partners with a safe, sustainable and reliable supply of Hydrogen. • It includes the A$15 million Hydrogen Industry Development Fund, providing funding for investors developing Hydrogen projects in Queensland.	• In addition to domestic opportunities for renewable Hydrogen, priorities include: attracting investment, collaborative research and development, and creating new export markets through its international partnerships. In 2019, Queensland signed a Memorandum of Understanding with the Japan Oil, Gas and Metals National Corporation (JOGMEC) to cooperate on Hydrogen and a Statement of Intent with the University of Tokyo's Research Center for Advanced Science and Technology (RCAST). • The State is working with a large number of private sector proponents to support the delivery of their renewable Hydrogen projects. • The Queensland Government's Redlands Research Facility will establish the Hydrogen Process Research and Development Project. • Partnering With BOC Australia to Drive A Hydrogenfuelled Future: The Queensland Government will trial a Fuel Cell Electric Vehicles (FCEVs) fleet. This was a key factor in BOC deciding to progress its A$3.1 million renewable Hydrogen project at Bulwer Island. Located at QUT's Kelvin Grove campus in Brisbane, the refueling station is expected to be operational by mid-2020.
Western Australia	Western Australia will develop industry and markets to be a major exporter of renewable Hydrogen. • Strategic Focus Areas: • Export • Remote applications • Blending in the gas network • Transport The role that renewable Hydrogen could play in other areas such as stabilizing the electricity network and decarbonizing industry is also acknowledged.	• The Renewable Hydrogen Fund aims to facilitate private sector investment and other avenues for financial support to the renewable Hydrogen industry. The Fund provides financial support for feasibility studies and capital works projects. • The Western Australian Government will continue to strengthen international partnerships, identify opportunities, and secure technology partnerships with a focus on Asia and Europe.
South Australia	• The Government of South Australia was the first jurisdiction to publish a Hydrogen strategy, in 2017, and to date has committed more than A$40 million in grants and loans to the development of Hydrogen projects. • Building on this investment, the government released South Australia's Hydrogen Action Plan in 2019, setting out the next steps for the development of the state's Hydrogen industry.	• Australian Gas Networks' (AGN) pioneering Hydrogen production facility, Hydrogen Park South Australia (HyP SA). Located at the Tonsley Innovation District, south of Adelaide, the facility will produce green Hydrogen that will be blended with natural gas and supplied to nearby homes and businesses via the existing gas network. • The A$11.4 million HyP SA demonstration project is supported by a A$4.9 million grant from the South Australian government. • Other major Hydrogen projects utilizing state funding include H2U's Port Lincoln Hydrogen and ammonia supply chain demonstrator, Neoen's Hydrogen superhub at Crystal Brook Energy Park, and University of South Australia's Renewable Energy Testbed, which incorporates a solar array, flow batteries, a Hydrogen fuel stack, and thermal energy storage. • In June 2020, GFG Alliance head Sanjeev Gupta has announced a high-cost refurbishment plan i.e Green steel for the Whyalla Steelworks in South Australia by 2024, marking a major step towards his goal to power the plant with green Hydrogen.

Region	Priorities	Actions
Tasmania	• The Tasmanian Office of the Coordinator General is actively working with a range of proponents to facilitate investment in renewable Hydrogen production for both domestic use and export. • Focusing on developing the Bell Bay Advanced Manufacturing Zone as a Hydrogen hub. The hub would begin as a 100MW green Hydrogen production facility with the possibility of expansion to 1000MW by 2030.	• The A$50 million Tasmanian Renewable Hydrogen Industry Development Funding Program has been launched to help activate renewable Hydrogen industry development in Tasmania as a part of Tasmanian Renewable Hydrogen Action Plan. • The funding program consists of: – a A$20 million Tasmanian Renewable Hydrogen Fund – up to A$10 million in support services including financial assistance for renewable electricity supply – A$20 million in concessional loans

Topic Box 1.2: The Australian Government sets a Roadmap for Low Emissions Technology Investment in 2020

- In September 2020, Minister for Energy and Emissions Reduction, the Hon Angus Taylor MP released a Technology Investment Roadmap, where the primary focus is on Low Emissions Technology. The priority technologies are those with the potential for transformational economic and emissions outcomes including clean Hydrogen, energy storage, low carbon steel and aluminum, carbon capture and storage and soil carbon. In support of the Low Emissions Technology Statement, the Australian Government announced a A$1.9 billion package including A$1.62 billion in new funding for ARENA over the next 10 years. The Statement outlines five priority technologies and economic stretch goals to make new technologies as cost-effective as existing technologies. These are:
  - Hydrogen production under A$2 per kilogram.
  - Long duration energy storage (6-8 hours or more) dispatched at less than A$100 per MWh.
  - Low carbon materials – low emissions steel production under A$900 per tonne, low emissions aluminium under A$2,700 per tonne.
  - CCS – CO_2 compression, hub transport, and storage under A$20 per tonne of CO_2.
  - Soil carbon measurement under A$3 per hectare per year – a 90 per cent reduction from current measurement costs and would transform the economics of soil carbon projects for Australian farmers.
- For the past several years, ARENA and CEFC has been driving down costs of new and emerging new technologies. Hence, the Government is exploring ways to give these agencies a broader range of technologies that reduce emissions across all sectors of the economy. It is intended that both agencies can support energy efficiency technologies, low emissions technologies (including in the agriculture and land sectors) and renewable energy technologies.
- In addition to ARENA and the CEFC, a number of existing broadbased programs, such as the CSIRO Innovation Fund, the Early Stage Venture Capital Limited Partnerships, and the Tax Incentives for Early Stage Investors, are designed to address these issues by encouraging investment in innovative companies developing and commercializing new technologies.

Australian Government Policies/Schemes and Agencies are used to curb Carbon emissions & enhance Renewable targets

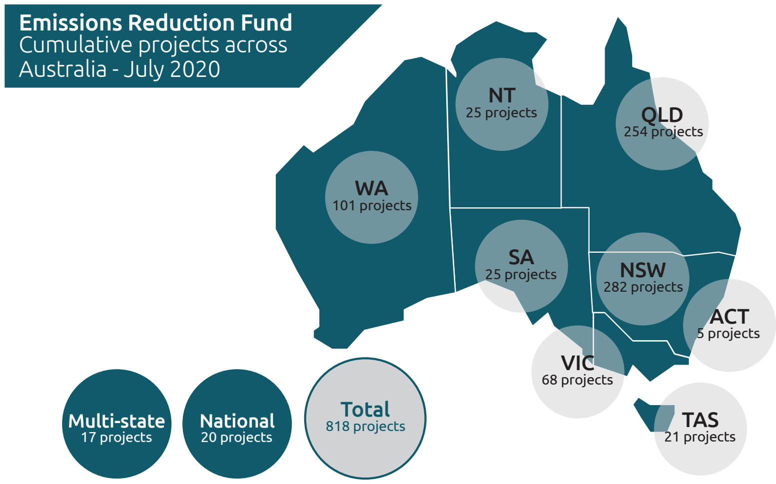
Climate Solution Fund/Emissions Reduction Fund (ERF)

- The CSF (renamed from ERF) is a voluntary scheme to provide incentives to certain organisations and individuals to adopt new practices and technologies for reducing emissions. It is enacted through the Carbon Credits (Carbon Farming Initiative) Act 2011, the Carbon Credits (Carbon Farming Initiative) Regulations 2011 and the Carbon Credits (Carbon Farming Initiative) Rule 2015.
- The fund was established by the Federal Government to support emissions reduction projects in Australia and to drive the Government's aim to reduce emissions to 26-28 per cent below 2005 levels by 2030.

Update 2019

- There are total 818 registered emissions reduction projects as of July 2020.

Figure 1.25 ~ Emissions Reduction Fund Cumulative Projects Across Australia – July 2020



Source: COAG Energy Council, Hydrogen for Transport, 2019

- The CSF was originally established as the Emissions Reduction Fund (ERF) in 2014 with an initial A$2.55B in funds. The ERF has since been rebranded as the CSF and has been provided with an additional A$2B in funds, which is intended to extend the CSF for a further 15 years.
- There are two components to participating in the CSF:
  - The first component is running and reporting on an eligible Emissions Reduction Fund project to earn Australian carbon credit units (ACCUs).
  - The second component to the Emissions Reduction Fund - Bidding to sell ACCUs through a carbon abatement contract. This component is optional and can occur at any time following project registration.

Cumulative registered projects by method type, July 2020

Method type	energy efficiency	industrial fugitives	savanna burning	transport	facilities	agriculture	vegetation	waste	Total
Registered projects	44	9	76	5	2	76	465	141	818

Australia

The Safeguard Mechanism

- The Australian government brought into effect the safeguard mechanism on July 1, 2016 that places upper caps (or baselines) on GHG emissions from large facilities, helping in providing a framework for Australian companies to measure, report and manage their emission level.
- The safeguard mechanism protects taxpayers' funds by aiming to ensure emissions reductions generated through the ERF does not get offset by significant increases in emissions above business-as-usual levels elsewhere in the economy.
- The safeguard mechanism was established as part of the Emissions Reduction Fund.
- It complements the emissions reduction elements of the Emissions Reduction Fund by sending a signal to businesses to avoid increases in emissions beyond business-as-usual levels.
- It operates under the framework of the National Greenhouse and Energy Reporting scheme and applies to facilities with direct scope emissions of more than 100,000 tonnes of carbon dioxide equivalent (t CO_2-e) per year.

Update 2019

- On 3 March 2020, the Federal Minister for Energy and Emissions Reduction registered the National Greenhouse and Energy Reporting (Safeguard Mechanism) Amendment (Prescribed Production Variables) Rule 2020 (Cth) (New Rule).
- The New Rule inserts government-determined prescribed production variables and default emissions intensity values into the National Greenhouse and Energy Reporting (Safeguard Mechanism) Rule 2015 (Cth) (Principal Rule) to give effect to amendments made to the Principal Rule in March 2019.
- The transition to new emissions baselines for companies covered by the Safeguard Mechanism has been delayed by a year as the ongoing coronavirus crisis makes it difficult for emitters to submit new baseline applications in time for the original deadline.

The Renewable Energy Target (RET)

- A scheme which encourages the additional generation of electricity from renewable sources to reduce greenhouse gas emissions in the electricity sector. It comprises two schemes
- Large-scale Renewable Energy Target (LRET): This target incentivises investment in renewable energy power stations, such as wind and solar farms, or hydro-electric power stations, by legislating demand for large-scale generation certificates (LGCs)
- Small-scale Renewable Energy Target (SRES): This target incentivises households, businesses and the community to install eligible small-scale systems such as rooftop solar panels, solar water heaters, small-scale wind or hydro systems by legislating demand for small-scale technology certificates (STCs)
- Additionally, investment in large-scale solar projects has been assisted with subsidies from the Australian Renewable Energy Agency (ARENA) and the Clean Energy Finance Corporation (CEFC), cutting the costs of renewable energy projects cut down to nearly half since it started.

Update 2019

- Since the beginning of 2020, Clean Energy Regulator (CER) has accredited 94 renewable energy projects with a total capacity of 1.3 gigawatts. These projects are expected to generate over 2,600 gigawatt hours in 2020, which is enough to power over 460,000 households.
- On 30 May 2020, with the help of the RET, Australian households have installed more than 2.43 million solar PV systems and 1.24 million solar water heater and air source heat pump systems.
- The A$5 million Solar Communities program provided funding for 385 community groups and selected regions across Australia to install rooftop solar PV panels, solar hot water and solar-connected battery systems to deliver lower electricity costs for community organizations.
- By Sep 2019, Large-scale Renewable Energy Target (LRET) capacity targets were achieved for 2020. By June 2020, over 50 per cent of small-scale technology certificate (STC) claims were submitted using solar panel validation (SPV).
  - SPV is made up of two parts — an app for installers to use on a mobile device and a database of serial numbers for approved solar photovoltaic (PV) modules, received directly from manufacturers. Installers use the app to scan solar panel serial numbers, which are then checked against a database to ensure they correspond to verified serial numbers for panels approved by the Clean Energy Council.
  - SPV provides customers with an electronic record of confirmation their installed solar panels are verified as part of SPV. The record includes information such as the make and model of the solar panels, their serial numbers, the time and date of installation and the location. Customers are now asking solar businesses if they are participating in SPV and for a record of verification for their solar panels.

The Clean Energy Finance Corporation (CEFC)

- CEFC was established under the Clean Energy Finance Corporation Act 2012 (CEFC Act), which defines how CEFC operate and invest.
- It invests in businesses and projects deploying clean energy technologies which are complying investments, that are solely or mainly Australian-based, across the various sectors of the economy.
- CEFC is a corporate Commonwealth entity under the Public Governance, Performance and Accountability Act 2013 (PGPA Act).

Update 2019

- In the 2019-20 financial year, CEFC made new investment commitments of just over A$1 billion and continued to invest through the economic disruption of the COVID-19 pandemic.
  - CEFC Supported 23 clean energy investments with a combined value of A$4.2 billion in the year to 30 June 2020.
  - CEFC finance extended to new areas of the economy, delivering Australia's first dedicated green bond fund, the CEFC's first green home loan, and a material uplift in the capacity of Australia's largest battery in South Australia.
  - The CEFC provided more than A$187 million wholesale finance to support ~6,700 smaller-scale investments in clean energy projects, including in agribusiness, property and transport.
  - The CEFC also committed just over A$13 million in three cleantech innovators, as well as increased investment of A$3.4 million in a further two Innovation Fund portfolio companies to accelerate their growth.

National Carbon Offset Standard (NCOS) (From Nov 2019, the Climate Active Carbon Neutral Standard)

- According to the Australian Government Initiative, Climate Active, being carbon neutral means reducing emissions where possible and compensating for the remainder by investing in carbon offset projects to achieve net-zero overall emissions.
- These offsets are generated from an activity that prevents, reduces or removes greenhouse gas emissions from being released into the atmosphere.
- Offsets are measured in metrics tonnes of carbon dioxide equivalent (CO_2e). The creation of one tonne of carbon offset ensures that there will be one less tonne of carbon dioxide in the atmosphere.
- Each tonne of carbon that is offset by an eligible project results in the creation of a certificate (representing the realisation of the offset) in respect of that tonne. The sale of these certificates is a source of funds to finance these offset projects.
- Through certificates, businesses that purchase these offsets can fund the projects that remove an amount of carbon from the atmosphere to compensate for the emissions that they cause.
- If offsets purchased by a business in a given year are equal to or greater than emissions caused by the business in that year, the business becomes "carbon neutral" or achieves a "net-zero" emissions position for that year.

Update 2019

- In Aug 2020, Australian Mines became the first mineral resources company to be certified a "Carbon Neutral Organisation" under the Australian Government's Climate Active program.
- City of Melbourne's operations have proudly been Certified Carbon Neutral by Climate Active (formerly the National Carbon Offset Standard) since 2012.
- In Aug 2020, Sydney's Woollahra Council was recognised as 'carbon neutral' by Climate Active.
- In Feb 2020, the City of Adelaide announced that operations will be powered by 100 per cent renewable electricity as part of a power purchase deal from 1 July 2020.
- In Oct 2019, Victoria's Hobson Bay City Council announced a range of initiatives to move towards its carbon neutrality goals, including a renewable energy power purchase agreement, deployment of EV infrastructure and rooftop solar.
- In 2019, Global sustainability solutions provider, South Pole, achieved official climate neutral certification for its Australian operations against the federal government's National Carbon Offset Standard (NCOS) (now the Climate Active Carbon Neutral Standard).

In 2019 sales tripled for electric vehicles within Australia with the momentum expected to continue into 2020.

To meet this surge, the Australian Renewable Energy Agency (ARENA) on behalf of Federal Government is investing heavily on EV infrastructure

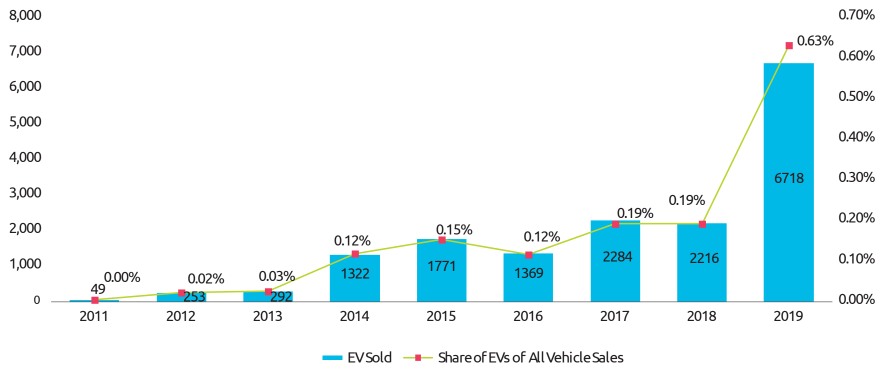
Consumers are growing increasingly aware of their environmental impact, especially after large scale bush fires, and hence hybrid vehicles are gaining its importance in consumers' minds. According to Fitch Ratings, Australian EV sales in 2020 will expand by 20.2 per cent, to reach an annual sales volume of just over 8,000 units (or 1.13 per cent of total sales).

- Australia has very low EV penetration among advanced countries - Only 0.6 per cent of new car sales in Australia are EVs.
- The Australian Electric Vehicle Market Study has estimated that Australia would require A$1.7 billion in private sector investment to support the creation of new electric vehicle charging infrastructure.

Electric Vehicles Market in 2019-2020

- Sales of electric vehicles which include plug-in hybrids went from 2,216 in 2018 to 6,718 in 2019. Categorically 80 per cent of those sales were all-electric vehicles.
- Moreover in H1, 2020, there have been 3,226 electric vehicles despite an overall drop of 20 per cent in vehicle sales due to the Covid-19 pandemic.
- Currently EVs market serves 28 electric models on sale and six more are due to arrive before the end of 2021.

Figure 1.26 ~ Sales of Electric Vehicles in Australia (2011-2019)



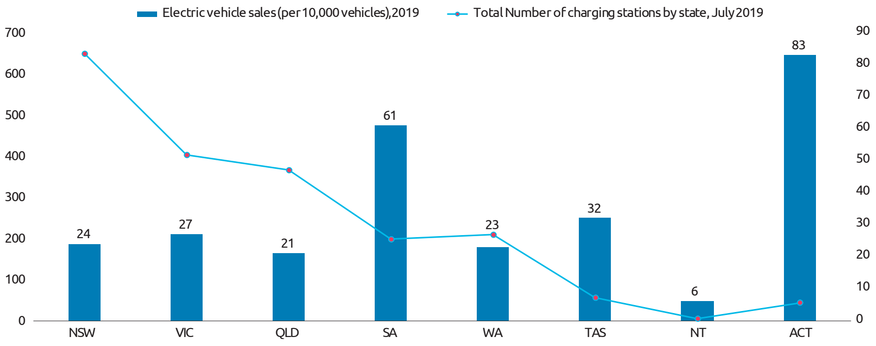
Electric Charging Stations

- As of July 2019, total number of electric vehicle charging stations (AC and DC) in Australia was 1,930. New South Wales holds the maximum no of AC & DC stations.
- Chargefox, which claims to be Australia's largest electric vehicle (EV) charging network, revealed the target locations for all 22 sites in the first phase of its ultra-rapid EV charging network to connect Adelaide, Melbourne, Sydney and Brisbane, with additional sites in Western Australia and Tasmania.
- In its Infrastructure Priority List 2020 report, Infrastructure Australia (IA) has identified the development of a fast-charging network for electric cars as one of Australia's highest national priorities over the next five years.

Emission Reduction Potential of Electric Vehicles

- According to a new report, 'Cleaner and Safer Roads for NSW,' every time an electric vehicle replaces a traditional vehicle on NSW roads, health costs are reduced by A$3,690 over a ten-year period. Emissions from internal combustion engine (ICE) vehicle in the Sydney-Newcastle-Wollongong area creates A$3 billion in health costs every year.
- However according to 2018 Data assessments, electric car upstream emissions (for a battery electric vehicle) in Australia can be estimated to be about 170g of CO_2 per km while in New Zealand it is estimated at about 25g of CO_2 per km on average. Upstream emissions of EVs essentially depend on the share of zero or low-carbon sources in the country's electricity generation mix.

Figure 1.27 ~ Region-wise Electric Vehicle Sales and Charging Stations



- Witnessing the surge in sales, the Australian Renewable Energy Agency (ARENA) has invested A$15 million into 42 new charging stations across roadside service centres in Adelaide, Melbourne, Canberra, Sydney, and Brisbane. The Australian federal government has also rolled out a national EV strategy as part of its Climate Solutions Package.
- In 2020, the Victorian Government is developing its Zero Emissions Vehicle Roadmap, a strategic policy to identify actions to address barriers to zero-emissions vehicle uptake and encourage a competitive environment.

Measures taken from Australian Federal Government to promote Electric Vehicles

- The Department of Transport offers reduced registration fees and stamp duty rates for purchases of green vehicles.
- In Aug 2020, on behalf of the Australian Government, the Australian Renewable Energy Agency (ARENA) announced A$838,000 in funding to Origin Energy Ltd to undertake an electric vehicle (EV) smart charging trial across the National Electricity Market (NEM). The A$2.9 million trial will look to evaluate the benefits of and barriers to controlled smart charging.

Hurdles in EV Expansion

- According to Bloomberg New Energy Finance 2020 report, with poor policy structure and limited standards & regulations in Australia, electric vehicle sales growth in Australia will continue to be slow in the coming years.
- It is expected that EVs will reach cost parity with traditional combustion engine cars by 2022. With the improvement in the availability of models on offer, declining costs and targets for the electrification of government and corporate fleets, it is expected that EV penetration will reach 3.2 per cent of total new car sales by 2023.
- People's perceptions around EV's range and infrastructure is also slowing its expansion. As many as 47 per cent of people believe electric vehicles can only travel 100-300 kilometres before recharging.

Growing Local capability

- With Australia being rich in lithium and other essential mineral elements required for lithium-ion battery production, Australia is well placed to capitalise on the mining of raw materials for battery production.
- In 2019, the Australian Federal Government provided a A$25 million grant to the Future Battery Industries Cooperative Research Centre for research, support and development of a battery production and recycling industry.
- The Queensland Government is also conducting a feasibility study in Townsville for a 15 GWh battery factory.
- Brisbane-based technology company Tritium, which specialises in the design and manufacture of EV chargers has become a leading global supplier of DC fast chargers and has exported more than 3000 charges to more than 30 countries.
- Renewables start-up Energy Renaissance is intending to build a 1 GWh lithium-ion manufacturing plant in Darwin.

Electric vehicle-to-grid trial in ACT:

In 2020, Canberra is planning to launch one of the largest electric vehicle (EV) vehicle-to-grid (V2G) trials in the world. ARENA has announced A$2.4 million in funding towards the ActewAGL trial to establish V2G services in Australia. The full cost of the trial is A$6.6 million.

As batteries on wheels, EVs using V2G technology can discharge electricity back to the grid. The technology is a potential boost to grid security.

The EVs will be part of the ACT Government fleet and will provide Frequency Control Ancillary Services (FCAS) to the National Electricity Market (NEM).

FCAS is used by the Australian Energy Market Operator (AEMO) to maintain the frequency of the electrical system and provide a fast injection or reduction of energy to maintain grid stability.

The trial will involve 50 Nissan LEAF cars, which will return energy to the grid when network demand is high.

Under the trial, the EVs will be used for normal transport operations around the Australian Capital Territory during business hours. They will be plugged into the network when not in use and therefore be available up to 70 per cent of the time to provide grid services.
(Source: Australian Government, Department of Industry, Science, Energy and Resources)

Will Australia reach its 2020 and 2030 emission reduction targets? National experts expressed concerned over Australia's current progress

- Australia produces around 1 per cent of global emissions and is the world's 14th largest emitter. Compared with other major economies and considering the population and the size of the economy, Australia is relatively emissions-intensive.
- Ranked 56th in Climate Change Performing Index in 2019, Australia continues to receive low ratings in the Energy Use category and ranks at the bottom of low performers in both the GHG Emissions and Renewable Energy categories.

Emissions in selected countries and regions

Country/Region	Share of global emissions (%)	Emissions per capita (t CO_2-e per person)	Emissions per unit of GDP (kg CO_2-e/US$)
China	23.5	8.4	1.0
United States	11.8	18.1	0.3
European Union	7.3	7.1	0.2
India	6.6	2.4	1.4
Indonesia	4.5	8.5	2.4
Japan	2.6	10.0	0.3
Canada	1.6	21.6	0.5
Republic of Korea	1.3	12.8	0.5
Australia	1.1	21.5	0.4
New Zealand	0.1	13.5	0.3

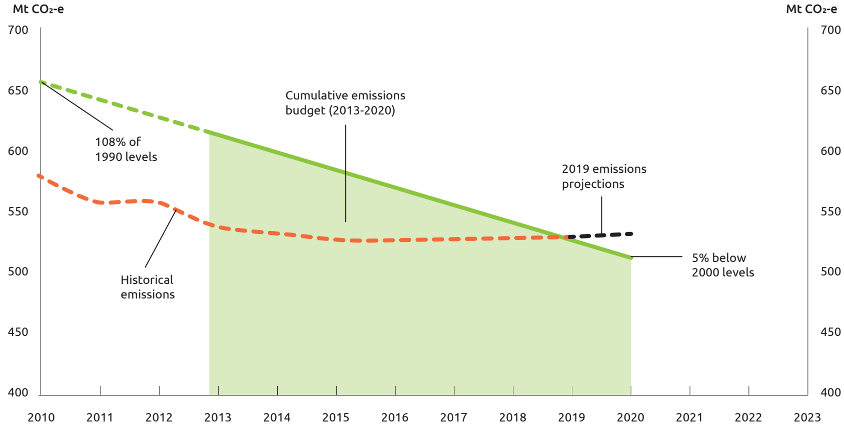
Australia signed following agreements over the time:

Year of target set	Treaty	Australian Target
1997	Kyoto Protocol First Commitment Period (CP1)	As a signatory to the Kyoto Protocol, ratified in 2007, Australia committed to limiting increases in net GHG emissions to 108 per cent of its 1990 levels from 2008 to 2012.
2012	Kyoto Second Commitment Period (CP2)	Reduce emissions 5 per cent below 2000 levels over the period from 2013-2020
2015	Paris Agreement	Reduce emissions of all GHGs including LULUCF 26-28 per cent below 2005 levels by 2030 following a budget approach.

Australia's progress toward meeting the 2020 target:

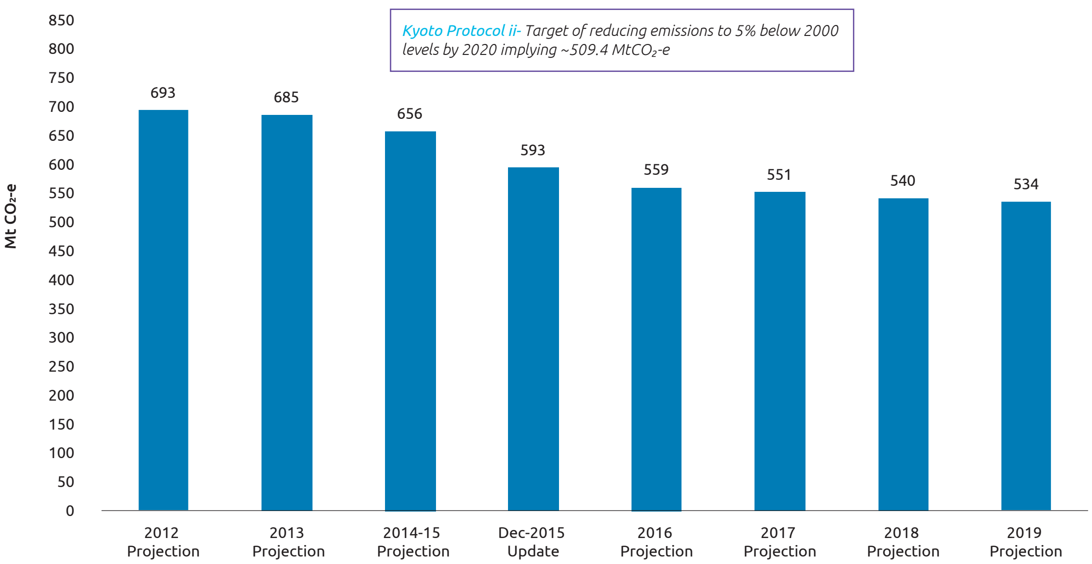
- Australia is expected to surpass the emissions reductions required to meet its 2020 target (5 per cent below 2000 levels) by 264 Mt CO_2 -e. These estimates are calculated against an emissions budget for the period 2013 to 2020.
- If Australia's overachievement of 128 Mt CO_2 -e from the first commitment period of the Kyoto Protocol is included, the overachievement is 411 Mt CO_2 -e.
- Australia's emissions in 2020 are expected to be 534 Mt CO_2 -e compared to a notional point target of 509 Mt CO_2 -e. Australia is set to overachieve its 2020 target because the target is calculated as a budget over the period 2013–2020.
- Since the 2018 projections, projected emissions in 2020 have been revised upwards for the fugitive emissions, industrial processes and product use, and waste sectors. This has been more than offset by reductions in emissions in 2020 due to:
  - reduced fuel consumption in manufacturing reported in the direct combustion sector.
  - a decline in the consumption of petrol in the transport sector.
  - floods in early 2019 and the ongoing effects of the drought.

Figure 1.28 ~ Australia's Cumulative Emissions Reduction Task to 2020



Source: www.industry.gov.au

Figure 1.29 ~ Projected Emissions in 2020 over time



Note: Since the 2018 projections, projected emissions in 2020 have been revised upwards for the fugitive emissions, industrial processes and product use, and waste sectors.
Source: Australia's emissions projections 2019

Australia

Cumulative Emission Reduction Task 2013 to 2020

Calculation of 2020 emissions reduction task	Emissions (Mt CO_2 -e)
Cumulative emissions 2013-2020	4,243
Emissions budget 2013–2020	4,508
Unadjusted emissions reduction task	**-264**
Voluntary action	9
Waste Protocol units	-28
Emissions reduction task	-283
Overachievement from 2008–2012	**-128**
Emissions reduction task with overachievement	**-411**

Australia's progress toward meeting the 2030 target

Australia's 2030 target under the Paris Agreement is to reduce emissions by 26 to 28 per cent on 2005 levels by 2030.

- Emissions are projected to decline to 511 Mt CO_2 -e in 2030 which is 16 per cent below 2005 levels. This is driven mainly by declines in the electricity sector because of strong uptake of rooftop solar and the inclusion of the Victoria, Queensland and Northern Territory 50 per cent renewable energy targets. Agriculture emissions are expected to increase as average seasonal conditions are assumed to return.
- Australia's abatement task to meet the 2030 target is projected to be between 395 Mt CO_2 -e (26 per cent reduction) and 462 Mt CO_2 -e (28 per cent reduction) over the period 2021 to 2030. When overachievement of Australia's 2020 target is included the task is reduced to -16 Mt CO_2 -e and 51 Mt CO_2 -e.
- The Australian Government has said it will use an emissions budget over the period 2021 to 2030 to assess progress to the target, and its official emissions projections indicate it will use up to 411 million tonnes of emissions reductions carried over from over-achievement of earlier targets.

The Kyoto Protocol, which preceded the Paris Agreement, allows a country to help meet its emissions target using carried-over emissions reductions ('carryover') from the over-achievement of a previous target. Under the Kyoto Protocol, carryover may only be used for the next target and cannot be rolled over again for successive targets.

- Using the 128 million tonnes of carryover from 2008–2012 to meet a 2030 target would not be allowed under the Kyoto Protocol rules; however, the Paris Agreement rules apply to 2030 targets. The Paris Agreement rules are currently silent as to how carryover would apply, although countries were encouraged to cancel Kyoto units as part of the decision adopting the agreement.
- There is a short-term benefit to Australia in using its carryover surplus in that it makes it easier to meet its 2030 target. However, the reduced task lowers the level of ambition represented by Australia's 2030 target to about a 14 per cent reduction on 2005 levels instead of a 26 to 28 per cent reduction. Relying on carryover credits to meet Australia's 2030 target will essentially defer Australia's transition and require accelerated emissions abatement in future years

Australia's emission reduction efforts will be better recognized by many in the international community if targets are met without the use of carryover credits. At the UNFCCC Conference in December 2019, Australia faced harsh criticism for its position on the use of carryover credits (Carbon Brief 2019). To date, Australia is the only country to have indicated it may use carryover to meet its commitment under the Paris Agreement. New Zealand has declared it will not use any carryover units to meet its Paris commitments.

Sectoral breakdown of 2019 projections results to 2030

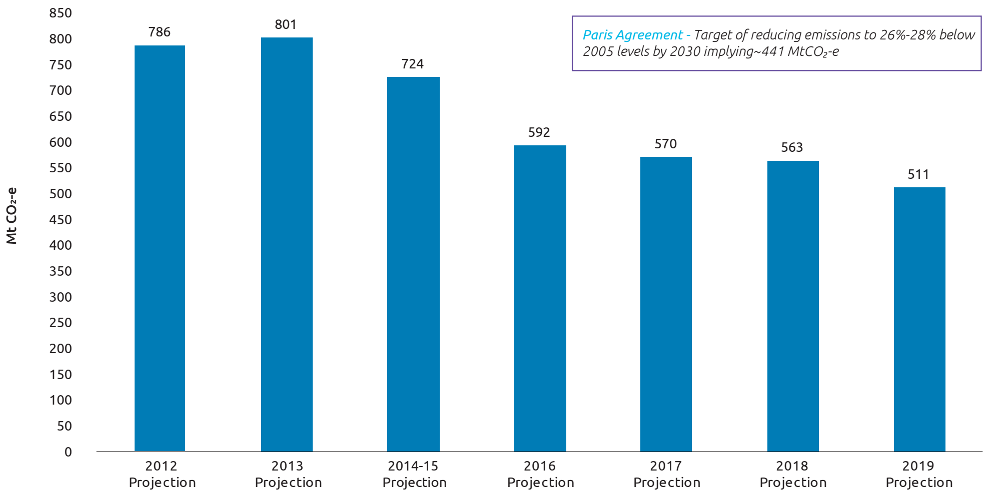
Emissions by sector (Mt CO_2-e)	Emissions (Mt CO_2 -e)			Projection	
	2000	2005	2019	2020	2030
Electricity	175	197	180	170	131
Direct combustion	75	82	101	104	106
Transport	**74**	**82**	**100**	**102**	**108**
Fugitives	40	39	56	60	59
Industrial processes and product use	27	32	35	35	32
Agriculture	78	76	67	67	74
Waste	16	14	12	12	11
Land use, land use change and foresty	51	89	-19	-16	-10
Total	**536**	**611**	**532**	**534**	**511**

Cumulative Emission Reduction Task 2021 to 2030

Calculation of 2030 emissions reduction task	26 per cent below 2005 level in 2030 (Mt CO_2 -e)	28 per cent below 2005 level in 2030 (Mt CO_2 -e)
Cumulative emissions 2021-2030	5,169	5,169
Emissions budget 2021-2030	4,777	4,710
Voluntary action	3	3
Emissions reduction task	395	462
Overachievement of Australia's previous targets	-283 (2013–2020) -128 (2008–2012)	
Total overachievement	-411	
Emissions reduction task including overachievement	-16	51

- Australia's emissions for the 2030 year are expected to be 511 Mt CO_2 -e compared to a notional point target of 441 Mt CO_2-e. The actual target is calculated based on cumulative emissions over the period 2021 to 2030 and not the point target of 441 MT CO_2-e.

Figure 1.30 ~ Projected Emissions in 2030 over time



Note: Since the 2018 projections, projected emissions in 2020 have been revised upwards for the fugitive emissions, industrial processes and product use, and waste sectors.
Source: Australia's emissions projections 2019

2-Infrastructure & Adequacy of Supply

Australia is making headway in strengthening generation capacity, while also taking measures to control unplanned transmission outages

Climatic variations not only impact electricity demand levels but with emerging renewable energy sources, there is a stronger correlation between the electricity generation and the climatic conditions.

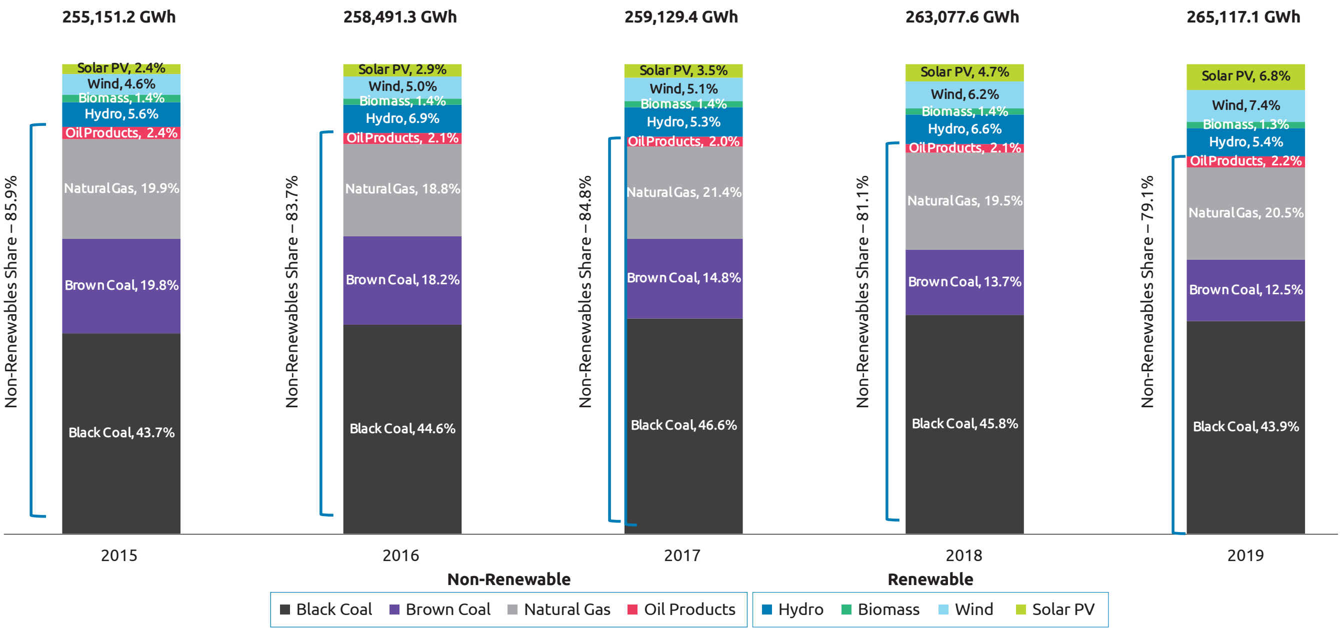
Thermal, solar and wind output and also the transmission lines are hampered during extreme weather events of bushfires, lightning and storms. Likewise, droughts reduce hydro output leading to loss of supply.

- The 2020 Australian Energy Statistics for electricity generation cover all electricity generation in Australia, including by power plants, businesses and households. The new data shows:
  - Approx. 21 per cent of Australia's electricity came from renewable energy in 2019. Contribution of renewable energy in 2018 was 18 per cent.
  - Wind farms accounted for approximately 7.4 per cent of output, and solar farms for 5.6 per cent.
  - The largest increase in renewable generation was in large-scale solar, up 270 per cent, followed by small-scale solar, up 25 per cent, and wind generation up 19 per cent.
  - The data also demonstrates the importance of coal-fired generation, which continues to be an essential part of Australia's energy mix, representing approximately 60 per cent of total generation in 2019.

The Australian Government has the intention to enter into bilateral agreements with state governments to support generation and transmission investments. The Prime Minister and the Premier of NSW announced the first such agreement in January 2020.

- It includes commitments to support timely network upgrades; development of a renewable energy zone; identification of options to maintain reliability as ageing coal-fired power stations retire; increasing the supply of gas; and emissions reduction in non-electricity sectors (Energy NSW 2020).

Figure 2.1 ~ Electricity Generation Mix in Australia



Source: Australian Energy Statistics by Department of the Environment and Energy, Australian Energy Statistics, Table O, March 2019

Many remote towns rely on diesel and LPG:

- Many areas rely on diesel and LPG generators, with fuels typically delivered by trucks. The use of diesel-based electricity generation can have negative effects on remote communities as it has potentially high supply costs and can require increased road maintenance due to transportation requirements.
- **Kaltukatjara in the Northern Territory, which is home to around 3,000 people, requires 60,000 litres of diesel fuel to be transported every eight weeks over a distance of more than 2,000 kilometres.**
- Poor road conditions or flooded roads can delay delivery and compromise energy security. Remote communities and businesses operating diesel generators can also face uncertain petroleum prices. Diesel generators can also have environmental impacts due to noise, emissions and spillage.
- The growth and development of communities can be constrained by the capacity of their power generation requirement; specially where new capacity is needed, and a major capital expenditure decision is required.
- Renewable energy and battery combinations are being included as part of the solution to the remote community energy dilemma.

Changing in generation mix in NEM:

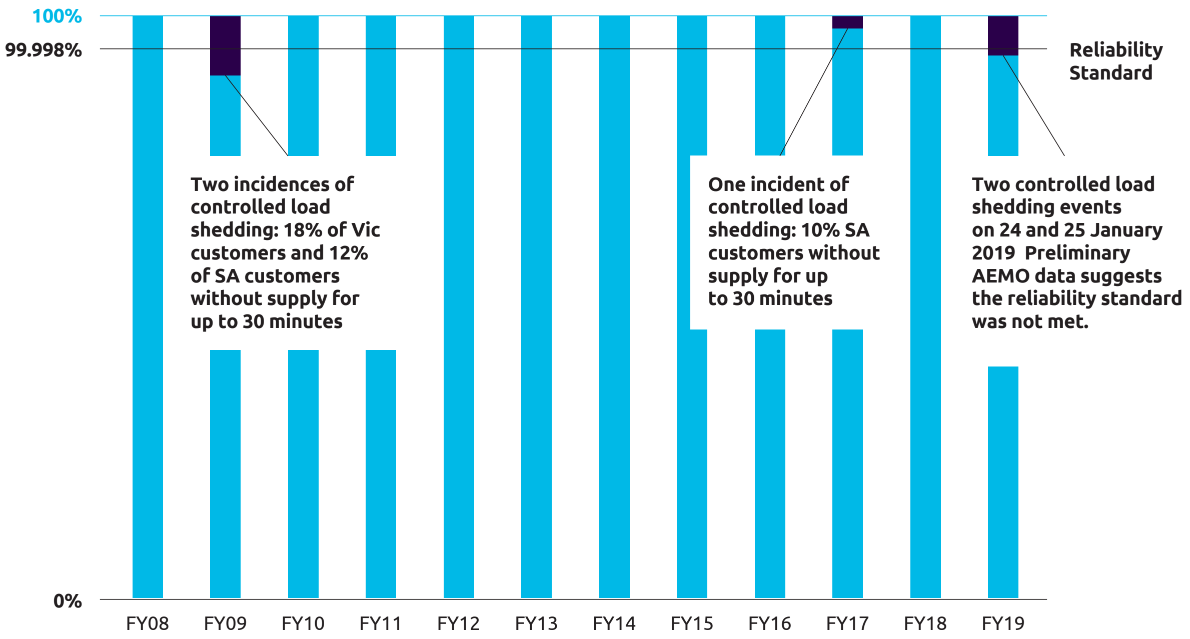
- The mix of electricity generation is changing, both at grid scale and at the individual customer level. Between 2014 and 2020, more than 4000 MW of coal fired generation left the market. No material coal fired or gas powered generation has been added to the market since a 240 MW upgrade to the Eraring power station in NSW was completed in 2013.
- Over this same period, more than 7000 MW of new renewable supply came online (mainly in the form of wind and large solar)
- Another 3340 MW of renewable capacity is committed for 2020, of which the bulk is wind (56 per cent) and solar (43 per cent) plant. There is also a shift away from the traditional model of having relatively few large power stations congregated close to fossil fuel sources, towards having many small to medium generators spread out across the system.
- New solar and wind plants are often being constructed in locations with the richest wind and solar resources, but many of these locations are remote areas where the network struggles to cope with more capacity.
- For every 1 MW of coal plant retiring, 2–3 MW of new renewable generation capacity is needed, because wind and solar plants can operate only when weather conditions are favorable.
- For this reason, increased supply from black coal fired stations has been needed to fill much of the supply gap left by the more recent brown coal plant closures in South Australia and Victoria. Coal fired generation remains the dominant supply source in the NEM, meeting around 68 per cent of energy requirements in 2019. At times, the market also uses gas-powered generation to manage the variability of renewables' output.
- As a result, gas plant is being used more often than in the past, at times even when gas fuel costs are high. Investment in gas powered generation has been negligible, however, with significantly higher gas prices making this plant less economically viable.

According to AEMC, the **reliability standard** requires at least 99.998 per cent of forecast customer demand to be met each year. It is reviewed by the independent **Reliability** Panel, which includes large energy users, consumer groups, industry and the **Australian** Energy Market Operator (AEMO).

Reliability risks in Victoria in summer:

- In 2019 the ESOO forecasted that the risk of load shedding in Victoria in 2019-20 was high, with the expected level of use in excess of both the reliability standard and the level of load shedding that was experienced previous summer.
- On 24 and 25 January 2019, the equivalent of approximately 375,000 households were without power for an hour in Victoria and South Australia and 200,000 customers without power for up to 2 hours, due to a combination of factors including extreme temperatures causing high demands and significant levels of unavailable thermal capacity. To restore the balance, the Australian Energy Market Operator (AEMO) instructed electricity networks to reduce load. This load shedding was despite the activation of all available RERT resources that were procured last summer.
- At the time of the crisis two major units in Victoria (Mortlake Unit 2 and Loy Yang Unit 2), which provide over 750 MW of capacity were unavailable due to long-term outages continuing the poor performance of aging brown coal generators in Victoria.

Figure 2.2 ~ Reliability Standard: AEMO should target zero load shedding in real time



Source: AEMC

Australia

NEM Major events during Q1 2020		
Date	**Regions**	**Details**
4 January 2020	New South Wales and Victoria	Multiple transmission lines in southern New South Wales tripped due to bushfires, resulting in the separation of the NEM into two islands, north and south of this area, for just under seven hours.
31 January 2020	Victoria and South Australia	On 31 January 2020, at approximately 1324 hrs, towers supporting two 500 kilovolt (kV) transmission lines in western Victoria were damaged, resulting in the disconnection of the South Australian region, Alcoa Portland aluminum smelter and Mortlake Power Station from the rest of the NEM power system. These systems were re-connected on 17 February 2020.
2 March 2020	Victoria and South Australia	A circuit breaker at Heywood Terminal Station tripped, resulting in disconnection of the South Australian region and Mortlake Power Station from the rest of the NEM power system for approximately eight hours.

- In general, AEMO decides when load shedding is needed in the National Electricity Market (NEM), which includes Queensland, New South Wales, the ACT, Victoria, Tasmania and South Australia.
- Before it turns to load shedding, AEMO has other measures it takes to try to overcome a power shortfall. These measures include importing more power from other states, tapping into emergency energy reserves or appeals to consumers to voluntarily reduce their energy consumption and/or pay large industrial electricity users to power down for a period of time.
- But after exhausting these options, if it still needs to reduce demand, AEMO instructs electricity transmission and distribution companies to carry out load shedding.

Note:

- **The Electricity Statement of Opportunities (ESOO)** provides technical and market data that informs the decision-making processes of market participants, new investors, and jurisdictional bodies as they assess opportunities in the National Electricity Market (NEM) over a 10-year outlook period.
- **The Reliability and Emergency Reserve Trader (RERT)** is a function conferred on AEMO to maintain power system reliability and system security using reserve contracts.

According to the AER report, power line outages, low operational demand, and generator outages were the main drivers for changes in inter-state transfers in the NEM region in the 1st quarter of 2020.

- **Victoria to South Australia** – unplanned transmission outages on the Heywood Interconnector were the key drivers of the 33 MW reduction in average transfers between Victoria and South Australia compared to Q1 2019. These outages, coupled with lower operational demand in Victoria, contributed to a 40 MW swing in average transfers, resulting in Victoria being a net exporter to South Australia.
  - On 31 January, an unplanned transmission outage caused by a severe storm resulted in the disconnection of the South Australian region, Alcoa Portland aluminium smelter, and Mortlake Power Station from the rest of the NEM power system for 18 days. The outage limited export from South Australia during periods of excess generation (which typically occur during windy daytime conditions).
- **Victoria to New South Wales** – compared to Q1 2019, total transfers between Victoria and New South Wales increased by 41 per cent, driven by increased local generation and reduced operational demand in Victoria, as well as high number of coal-fired unit outages in New South Wales in February and March.
- **Tasmania to Victoria** – total transfers between Tasmania and Victoria increased compared to recent quarters. Despite increased output from hydro generators, Tasmania remained a net importer in the first quarter (84 MW), predominantly importing overnight and during the day when Victorian pool prices were lower while exporting during the evening peak when Victoria prices were high.
- **New South Wales to Queensland** – transfers continued to occur mostly in a southerly direction on the New South Wales and Queensland interconnectors. The amount of transfers was partially offset by lower operational demand in New South Wales and increased imports from Victoria, and transfers reduced by 10 per cent compared to Q1 2019.

As the number and range of weather events such as prolonged extreme temperatures, cyclones and bushfires increase as a result of climate change, the challenge of maintaining the secure operation of the power system will grow. As the market transitions, intervention to manage power system security and reliability risks has risen, imposing significant costs on energy customers.

- In March 2020, the COAG Energy Council had a discussion withy Energy Security Board (ESB) aimed at improving the reliability of the electricity system. The Council agreed to implement interim measures to deliver further reliability by establishing an out-of-market capacity reserve and improving triggering arrangements for the Retailer Reliability Obligation (RRO). Both measures will be initiated to keep unserved energy to maximum 0.0006 per cent in any region.
- The Australian Energy Market Operator has instructed some generators to operate even when it is not economic. South Australia, Victoria and Queensland have been the focus of these interventions.
- Investment in 'firming' capacity (such as fast start generation, demand response, battery storage and pumped hydro plant) is needed to fill supply gaps when a lack of wind or sunshine curtails renewable plant.
- The Reliability and Emergency Reserve Trader mechanism was activated in each of the past three summers to secure back-up supply, at a cost of A$126 million. The Retailer Reliability Obligation, launched in July 2019, was activated in January 2020 (in South Australia).
- Victoria at A$126 per megawatt hour (MWh) edged South Australia (A$125 per MWh) as the NEM's highest price region in 2019. Wholesale prices peaked early in the year, due to high fuel costs and periods of (weather driven) high demand. Generator outages in Victoria also impacted the market.
- The Liberal National Government is focusing on multi-pronged policy approach to address energy affordability, reliability and security challenges faced by NEM:
  - The A$1 billion Grid Reliability Fund
  - Underwriting the New South Wales-Queensland Interconnector
  - Implementing the Retailer Reliability Obligation
  - Building Snowy 2.0, and
  - Supporting Tasmania's MarinusLink and Battery of the Nation.

Retailer Reliability Obligation:
As NEM is undergoing a transition towards lower emission electricity system, they are taking measures to ensure electricity supply. Hence COAG Energy Council agreed to implement the Retailer Reliability Obligation (RRO) to help manage the risk of declining reliability.

- RRO was developed to encourage investment in dispatchable electricity generation in regions of the NEM that are expected to experience a gap between generation and peak forecast demand.
- The RRO came into effect on 1 July 2019. It will ensure energy retailers (and some large energy users) are accountable for reliability in the National Electricity Market (NEM).
- If the RRO is triggered, it will require retailers to demonstrate they are sufficiently contracted to meet their share of expected system peak demand.
- The RRO is designed to be a long-term solution to ensuring the electricity system operates to reliably meet electricity demand at the lowest cost.

- In July 2020, Australia government granted A$495,680 through the Australian Renewable Energy Agency (ARENA) to the Monash University's Grid Innovation Hub for a study to help strengthen unstable parts of the energy grid for renewable energy. Large renewable resources, such as wind and solar farms, can be located in weaker areas of the electricity grid prone to stability issues. This study aims to explore a range of solutions which address stability issues so as to avoid costly connection delays and network remediation solutions. It will also help to reduce the risks for developing new renewable generation connections.
- In May 2019, the Australian Renewable Energy Agency (ARENA) announced A$2.5 million in funding for AEMO to run a virtual power plant trial over a 12–18 month period, to demonstrate the technology's capabilities to deliver energy and grid stability services. AEMO invited existing pilot scale projects to participate, including ARENA funded AGL and Simply Energy pilot scale projects in South Australia.
  - On March 2020, The Australian Energy Market Operator (AEMO) has published its first knowledge sharing report under its landmark virtual power plant (VPP) demonstrations program, which is intended to provide insights into the scalability and network services potential of VPPs. The report details how the South Australia-based Tesla-Energy Locals VPP responded to price signals and frequency level and helps further understand the benefits consumers can have from participating in VPPs.
  - On 30th July 2020, AEMO confirmed the extension of the VPP Demonstration to June 2021. The extension in the demonstration will facilitate a broad range of technologies and businesses to participate in the demonstration, while enabling AEMO to obtain further insights into the technical, market and consumer impacts of the DER participation in contingency Frequency Control Ancillary Services (FCAS) markets.
  - During FY21, AEMO will be working with industry and consumer groups to explore the on-going arrangements for DER to participate in the contingency FCAS markets. AEMO's VPP team is keen to engage with active and potential VPP participants on the technical settings, business models and regulatory arrangements to support long-term arrangements for DER participation in FCAS markets - expected to commence in FY22.

Topic box 2.1: A lack of infrastructure is undermining SA's goal to lead the nation in renewable energy

South Australia's ambition is to be the national leader in renewable energy is being hampered by the lack of infrastructure to support the transition, according to economist Ross Garnaut.
A windfarm that was approved almost 20 years ago, was never developed because of a lack of support for large-scale operations. Dr Garnaut highlighted the Eyre Peninsula and Spencer Gulf as two of the regions most likely to be able to both create renewable energy and house the industries that want to use it.

The ElectraNet electricity transmission line on the state's west coast is currently not able to support large-scale renewable businesses. The funding has been approved by the AER for the Eyre Peninsula transmission line with scheduled works expected to begin in April 2021.
Melbourne-based renewables company Ausker Energies won approval to build a 5-megawatt windfarm on a property near Elliston in 2001. Tests conducted by the company found the area had some of the highest wind speeds in mainland Australia. But managing director, Jacob Cherian, said the company was not able to start the project as there was no network to support its power generation. That approval has now lapsed, but the company is revisiting the project, after being given renewed hope by ElectraNet's plan to provide a connection at Yadnarie — about 130km from the proposed site at Tungketta Hill — as it upgrades the transmission line on the peninsula's east coast.

Regional Development Australia Whyalla and Eyre Peninsula CEO, Dion Dorwood, said despite the peninsula being identified as one of the world's greatest energy resource zones, the low capacity on its transmission lines was holding back its economic growth. South Australian Minister for Energy and Mining, Dan van Holst Pellekaan, said the state had great potential as a source of renewable energy and economic growth. But he said any upgrades to line capacity were the responsibility of ElectraNet, which purchased the infrastructure from the South Australian government in 1999.

The company said it did not currently have plans to upgrade the existing transmission line closest to the state's west coast, between Yadnarie and Wudinna.

In its 2018 Integrated System Plan, the Australian Energy Market Operator ranked western Eyre Peninsula as a lower priority for renewable development than other areas of the state, including northern SA, the mid-north, and Roxby Downs.

Draft 2020 Integrated System Plan - roadmap to address future generation and transmission issues the National Electricity Market (NEM) is expected to face over the next 20 years

In June 2020, The Australian Energy Market Operator (AEMO) has released its Draft 2020 Integrated System Plan (ISP) and it calls for significant increases in renewable energy across the country, as well as the increased use of virtual power plants (VPP's) and demand-side participation over the coming 20 years. It identified key investments needed for Australia's future energy system. This includes in distributed energy resources, variable renewable energy, supporting dispatchable resources and power system services, and the transmission grid.

For the electricity system to remain stable and secured, AEMO outlined the grid needs significant new investment in new renewable resources and up to 21GW in new flexible dispatchable resources in order to firm those variable renewables. To highlight the changes occurring within the power system, the Draft 2020 ISP identified:

- Rooftop solar capacity is expected to double or even triple, providing up to 22 per cent of total energy by 2040.
- More than 30GW of large-scale renewable energy is needed to replace coal-fired generation by 2040, with 63 per cent of Australia's coal-fired generation set to retire by then.
- Up to 21GW of new dispatchable resources are needed to back up renewables, in the form of utility-scale pumped hydro or battery storage, demand response such as demand-side participation, and distributed batteries participating as virtual power plants.
- System services including voltage control, system strength, frequency management, power system inertia and dispatchability all need to be managed as the generation mix changes.
- Targeted and strategic investment in the grid is needed to balance resources across states and unlock much needed Renewable Energy Zones (REZ).

To maximize economic benefits, as traditional generators retire, the Draft ISP sets out a plan to invest in a modern energy system with significant consumer-led distributed energy resources – such as rooftop solar – and utility-scale variable renewable energy, supported by sufficient dispatchable resources and well-targeted augmentations to the electricity network. The Draft ISP identified projects to augment the transmission grid as part of the optimal development plan.

It also helped to look out for investment opportunities for the market and targeted transmission augmentation necessary to achieve the best outcomes for consumers. It aimed to ensure Australians enjoy affordable, secure and reliable energy in the coming decades as old generation assets retire and they are replaced with a combination of new technologies and upgraded transmission links.

Topic Box 2.2: Australia, the third largest producer of uranium, might consider nuclear power:

Australia hosts 33 per cent of the world's uranium deposits and is the world's third largest producer of uranium after Kazakhstan and Canada. Australia is the only G20 country until now where nuclear power remains banned by Federal Law, even though nuclear energy proponents such as The Minerals Council of Australia are demanding the repeal of legislation. The Energy Security Board proposes to fairly weigh all available technology characteristics and the outcomes they can deliver, and to this effect, in August 2019, the Energy Minister Angus Taylor says he has requested the Standing Committee on the Environment and Energy to investigate nuclear as a power source for Australia.

An Australian federal inquiry December 2019 recommended partially lifting a nationwide ban on nuclear energy, urging that the government pursue a "goal-oriented" and community-focused strategy as it considers the prospect of including nuclear energy as part of the nation's future energy mix.

- The measure is notable because though Australia has the world's largest reserves of uranium, and the world's third-largest uranium exporter, mainly to North American, European, and Asian countries, the country only operates a single nuclear reactor in New South Wales mainly for medical research and other purposes.
  - In 1998, owing to formidable anti-nuclear sentiment attached to French nuclear weapons testing in the Pacific and the surreptitious bombing of a Greenpeace vessel, Rainbow Warrior, that had been heading to protest the French nuclear test site, parliament introduced a moratorium that prohibited construction or operation of a number of nuclear installations, including nuclear power plants. The moratorium was introduced as Parliament was crafting laws to ensure the security and safety of nuclear activities and radioactive materials.

- An examination of these factors—along with 309 submissions the inquiry drew from public hearings across the country—led the committee to recommend that the government consider nuclear technology as part of its future energy mix. However, as part of that consideration, the government should also deepen its understanding of nuclear technology in the Australian context. The inquiry urged the government to lift the current moratorium only for new and emerging nuclear technologies on the condition that approvals for nuclear facilities have the "informed consent" of affected local communities.
- In recent years, a number of inquiries have been undertaken into nuclear issues in Australia. The Australian Parliament House of Representatives Standing Committee on Environment and Energy held an inquiry into the prerequisites for nuclear energy in Australia and reported on 13 December 2019. The NSW Parliament conducted an inquiry into uranium mining and the potential of nuclear power in NSW (report tabled in March 2020). The Victorian Parliament also has an inquiry into nuclear prohibition (submissions closed in February 2020).
- Australia has one nuclear reactor at Lucas Heights (south of Sydney). It is used chiefly for the production of medical isotopes and not used to generate electricity. The facility produces tens of cubic metres of low and intermediate level radioactive waste each year. Australia is currently working to establish a National Radioactive Waste Management Facility for the permanent storage of low-level waste from nuclear medicine and research activities and the temporary storage of intermediate-level waste. This is progressing under the National Radioactive Waste Management Act 2012. The Government has identified a site near Kimba in South Australia to host the facility and this selection has gone before Parliament in the National Radioactive Waste Management Amendment (Site Specification, Community Fund and Other Measures) Bill 2020.
- However, before Australia can begin developing a nuclear power industry, the committee found that the nation must investigate all aspects of its nuclear fuel cycle management capabilities, from mining to waste management. It should also explore nuclear applications beyond power generation, such as for medical uses, desalination, radiography, silicon irradiation, and the production of Hydrogen as an alternative to fossil fuels.

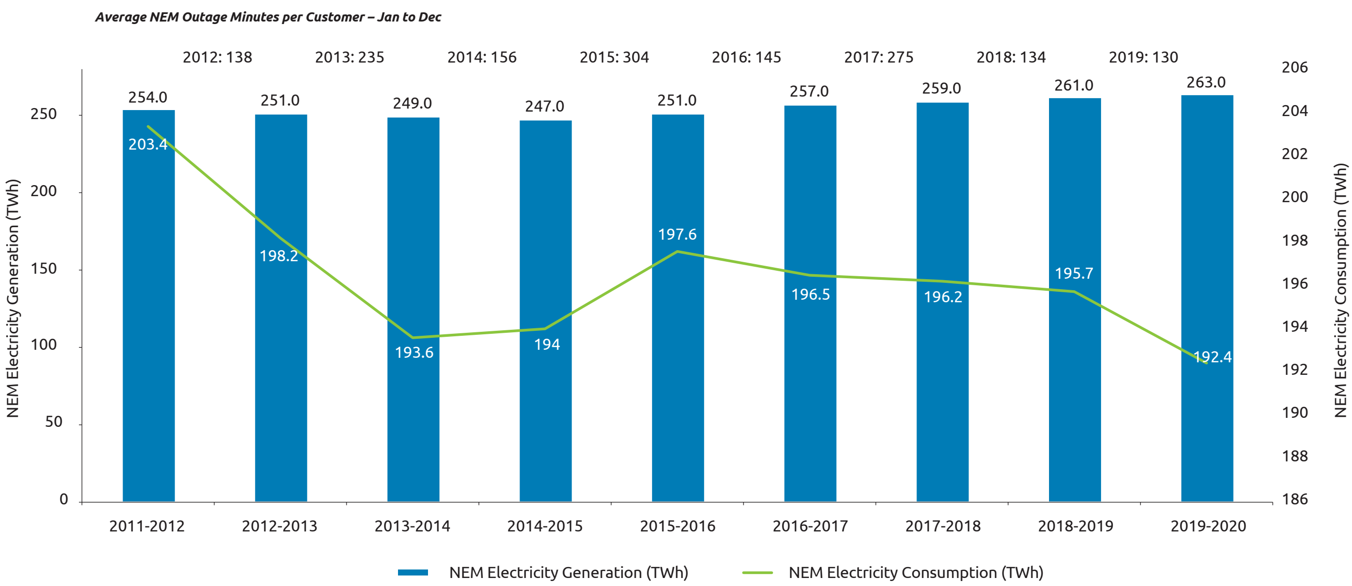
Electricity consumption in the NEM declined in 2019 due to the growth of solar panels and government policies

Despite the growing number of connections and increased reliance on electricity, growth in electricity consumption has been in decline across the NEM.

- **Overall in 2019 there was a decline in electricity consumption by 1.69 per cent.**
- Continued growth in the uptake of embedded PV systems (rooftop PV and larger commercial PV 'non-scheduled' generation [PVNSG] systems) is reducing the electricity consumption and demand required to be met by the grid. By January 2020 over 2 million households and businesses in the NEM had installed solar PV systems to produce electricity. These systems met around 5 per cent of total energy requirements in the NEM in 2019.
- Relatively strong growth in rooftop PV systems is forecast over the next five years.
- Over the medium term, AEMO's forecasts capture likely growth in PVNSG incentivized by state/territory government incentives in Victoria, Queensland, and the Australian Capital Territory (ACT).
- EE (Electricity Efficiency) policies and measures also are acting to reduce electricity consumption, affecting both annual electricity consumption and the magnitude of peak electricity demands in the residential and commercial sectors.
  - The impacts in the industrial sector are more modest, as policy support to date has focused on the residential and commercial sector.
  - State energy savings schemes are currently scheduled to end between 2020 and 2030, with EE savings expected to decline, particularly after 2030, because post-2020 targets are yet to be set.
- Overall, improvements in energy productivity, growth in other non-scheduled generation, and a gradual shift away from energy intensive industries led to the decline in consumption.

- **In 2020 Covid-19 impacted the overall energy system by reducing energy consumption to record lows.**
  - As of March 2020, there were significant reduction in operational demand in the National Electricity Market (NEM). Overall, demand was down 6.7 per cent, with South Australia experiencing the biggest reduction of 11.1 per cent and a new record low.
  - Operational demand was down 2 per cent when compared to Q2 2019, with COVID-19 contributing to an estimated 2.1 per cent reduction and an increase in rooftop PV contributing a further 1.2 per cent reduction.
  - This was offset by increased heating requirements due to cooler weather, which increased demand by 1.3 per cent.
  - By sector, there were large reductions in commercial demand (around 10-20 per cent) and large increases in residential demand, while industrial demand was mostly flat.

Figure 2.3 ~ NEM Electricity Generation vs. Electricity Consumption (terawatt-hours) and Average Outage Minutes per Customer, 2011-2020E



Source: Department of the Environment and Energy, Australian Energy Statistics, Table O, March 2019, Australian Energy Regulator, Clean Energy Australia Report 2019

Australia

NEM at a glance

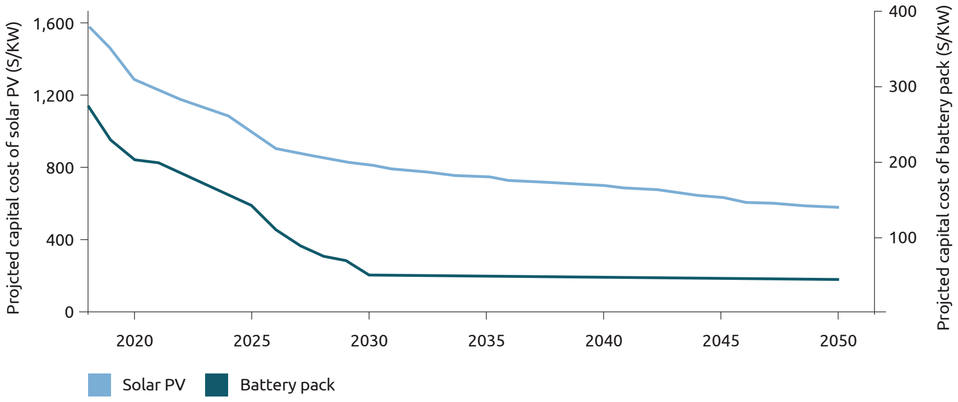
Participating jurisdictions	Qld, NSW, Vic, SA, Tas, ACT
NEM regions	Qld, NSW, Vic, SA, Tas
NEM installed capacity (including rooftop solar)1	60 824 MW
Number of large generating units	268
Number of customers	10 million
Total electricity consumption 2019	205.5 TWh
National maximum demand 2019	33,941 MW

The cost of solar panels and batteries is falling

According to the Wood Mackenzie's report on Australia's energy storage market, Australia is set to add 1.2 gigawatt-hours of energy storage capacity in 2020, more than double the 499 megawatt-hours installed in 2019. This will increase the country's cumulative storage capacity to 2.7 gigawatt-hours in 2020.

- For the first time, front-of-the-meter (FTM) capacity, at 672 megawatt-hours, will overtake the 581 megawatt-hours of behind-the-meter (BTM) capacity in 2020, a result of funding from state and federal government programs as well as the Australian Renewable Energy Agency.
  - BTM installations have traditionally led capacity growth as state governments have been issuing subsidies for rooftop solar and residential storage as well as funding for distributed energy resources. Residential, commercial and industrial customers are also incentivized to install BTM systems to manage rising electricity bills and power outages.
  - The FTM market's leading position is likely to be short-lived as the industry faces many uncertainties. Coronavirus-related restrictions and an economic downturn could cause delays or cancellations for the 4.6 gigawatt-hours of announced projects in the pipeline over the next five years.
- Australia has one of the highest rates of adoption of household rooftop solar systems in the world. Uptake of batteries, smart appliances and electric vehicles is likely to continue to grow, as CSIRO forecasts indicate continued decline in the cost of solar panels and battery storage technology.
  - Over the next 10 years, more consumers will likely adopt home battery storage as battery prices have fallen by 80 per cent over last decade, and are expected to continue to drop until 2030.
- By 2050, CSIRO and Energy Networks Australia estimate that between 30 per cent to 45 per cent of annual electricity consumption could be supplied from consumer owned generators.
  - Large scale investment, helped by incentives, is already occurring. In September 2018, there were 55 large-scale energy storage projects that were existing, under construction, planned or proposed.
  - Regulation will play a large role in how consumers adopt storage behind the meter, and investment in larger scale utility storage in the wholesale market. It will be a challenge to ensure that regulatory frameworks are flexible and transparent enough to encourage private and consumer investment in energy storage.
- Battery storage has potential to delay or negate the need for network investment and help smooth the intermittent nature of renewable generation. Large fixed batteries such as the Hornsdale Power Reserve in South Australia provide rapid frequency control services that improve grid stability and reduce energy bills.

Figure 2.4 : The projected capital costs of solar PV and batteries are forecast to continue to decline



Source : Commonwealth Scientific and Industrial Research Organization

Bruny Island Battery Trial has saved taxpayers costs without sacrificing reliability

- Bruny Island is connected to Tasmania's main grid via an undersea cable, which overloads at times of peak demand. Rather than incurring the huge costs of upgrading the cable (approx. cost A$1 million per kilometer) or installing diesel generators; residents have been provided with subsidies to install 40 battery and rooftop solar PV systems.
- These batteries are used in a smart, automated way to reduce network costs, and deliver reliable and secure electricity. Battery owners maximize the value of their battery systems by exporting electricity when the need for energy is high. This shaves peak demand while keeping the network within voltage and capacity limits.
- Since energy generation is more localized, there is less demand for distribution, reducing the cost of building, upgrading and maintaining poles and wires, thereby reducing costs to all electricity users.
- Energy systems on Rottnest Island in Western Australia and King and Flinders Islands in Tasmania also have a high proportion of renewable energy assets, high system quality and reliability. Both projects have significantly reduced diesel consumption.

Prospective Energy Storage Installations - by State

Queensland:

- In Jan 2020, AGL Energy and Vena Energy Australia have announced plans to build Australia's biggest battery, which will play a major role in improving grid stability and support the state's shift to renewable energy. Located near Wandoan in the state's south-west, the battery system will have an initial capacity of 100 MW and store 150 MWh of energy, marking the first stage of a major renewable project that could supply up to 400,000 homes with solar energy.
- In August 2020, Genex Power has announced plans to build another battery in Queensland, a 50MW facility with 1.5 hours of storage that will it be built in addition to the Kidston pumped hydro project in the north of the state.

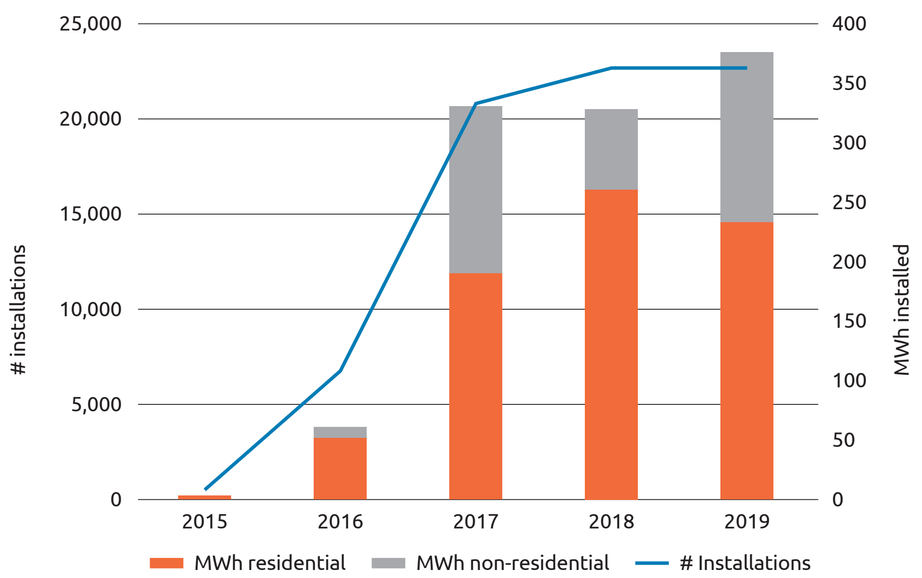
South Australia:

- South Australia's working Tesla battery's output and storage is set for an upgrade that will increase output by 50 per cent, with help from the State and Federal Government. It would take the battery's output from 100 to 150 megawatts, with the South Australian Government committing A$15 million and the Australian Renewable Energy Agency contributing A$8 million. The upgrade is expected to be completed by mid-2020 and provide more security to the grid.
- The South Australian government has introduced the Home Battery Scheme which allows residents access to state government subsidies and low-interest loans - provided by the Clean Energy Finance Corporation - As per the latest subsidies introduced in 15th April 2020:
  - Energy concession holder - A$400 per kWh
  - All other households - A$300 per kWh
  - Maximum subsidy per battery installation - A$4,000

Northern Territory:

- The Northern Territory announced that it has approved procurement for a large-scale battery system to help balance the local Darwin-Katherine electricity grid. Although it will cost around A$30 million the state government expects it to "pay for itself in approximately five years". The procurement process was initiated in April 2020, and the battery energy storage system (BESS) is expected to go online by the second half of the year 2022.
- As with South Australia, the Northern Territory is opening up a financial support scheme to encourage households and businesses to also purchase their own solar-plus-storage systems. A grant of A$6,000 is being offered for PV systems with inverters and battery equipment selected from an approved list of vendors. Batteries must have a capacity of at least 7kWh.
- Meanwhile, a government-owned energy supply startup, Jacana Energy, will offer a standard feed-in tariff (FIT) of A$0.083 / kWh to "all new businesses and households with behind-the-meter solar installations of up to 30kW in size".

Figure 2.5 ~ Energy Storage System Installations 2015-2019



Source: onestepoffthegrid.com.au

Prevalent Types of Energy Storage Technologies

Lead-acid Batteries	Lithium-ion Batteries	Flow Batteries
Advanced lead acid batteries are being developed that leverage older lead-acid battery technology with modern supercapacitors Lacks efficiency compared to modern battery types Lasts for 1,500 life cycles	Has high charging efficiency and low self-discharge Suited for very small to expansive multiple installations Can be built alongside new wind or solar plants or retrofitted to existing plants Last for up to 10,000 life cycles	Contain two electrolyte solutions in two separate tanks, which flow through two independent loops. A current is created when electrons travel from a negative solution to a positive solution across a membrane They have indefinite (10,000+) life cycles
Pumped Hydro	**Thermal Energy**	**Hydrogen Storage**
It makes use of two vertically separated water reservoirs. Once water is pumped up to a higher level, it runs as a conventional hydro power plant producing electricity; when energy is needed water is released driving a turbine It is the most widely adopted large-scale energy storage technology	Stores energy as heat (or cold) in materials such as concrete or rock, water, or materials like molten salts It is known to be low cost, flexible, and can be deployed at large-scale Recently being paired with concentrating solar plants to produce electricity	Involves using excess electricity to drive electrolysis - the separation of water into O2 and H molecules. The H produced is captured, stored and later fed into a gas turbine power plant or fuel cells to make electricity Can store energy for extended periods, suited for bulk power rather than rapid response

Victoria:

- In March 2018, on behalf of the Australian Government, ARENA committed A$25 million to two gridconnected, utility-scale batteries.
  - The 30 MW/30 MWh Ballarat Battery Energy Storage System (BESS) owned by AusNet Services and operated by EnergyAustralia.
  - The 25 MW/50 MWh Gannawarra battery system owned by Edify and Wirsol and was supplied by Tesla, operated by EnergyAustralia under a long-term offtake agreement.

New South Wales:

- In 2020, the state government's new Emerging Energy Program i.e. the grant-based scheme awarded A$75 million to accelerate the deployment of dispatchable generation or storage. Several technologies were shortlisted for funding, including lithium ion batteries, pumped hydro, conventional/biogas, Virtual Power Plants (VPP) and Concentrated PV. The majority of capital was awarded to lithium ion battery projects, which make up almost half of the projects on the short list.
- NSW is also investing in its first Hydrogen energy storage system alongside a solar-battery system to store renewable energy, at Manilla. In its world-first application, Hydrogen energy storage technology developed at UNSW Sydney and the storage deployment will be backed by a NSW government grant as part of a funding round that has awarded seven solar and battery community projects across the state. It is expected to be operational early 2021. The storage component will be installed during 2021.
- In March 2020, New South Wales Independent Planning Commission approved the plan to develop a 720 MW solar farm coupled with up to 400 MWh of battery storage. This project has passed an important milestone now that a grid-connection agreement has been locked in with Transgrid, the operator of the electricity transmission network. The A$768 million New England Solar Farm will be built across two solar fields six kilometers east of Uralla in one of the three renewable energy zones proposed by the state government. With more than 2.4 million solar panels, 150 power conversion units, and a lithium-ion battery storage facility, the project will connect to TransGrid's existing 330 kV transmission line, which transects the development site.
- The NSW government also moved recently to approve the 290MW Wollar Solar Farm. The project, featuring a proposed 30MW/30MWh battery storage add-on, has been deemed in the public interest.

Tasmania:

- The Battery of the Nation initiative is about investigating and developing a pathway of future development opportunities for Tasmania to make a greater contribution to the National Electricity Market (or NEM). With the support of ARENA funding, the Future State NEM analysis explored how the Tasmanian hydro system can support further on-island renewables development, such as wind, through augmentation of existing hydro-electric power plants, pumped hydro energy storage development and further interconnection with the broader NEM.
  - In 2020, Hydro Tasmania is focusing on examining the role of storage in supporting a reliable, resilient future energy market. It has found that that Tasmania's clean energy stacks up as very cost competitive, hence further validating the case for an expansion of Tasmania's hydropower system.

Western Australia:

- In early 2019, the State government announced the Western Australian Battery Industry Strategy as a collaboration between government, industry, research organizations and the community.
- Placed a bid for Future Batteries Industries Cooperative Research Centre (CRC) to be headquartered in Perth.
- Gas company ATCO is developing an industry-leading ATCO Hydrogen Microgrid, known as Clean Energy Innovation Hub (CEIH), based at the company's Jandakot Operations facility in Western Australia. This will play a key role in the future energy mix, bringing natural gas and clean gas including Hydrogen to customers. It will be crucial to reducing energy costs and emission.

World's first "plug-in" home battery set to be tested in Australia

- A potentially game-changing plug-and-play home battery storage solution is set to be tested on the Australian market.
- The Wyoming-based company, called Orison has been working since 2013 on transforming home energy storage from a relatively high maintenance piece of electricity infrastructure into a regular, household electrical appliance that can be purchased directly and plugged in, like any other.
- And they claim to have come up with a compact home battery whose components can be shipped directly to a household, easily assembled, and then plugged into the wall and switched on. No electricians, utility approvals, or permits required.
- Once installed, the battery (A$3080 for 1.8 kilowatts/2.2 kilowatt-hours) and a connected home energy monitor (A$420) coordinate charge and discharge around rooftop solar production and electricity rates. In the case of an outage, the battery can not island the home, but can still power devices that are plugged into it.

Gas-powered electricity generation (GPG) plays an important role in the Australian electricity market to drive reliability and security

Gas Power Generation Market in 2019-20

- According to the figures from Australian Energy Statistics reports released in May 2020, in 2019 gas-fired power generation (GPG) grew by 6 per cent in the past year to 21 per cent of total generation, while coal-fired power stations contributed 56 per cent of electricity generation.
- This report also showed that both Gas power generation and renewable energy generation increased in the same proportion to both serve 21 per cent of the power generation in the country.
- In South Australia, electricity generation is shared equally between gas and renewables (half from gas and half from renewables). The transition away from coal has been completed and the state is now covered by either Gas generation or renewable generation.

New Future Additions of Gas fired Power Plants

- In Dec 2019, the Federal government announced the underwriting of a new gas generator plant with APA Group, Dandenong, to be co-located with APA Group's existing LNG storage facility at Greens Rd, Dandenong South. The Federal Government will also approve the Quinbrook Infrastructure Partners gas generation project in Gatton in Queensland.
- In Jan 2020, SA Power Generation (SAPGen) has revealed plans to build a A$650 million gas power plant, one of the largest in South Australia, near Mannum.
- In Aug 2020, EnergyAustralia, one of the big three energy "gentailers" in Australia is looking at a total of up to 1,000MW in new fast-response gas generation capacity to support the clean energy transition.

Gas-powered electricity generation (GPG) plays to drive reliability and security

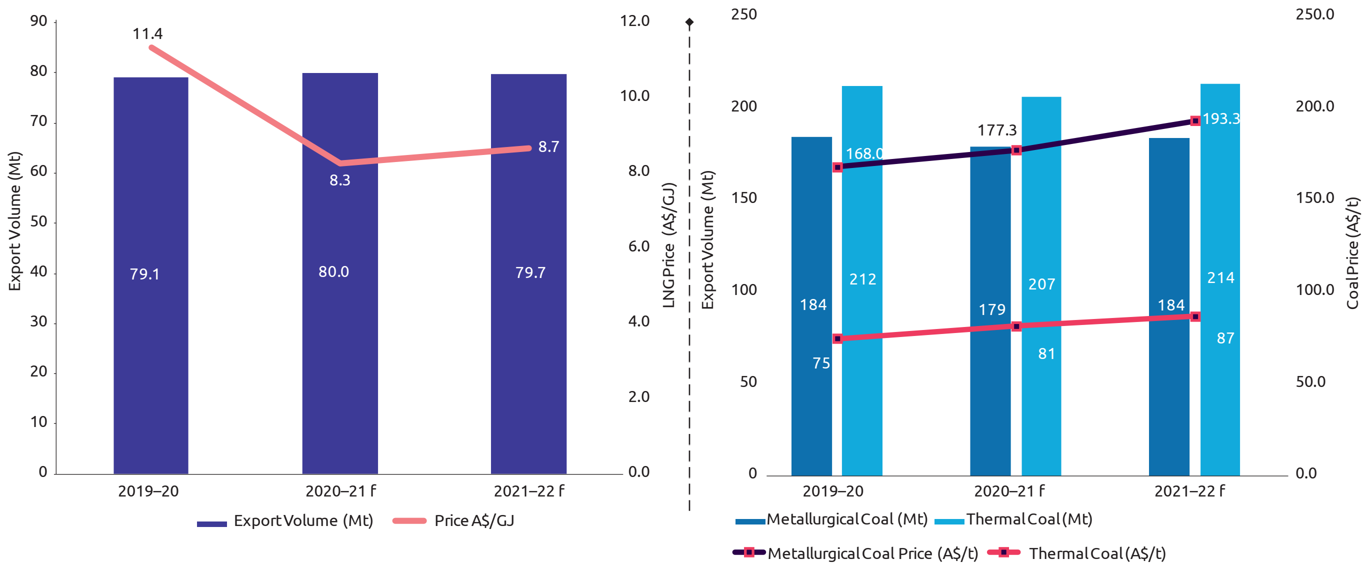
Australia Government is trying to re-establish a strong economy with the help of gas as part of Australia's recovery from the COVID-19 recession. In Sep 2020, the Government declared that it increase gas supply into the domestic market by:

- Setting new gas supply targets with states and territories and enforce potential "use-it or lose-it" requirements on gas licenses.
- Unlocking five key gas basins starting with the Beetaloo Basin in the NT and the North Bowen and Galilee Basin in Queensland, at a cost of A$28.3 million.
- Avoiding any supply shortfall in the gas market with new agreements with the three east coast LNG exporters that will also strengthen price commitments.
- Supporting CSIRO's Gas Industry Social and Environmental Research Alliance with A$13.7 million.
- Exploring options for a prospective gas reservation scheme to ensure Australian gas users get the energy they need at reasonable prices.

The Government will also boost the gas transport network by:

- Identifying priority pipelines and critical infrastructure as part of an inaugural National Gas Infrastructure Plan (NGIP) worth A$10.9 million that will also highlight where the government will step in if the private sector doesn't invest.
- Reforming the regulations on pipeline infrastructure to promote competition and transparency.
- Improving pipeline access and competition by kick-starting work on a dynamic secondary pipeline capacity market.

Figure 2.6 ~ Forecasted LNG and Coal Export Volume (Metric tonne) with respective LNG Price (A$/GigaJoule) and Coal Price (A$/tonne)



Note: AUD/USD = 0.75 used for coal price conversion
Source: Resources and Energy Quarterly June 2020

> **Note:**
>
> **Thermal coal or brown coal**, also called steaming **coal**, has a lower energy content and higher moisture and is used to generate electricity. **Metallurgical** or **coking coal or black goal** has a higher energy content and lower moisture and is used to make iron, steel and other metals.

Australia

- Australia's network of natural gas infrastructure complements the electricity network and also assists in mitigating peak electricity demand, the primary driver of long-term electricity network costs.
- While the gas and electricity markets have been historically inter-linked, the markets have transitioned from a period of abundant gas reserves and an over-supplied NEM to a situation where the supply-demand balance is tight in both gas and electricity markets. Adequacy issues in one sector are now increasingly likely to drive adequacy issues in the other.
- The Draft 2020 ISP (Integrated System Plan) forecasts that a mix of existing generation, storage, and new distributed and utility-scale renewable generation will help maintain reliability at lowest cost after the planned staged closure of the coal-fired Liddell Power Station between 2022 and 2023.
- The June 2019 GSOO for eastern and south-eastern Australia confirmed that the risk of previous gas shortfalls has been reduced due to additional production and supply, including the Northern Gas Pipeline connection.
- A continued interest in LNG import terminals (in VIC, NSW and SA) is expected to ease pressure on meeting southern gas demand during peak periods and reduce pipeline constraints - though it would only marginally be able to ease the domestic gas price pressures.
- In terms of supply, existing and committed gas developments are forecasted to provide adequate supply to meet demand until 2023 under neutral demand conditions. Post 2023, there is expected to be an availability meltdown that would require development of new reserves and resources.
- The Government wants the private sector to step-up and make timely investments in the gas market. If the private sector fails to act, the Government will step in – as it has done for electricity transmission – to back these nation building projects. The Government has already taken a number of important steps to ensure affordable and reliable gas prices for Australian users, including increasing domestic supply through the Australian Domestic Gas Security Mechanism, supporting the development of the Beetaloo Basin, and successive Heads of Agreement with east coast LNG exporters.

NEM 2025:

- The CoAG Energy Council has tasked the Energy Security Board with advising on a long term, fit-for-purpose market framework that could apply from the mid-2020s, to support energy reliability and security, and emission reductions. The plan (NEM 2025) will consider opportunities and challenges, including:
- Incentivising timely and efficient generation investment (including the right level and mix of technologies), and coordinating it with transmission investment to integrate renewable energy into the grid in a way that maintains system security and reliability.
- Optimising the contribution of DER to efficiency, security and reliability outcomes.
- Identifying additional security services such as frequency, inertia and system strength that may be needed in future, and how best to source and pay for those services.
- In April 2020 the Energy Security Board identified market frameworks that could meet the project objectives of NEM 2025:
  - Two sided markets, where consumers signal the value that they place on energy and are active in responding to wholesale prices. Consumer behaviour under this model is transparent, with real time information used to keep the power system operating securely and reliably. This model would build on the wholesale demand response mechanism to be launched in October 2021.
  - 'Ahead' markets, where electricity supply and demand are scheduled (sold) ahead of the real time market. This model provides AEMO with greater visibility of energy market needs and, and it also allows the time to plan accordingly.
  - System services markets, for products that are not currently valued. They include markets for operating reserves, frequency management (through synchronous inertia and fast frequency response) and system strength.
- The Energy Security Board will release a detailed analysis by the end of 2020 on a package of measures to adapt the existing market design.

Australian government is focusing on several technologies to bring efficiency into the electricity system

1 Storage Technology

Wholesale generation market rules are adjusting to recognize the benefits of storage technology.

- In 2018, two new large scale lithium-ion battery facilities were connected to the NEM.
- Large fixed batteries, such as the Hornsdale Power Reserve, in South Australia are able to very effectively provide the rapid frequency control services that will be required to manage grid stability as the grid transforms. The coming wave of variable renewable energy is also an opportunity for a growing role for one of Australia's older renewable energy technologies, hydroelectricity. Pumped hydro offers advantages over other storage methods, such as a longer technical life (50 years compared to current estimates of up to 15 for most batteries), and a relatively low unit price, particularly when built at scale.
- The Australian Renewable Energy Agency has identified approximately 22,000 potential pumped hydro energy storage sites around Australia with merit for investigation. Together they have much more potential storage capacity than required across the NEM to support variable renewable energy. TasNetworks and ARENA are also proposing a second Bass Strait interconnector that would enable untapped renewable resources in Tasmania (including HydroTasmania's Battery of the Nation initiative focused on pumped hydro potential)to be used to supply and firm renewable generation in the NEM.

2 Open Energy Networks

- AEMO and the ENA partnered on the Open Energy Networks program, collaborating with the energy sector to recommend a blueprint to recognise an integrated system and two-sided market place to enable DER to be aggregated, incentivised and optimised in the distribution network. The recommendation released in 2019 which laid out the roadmap to best integrate DER, and will inform policy, regulatory change, and pilots necessary to transition to a distributed world.
- AEMO is also collaborating with stakeholders across the sector to introduce important access reforms, opening energy to a range of new entrant business models with aggregators or third parties to create solutions that benefit consumers and the grid, such as the demand response mechanism rule changes currently before the AEMC. These projects are essential to ensure the provision of secure, reliable and affordable electricity.
  - The Demand Response Rule change will establish a new 'wholesale demand response mechanism allowing large energy users to trade reductions in electricity use in the electricity market. This rule change allows the market to encourage a smarter, demand side response that saves energy use at critical peak times, rather than using a "supply-side" response that simply encourages generators to burn more fuel. It will be particularly important in summer, and should lower prices for all.

3 VPP demonstration program

- In April 2019, ARENA announced A$2.46 million for AEMO's VPP demonstration program to test the operational capabilities of VPPs. This program will allow for aggregations of DER, such as rooftop PV systems, batteries and controllable-load devices, operated as 'virtual power plants' using software and communications technology. The program will aim to deliver scalable energy and network services traditionally performed by large-scale, conventional electricity generators.
- This initiative will contribute to unlocking new value for Australian consumers with DER, including an estimated two million rooftop solar systems, benefiting all energy users through a more efficient and affordable power system.
- With the collaboration between AEMO, the AEMC, the AER and industry members, its program will help to establish the framework to support these VPP demonstrations. Registration for the trial opened in July 2019 and the trial commenced in October 2019. Learnings from the trial will inform regulator and technical operational change.

Digitalisation of the power system provides the ability to give consumers and their representatives much better information to achieve better outcomes. In 2019, Australia was engaged in activities to enhance value from energy-related data and data availability for consumers.

4

Analytics

- In February 2019, AEMO, the Australian Government and CSIRO jointly launched the NEAR Program, a data analytics program that pioneers the collection, integration and enhancement of energy data to support better consumer outcomes. The program is funded by the Australian Government, which committed over A$ 20 million. It will be delivered by CSIRO in close collaboration with AEMO.
- Building on the EUDM (Energy Use Data Model) pilot program, the NEAR Program includes an extensive research program, using the latest data science to develop new datasets to develop the efficient energy system of tomorrow.
- Over periods of extreme heat or system stress, outputs from the NEAR Program will help identify areas of risk and provide evidence to support appropriate demand-response options.
- In addition, the program will also address increasing energy costs, linking consumer patterns with energy sector data to build a fuller picture of the modern Australian energy user.
- NEAR Program research has already contributed important data to the Retail Electricity Prices Inquiry for the Australian Competition and Consumer Commission (ACCC), quantifying the impact of tariff structures on electricity costs for Australian households.

5

Cyber Security

- To maintain energy security and propel Australia's energy future in an increasing data-driven, technology-enabled landscape, AEMO developed the Australian Energy Sector Cyber Security Framework in collaboration with energy market participants, the Australian Cyber Security Centre (ACSC) and the Critical Infrastructure Centre. The framework provides market participants with useful resources to assess their vulnerabilities, rate capabilities, and ultimately strengthen the cyber resilience across the energy sector.
- AEMO co-facilitated a sector-wide, national cyber security emergency exercise with the ACSC in November 2019 which improved cyber incident response preparedness.

6

Digital - Twin

- In an alliance with Australia's Commonwealth Scientific and Industrial Research Organisation (CSIRO) and with funding from the Australian Renewable Energy Agency (ARENA), AEMO is looking for ways to enable digital twins in the electricity system— data-informed replicas that shows the National Electricity Market (NEM) and Western Australia's Wholesale Electricity Market (WEM) in real time, and can be used to model proposed changes to every aspect of the grids.

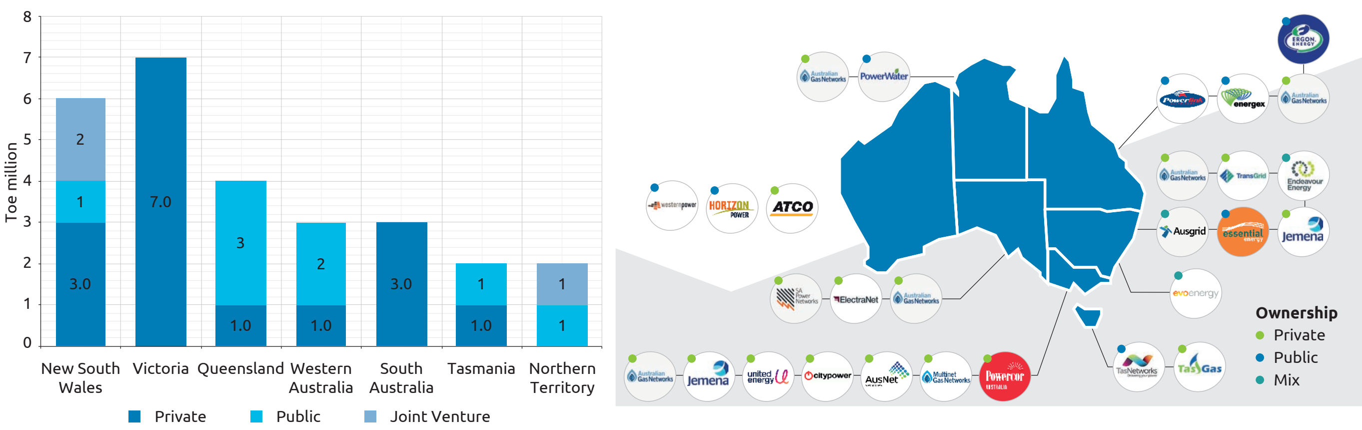
3-Supply & Final Customer

Energy Market Systems in Australia

Energy market is mainly comprised of NEM, WEM and The Northern Territory Systems:

- The National Electricity Market (NEM) brought together historically developed state-based electricity systems as a spot market of five regions in 1998. There are over 419 participants in the market, including generators of electricity, transmission and distribution service providers, and retailers that sell to a customer base of over nine million households and businesses. Electricity generation in the NEM represents over 80 per cent of total electricity consumed in Australia.
  - NEM operations currently include Queensland, New South Wales, Australian Capital Territory, Victoria, Tasmania and South Australia. Western Australia and the Northern Territory are not connected to the NEM.
  - The NEM has a total electricity generating capacity of 55,269 MW (as of April 2020).
- The Wholesale Electricity Market (WEM) in Western Australia commenced in 2006. The WEM serves over one million customers and operates under different market rules to the NEM. The WEM supplies the South-West Interconnected System (SWIS), which serves the main population centres of south-west Western Australia, including Perth. The other major system in Western Australia is the North West Interconnected System (NWIS) in the Pilbara. The NWIS generates and transmits electricity to local communities, as well as into major resource operations.
- The Northern Territory system is composed of three unconnected regulated electricity systems: Darwin-Katherine (serving approximately 150,000 customers), Tennant Creek (7,000 customers) and Alice Springs (28,000 customers). Most of the electricity consumed in the Northern Territory is from locally-produced gas.
- Numerous small regions across Australia are not connected to any of the above systems, including small remote inland and coastal communities, islands near the Australian mainland and Tasmania and external territories. These rely on a mix of locally-generated energy, via diesel or solar photovoltaics (solar PV), or imported energy.

Figure 3.1 ~ Energy Networks Ownership Structure



Source: Energynetworks.com.au

Ownership Structures:

- There are 22 electricity and gas network businesses in Australia with a mix of public and private ownership.
- 100 per cent privately owned electricity networks: Victoria, South Australia.
- 100 per cent government owned electricity networks: Tasmania, Western Australia, Northern Territory and Queensland.
- In NSW, one electricity network is privately owned, two are 50.4 per cent privately owned and one is fully government owned. The Australian Capital Territory's electricity network is a joint public and privately owned entity.
- Australia's gas distribution providers are all privately owned, with the exception of the ACT's, which is half government owned.

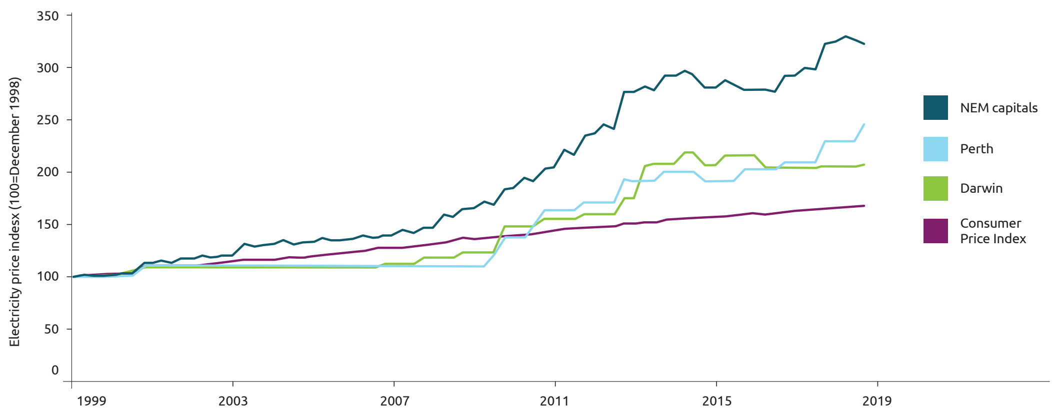
The overall affordability of electricity in Australia has been a concern for many years, with 2019 reaching record highs in wholesale prices

Energy affordability has become a major concern for users:

According to the AEMO, electricity prices across the Australia's main grid rose to record highs in the first quarter of 2019

- In 2019 wholesale prices across the NEM (on a volume-weighted average basis) averaged close to A$100 per MWh, up from A$90 per MWh in 2018, but slightly lower than the 2017 average of A$106 per MWh. Wholesale prices remained elevated in some regions during the second quarter of 2019, compared with the same quarter in 2018.
  - Victoria (A$126 per MWh) edged out South Australia (A$125 per MWh) as the NEM's highest price region. Prices were higher in Victoria compared to other states, partly due to planned and unplanned outages reducing brown coal generation.
    - An unplanned outage at Loy Yang A ran from May to December 2019, removing 11 per cent of low-cost generation from the region. Loy Yang B unit 2 was also unavailable, due to a planned upgrade. Outages at the Yallourn and Mortlake power stations compounded the situation, resulting in Victoria setting record prices of over A$100 per MWh in the second and third quarters of 2019.
  - South Australia recorded its third consecutive year of triple digit average prices, and more than doubled its 2015 average before the closure of the region's last brown coal generator, Northern.
  - Queensland (A$75 per MWh) and NSW (A$89 per MWh) were the lowest price regions.
  - Tasmania recorded a 30 per cent year-on-year rise in spot prices—the largest for any region, with prices averaging A$95 per MWh. A fault on the Basslink interconnector between Tasmania and Victoria meant the connection was unavailable for around six weeks in August–September 2019, contributing to Tasmania having higher third quarter prices than a year earlier.
- Household energy costs across Australia have grown faster than inflation in the past decade. However, this growth has not been equal, with cost increases faced by average customers in most of the NEM outpacing observed trends in Perth and Darwin. A significant part of the reason for this is due to price-setting and a taxpayer subsidy by the Western Australian and Northern Territory Governments.

Fig 3.2 ~ Electricity costs have risen much more than general inflation in the last decade, but costs in Perth and Darwin have risen less than in the NEM capitals



Source : Australian Bureau of Statistics (2019)

Queensland has had the lowest electricity prices for last few years due to the following reasons:

- Deregulated South East Queensland electricity prices on 1 July 2016 to enhance market competition.
- In mid 2017, the Queensland Government directed state-owned generators to alter their bidding practices and put downward pressure on wholesale electricity prices. This direction has been one of the main reasons why Queensland has had the lowest wholesale electricity prices in the NEM for the last two years, despite growing max demand. This bidding direction ended on 30 June 2019. It is important to check whether the bidding behavior from state owned generators reverts back to old patterns over the coming summers.
- Directed Energex and Ergon Energy not to challenge the Australian Energy Regulator's decision on network revenues, thereby locking in lower network tariffs between 2015 and 2020.
- Extended the Electricity Rebate to Health Care Card holders and asylum seekers.
- In late 2017, Queensland Government has directed Stanwell to return its 385 megawatt Swanbank E gas power station to service to support the market and reduce volatility in the Queensland wholesale market.
- Provided electricity price relief by investing A$770 million to cover the cost of the Solar Bonus Scheme.

- As well as the increase in wholesale prices, 2019 consumer prices were also impacted by the following
  - **Increased Demand:**
    - With the rising temperature in Australia and hotter summer days, the operational demand increased especially in the late afternoon and evening when consumers turned on their air cooling systems, resulting in peaking demand and higher prices.
  - Maximum demand for Victoria occurred on the 25th of January 2019. Due to the heat and reduced generation availability, governments and utilities called for electricity conservation. Additionally, AEMO procured demand-side participation through the Reliability and Emergency Reserve Trader (RERT) mechanism and there was forced load shedding.
  - The spot price in New South Wales on 31 January 2019 peaked at A$1913/MWh (average for the half hour ending 16:30).

Summer 2019 maximum demand with adjustments per NEM region

Region	Time of maximum (NEM time)	Operational as generated	Auxiliary load	Operational sent out	Adjustment (firm)	Adjustment (potential)	Adjusted sent out
NSW	31 Jan 19 16:30	13821	-501	13320	0	0	13320
QLD	13 Feb 19 17:30	10044	-552	9492	20	0	9512
SA	24 Jan 19 19:30	3240	-100	3140	82	55	3277
TAS	15 Jan 19 15:30	1330	-18	1312	0	0	1312
VIC	25 Jan 19 13:00	9110	-335	8775	5100	120	9405

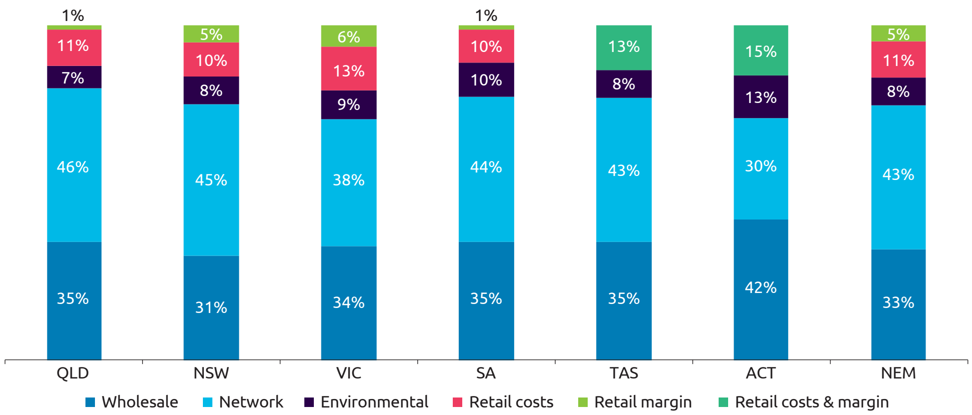
Note: The load shedding and RERT is considered firm, while an estimation of voluntary electricity conservation is considered potential.

- **Investment in network assets:**
  - For the last few years, wholesale electricity prices have risen steeply due to the closure of key coal-fired generation assets, issues with network reliability due to ageing assets, and rising costs for generation inputs such as coal and gas.
- Network investment increased for the third consecutive year in 2019, including a 9 per cent rise for electricity distribution. But investment in 2019 remained 41 per cent below the peak recorded in 2012. The majority of forecast investment in distribution networks is to replace and refurbish old assets, rather than to expand the networks.

Figure 3.3 ~ Average Wholesale Electricity Prices

Source: reneweconomy.com.au

Figure 3.4: Residential Electricity Bill Composition (cents per Kilowatt-hours) Estimation for 2018-19



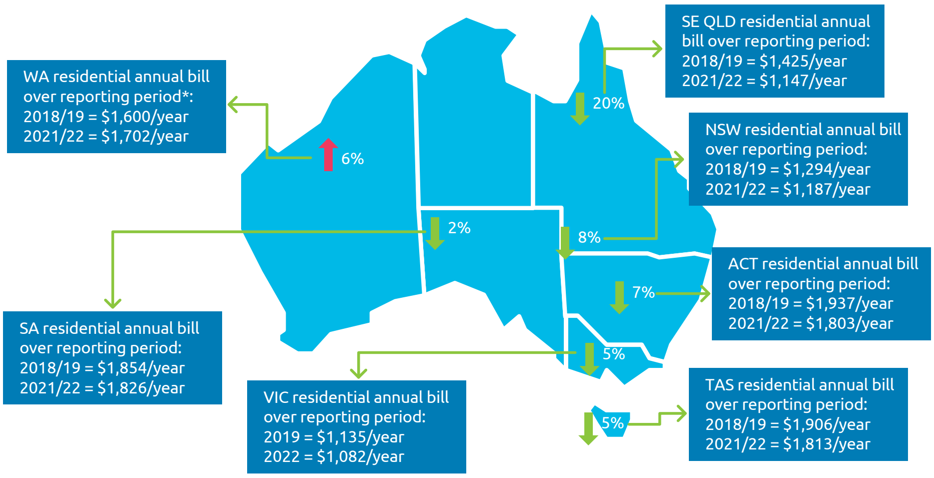
Note: Data are estimates for 2018–19, Average residential customer prices excluding GST (real $2018–19).
Retail costs and margin are combined for the ACT and Tasmania due to data availability

Source: State of the Energy Market 2020, Australian Energy Regulator

Annual residential bills (weighted by customer numbers) are expected to decrease by 7.1 per cent (or A$97) over the three-year reporting period (2018/19-2021/22)

- Wholesale costs are expected to go down by 11.6 per cent (or A$62) over the reporting period contributing -4.6 percentage points. This is driven by the influx of new generation of 8,594 MW. Committed projects make up 60 per cent of the total new generation and the rest of this is modelled by the AEMC.
- Regulated network costs are expected to decrease by 1.8 per cent (or A$11) over the reporting period contributing -0.8 percentage points. This is driven by a reduction in distribution costs and metering costs, mainly in South East Queensland.
- Environmental costs are expected to go down by 23.9 per cent (or A$21) over the reporting period contributing -1.6 percentage points. This is driven by a decrease in Large-scale Renewable Energy Target (LRET) costs stemming from a reduction in the cost of large-scale generation certificates (LGCs).
- The residual cost will have a minor reduction, contributing -0.1 percentage points to the overall reduction in annual residential bills.
- The average residential electricity prices are calculated by multiplying the consumption of the representative consumer in each jurisdiction by the price they pay for electricity. The representative consumer's consumption is either based on the most common consumption profile of consumers in each jurisdiction, or a quantity provided by the jurisdictional government.
- The prices used for each jurisdiction are the average of the lowest representative offer from each retailer, weighted by market share. The national results are then determined by weighting the jurisdictional price and bill outcomes by the number of consumers in each state or territory.

Figure 3.5~ Trends in Annual Residential Bills – forecasted over 3-year period 2018/19 – 2021/22



Source: AEMC analysis

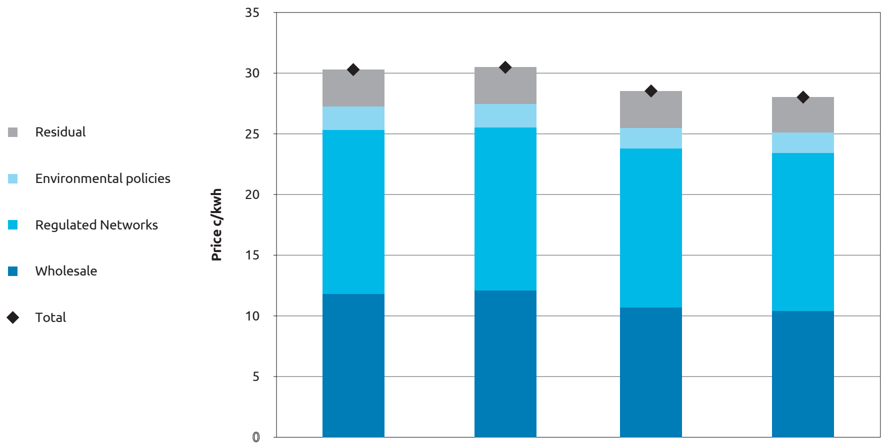
Note: * A different methodology has been used for WA allowing the AEMC to estimate both electricity cost of supply and residentialprice. our results for WA should be treated with caution given the different methodology that has been used to establish these prices. Residential electricity prices are set by the WA Government.

According to AEMC report, "On a national basis, residential electricity prices and bills are expected to decrease in the period from 2018-19 to 2021-22. This trend is primarily driven by wholesale costs reducing in most of the states and territories. It is estimated prices will fall markedly over the whole reporting period as new capacity enters the system. Total capacity of committed projects includes 2,338 MW of solar, 2,566 MW of wind and 210 MW of OCGT. "

Did Covid-19 disruptions impact electricity prices in the first half of 2020?

- Wholesale electricity prices fell by between 48 per cent to 68 per cent compared to the second quarter of 2019 – with lower-priced offers, lower gas and coal prices, and new renewable supply driving the reduction.
  - Queensland's quarterly average price of A$34/MWh represents the lowest mainland NEM price since Q4 2016, and the lowest Queensland price since Q2 2015.
  - South Australia recorded its lowest quarterly average since Q1 2015, Victoria its lowest average price since Q4 2016, New South Wales its lowest average price since Q1 2016, and Tasmania its lowest average price since Q4 2011.
- A significant increase in comparatively low-priced offers, coupled with a 2 per cent reduction in operational demand, were the key drivers for the fall in spot electricity prices.
  - Overall, there was a 2,257 MW increase in low-priced offers (below A$35/MWh) on average compared to Q2 2019.

Figure 3.6~Trends in National Supply Chain Components – forecasted over 3-year period (2018/19-2021/22)



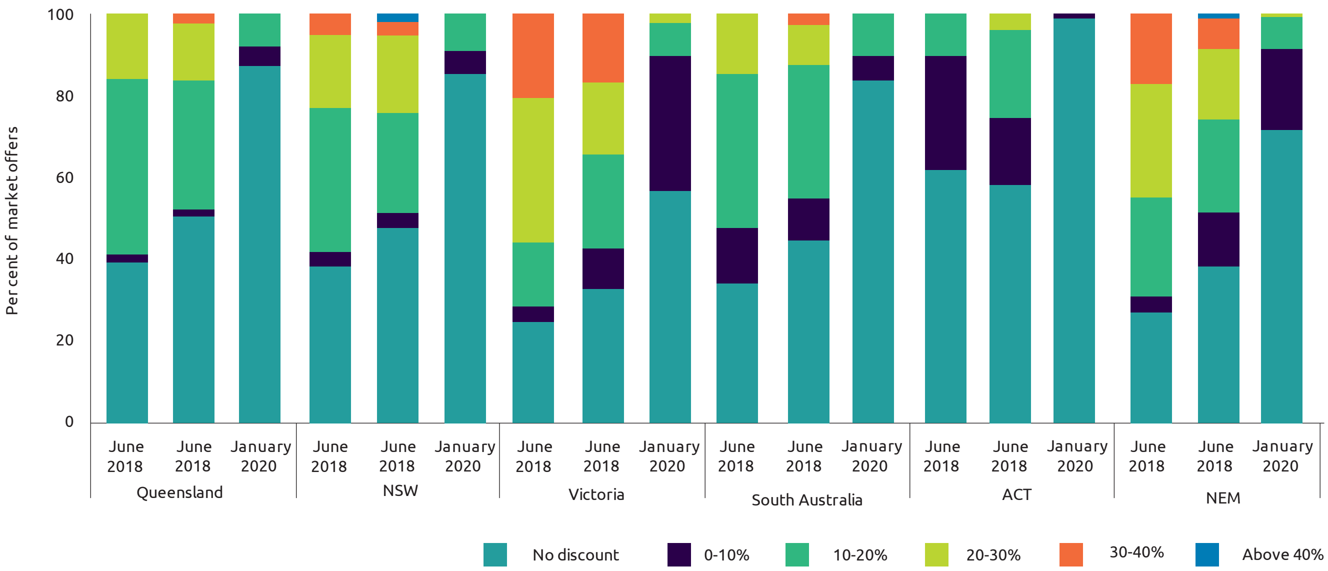
	2018/19 Base Year		2019/20 Current Year		2020/21		2021/22	
	c/kwh	$/year	c/kwh	$/year	c/kwh	$/year	c/kwh	$/year
Environmental policies	**1.98**	**$90**	**1.94**	**$89**	**1.67**	**$76**	**1.51**	**$68**
LRET	0.77	$35	0.64	$30	0.40	$19	0.27	$13
SRES	0.68	$31	0.74	$34	0.67	$31	0.62	$29
Jurisdictional Schemes	0.35	$16	0.39	$18	0.39	$18	0.41	$18
Efficiency Schemes	0.18	$8	0.18	$8	0.20	$8	0.20	$8
Environmental policies	**13.28**	**$601**	**13.36**	**$604**	**12.94**	**$584**	**13.06**	**$590**
Transmission	2.22	$101	2.09	$95	2.18	$100	2.28	$105
Distribution	10.05	$456	10.34	$468	9.88	$446	9.90	$448
Metering	1.01	$44	0.93	$41	0.88	$38	0.87	$38
Wholesale	**11.90**	**$540**	**12.14**	**$550**	**10.84**	**$496**	**10.45**	**$477**
Residual	**3.05**	**$140**	**2.92**	**$132**	**2.97**	**$134**	**3.04**	**$137**
Total	**30.21**	**$1,370**	**30.35**	**$1,375**	**28.42**	**$1,290**	**28.06**	**$1,273**

Source: AEMC analysis

In a competitive market, retailers offer a range of products and services to attract and retain customers. Energy retailers compete primarily on price, but with the introduction of standing offer price caps and new restrictions around discounting, retailers are looking to differentiate their products in other ways:

- Price competition between retailers tends to play out through 'headline' discounts. In the last 2 years, around 66 per cent of offers included discounts that came with the condition on the customer meeting certain terms such as paying on time, e-billing, or paying by direct debit. Most discounts offered minimum10 per cent off the original bill, with some offering up to 40 per cent off. However, the size of a discount was often deceiving, as retailers measured and applied discounts off different price bases.
  - Advertising based on conditional discounts can be tricky, because customers can be exposed to a much higher price if the conditions are not met. In 2018, over 25 per cent of residential customers (and over 50 per cent of hardship customers) on offers with conditional discounts did not meet the conditions required to receive the discounted price.
- The total number of missed conditional discounts was lower in 2019, however, there is no clear data to understand whether this outcome reflected higher rates of customers achieving discount conditions, or fewer customers on contracts with conditional discounts.
- Reforms introduced in 2019 declined the practice of conditional discounting in electricity offers (and the size of discounts) significantly across all regions. From 1 July 2019, the Electricity Retail Code covered retailers in South Australia, NSW and south east Queensland. The code:
  - Prohibits retailers from charging customers on standing offers more than the default market offer.
  - Requires retailers to base any discount advertising off the default price.
  - Prohibits retailers from including conditional discounts in their most prominent advertised price for market offers.
- Following the reforms, the proportion of electricity offers with guaranteed prices (no conditional discounts) rose significantly and by January 2020 accounted for over 80 per cent of offers in Queensland, NSW, South Australia and the ACT. In Victoria, they comprised almost 60 per cent of offers.

Figure 3.7~ Conditional Discounts for Residential Electricity Market Offers



Source: AER.gov.au

Australia

The Victorian Government is progressing similar reforms to retailer advertising.

- In July 2019, Victoria introduced its own Victorian Default Offer ("VDO") for electricity customers together with Deemed Best Offer, Clear Advice Entitlement and GST Inclusive Pricing rules for energy retailers. Victoria has introduced a series of new rules, including a default offer regime, through a combination of changes to the Victorian Energy Retail Code, and amendments to the Electricity Industry Act 2000 (Vic) and Orders in Council made under that legislation.
- The Victorian regime also features a regulated price, set by the ESC. The VDO reference price is expressed as a tariff rather than a reference bill. Electricity retailers must offer a Victorian default offer, replacing the standing offer, that is equal to or less than the VDO reference price. When advertising discounts, they must express those discounts against the VDO reference price and disclose how the discount was calculated.
- In addition, energy retailers in Victoria must comply with a significant range of new obligations designed to give small customers an entitlement to clear, timely and reliable information to assist the customer to assess the suitability of, and select, a customer retail contract, and to identify whether they are on their retailer's Deemed Best Offer.

Prohibiting Energy Market Misconduct – Big Stick Legislation commenced June 2020

- The Morrison Government's new measures to deal with misconduct in the electricity sector and ensure Australian households, businesses and industries get a fair deal on energy came into effect on the 10th of June 2020 (Treasury Laws Amendment (Prohibiting Market Misconduct) Act 2019). This new legislation holds the energy companies to account for misconduct with the aim to drive down energy prices and strengthen supply. It will ensure reductions in wholesale costs are passed on to customers, while penalties will apply for anti-competitive behavior or moves to manipulate electricity prices.
- The legislation creates 3 new prohibitions against certain misconduct in electricity retail, wholesale and contract markets, which is detrimental to competition and consumers.
  - The retail pricing prohibition targets conduct by electricity retailers, when they fail to pass on savings to consumers due to lower supply chain costs over a substantial and sustained period.
  - The contract liquidity prohibition targets conduct by electricity generators when they refuse to offer contract to an electricity retailer for anti-competitive purposes.
  - The wholesale prohibition targets conduct by generators when selling electricity into the wholesale market, preventing generators from acting in a way that is fraudulent, dishonest or in bad faith to distort or manipulate wholesale electricity prices.
- Breaches of the prohibitions are backed by a graduated series of remedies, which can only be used if they are proportionate and targeted to the misconduct, including:
  - Warning and infringement notices by the Australian Competition and Consumer Commission (ACCC).
  - Court-ordered civil penalties up to the greatest of: A$10 million; 3 times the value of the total benefit attributable to the conduct or 10 per cent of the annual turnover of the corporation in the 12 months before the conduct occurred.
  - Treasurer-issued contracting orders on the recommendation of the ACCC, requiring generators to offer contracts for sale to retailers.
  - A Federal Court-issued divestiture order, following an application by the Treasurer, made on the recommendation of the ACCC.

Source: minister.industry.gov.au

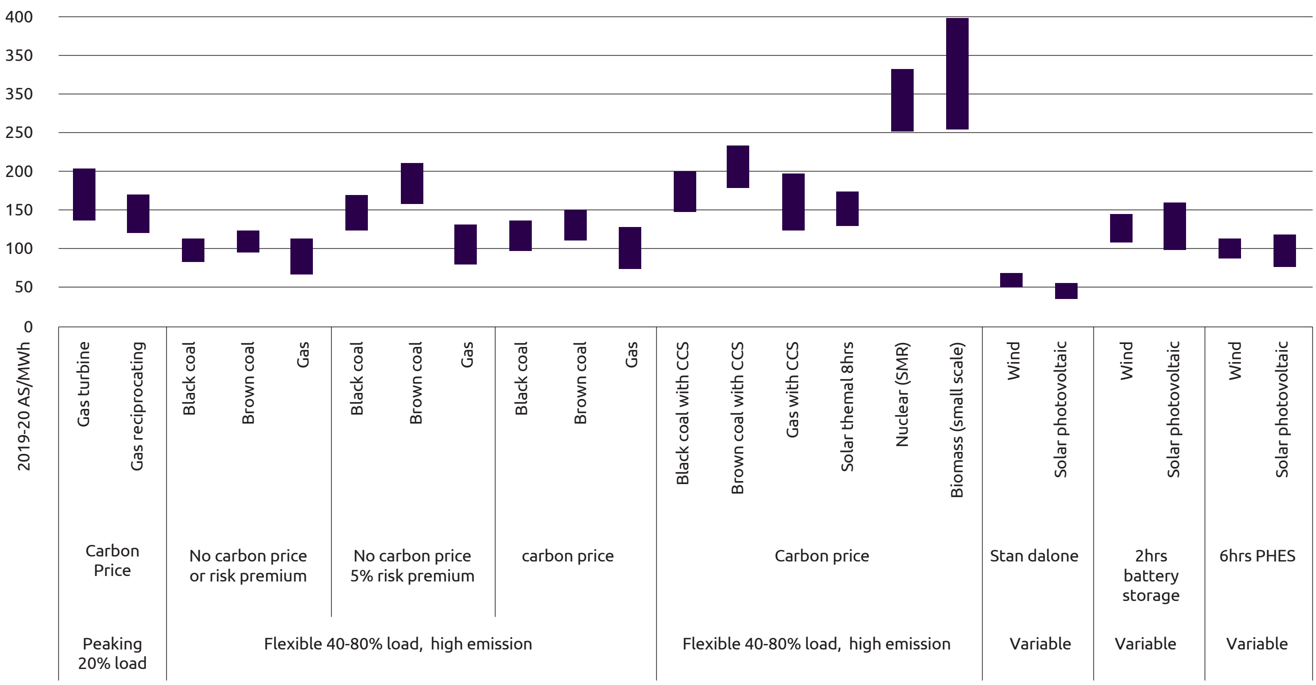
The latest Levelised Cost of Electricity Modelling confirms the cheapest form of electricity generation into the future will be renewables

Levelised Cost of Electricity modelling by AEMO and CSIRO is carried out to assist with future investment decisions. The levelised cost of electricity (LCOE) directly compares electricity generating technologies using a common metric by converting all costs into annual operating costs (i.e. capital costs are amortized into equivalent annual payments), adds them together and divides them by annual output in energy terms, typically MWhs. AEMO and CSIRO collaborated to carry out Australia's electricity market modelling as part of strategy planning for the government, institutions, and industry.

The GenCost 2019 -20 report compares the projected cost of electricity generation and storage by technology. The projection methodology is based on a global electricity generation and capital-cost projection model, which takes into account that the cost reductions experienced in Australia largely depend on global technology deployment.

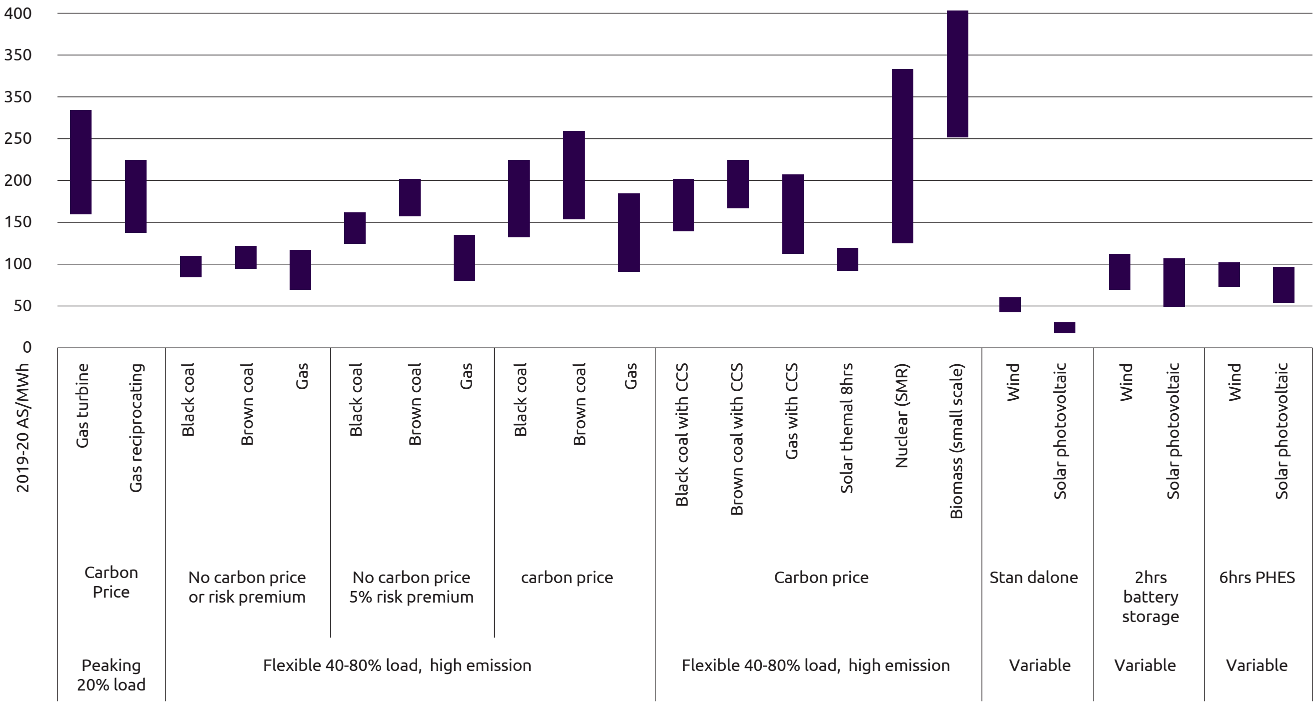
- The global generation mix is expected to be dominated by wind and solar photovoltaic (PV) by 2050 as a broader set of global technology drivers has resulted in a wider range of potential capital-cost reduction paths for wind and solar PV. It is estimated that carbon capture and storage (CCS) and nuclear small modular reactors will play a larger role in the coming years.
- At 20 per cent capacity factor, gas reciprocating engines are a lower-cost peaking technology than gas turbines owing to higher fuel efficiency offsetting slightly higher capital costs. Among the flexible load high emission technology options, if there is no climate policy risk, the relative competitiveness of fossil fuel generation is largely a function of what fuel price the project is able to secure (with gas being competitive at low gas prices but less competitive at higher prices). If climate policy risks are a concern (either through a carbon price or the risk of a future climate policy being built into the financing rate) then gas is the lower cost option reflecting its lower emission intensity than coal. These fossil fuel technology comparisons remain the same through to 2050 because, as mature technologies, their capital costs are stable. Any changes in relative competitiveness are largely due to fuel prices and climate policy risk.
- In the low-emission flexible generation technology category, solar thermal with 8 hrs storage and gas or coal with CCS have the lowest cost in 2020. Gas with CCS has a lower capital cost but higher fuel cost than coal with CCS. The relative price of fuels (inclusive of any potential future carbon pricing) will ultimately determine which of the CCS technologies are most competitive.
- From the early 2030s, under the Diverse technology scenario (where there is an assumption that renewable technology resources are limited), nuclear SMR capital costs are estimated to reduce substantially.
- In the variable technology category, wind and solar photovoltaic costs are similar in 2020 at around A$50/MWh. However, over time, solar photovoltaic capital costs fall faster and by 2050 the LCOE range is projected to be lower than for wind. When storage is added to solar and wind, this raises their costs to a similar level of that of fossil fuels without a carbon price or risk premium.

Figure 3.8~ Levelised Cost of Electricity Comparison by Technology and Category for 2020



Source: AEMO

Figure 3.9~ Levelised Cost of Electricity Comparison by Technology and Category for 2050



Source: AEMO

Technology Roles and Abilities

Peaking 20 per cent load	Technologies operating at 20 per cent load (capacity factor). In a real scenario, a peaking generation plant might have a capacity factor in a broad range (e.g. 5 per cent up to 25 per cent). Here, 20 per cent has been chosen, at the higher end of the range, for ease of representation on the same chart as other technologies. At the lower end of the capacity factor range, costs are very high in energy terms. (i) Gas reciprocating engines are used in land fill gas sites and other smaller applications in both peaking and larger capacity factor roles (ii) Fuel cells are included because of their fast ramping capability but due to high current costs only become relevant in later decades as their capital costs fall and higher carbon prices increases open-cycle gas costs
Flexible 40-80 per cent load	Technologies which normally operate with a capacity factor in the range of 40 to 80 per cent . The higher end of this range is sometimes termed "baseload" and indicates technologies which tend to maintain a fairly constant output for most of the day. At the lower end of this range, solar thermal with 8 hours storage is included. Over time, it is expected that there will be fewer technologies operating in baseload mode with high capacity factors. As the share of both behind-the-meter and large-scale variable renewables with near-zero operating costs increases, it is more difficult for fossil fuel generation with positive operating costs to successfully compete to stay operating at all times of the day. As such, the cost ranges included for the fossil generators assumes a capacity factor range of 60 per cent to 80 per cent. From a technical perspective, the minimum-run requirement for fossil generators is 30 per cent for gas and 40 per cent for coal.
Variable	Includes renewable generation sources such as wind and solar photovoltaics, as well as wave power. Carbon prices are not relevant to this category. The variable generation is categorized into: (i) standalone (ii) storage capacity of 2 hours using battery storage (iii) storage capacity of 6 hours using pumped hydro energy storage (PHES)

Meanings and Definitions of Technologies	
Fuel Cell	A fuel cell produces electricity through a chemical reaction, but without combustion. It converts Hydrogen and oxygen into water, and in the process also creates electricity.
Black Coal	Black coal is a soft coal containing a tarlike substance called bitumen or asphalt. It is of higher quality than lignite coal but of poorer quality than anthracite. Black Coal has slightly lower carbon content than anthracite (45 per cent -86 per cent). The wide range of carbon content in bituminous coal warrants use for both electricity and steel production.
Brown Coal	Lignite is often called "brown coal" because it is lighter in color than the higher ranks of coal. It has the lowest carbon content out of all the coal ranks (25 per cent -35 per cent) and it has a high moisture content and crumbly texture. It is mainly used in electricity generation.
Carbon Capture Storage (CCS)	A technology that can capture up to 90 per cent of the carbon dioxide (CO_2) emissions produced from the use of fossil fuels in electricity generation and industrial processes, preventing the carbon dioxide from entering the atmosphere.The use of CCS with renewable biomass is one of the few carbon abatement technologies that can be used in a 'carbon negative'mode – actually taking carbon dioxide out of the atmosphere and either compressing underground or utilizing in other processes.
Nuclear Small Modular Reactors (SMR)	SMRs are advanced reactors that produce 300 MW or less of electricity. They utilize components that can be factory built, helping minimize costs, improving quality and reducing construction schedules.
Biomass Small Scale	The conversion of wood or other carbon-rich dry biomass into a combustible gas and then into electricity via a generator set – a perfect solution for remote rural areas with a lack of electricity but an abundance of shrubs, straw, rice and peanut husks or other forms of biomass.
Carbon Price	An approach to reducing carbon emissions that uses market mechanisms to pass the cost of emitting on to emitters with the goal to discourage the use of CO_2-emitting fossil fuels to protect the environment, and address the causes of climate change, and meet national and international climate agreements.
Risk Premium	While evaluating cost of capital, two types of risk are included; 1. risk free (reflects time value of money) 2. risk premium (dependent on type of technology, country in which installation is being done, sometimes a combination of both). Risk premium is the return on assets in excess of the risk-free rate of return. It is primarily the risk premium that causes the variance in the observed cost of capital.
Pumped Heat Electrical Storage (PHES)	Electricity is used to drive a storage engine connected to two large thermal stores. To store electricity, the electrical energy drives a heat pump, which pumps heat from the "cold store" to the "hot store". To recover the energy, the heat pump is reversed to become a heat engine. The engine takes heat from the hot store, delivers waste heat to the cold store, and produces mechanical work. When recovering electricity, the heat engine drives a generator.

The Federal, State and Territory governments are working together to manage the impacts of coronavirus (COVID-19) on the energy sector

- The Council of Australian Governments Energy Council (COAG Energy Council), comprising the Australian Government and state and territory government energy ministers, have met to agree a coordinated and comprehensive approach to identifying and managing the impacts of COVID-19 on the energy sector.
- The Australian Energy Regulator (AER) has set reasonable expectations of energy companies to protect households and small business customers during the COVID-19 pandemic. The AER's Statement of Expectations sets out a range of measures, including:
  - Waived any disconnection, re-connection and/or contract-break fees for small businesses which have gone into hibernation, along with daily supply charges to retailers, during any period of disconnection until at least 31 October 2020.
  - Offered all households and small businesses who indicate they may be in financial stress a payment plan or hardship arrangement.
  - Will not disconnect residential or small business customers in financial distress that have made contact with their retailer or responded to communications before 31 October 2020 and potentially beyond.
  - Deferred referral of any customer to a debt collection agency for recovery actions, or credit default listing until at least 31 October 2020 and possibly beyond.
  - Minimised the frequency and duration of planned outages for critical works, as well as providing as much notice as possible to help households and businesses to manage during any outage.

4-Financials

Electricity Generation and Output:

In 2019, AGL, Origin Energy and Energy Australia remained the three dominant players in electricity generation and output in the National Electricity Market. While AGL has significant presence in NSW, SA and VIC, Origin has a wide presence in NSW, QLD, SA and VIC.

NSW:

- In 2019, Energy Australia gained market share in generation capacity by 1 per cent. AGL & Origin continued to lead the market although between 2018 and 2019 their market share remained unchanged.
- Snowy Hydro generation capacity remained unchanged in 2019 at 22 per cent and generation output declined by 1 per cent compared to previous year due to limited water availability
- In generation output, AGL increased its market share by 2 per cent to 42 per cent in 2019 compared to last year. Origin remained the second largest player by maintaining its market share of 28 per cent.
- A new strategy adopted by the NSW government has ensured access to a A$1 billion federal Grid Reliability Fund & also guaranteed support for three NSW generation projects under the federal Underwriting New Generation Investments (UNGI) program.

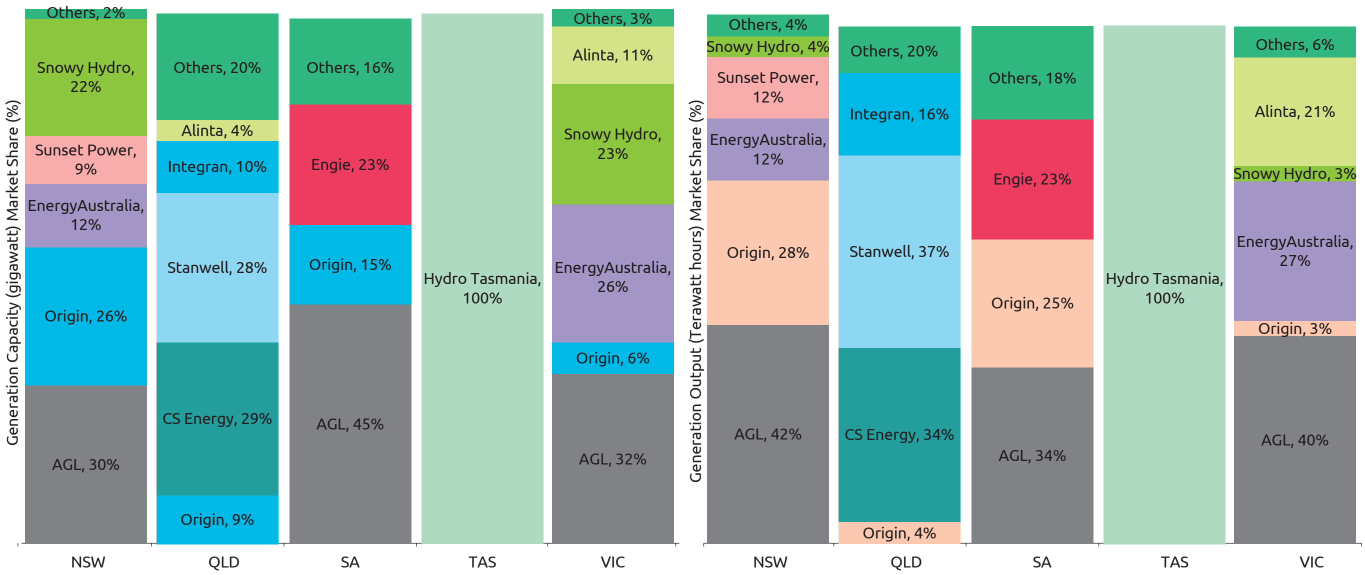
South Australia:

- In 2019, AGL Energy was the dominant generator, with 45 per cent generation capacity increasing by 1 per cent from 2018. AGL's market share for output was 34 per cent.
- in terms of generation capacity, Origin Energy & Engie hold 15 per cent & 23 per cent market share respectively and lost market share by 1 per cent & 3 per cent respectively compared to last year.
- In generation capacity, Energy Australia & Alinta have around 16 per cent market share in South Australia, having gained 2 per cent from 2018. Generation output remained unchanged at 18 per cent market share.

Victoria:

- In 2019, AGL Energy (32 per cent generation market share compared to 33 percent in 2018) and Energy Australia (26 per cent generation market share with no change from previous year) continue to control the majority of generation capacity.
- The government-owned Snowy Hydro (generation capacity of 23 per cent) is the next largest participant in generation capacity. Snowy Hydro contributed only 3 per cent of output in Victoria, despite holding over 20 per cent of capacity in the region. Reasons are limited water availability due to drought conditions in 2019, and its gas-peaking plant operating infrequently.
- In 2019, AGL's generation output declined from 42 per cent to 40 per cent.

Figure 4.1 ~ Market Shares in Generation Capacity and Generation Output – 2018-19



Note: Generation capacity based on 2019–20 summer capacity, except for wind and solar, which are adjusted based on AEMO's 'firm contribution' estimates to account for generation likely to be operational during periods of maximum demand. Capacity is allocated to the business that controls the trading rights for each generator. Import capacity via interconnectors and rooftop solar PV capacity is excluded.

Output in 2019. Ownership is attributed by trading rights at the time. Output is split on a pro rata basis if ownership changed in 2019. Data exclude output from rooftop solar PV systems and interconnectors.

Source: AER - State of the Energy Market 2020

Queensland:

- In Queensland, state-owned corporations Stanwell and CS Energy control 57 per cent of generation capacity, including power purchase agreements over privately-owned capacity. Both the players have lost 5 per cent market share in terms of generation. CS Energy's and Stanwell's assets were transferred to a third state-owned corporation, CleanCo, in October 2019.
- CleanCo was created to increase wholesale-market competition and support growth in the state's renewable energy industry. It controls 8 per cent of the state's capacity, including all hydropower plants.
- In 2019, CS Energy and Stanwell led the QLD generation output capturing 67 per cent of market share in terms of generation output. CS Energy lost 4 per cent of its market share compared to previous year, whereas Stanwell market share remained the same.
- The largest private operators are Intergran (10 per cent of capacity) and Origin Energy (9 per cent).

Tasmania:

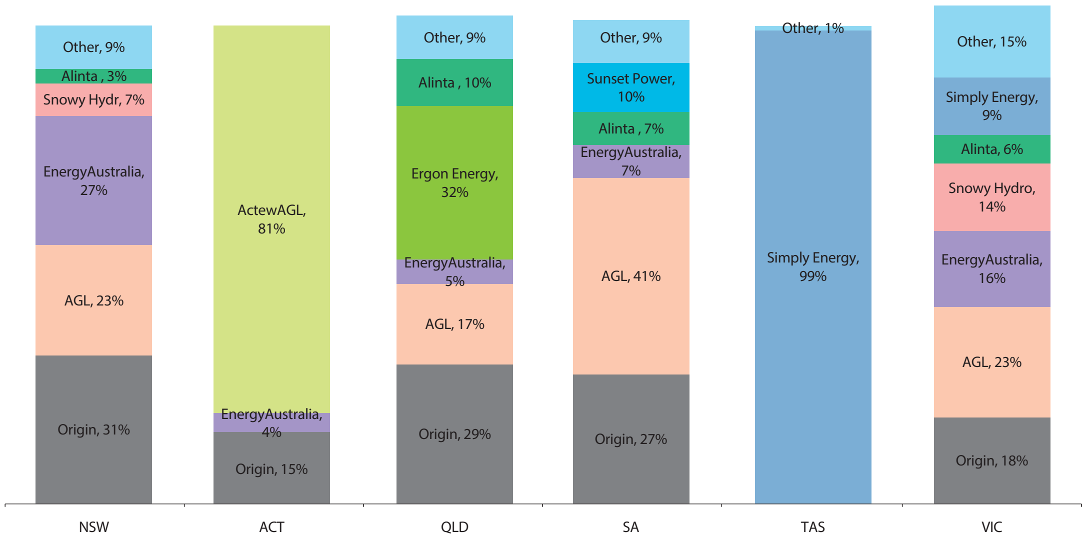
- Hydro Tasmania continues to dominate the market with 100 per cent market share.

Retail Energy Market:

Only 22 retail brands offer energy products in all four of the largest markets—south east Queensland, NSW, Victoria and South Australia. NSW has the largest number of active electricity retailers (37), followed by Queensland (31), Victoria (30) and South Australia (27).

- Three businesses — AGL Energy, Origin Energy and EnergyAustralia — continue to dominate the retail market, supplying 63 per cent of small electricity customers and 75 per cent of small gas customers in eastern and southern Australia. But smaller retailers are building market share.
- 'Second tier' retailers have built significant market share in some regions - Snowy Hydro, Alinta Energy and Simply Energy have emerged as strong 'gentailers'.
  - Snowy Hydro (owned by the Australian Government and trading as Red Energy and Lumo Energy) supplies around 8 per cent of electricity customers and 9 per cent of gas customers — its market share is highest in Victoria, supplying 14 per cent of electricity customers and 15 per cent of gas customers.
  - Alinta Energy (owned by Hong Kong-based Chow Tai Fook Enterprises) supplies 5 per cent of electricity customers and 3 per cent of gas customers — its market share is highest in Queensland (10 per cent of electricity customers) and South Australia (7 per cent of electricity customers and 6 per cent of gas customers).
  - Simply Energy (owned by French multinational Engie) supplies 4 per cent of electricity customers and 6 per cent of gas customers, including 9–10 per cent of customers in Victoria and South Australia.
- Smaller retailers also gained market share, increasing from 5 per cent of small customers in 2016 to 8 per cent in 2019. In gas, smaller retailers accounted for 4.4 per cent of small customers in 2019.
  - Smaller retailers have had more success in Victoria than elsewhere, supplying almost 15 per cent of small electricity customers and almost 7 per cent of small gas customers. This outcome may reflect Victoria's relatively mature market, with prices for gas and electricity deregulated in 2009 — earlier than in other regions.
- In April 2020, 89 businesses held authorisations to retail electricity and 35 businesses held authorisations to retail gas. Sixteen new retailers were authorised to retail electricity, and six to retail gas, from the start of 2019.
  - The number of authorised retailers may differ from the number of brands a customer sees in the market. Not all authorised retailers are active in the market at any time. Some businesses hold multiple authorisations for commercial purposes despite operating under a single brand. In other cases, multiple brands may operate under one authorization.

Figure 4.2 ~ Electricity Retail Market Share (%) among Residential and Small Business Customer Segments, 2019



** % numbers may differ due to rounding off

Source: AER - State of the Energy Market 2020, Retail energy market performance report, December 2019;

- In the seven months to January 2020, standing offer prices for residential customers fell by 14–19 per cent in Victoria, 11–13 per cent in NSW, 12 per cent in South Australia, and 10 per cent in south east Queensland.
- But electricity standing offer prices remain higher than market offers. A customer switching from the median standing offer to the best market offer in their distribution zone could have saved up to 20 per cent (A$300–400 in annual savings) in January 2020.
- Retailers are moving away from discounting towards simpler, more stable pricing. This shift coincided with reforms introduced in 2019 that restricted advertising based on large headline discounts. Offers with conditional discounts accounted for around two thirds of offers in Queensland, NSW, South Australia and the Australian Capital Territory (ACT) in 2018, but less than 20 per cent of offers by 2020.

NSW:

- NSW is the most concentrated of the major electricity markets. In 2019, the 'big three' (AGL, Origin and Energy Australia) accounted for 82 per cent of NSW electricity customers, compared to 85 per cent market share in the previous year.
- Snowy Hydro accounts for another 7 per cent of customers – an increase of 1 per cent from the last year.
- The other 36 retailers in NSW share 11 per cent of the market.

South Australia:

- In 2019, AGL captured the highest electricity market share, 41 per cent, a decline by 1 per cent compared to last year. Origin gained 1 per cent of the market from last year to move to 27 per cent.

Victoria:

- AGL is the electricity market leader with a 23 per cent share in 2019. There has been no change in AGL's market share over the past year.

Queensland:

- Queensland is characterized by its price-regulated electricity environment.
- Origin Energy (29 per cent) and the state government-owned Ergon (32 per cent) dominate the electricity retail market. Market share for Origin has declined by 3 per cent between 2018 and 2019.
- Ergon has greater penetration in the rural and regional QLD small customer segment. In Queensland, Origin Energy and AGL Energy account for 94 per cent of retail gas customers.

The ACT and Tasmania

- The ACT and Tasmania have limited competition in electricity and gas markets, reflecting the relatively small scale of their markets and greater price regulation.

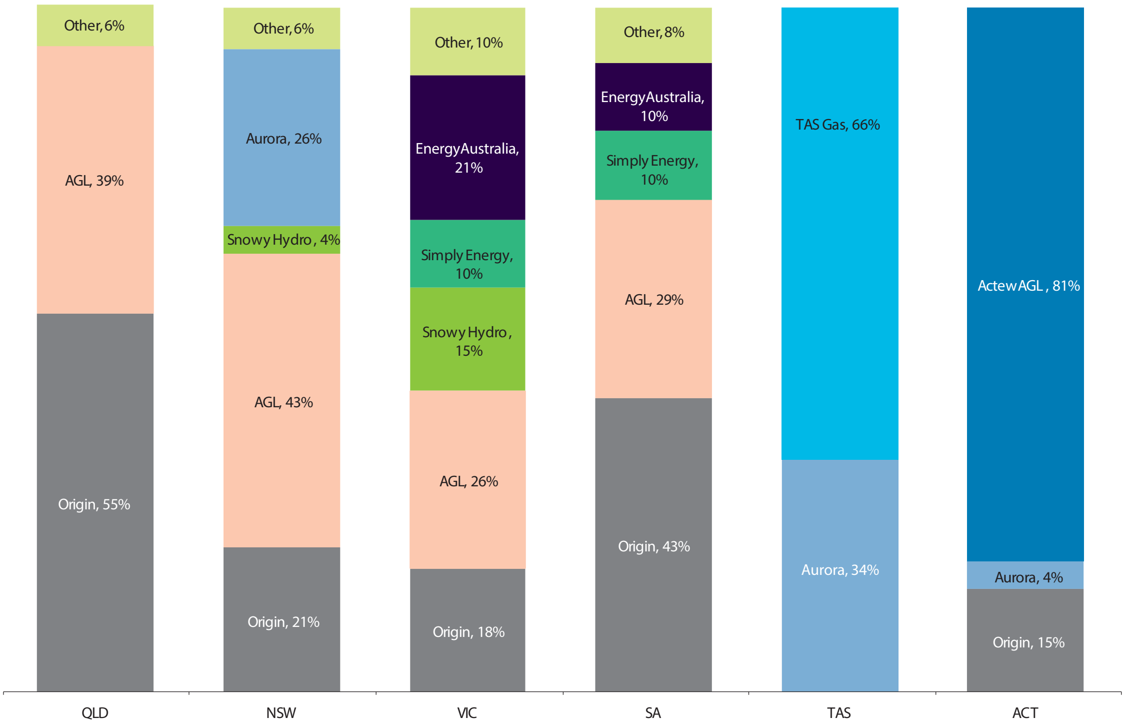
Retail Gas Market:

- Retail markets tend to be more concentrated in gas than electricity, in part because the markets are smaller in scale. Overall, —AGL Energy, Origin Energy and Energy Australia (the 'big three')—supply 75 per cent of small gas customers.
- Three 'second tier' retailers have built significant market share in some regions:
  - Snowy Hydro (owned by the Australian Government and trading as Red Energy and Lumo Energy) supplies around 9 per cent of gas customers—its market share is highest in Victoria, supplying 15 per cent of gas customers.
  - Alinta Energy (owned by Hong Kong based Chow Tai Fook Enterprises) supplies 3 per cent of gas customers.
  - Simply Energy (owned by French multinational Engie) supplies 6 per cent of gas customers, including approx. 10 per cent of customers in Victoria and South Australia.
- In the gas market, smaller retailers accounted for 4.4 per cent of small customers in 2019. Smaller retailers have had more success in Victoria than anywhere else, supplying almost 7 per cent of small gas customers. This outcome may reflect Victoria's relatively mature market, with prices for gas deregulated in 2009—earlier than in other regions.

Country wise gas retail market share:

- In NSW, the big 3 AGL Energy, Origin Energy and Energy Australia hold 90 per cent market share.
- In Victoria, AGL and Energy Australia holds 47 per cent market share.
- In Queensland, Origin Energy and AGL Energy account for 94 per cent of retail gas customers.
- The ACT and Tasmania—The dominant retailers in these regions are typically government owned (or part owned) businesses with limited operation outside their home region. ActewAGL (a joint venture between the ACT Government and AGL Energy) supplies almost 81 per cent of ACT gas customers. However, this market acquired more depth in 2019, when Origin Energy increased its market share to 15 per cent— an increase of 6 per cent from 2018. In Tasmania, Tas Gas and Aurora energy account for 66 per cent and 34 per cent respectively.

Figure 4.3 ~ Gas Retail Market Share (%) among Small Customers, 2019



Note: Includes residential and small business customers. All data at December 2019, except Victoria (electricity and gas, June 2019) and Tasmania (gas, June 2019)
Source: AER State of the Energy Market 2020

Market Players & Covid-19 Effects

According to the Australian Energy Market Commission, the Covid-19 pandemic has increased the risk that multiple power retailers could default during the crisis because of an increase in costs and nonpayment.

As per AEMC report,

- Electricity retailing is a relatively high-volume, low-margin industry. Electricity retailers carry the credit and cash-flow risks for the entire electricity sector. On average, across the NEM, for every A$100 of revenue received or owed to retailers they must pay: A$43 in network charges to network businesses, A$33 in wholesale purchase costs to generators, A$8 to meet the costs of various environmental obligations, and A$11 in their own retailing costs. This leaves retailers an average margin of A$4.

Examples:

- AGL Energy has witnessed 38 million dollars of increased costs over FY20 from COVID-19 related impacts – 20 million from increased net bad debt expense and 18 million from increased on-site operating costs due to the implementation of payment extensions and the installment payment plans & waviers.
- Origin Energy has reduced its electricity generation in response to lower demand due to COVID-19. Retail volumes were down 9 per cent on Jun-19 quarter due to lower usage from solar/energy efficiency and COVID-19. Business volumes were down by 11 per cent on Jun-19.
- Energy Australia has reported its EBIT has decreased by 20 per cent in the last six months due to Covid-19 as Energy Australia Energy Australia has expanded its hardship support for households, and in May launched Rapid Business Assist for small businesses.

In order to preserve continuity of supply to customers following the insolvency of a retailer, the National Energy Retail Law (NERL) sets out arrangements which provide for the immediate transfer of customers of a failing retailer to other retailers that act as a "Retailer of Last Resort" (ROLR).

- Under the Retail Law, the AER is responsible for overseeing the national Retailer of Last Resort (RoLR) scheme. The scheme is principally designed to ensure that in the event of retailer failure, arrangements are in place to ensure that customers continue to receive electricity and/or gas supply.
- However, there is the risk of financial contagion from the failure of a large retailer or a number of smaller retailers over a relatively short period, that could result in widening insolvency across the sector.

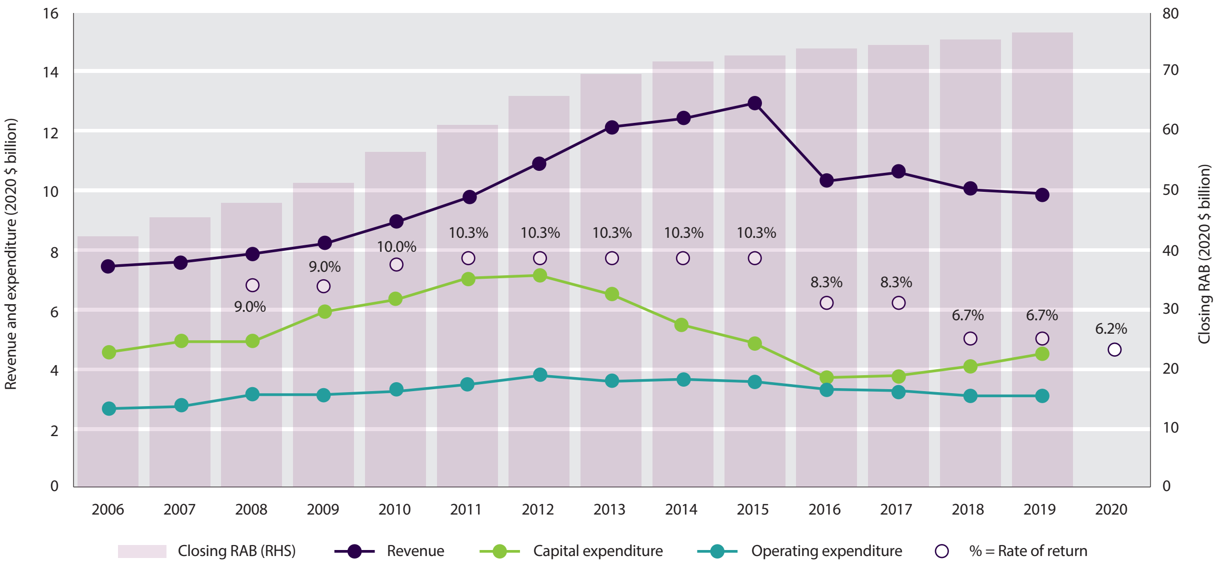
NEM COVID-19 Effect:

- The COVID-19 pandemic began to affect expectations in contract markets. Volumes of electricity future contracts for the second and third quarters of 2020 fell by 11 per cent in the last two weeks of March 2020.
- Commitments were made by energy retailers and some distribution networks to reduce the financial burden on impacted customers while COVID-19 related restrictions remain in place.
- Several state governments have also announced COVID-19 specific support packages for households and businesses.
  - In Queensland, households received a A$200 utility payment to assist with their electricity and water bills, and small businesses consuming less than 100 000 kilowatt hours received a A$500 utility rebate.
  - In Tasmania, Aurora Energy—in conjunction with the state government—capped price increases in energy bills for 12 months and announced a 100 per cent waiver for small business customers on their next bill after April 2020.

Regulated Electricity network:

- Energy network businesses earned a total of A$12.6 billion (A$1211 per customer) in 2019.
- Electricity distribution revenue decreased by 2 per cent in 2019 following a 5 per cent decrease in 2018 . Electricity distribution revenue in 2019 hit its lowest point since 2011 and was 23 per cent lower than the peak recorded in 2015. Transmission revenue in 2019 was at its lowest level in over a decade.
  - Distribution network businesses earned around 79 per cent of all network revenue. They earned just under A$10 billion (A$953 per customer) in revenue in 2019, which was 2 per cent lower than the previous year, and 23 per cent lower than the revenue peak of A$13 billion (A$1324 per customer) in 2015.
  - Transmission network businesses earned around 21 per cent of all network revenue. They earned A$2.7 billion (A$258 per customer) in revenue in 2019, which was 1 per cent lower than the previous year, and 17 per cent lower than the revenue peak of A$3.3 billion (or A$340 per customer) in 2013.
- Declining allowable network revenue since 2016, combined with rising customer numbers, have translated into lower network charges in retail energy bills for most customers. Current AER decisions reduced distribution charges in residential electricity bills by an average 0.6 per cent across all states and territories.
- Network investment increased for the third consecutive year in 2019, including a 9 per cent rise for electricity distribution. But investment in 2019 remained 41 per cent below the peak recorded in 2012. The majority of forecast investment in distribution networks is to replace and refurbish old assets, rather than to expand the networks.

Figure 4.4 ~ Electricity Distribution Revenue and Drivers

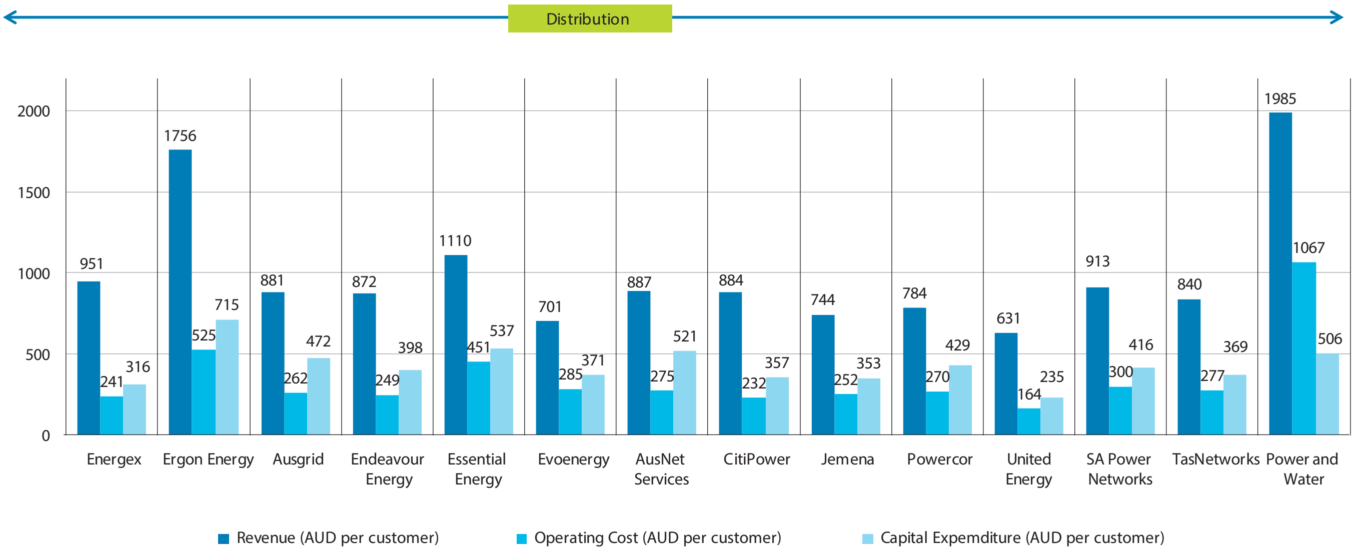


Note:

- RAB – Regulatory Asset Base
- All data are CPI adjusted to June 2020 dollars. Rates of return are weighted average cost of capital (WACC) forecasts in AER revenue decisions and Australian Competition Tribunal decisions for transmission networks. The rates of return shown represent the highest rate applicable to the distribution network businesses in each year.

Source: AER modeling, economic benchmarking regulatory information notice (RIN) responses, category analysis RIN responses.

Figure 4.5 ~ Electricity Distribution Networks—financial indicators



Note: (a) . Revenue, capital expenditure, operating expenditure and asset base are actual outcomes for the regulatory year ending in 2019. Distribution networks businesses report on a financial year basis (to 30 June), except in Victoria, where they report on calendar year basis. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system

Source: AER State of the Energy Market 2020, AER economic benchmarking RINs; AER regulatory determinations and AER modelling

Electricity network investment

- Electricity network businesses make investments in electricity capital equipment such as poles and wires, and other related infrastructure for supplying electricity to the end-customers. The investment drivers depend on the network's age, technology, load characteristic, demand for new connections, reliability and safety prerequisites, replacing worn out and obsolete equipment or to expand a network's capability in response to changes in electricity demand.
  - According to The Australian Energy Market Commission (AEMC), by 2030 6,000MW of generation will close and be replaced by 22,000MW of intermittent renewable generation and 6,000MW of storage. These numbers roughly double by 2040.
  - The Australian Energy Market Operator (AEMO) recently delivered a draft Integrated System Plan (ISP) which called for nine major new transmission projects to be undertaken in the near term, at an estimated cost of between A$6 billion and A$9 billion. Other smaller developments will also be required.
- As part of the revenue determination process, the AER forecasts a network's efficient investment requirements for the imminent period. This approved investment gets added to the network's regulated asset base (RAB). As the RAB grows, the returns paid to shareholders and lenders who fund those assets also rises — this cost is passed on to customers.
- There is a tendency for network operators to over-invest to maximize the returns. As part of 2015 reforms by the AER, in order to protect customers and do away with inefficient investments, network operators are rewarded if they under-spend the forecasted investment submitted and approved over the respective plan period, by allowing operators to retain the difference' between the forecast and actual capital costs.
- Electricity networks invested A$5.3 billion in network assets in 2019, which was an 8 per cent increase on the previous year's investment. While network investment in 2019 rose for a third consecutive year, expenditure was still 41 per cent lower than the A$8.9 billion invested in 2012.
- Distribution networks accounted for around 86 per cent of total network investment in 2019. Distribution network businesses invested A$4.5 billion in network assets in 2019, which was a 9 per cent increase on the previous year's investment. Examples of the types of capital expenditure to be carried out on the network in this regulatory period include:
  - Endeavour Energy's approved investment was 9 per cent higher than in its previous regulatory period, to accommodate growth, replace ageing infrastructure, and invest in technology to transform the business and improve customer service. Endeavour Energy was one of two distribution network businesses — the other being Power and Water (Northern Territory) — granted investment approvals that were higher than spending in the previous period.

- Evoenergy's (ACT) approved capital expenditure for the regulatory period commencing July 2019 will allow it to manage its ageing asset base to meet safety and reliability standards, accommodate urban developments, and meet the ACT Government's requirements on planning and system security.
- In Tasmania, TasNetworks' approved capital expenditure for the regulatory period commencing July 2019 is to support the replacement of assets in poor condition, system security, and the transition to clean energy. The AER approved three projects (each costing between A$278 million and A$1 billion) on a 'contingent' basis, requiring trigger events such as the construction of a second interconnector to the mainland to occur.
- AER decisions in place on 1 July 2020 forecast distribution network investment to be 8 per cent lower on average over the current five-year regulatory period compared with the previous period. Transmission investment is forecast to be 15 per cent lower.

- Transmission network businesses invested A$756 million in network assets in 2019, which was a 2 per cent decrease on the previous year's investment.

AER Decision Trends 2018-2019:

The Australian Energy Regulator (AER) sets the maximum revenue that a network business can earn from its customers through network charges. While the decision sets network revenue rather than prices, the two are closely related. Network businesses set prices by spreading their allowed revenue across the customer base. As part of the regulatory process, the AER also assesses tariff structure statements that set out a network's pricing policies, and annually reviews prices to ensure they are consistent with the revenue decision and reflect efficient costs.

- Since January 2019, the AER has finalised revenue decisions for electricity distribution networks in Queensland (Energex and Ergon Energy), NSW (Ausgrid, Endeavour Energy and Essential Energy), South Australia (SA Power Networks), Tasmania (TasNetworks), the ACT (Evoenergy), and the Northern Territory (Power and Water). The AER also finalised its revenue decision for the electricity transmission network in Tasmania (TasNetworks) and for the Directlink interconnector between NSW and Queensland. These decisions all cover a five-year regulatory period.
- AER approved six tariff structure statements for distribution businesses in NSW, ACT, Tasmania and the Northern Territory that encourage consumers to make better choices about how to use electricity.
  - Approved annual network tariff applications from 14 electricity distribution businesses and nine gas transmission and distribution businesses.

Recent AER Revenue Decision - Key Outcomes
Forecast Change From Previous Regulatory Period

Network	Location	Decision Date	Revenue (%)	Operating Expenditure (%)	Capital Expenditure (%)	Rate Of Return (%)	Annual Retail Bill Impact (%)
Transmission Networks							
TasNetworks	Tas	30 April 2019	27.8 ↓	11.9 ↓	9.1 ↑	5.5	0.6 ↑
Distribution Networks							
Energex	Qld	5 June 2020	26.5 ↓	4.3 ↓	23.7 ↓	4.7	0.8 ↓
Ergon Energy	Qld	5 June 2020	23.3 ↓	8.6 ↓	17.8 ↓	4.7	0.8 ↓
Ausgrid	NSW	30 April 2019	20.0 ↓	17.4 ↓	5.8 ↓	5.7	0.7 ↓
Endeavour Energy	NSW	30 April 2019	15.4 ↓	1.5 ↓	9.0 ↑	5.7	0.3 ↓
Essential Energy	NSW	30 April 2019	12.3 ↓	7.3 ↓	6.2 ↓	5.8	0.2 ↑
SA Power Networks	Tas	5 June 2020	8.2 ↓	10.4 ↑	6.2 ↓	4.8	0.4 ↓
TasNetworks	Tas	30 April 2019	3.1 ↓	6.5 ↑	1.0 ↓	5.3	0.6 ↑
Evoenergy	ACT	30 April 2019	19.6 ↓	3.9 ↑	17.4 ↓	5.5	0.5 ↑
Pwer and Water	NT	30 April 2019	15.8 ↓	20.9 ↓	14.4 ↑	4.9	0.8 ↓

Note:
1. Rate of return is the nominal vanilla rate for the first year of a determination. The rate is updated annually to reflect changes in debt costs.
2. Retail bill impact is the change in the average annual customer bill compared with the customer bill in the final year of the previous period, adjusted for inflation, assuming retailers pass through outcomes of the decision.

Source: AER estimates.

Legal reviews of AER decisions on NSW and ACT networks

- One of the longest running appeal processes (with ongoing ramifications in 2020) related to the Australian Energy Regulator's (AER) revenue decisions in 2015 for five New South Wales (NSW) and Australian Capital Territory (ACT) energy networks. While the Australian Government abolished limited merits review in October 2017, legal processes and their regulatory impacts on those five networks ran for several years.
- The decisions covered three NSW electricity distributors (Ausgrid, Endeavour Energy and Essential Energy), the ACT electricity distributor Evoenergy, and NSW gas distributor Jemena Gas Networks. The five businesses sought a review of the AER's decisions, seeking to recover around A$5 billion in additional revenue from customers. The Australian Competition Tribunal in February 2016 decided in favour of the network businesses in several areas.
- In 2017 the Federal Court upheld the Tribunal's findings on some matters and instructed the AER to remake its five revenue decisions. The lengthy process posed unique challenges. To manage price uncertainty for energy customers, the AER accepted enforceable undertakings from the five network businesses to limit rises in distribution charges to consumer price index (CPI) changes for the three years to 30 June 2019.
- The AER remade its revenue decisions on all five network businesses by January 2019. Following the original decisions, each business had embarked on reforms to reduce its operating costs, without compromising network reliability and security. The AER's remade decisions accounted for the businesses' constructive engagement with their stakeholders — including consumer groups and affected distribution businesses — to reach a common position on key issues.
- The AER also recognised the proposals provided certainty and price stability to customers and allowed a timely resolution to an unusually lengthy process. All final decisions resulted in approved revenues below what had been recovered from customers while the remittals were being finalised. The networks are returning excess revenue to customers through lower charges over the regulatory period, which began in July 2019.

Customers win out with AER revenue decisions

- The Australian Energy Regulator (AER) remade the decision on the amount of revenue that Ausgrid was entitled to recover over the 2014-19 regulatory period, as well as remaking the draft decision for the Jemena's 2015-20 access arrangement period.
  - This is consistent with the AER's draft decision, issued in November 2018, and means Ausgrid can recover total revenues of A$9.1 billion from its customers, resulting in A$310.9 million being returned to customers in the next regulatory period (2019-24).
  - In 2015, Ausgrid proposed to recover A$12 billion from consumers over the 2014-19 regulatory period, but the AER approved the significantly lower amount of A$8.8 billion in its final decision. Legal action followed, resulting in the AER's 2015 final decision being set aside by the Australian Competition Tribunal.
  - The revised amount to be recovered from consumers is A$341.1 million above what the AER approved in its 2015 decision. Under the interim arrangements that were put in place, Ausgrid recovered approximately A$652 million more revenue than was set out in the 2015 final decision.
- In 2015, Jemena proposed to recover A$2.6 billion from consumers over the 2015-20 access arrangement period, but the AER approved the lower amount of A$2.2 billion in its final decision. Legal action followed, resulting in the AER's 2015 final decision being set aside by the Australian Competition Tribunal.
  - The AER has remade this set aside decision and if implemented in full, JGN will be allowed to recover A$2.2 billion from its customers over the 2015-20 access arrangement period. If implemented, this will result in a revenue allowance of A$17.6 million (or 0.8 per cent) above the AER's 2015 final decision after incorporating updated information, and A$169 million as of 30 June 2020 being returned to consumers in the next access arrangement period (2020-25).

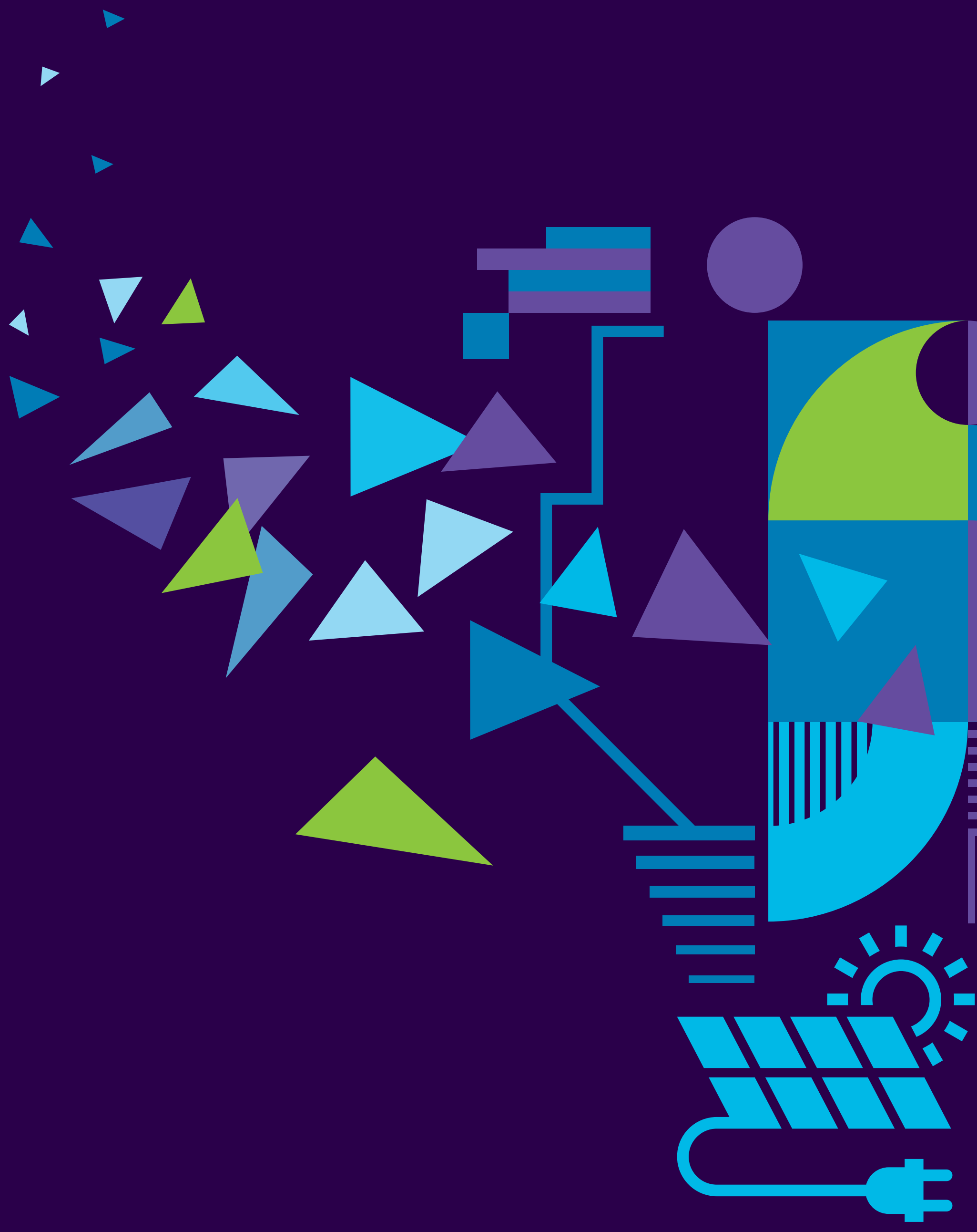
Source: AER report

AER strengthens frameworks to allow a customer-centric approach to key decisions

- The AER is piloting an early engagement approach in partnership with Energy Networks Australia and Energy Consumers Australia. The first business to trial the model, AusNet Services engaged an independent customer forum to negotiate its regulatory proposal. Customer engagement included interviews, field visits, commissioned research, observations (such as focus groups, deep dives, workshops and public forums) and reviews (of complaints data, guaranteed service level data and reliability data, and of AusNet Services customer research).
  - The purpose of this Early Engagement Plan is to explain the detail of how they propose to implement the negotiated regulatory approach, increase transparency, and achieve the highest possible levels of customer focus. It includes:
    - Governance arrangements for the customer representative group, which will be known as the Customer Forum
    - Recruitment of the Customer Forum members
    - The proposed operation of the Customer Forum
    - An indicative scope of issues that could be negotiated with the Customer Forum
    - How the Customer Forum integrates with AusNet Services' broader customer engagement activities for the 2021-25 EDPR
    - Proposed role of the AER, ECA and AusNet Services' Customer Consultative Committee
- This engagement illustrated the complexity of consumer preferences. As an example, customers supported sensible investment by AusNet Services to allow solar exports, so this energy is not wasted and helps reduce all customers' bills. Further, they supported sharing the costs among customers and with government. AusNet Services lodged its regulatory proposal in January 2020, which the AER is assessing.
- For the energy retail market, AER is strengthening frameworks to support customers in vulnerable circumstances. It revised hardship guidelines in 2019, and published research (by the Consumer Policy Research Centre) in 2020 on regulatory approaches to customer vulnerability.
- While energy prices have moderated, they continue to be a source of financial pressure for customers in vulnerable circumstances. Payment plans and hardship programs are the key mechanisms in place to support customers facing payment difficulties.
  - The AER has focused on improving frameworks around these tools to promote better customer outcomes, releasing a Sustainable Payment Plans Framework in 2017 and a revised hardship guideline in 2019. To better understand issues facing customers in vulnerable circumstances, the AER in 2020 published research (by the Consumer Policy Research Centre) on regulatory approaches to customer vulnerability.

Network Performance Reports:

- To assess network performance, the AER has gathered data for key performance measures relating to revenue, asset base, expenditures, reliability, maximum demand, energy delivered and circuit length from regulated networks since 2006. This data was made publicly available for the first time in 2018–19.
- Where applicable, both forecast and actual data is provided for measures presented annually for the National Electricity Market in total, as well as for individual businesses. Actual data has been sourced from individual annual Regulatory Information Notice (RIN) responses from the network businesses, including economic benchmarking and category analysis RINs or historical data provided at the time of regulatory determinations.
- By bringing together and publishing the key metrics from a range of sources, the reports make it easier for stakeholders to evaluate performance.



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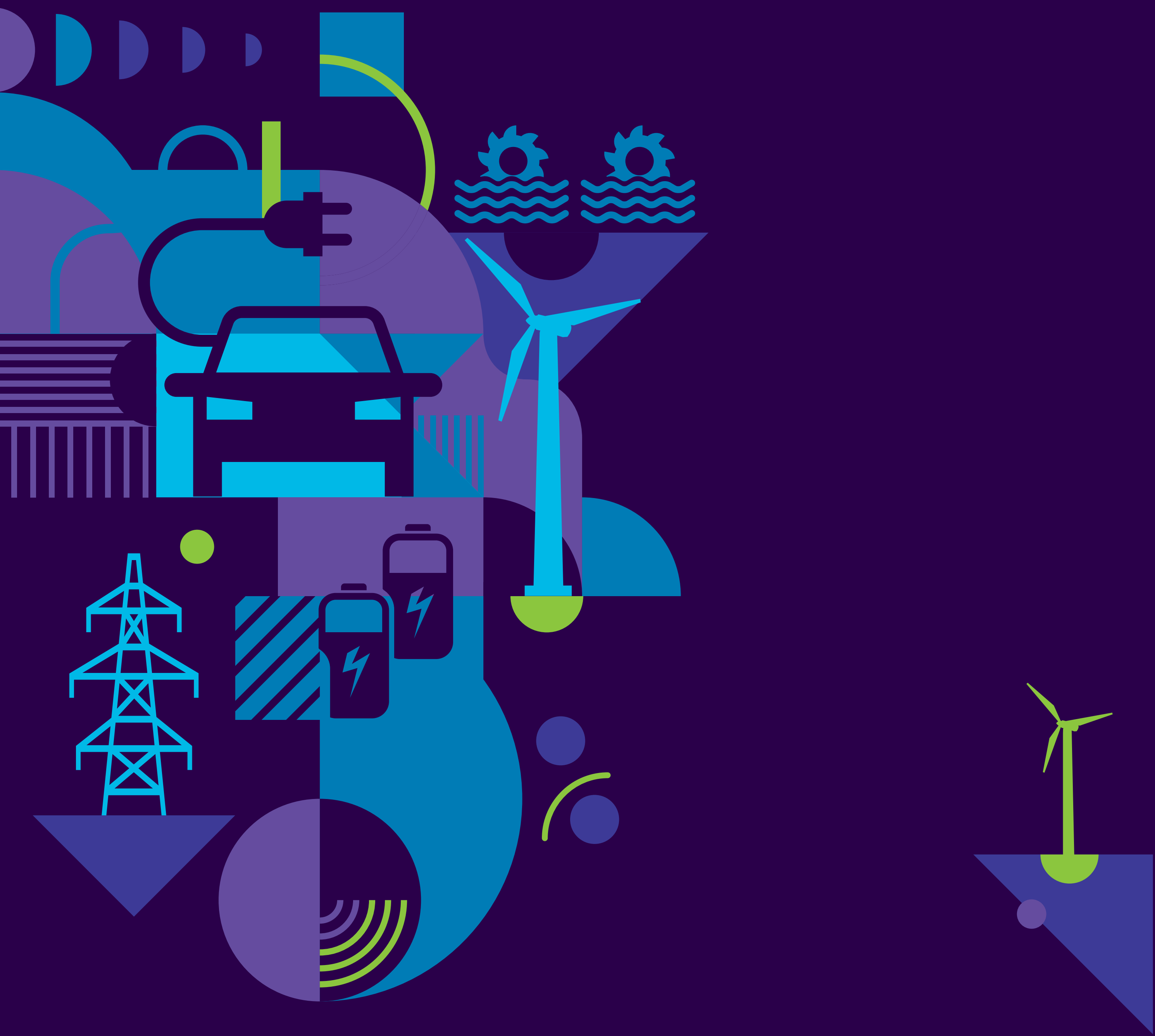

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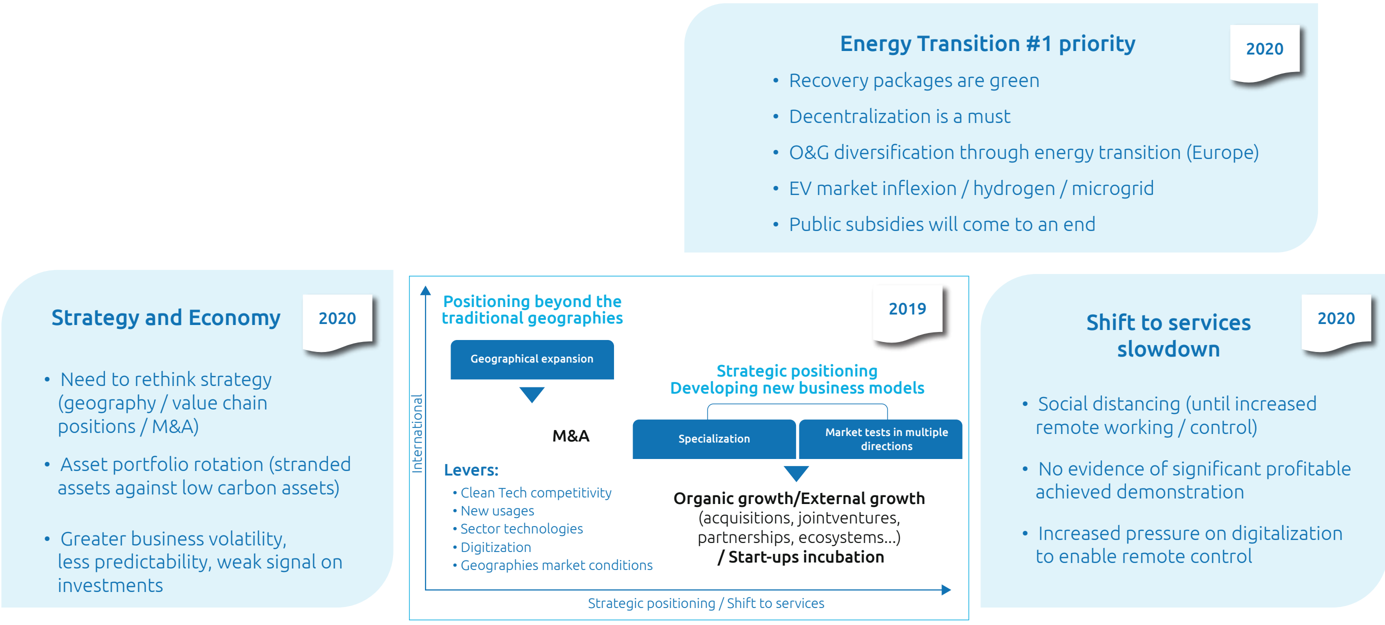
Transformation roadmap to rethink after the pandemic



COVID-19 will lead to a new transformation paradigm

In 2019, WEMO outlined two transformation routes (geographical expansion and new business models), leveraging partnerships, whatever their form.

COVID-19 will lead to high financial pressure with the obligation to revise company strategy and positioning

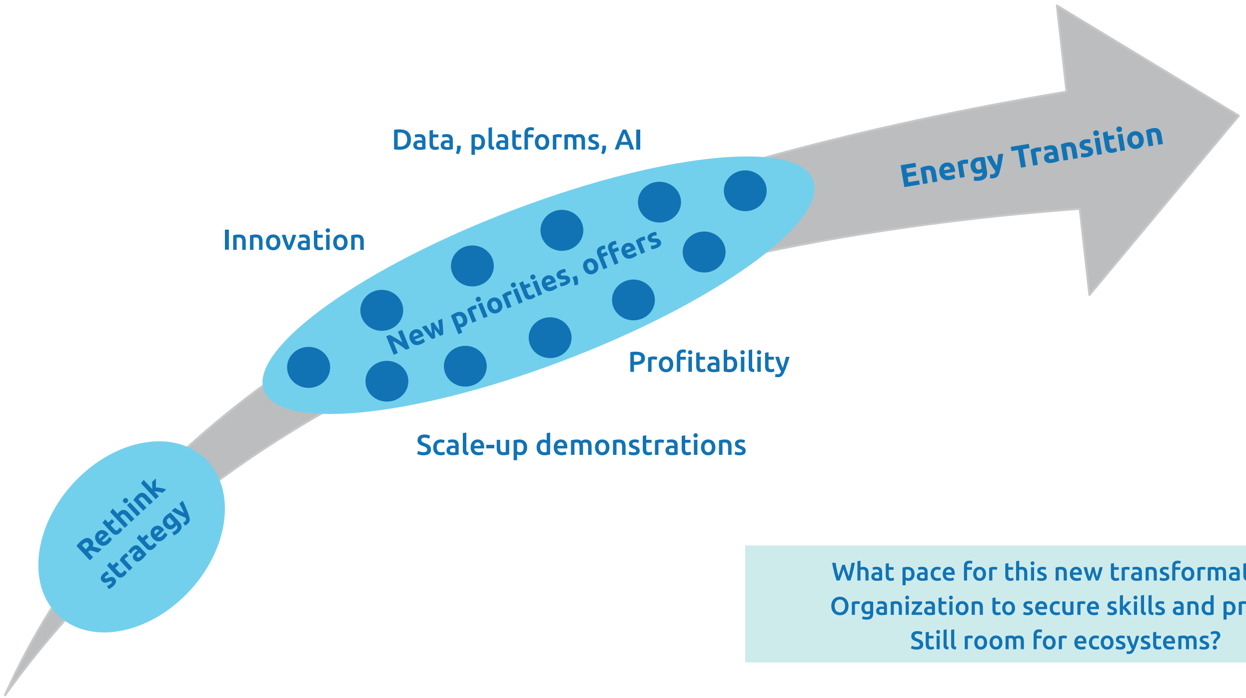
- More market volatility (agility needed), financial pressure with cost reduction programs as a consequence, concentration on value chain components where championing the market is possible, assets arbitrages and M&A opportunities.

Energy services is no longer the holy grail

- Social distancing prevents easy field force service for as long as digital remote management remains unimplemented
- Profitability remains low while players look for secure and significant margins.

Energy transition is a must and not only because of the green requirement of recovery packages

- Utilities, particularly in Europe, have demonstrated their commitment to decarbonization, at least with scopes 1 and 2, on average achieving a 10% decrease in carbon intensity over the last five years, notably from fossil fuel decommissioning.
- Stakeholders in O&G majors put high pressure on carbon neutrality commitments. Some European majors have taken the energy transition opportunity to diversify their business in the context of near peak oil production.
- For O&G players leveraging energy transition, the question is more about the scope of sustainability and where to start: renewables, storage, hydrogen, EV charging, biofuels, biogas…



What pace for this new transformation?
Organization to secure skills and profit?
Still room for ecosystems?

COVID-19 impacted on the energy sector; falling demand and prices are impacting on cash flow. There is a need for more independence; relocation of companies should also be considered, as well as revisiting priorities and innovating for the future. M&As, divestments and investments are all accelerating

Mergers & Acquisitions/ Divestments / Investments	• Jan 2020: **Engie** exited the UK domestic supply market in deal with Octopus Energy • March 2020: **Statkraft** announced its acquisition of an electric vehicle (EV) charging business in the UK from Swedish peer Vattenfall AB • March 2020: **Energias de Portugal SA (EDP),** Portugal's largest utility company, agreed to sell six hydro power plants in the Douro river basin to a consortium led by France's Engie SA for $2.4bn. • May 2020: It was announced that **Engie** is considering selling businesses including industrial and nuclear plant maintenance specialist **Endel**, as it tries to recentre on its most profitable activities. • May 2020: **Centrica** sold its North America operations to NRG Energy • June 2020: **Sempra Energy** completed the sales of its Chilean businesses. The transactions are expected to result in approximately $5.82 billion in combined total cash proceeds, subject to customary post-closing adjustments. The company's investments are now focused in top-tier markets in North America. • June 2020: **AES Corporation** announced an agreement to sell 100% of its equity interest in the 295 MW Itabo power plant in San Cristobal, Dominican Republic to Grupo Linda, a Dominican-based conglomerate. • July 2020: **E.ON** announced that it will sell its entire end-customer electricity and gas business in the Czech Republic to Hungarian energy group MVM • August 2020: **Ørsted** divested its Danish power distribution business (Radius), residential customer business, and city light business to SEAS-NVE	Innovation	**Cybersecurity:** • May 2020: **Enel X and Mastercard** are launching a new lab in Israel to advance innovations in financial technology and cybersecurity for the payments and energy ecosystem globally. **Microgrids:** • August 2020: **Schneider Electric and Huck Capital** launched 'Energy-as-a-Service' microgrids for small and medium-sized commercial and industrial (C&I) buildings **EVs:** • May 2020: **Centrica and UK motor manufacturer Lotus** are working together to develop a plug-in device that fully integrates future mobility and renewable energy. **Other innovation:** • Jan 2020: **Canadian Hydro-Québec and the University of Texas** at Austin entered into a licensing agreement to accelerate a new type of electrolyte for use in solid-state lithium batteries. • Jan 2020: **Ørsted** opened its United States Innovation Hub in Providence, Rhode Island as part of its commitment to building an offshore wind industry supply chain in the US. Sempra Energy opened its 'Center of Excellence' in Houston, Texas to display interactive technologies. • March 2020: **Northvolt and Vattenfall** launched a new battery energy storage unit, Voltpack Mobile System, a modular lithium-ion battery system envisioned as a zero-emissions alternative to diesel generators • July 2020: **Duke Energy** invested in SustainRNG to develop renewable natural gas on dairy farms. The advanced methane generation technology has been invented by Trane Technologies which has exclusively licensed its system to SustainRNG. In this technology, methane is converted to renewable energy and distributed through natural gas pipelines. • Sept 2020: **Total** and French car manufacturer **PSA** joined forces to create ACC, a European car battery Gigafactory.
Changed Business Priorities	• Mar 2020: **Ørsted** announced funding for nearly $13 billion worth of investments in projects in Taiwan in 2020 amid COVID-19. • April 2020: **Next Era Energy** laid out plans to combine its flagship utility Florida Power & Light Co. with recently acquired Gulf Power Co. into a single electricity operating system starting in 2022. • May & Aug 2020: **Engie** is planning to review the business opportunities of its Scottish construction and regeneration business in the aftermath of the pandemic and will consider necessary actions later. Engie also announced its desire to sell Energy Services. It could also sell minority stakes in co-owned listed companies, including water and waste management group "Suez SA" and gas transmission operator "GRT Gaz".		

Glossary

ACER
Agency for the Cooperation of Energy Regulators, created under the EU Third Legislative Package, adopted in April 2009

ACORE
Stands for American Council on Renewable Energy, is a national non-profit organization that unites finance, policy and technology to accelerate the transition to a renewable energy economy.

AEMC
Set up by the Council of Australian Governments through the Ministerial Council on Energy in 2005, the Australian Energy Market Commission makes and amends the National Electricity Rules, National Gas Rules and National Energy Retail Rules, and also provides market development advice to governments.

AEMO
The Australian Energy Market Operator is responsible for operating Australia's largest gas and electricity markets and power systems, including the NEM and Wholesale Electricity Market (WEM) and power system in Western Australia.

AGA
American Gas Association Representing more than 200 local energy companies that deliver clean natural gas throughout the United States.

AMI
Stands for Advanced Metering Infrastructure, it is the collective term to describe the whole infrastructure from Smart Meter to two way-communication network to control center equipment and all the applications that enable the gathering and transfer of energy usage information in near real-time.

Backwardation/Contango
"Contango" means that long-term prices are more expensive than short-term prices, depicting a relaxed short-term market, whereas "backwardation" reveals more tension in the short-term reflected in higher short-term prices than in the long-term

Base load
The minimum amount of electricity delivered or required over a given period, at a constant rate

Battery of the Nation
The Battery of the Nation initiative is investigating and developing a pathway of future development opportunities for Tasmania to make a greater contribution to the NEM.

Bilateral contracts/OTC
A contractual system between a buyer and a seller agreed directly without using a third party (exchanges, etc.). Also named as OTC for Over The Counter

Black Certificates
Exchangeable or tradable CO_2 allowances or quotas within the European Trading Scheme and Kyoto protocol (see EUA)

CAISO
Stands for California Independent System Operator is the non-profit Independent System Operator serving California that oversees the operation of California's bulk electric power system, transmission lines, and electricity market generated and transmitted by its member utilities.

CAPEX
Capital Expenditure, funds used by a company to acquire or upgrade physical assets

Carbon Budget
Carbon budget' is the cumulative quantity of CO_2 emissions that are allowed in order to keep global warming below a certain warming threshold

Carbon Cost Coalition
A multi-state coalition of state legislators from 12 states of the USA, who are focused on reducing carbon emissions, ensuring equity in policy proposals, developing market-based solutions, creating a resilient local economy and improving public health.

CCGT/Combined cycle power plant
Combined Cycle Gas Turbine. Thermal power plant, usually running on gas-fired turbines, where electricity is generated at two consecutive levels: firstly by gas combustion in the turbines, and secondly by using energy from the product of the gas combustion process in boilers, which supply heat to steam turbo-generators.

This process provides high levels of thermal output (55 to 60%, compared with only 33 to 35% for conventional thermal power plants)

CCS
Carbon Capture and Storage. Technologies used for isolating carbon dioxide from fuel gas (at combustion plants) and storing it. This means that a significantly lower amount of CO_2 is emitted into the atmosphere

CDM
Clean Development Mechanisms, a mechanism under the Kyoto Protocol through which developed countries may finance greenhouse-gas emission reduction or removal projects in developing countries, and receive credits for doing so which they may apply towards meeting mandatory limits on their own emissions

CEER/ERGEG
Council of the European Energy Regulators and European Regulators Group for Electricity and Gas. ERGEG was dissolved with the creation of ACER, all ERGEG works are found in CEER website

CER
Certified Emission Reduction. Quotas issued for emission reductions from Clean Development Mechanism (CDM) project activities

CHP/Cogeneration
Combined Heat and Power. System of simultaneous generation of electricity and heat. The output from cogeneration plants is substantially better than it would be if they produced only electricity

Churn/Switch
Free (by choice) movement of a customer from one supplier to another

Clean Coal
New technologies and processes allowing electricity generation from coal while lowering CO_2 emissions

Clean Dark Spread/Clean Spark Spread
The Clean Dark Spread is the difference between electricity's spot market price and the cost of electricity produced with coal plus the price of related carbon dioxide allowances while the Clean Spark Spread is the same indicator but with electricity produced with natural gas

Climate Change
Climate change is any significant long-term change in the expected patterns of average weather of a region (or the whole Earth) over a significant period of time.

Climate Risk Index
Climate Risk Index is released by Germanwatch which analyses to what extent countries and regions have been affected by impacts of weather-related loss events (storms, floods, heat waves etc.)

Copenhagen Accord
A voluntary agreement between the United States, China, Japan, Canada, Mexico, Russia and hundreds more making up over 80% of the global population and over 85% of global emissions that is based on goodwill of each member country assuming that each country will live up to their part in saving the climate by reducing greenhouse gases.

CSIRO
Commonwealth Scientific and Industrial Research Organization is an independent Australian federal government agency responsible for scientific research.

Decentralised generation
Production of electricity near the point of use, irrespective of size and technology, capacity and energy sources

Demand response
Any program which communicates with the end-users regarding price changes in the energy market and encourages them to reduce or shift their consumption

DER
Distributed Energy Resources refer to distribution level resources that produce electricity or actively manage consumer demand such as solar rooftop PVs, batteries; and demand response activities that manage hot water systems, pool pumps, smart appliances and air conditioning control.

Deregulated Market
A "deregulated electricity market" allows for the entrance of competitors to buy and sell electricity by permitting market participants to invest in power plants and transmission lines

DG Competition
European Union's Directorate General for Competition which role is to enforce the competition rules of the Community Treaties

DG TREN
European Union's Directorate General for Transport & Energy that develops EU policies in the energy and transport sectors

Distributed generation
Any technology that provides electricity closer to an end-user's site. It may involve a small on-site generating plant or fuel cell technology

Distribution System Loss
Distribution System Losses are losses pertaining to distribution of electricity. While technical losses are at times under the control of utilities, non-technical losses are external forces that impact the efficiency of the system and lead to revenue leakage

Dividend per share
Dividend per share (DPS) is the sum of declared dividends issued by a company for every ordinary share outstanding. The figure is calculated by dividing the total dividends paid out by a business, including interim dividends, over a period of time by the number of outstanding ordinary shares issued

DMO
Default market offers also known as the 'standing offers' are default, government-regulated energy offers which do not include any discount.

DOE (Philippines)
The Philippines' Department of Energy is the executive department of the Philippine Government responsible for preparing, integrating, manipulating, organizing, coordinating, supervising and controlling all plans, programs, projects and activities of the Government relative to energy exploration, development, utilization, distribution and conservation

Domestic consumers
Residential customers

Dual Monopoly
A situation wherein; two companies dominate the market . In other words two companies control production and supply of a product

EBIT
Earnings Before Interest and Taxes. EBIT may also be called operating income; i.e. the product of the company's industrial and commercial activities before its financing operations are taken into account. EBIT is a key ratio for gauging the financial performance of companies

EBITDA
Earnings Before Interest, Taxes, Depreciation and Amortization. EBITDA is a key ratio for gauging the cash flow of companies

EERS
Stands for Energy Efficiency Resource Standards establishes specific, long-term targets for energy savings that utilities or non-utility program administrators must meet through customer energy efficiency programs.

Electricity Tariffs
The amount of money frame by the supplier for the supply of electrical energy to various types of consumers in known as an electricity tariff

Eligible customer
Electricity or gas consumer authorised to turn to one or more electricity or gas suppliers of his choice

Energy Efficiency
Energy efficiency means using less energy to perform the same task

Energy Innovation and Carbon Dividend Act of 2019
The Energy Innovation and Carbon Dividend Act of 2019 is a bill in the United States House of Representatives that proposes a fee on carbon at the point of extraction to encourage market-driven innovation of clean energy technologies to reduce greenhouse gas emissions.

Energy Mix
Refers to the combination of the various primary energy sources used to meet energy needs in a given geographic region. It includes fossil fuels (oil, natural gas and coal), nuclear energy, non-renewable waste and the many sources of renewable energy (wood, biofuel, hydro, wind, solar, geothermal, heat from heat pumps, renewable waste and biogas).

Energy Regulatory Commission
Power Generation in Philippines is regulated by Energy Regulatory Commission (ERC). It is an independent electric power industry regulator that equitably promotes and protects the interests of consumers and other stakeholders, to enable the delivery of long-term benefits that contribute to sustained economic growth and an improved quality of life

Energy Transition Index
The Energy Transition Index(ETI) benchmarks countries on the performance of their energy system, as well as their readiness for transition to a secure and sustainable energy future. The ETI aggregates indicators from 40 different energy, economic and environmental datasets in order to provide a

comprehensive of the world's energy system

Energy Trilemma Index
The World Energy Trilemma Index is an annual comparative ranking of 125 countries on their ability to balance energy priorities

ENSO
Stands for El Niño-Southern Oscillation which is a recurring climate pattern involving changes in the temperature of waters in the central and eastern tropical Pacific Ocean, affecting the climate of much of the tropics and subtropics. The warming phase of the sea temperature is known as El Niño and the cooling phase as La Niña.

ENTSO-E
European Network of Transmission System Operators for Electricity. ENTSO-E, the unique association of all European TSOs, was created at the end of 2008 and is operational since July 1, 2009. All former TSOs associations such as UCTE or ETSO are now part of ENTSO-E

ENTSO-G
European Network of Transmission System Operators for Gas. ENTSO-G was created at the end of 2009 and comprises 32 gas TSOs from 22 European countries

EPIC
Stands for Energy Policy Institute at Chicago, it is an interdisciplinary research and training institute focused on the economic and social consequences of energy policies.

EPR
European Pressurized Reactor. Third generation of nuclear plant technology using advanced Pressurized Water Reactor (PWR)

ERU
European Reduction Unit. A unit referring to the reduction of greenhouse gases, particularly under the Joint Implementation where it represents one ton of CO_2 reduced

ETS
Emissions Trading Scheme. An administrative approach used to control pollution by providing economic incentives for achieving reductions in the emissions of pollutants. The European Union Emissions Trading Scheme has been in operation since January 1, 2005

EUA
European Union Allowances. Quotas allocated by the National Allocation Plans in compliance with the European Trading Scheme

Eurelectric
Professional association which represents the common interests of the Electricity industry at pan-European level

European Commission (EC)
A governing body of the European Union that oversees the organization's treaties, recommends actions under the treaties, and issues independent decisions on EU matters

European Council
A body formed when the heads of state or government of European Union member states meet. Held at least twice a year, these meetings determine the major guidelines for the EU's future development

European Parliament (EP)
The assembly of the representatives of the Union citizens

European Union (EU)
The European Union (EU) is a group of 28 countries that operates as a cohesive economic and political block

EVs
Electric vehicles is an alternative fuel automobile that uses electric motors and motor controllers for propulsion, in place of more common propulsion methods such as the internal combustion engine (ICE).

EWEA
European Wind Energy Association

FERC
Stands for The Federal Energy Regulatory Commission, is the United States federal agency that regulates the transmission and wholesale sale of electricity and natural gas in interstate commerce and regulates the transportation of oil by pipeline in interstate commerce.

FID
Final Investment Decision

FLNG
Stands for Floating Liquefied Natural Gas, efers to water-based liquefied natural gas (LNG) operations employing technologies designed to enable the development of offshore natural gas resources

Forwards
A standard contract agreement for delivery of a given quantity at a given price, for a given maturity (OTC markets)

Futures
A standard contract agreement for delivery of a given quantity at a given price, for a given maturity (organized exchanges). The maturities may differ across power exchanges (weekly, half-yearly, quarterly, monthly, annually).
Maturity Y+1 corresponds to the calendar year after the current year

GCF
The Green Climate Fund is a global fund that was formed to support climate change vulnerable nations, especially the "Least Developed Countries" to fulfil their climate change goals and lower their GHG emissions.

GDP
Stands for Gross Domestic Product, is a monetary measure of the market value of all the final goods and services produced in a country over a specific time period, often annually.

GECF
Gas Exporting Countries Forum. GECF is a gathering of the world's leading gas producers

GIE
Gas Infrastructure Europe. GIE is the association representing gas transmission companies (GTE), storage system operators (GSE) and LNG terminal operators (GLE) in Europe

Green Bond
A green bond is a bond specifically earmarked to be used for climate and environmental projects. These bonds are typically asset-linked and backed by the issuer's balance sheet, and are also referred to as climate bonds

Green Certificates
A Guarantee of Origin certificate associated with renewable targets fixed by national governments. Green Certificates are often tradable

Greenhouse effect
The warming of the atmosphere caused by the build up of 'greenhouse' gases, which allow sunlight to heat the earth while absorbing the infrared radiation returning to space, preventing the heat from escaping. Excessive human emissions including carbon dioxide, methane and other gases contribute to climate change

Grid
An electrical grid, electric grid or power grid, is an interconnected network for delivering electricity from producers to consumers.

Grid 2.0
Grid 2.0 refers to the grid system which will transform how gas, solar and thermal energy is managed into a single intelligent network efficiently. This builds on Singapore's past investments in smart meters, grid storage, solar photovoltaics, as well as various energy efficiency and

demand management solutions to address Singapore's unique energy challenges, and also grow the base of capabilities.

Guarantee of Origin
A certificate stating a volume of electricity that was generated from renewable sources. In this way the quality of the electricity is decoupled from the actual physical volume. It can be used within feed in tariffs or Green Certificate systems

HHI
Herfindahl-Hirschman Index, a commonly accepted measure of market concentration. It is calculated by squaring the market share of each firm competing in a market, and then summing the resulting numbers. The HHI number can range from close to zero to 10,000

Hub (gas)
Physical or virtual entry/exit points for natural Gas

Hub (retail)
Inter Company Data Exchange platform primarily enabling Suppliers and Distribution companies to exchange client related data and making supplier's switching more reliable

ICPT Mechanism
The ICPT is a mechanism approved by the Government and implemented by ST since 1 January 2014 as part of a wider regulatory reform called the Incentive Based Regulation ("IBR"). ICPT mechanism allows TNB to reflect changes in fuel and generation costs in consumer's electricity tariff every six months. This mechanism is implemented according to Section 26 of Electricity Supply Act 1990 [Act 447]. The impact of ICPT implementation is neutral on TNB and will not have any effect to its business operations and financial position

IED
Industrial Emissions Directive, a European Union Directive that sets strict limits on the pollutants that industrial installations are allowed to spew into the air, water and soil. Installations have until 2016 to comply with the limits

Incentive Based Regulation
An incentive-based regulatory approach aims to reduce environmentally-harmful pollutants by offering inducements to polluters who limit their emissions

Installed capacity
The installed capacity represents the maximum potential net generating capacity of electric utility companies and auto-producers in the countries concerned

International Energy Consultants
IEC is a Perth-based consulting firm which specializes in providing power market advisory services to companies operating in and associated with the IPP sector within the Asia-Pacific region

Investment Tax Credits
A tax related incentive that allows individuals or entities to deduct a certain percentage of specific investment related costs from their tax liability apart from usual allowances for depreciation.

IPCC
Intergovernmental Panel on Climate Change, the leading body for the assessment of climate change, established by the United Nations Environment Programme (UNEP) and the World Meteorological Organization (WMO) to provide a clear scientific view on the current state of climate change and its potential environmental and socio-economic consequences

IUS
Stands for the Integrated Utility Services, developed by Rocky Mountain Institute wherein utility companies could seamlessly blend an array of products, services and financing tools that have not previously been integrated.

JI
Joint Implementation, a mechanism under the Kyoto Protocol allowing industrialised countries with a greenhouse gas reduction commitment to invest in emission reducing projects in another industrialised country as an alternative to emission reductions in their own countries

Kyoto Protocol
The United Nations regulatory frame for greenhouse gases management, adopted in December 1997 and entered into force in February 2005. It encompasses 6 greenhouse gases: CO_2, CH_4, N_2O, HFC, PFC, SF_6

LCOE (levelized cost of energy)
LCOE is the cost of electricity produced by a generator calculated by accounting for all of a system's expected lifetime costs (including construction, financing, fuel, maintenance, taxes, insurance and incentives), which are then divided by the system's lifetime expected power output (kWh).

LCOS (levelized cost of storage)
It quantifies the discounted cost per unit of discharged electricity for a specific storage technology and application.

LCPD
Large Combustion Plant Directive, a European Union Directive that aims to reduce acidification, ground level ozone and particulates by controlling the emissions of sulphur dioxide, oxides of nitrogen and dust from large combustion plant. All combustion plant built after 1987 must comply with the emission limits in LCPD. Those power stations in operation before 1987 are defined as 'existing plant'. Existing plant can either comply with the LCPD through installing emission abatement (Flue Gas Desulphurisation) equipment or 'opt-out' of the directive. An existing plant that chooses to 'opt-out' is restricted in its operation after 2007 and must close by the end of 2015

LNG
Liquefied Natural Gas. Natural gas that has been subjected to high pressure and very low temperatures and stored in a liquid state. It is returned to a gaseous state by the reverse process and is mainly used as a peaking fuel

LNG Netback Price
A measure of an export parity price that a gas supplier can expect to receive for exporting its gas.

Load balancing
Maintaining system integrity through measures which equalize pipeline (shipper) receipt volumes with delivery volumes during periods of high system usage. Withdrawal and injection operations into underground storage facilities are often used to balance load on a short-term basis

Load factor
Ratio of average daily deliveries to peak-day deliveries over a given time period

LULUCF
Referred to as Forestry and other land use defined as the greenhouse gas inventory sector that covers emissions and removals of greenhouse gases resulting from direct human-induced land use such as settlements and commercial uses, land-use change, and forestry activities.

Market coupling
Market coupling links together separate markets in a region, whereas market splitting divides a regional market into prices zones. Market coupling minimises prices differences and makes them converging wherever transmission capacity is sufficient. Cross-border market coupling also drives better use of interconnection capacity

Market Liberalization
The process of removing government control and opening up the markets to private companies

Merit order
The merit order is a way of ranking available sources of energy, especially electrical generation, in ascending order of their short-run marginal costs of production, so that those with the lowest marginal costs are the first ones to be brought online to meet demand, and the plants with the highest marginal costs are the last to be brought on line

MESI 2.0
The Malaysian Electricity Supply Industry (MESI) under the MESI 2.0 initiative, has three key aims, which are to increase industry efficiency, future-proof the industry, and empower consumers

Metering
Measurement of the various characteristics of electricity or gas in order to determine the amount of energy produced or consumed

MyPower
MyPower, (which is a part of Malaysian Energy Supply Industry-MESI) stands for Malaysia Programme Office for Power Electricity Reform, will design and drive the implementation of energy reform over the next three years

NAP
National Allocation Plan. List of selected industrial and power installations with their specific emissions allowance (under the ETS system)

Natural Gas
Mixture of gases which are rich in hydrocarbons. Gases such as methane, nitrogen, carbon dioxide etc. are naturally found in atmosphere. Natural gas reserves are deep inside the earth near other solid & liquid hydrocarbons beds like coal and crude oil.

NDC
Stands for the Nationally Determined Contributions, it implies the achievement of long term goals made under the Paris Agreement which embody efforts by each country to reduce national emissions and adapt to the impacts of climate change.

NEEAPs
National Energy Efficient Action Plans, plans providing detailed roadmaps of how each Member State expects to reach its energy efficiency target by 2020

NEG
National Energy Guarantee was an energy policy proposed by the Turnbull government in late 2017 to deal with rising energy prices in Australia and lack of clarity for energy companies to invest in energy infrastructure.

NEM
The National Electricity Market of Australia interconnects five regional market jurisdictions – Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia, and Tasmania.

Nomination
A request for a physical quantity of gas under a specific purchase or transportation agreement

Non-Domestic Consumers
Commercial and industrial customers, and others

NREAPs
National Renewable Energy Action Plans, plans providing detailed roadmaps of how each Member State expects to reach its legally binding 2020 target for the share of renewable energy in their final energy consumption

NTC
Net Transfer Capacity. NTC is the expected maximal electrical generation power that can be transported through the tie lines of two systems without any bottlenecks appearing in any system

Off-peak
Off-peak energy is the electric energy supplied during periods of relatively low system demands as specified by the supplier

On-peak
On-peak energy is electric energy supplied during periods of relatively high system demand as specified by the supplier

OPEC
Organization of the Petroleum Exporting Countries

Open season
A period (often 1 month) when a pipeline operator accepts offering bids from shippers and others for potential new transportation capacity. Bidders may or may not have to provide “earnest” money, depending upon the type of open season. If enough interest is shown in the announced new capacity, the pipeline operator will refine the proposal and prepare an application for construction before the appropriate regulatory body for approval

OPEX
Operational Expenditure, expenditures that a business incurs as a result of performing its normal business operations

P/E
Price / Earning ratio. The ratio of the share price to the Earning per share (EPS). P/E ratio is one of the tools most commonly used for valuing a company share

Paris Agreement
The Paris Agreement is an agreement within the United Nations Framework Convention on Climate Change, dealing with greenhouse-gas-emissions mitigation, adaptation, and finance, signed in 2016.

Peak load
The highest electrical level of demand within a particular period of time

Peak shaving
Reduction of peak demand for natural gas or electricity

PPA
Stands for Power Purchase Agreements that freezes a price and a notional energy volume for both the buyer and seller of electricity for a specific period of time. This price agreement acts as the final agreed price for a development project that is either achieving financial close or remaining on the shelf. The agreement also includes reference to cases of failure to meet the contract terms and conditions including, the payment of liquidated damages.

PPU
(Programmations pluriannuelles de l’énergie) Multi-year Energy Programming, a tool for planning and steering national energy policy, which defines the priorities for actions and the specific objectives to be achieved over the period 2016-2023, targeting all energy sources, in order to achieve the national objectives set by the LTE

REBA
Stands for Renewable Energy Buyers Alliance, is a a membership association of large clean energy buyers, energy providers, and service providers that, together with NGO partners, are committed to unlocking the marketplace for all nonresidential energy buyers to lead a rapid transition to a cleaner, prosperous, zero-carbon energy future.

Regulated Market
A regulated electricity market contains utilities that own and operate all electricity

RES
Renewable Energy Sources. Energy (electricity or heat) produced using wind,

sun, wood, biomass, hydro and geothermal. Their exploitation generates little or no waste or pollutant emissions

RGGI
Stands for Regional Greenhouse Gas Initiative, which is the first mandatory market based program in the United States to reduce greenhouse gas emissions is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont to cap and reduce carbon dioxide (CO_2) emissions from the power sector.

Rhodium Group
Rhodium Group is an independent research provider combining economic data and policy insight to analyze global trends.

SAIDI
Stands for System Average Interruption Duration Index that measures the average outage duration for each customer served in units of time, often minutes or hours.

SGIG
NA

Shippers
The party who contracts with a pipeline operator for transportation service. A shipper has the obligation to confirm that the volume of gas delivered to the transporter is consistent with nominations. The shipper is obligated to confirm that differences between the volume delivered in the pipeline and the volume delivered by the pipeline back to the shipper is brought into balance as quickly as possible

SLCP
Stands for Short-lived Climate Pollutants that identifies black carbon, methane, tropospheric ozone, and fluorinated gases. Currently, fluorinated gases (HFCs, perfluorocarbons (PFCs), SF6, and NF3) account for 3 percent of domestic greenhouse gas emissions in terms of carbon dioxide equivalency (CO_2e)

Smart Grid
An electricity supply network that uses digital communications technology to detect and react to local changes in usage.

Solar Power Europe
European Photovoltaic Industry Association. The association that represents the photovoltaic (PV) industry towards political institutions at European and international level.

Spot contract
Short-term contract, generally a day ahead

State Ownership
State ownership is the ownership of an industry, asset, or enterprise by the state or a public body representing a community as opposed to an individual or private party

Super Pollutants
Methane and black carbon identified as the Super Pollutants being some of the most aggressive contributors to global warming.

System Loss
System losses occur when 100% efficiency isn't achieved in either conversion or transport of energy.System losses are of two types:1. Technical Loss, driven by the characteristics for the equipment and materials 2. Non-technical Loss, driven by theft, meter readings, pilferage etc.

Take-or-pay contract
Contract whereby the agreed consumption has to be paid for, irrespective of whether the consumption has actually taken place

TCI
Stands for Transportation and Climate Initiative, it is a regional collaboration of 12 Northeast and Mid-Atlantic states and the District of Columbia that seeks to improve transportation, develop the clean energy economy and reduce carbon emissions from the transportation sector.

Third Energy Package
Third Energy Package. A legislative package proposed on September 19, 2007 by the EC in order to pursue the liberalisation of the electricity and gas markets

TPA
Third Party Access. Recognised right of each user (eligible customer, distributor, and producer) to access in a non discriminatory and efficient manner transmission or distribution systems in exchange for payment of access rights

UFC
Federal Union of Consumers

Unbundling
Separation of roles according to the value chain segment (generation, transmission, distribution, retail) required by European Directives for enabling fair competition rules

UNEP
United Nations Environment Program

US Climate Alliance
The United States Climate Alliance is a bipartisan coalition of governors committed to reducing greenhouse gas emissions consistent with the goals of the Paris Agreement

US Energy Information Administration
The U.S. Energy Information Administration (EIA) is a principal agency of the U.S. Federal Statistical System responsible for collecting, analyzing, and disseminating energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment.

Utility Death Spiral
In 2013, the Edison Electric Institute (EEI) released a report positing that an eroding revenue stream, declining profits, rising costs, and ever-weakening credit metrics would diminish the ability of electric utilities to survive in an increasingly off-the-grid world.

White Certificate
A certificate stating a volume of engaged energy savings (electricity, gas, fuel, …) at end-users' site, like a home or a business. They are tradable or not

Wholesale Electricity Market
The wholesale market is where electricity is traded (bought and sold) before being delivered to end consumers (individuals, households or businesses) via the grid

List of Acronyms

1. ACCC: Australia Competition and Consumer Commission
2. ACEEE: American Council for an Energy Efficient Economy
3. ACORE: American Council on Renewable Energy
4. ACT: Australian Capital Territory
5. ADIT: Accumulated Deferred Income Tax
6. AEMC: Australian Energy Market Commission
7. AEMO: Australian Energy Market Operator
8. AER: Australian Energy Regulator
9. AGA: Advanced Grid Analytics
10. AMI: Advanced Metering Infrastructure
11. APEC: Asia-Pacific Economic Cooperation
12. APGCC: ASEAN Power Grid Consultative Committee
13. APRA: Australian Prudential Regulation Authority
14. ARENA: Australian Renewable Energy Agency
15. ARFVTP: Alternative and Renewable Fuel and Vehicle Technology Program
16. ARRA: American Recovery and Reinvestment Act
17. ASEP: Access to Sustainable Energy Program
18. ASIC: Australian Securities & Investments Commission
19. ASEAN: Association of Southeast Asian Nations
20. BAU: Business-as-usual
21. Bcm: Billion cubic meters
22. BESS: Battery Energy Storage System
23. Bloomberg NEF: Bloomberg New Energy Finance
24. BNEF: Bloomberg New Energy Finance
25. BoM: Bureau of Meteorology
26. B2C: Business-to-Consumer
27. CAFÉ: Corporate Average Fuel Economy
28. CAGR: Compound Annual Growth Rate
29. CAISO: California Independent System Operator
30. CapEx: Capital Expenditure
31. CARC: Customer Acquisition and Retention Costs
32. CAT: Climate Action Tracker
33. CC: Contestable Consumers
34. CCA: Climate Council Authority
35. CCC: Climate Change Commission
36. CCGT: Combined Cycle Gas Turbine
37. CCS: Carbon Capture and Storage
38. CEFC: Clean Energy Finance Corporation
39. CER: Clean Energy Regulator
40. CEVS: Carbon Emissions-Based Vehicle Scheme
41. CO_2: Carbon dioxide
42. CO_2e: Carbon dioxide Equivalent
43. COAG: Council of Australian Governments
44. CPI: Consumer Price Index
45. COP22: 22nd Conference of the Parties
46. CPP: Clean Power Plan
47. CREZ: Competitive Renewable Energy Zones
48. CRI: Climate Risk Index
49. CRM: Customer relationship management
50. CSI: Customer Satisfaction Index
51. CSI: California Solar Initiative
52. CSIRO: Commonwealth Scientific and Industrial Research Organization
53. CSP: Competitive Selection Process
54. CST: Concentrated Solar Thermal
55. CTS: Costs to Serve
56. DEE: Department of Environment and Energy
57. DER: Distributed Energy Resource
58. DES: Distributed Electricity and Storage
59. DILG: Department of the Interior and Local Government
60. DfE: Design for Efficiency
61. DMIRS: Department of Mines, Industry Regulation and Safety
62. DMO: Distribution Market Operator
63. DMO: Default Market Offer (aka 'standing offers')
64. DoE: Department of Energy
65. DPPA: Direct Power Purchase Agreement
66. DREAMS: Development for Renewable Energy Applications Mainstreaming and Market Sustainability
67. DSO: Distribution System Operator
68. DSL: Distribution System Loss
69. DSM: Demand-side Management
70. DU: Distribution Utilities
71. EASe: Energy Efficiency Improvement Assistance Scheme
72. eceee: European Council for an Energy Efficient Economy
73. EBITA: Earnings before Interest, Taxes, and Amortization
74. EBITDA: Earnings before Interest, Tax, Depreciation and Amortization
75. EBSS: Efficiency Benefit Sharing Scheme
76. EC: Energy Commission
77. ECF: Equity Crowd Funding
78. EE: Energy Efficiency
79. EERS: Energy Efficiency Resource Standards
80. EIA: Energy Information Administration
81. EMA: Electricity Market Authority
82. EMC: Energy Market Company
83. EMS: Energy Management System
84. ENSO: El Niño-Southern Oscillation
85. ENTR: Electricity Network Transformation Roadmap
86. EPA: Environmental Protection Agency
87. EPBC: Environment Protection and Biodiversity Conservation
88. EPIC: Energy Policy Institute at University of Chicago
89. EPS: Earnings per Share
90. ERCOT: The Electric Reliability Council of Texas
91. ERC: Energy Regulatory Commission
92. ERF: Emissions Reduction Fund
93. ESB: Energy Security Board
94. ESCO: Energy Service Company
95. ESOO: Electricity Statement of Opportunities
96. ETI: Energy Transition Index
97. ETS: Emissions Trading Scheme
98. EV: Electric Vehicle
99. EVN: Vietnam Electricity Company
100. FERC: The Federal Energy Regulatory Commission
101. FFO: Funds from Operation
102. FFR: Fast Frequency Response
103. FLNG: Floating liquefied natural gas
104. FPSS: Future Power System Security
105. FPA: Federal Power Act
106. FRC: Full Retail Contestability
107. FUM: Forecast Uncertainty Measure
108. GCF: Green Climate Fund
109. GDP: Gross Domestic Product
110. GEOP: Green Energy Option Program

111. GHG: Greenhouse Gas
112. GIS: Geographic Information System
113. GJ: Gigajoules
114. GMI: Grid Modernization Initiative
115. GMLC: Grid Modernization Lab Consortium
116. GMRG: Gas Market Reform Group
117. GREET: Grant for Energy Efficient Technologies
118. GSSF: Grid Scale Storage Fund
119. GSOO: Gas Statement of Opportunities
120. GTFS: Green Technology Financing Scheme
121. GW: Gigawatt
122. GWh: Gigawatt-hours
123. HDB: Housing and Development Board
124. HEV: Hybrid Electric Vehicle
125. HFCs: Hydrofluorocarbons
126. HK Electric: Hongkong Electric Company
127. HVAC: Heating, Cooling & Ventilation
128. HKSAR: Hong Kong Special Administrative Region
129. IA: Investment Allowance
130. IBR: Incentive Based Regulation
131. ICPT: Imbalance Cost Pass-Through
132. ICT: Information and Communication Technologies
133. IEA: International Energy Agency
134. IEC: International Energy Consultants
135. IEMOP: Independent Electricity Market Operator of the Philippines
136. IEP: International Environmental Partnership
137. IFC: The International Finance Corp
138. INDC: Intended Nationally Determined Contribution
139. IoT: Internet of Things
140. IOUs: Investor-owned Utilities
141. IPCC: Intergovernmental Panel on Climate Change
142. IPP: Independent Power Producer
143. IPv6: Internet Protocol version 6
144. ISEM: Institute for Superconducting and Electronic Materials
145. ISO: International Organization for Standardization
146. ISP: Integrated System Plan
147. ITC: Investment Tax Credits
148. IUS: Integrated Utility Services
149. IVR: Interactive Voice Response
150. kgoe: Kilograms of oil equivalent
151. KV: Kilovolt
152. KW: Kilowatt
153. KWh: Kilowatt-hours
154. LCOE: Levelized Cost of Energy
155. LDC: Least Developed Countries
156. LNG: Liquefied Natural Gas
157. LPG: Liquefied Petroleum Gas
158. LRET: Large-scale Renewable Energy Target
159. LSS: Large Solar Scale
160. LULUCF: Land Use, Land Use Change and Forestry
161. M2M: Machine to Machine
162. M&A: Merger and Acquisition
163. MESI: Malaysian Energy Supply Industry
164. MENA: Middle East and North Africa region
165. MESTECC: Minister of Energy, Science, Technology, Environment and Climate Change
166. MDB: Multilateral development banks
167. MDM: Meter Data Management
168. MIDA: Malaysian Investment Development Authority
169. MIT: Massachusetts Institute of Technology
170. MMBTU: Million Metric British Thermal Units
171. MMT: Million Metric Tonnes
172. MMTPA: Million Metric Tonnes Per Annum
173. MNCAA: The Mayors National Climate Action Agenda
174. MoT: Ministry of Transport
175. MOEA: Ministry of Economic Affairs
176. MOIT: Ministry of Industry and Trade
177. MOU: Memorandum of Understanding
178. MSCI: Morgan Stanley Capital International
179. $MtCO_2$-e: Million Tonnes of Carbon Dioxide Equivalent
180. Mt: Million Tonnes
181. Mtoe: Million Tonnes of Oil Equivalent
182. MW: Megawatt
183. MWe: Mega Watt Electrical
184. MWp: Mega Watt Peak
185. MWh: Megawatt-hours
186. NAFTA: North American Free Trade Agreement
187. NCOS: National Carbon Offset Standard
188. NDC: Nationally Determined Contributions
189. NEA: National Environment Agency
190. NEA: Nuclear Energy Agency
191. NEB: National Energy Board
192. NECF: National Energy Customer Framework
193. NEPA: National Environmental Policy Act
194. NEM: Net Energy Metering
195. NEM: National Electricity Market
196. NEMEMF: National Electricity Market Emergency Management Forum
197. NEMS: National Energy Modeling System
198. NGERAC: National Gas Emergency Response Advisory Committee
199. NGV: Natural Gas Vehicle
200. NIA: National Irrigation Administration
201. NIC: Network Interface Card
202. NOL: Net Operating Loss
203. NREP: National Renewable Energy Program
204. NSP: Network Service Providers
205. NSPS: New Source Performance Standards
206. NSW: New South Wales
207. NT: Northern Territory
208. OCBC: Oversea-Chinese Banking Corporation
209. OECD: Organization for Economic Co-operation and Development
210. OEM: Open Electricity Market
211. PACE: Property Assessed Clean Energy
212. PAG: Providence Asset Group
213. PASA: Projected Assessment of System Adequacy
214. PDP: Power Development Plan
215. PHEV: Plug-in Hybrid Electric Vehicle
216. PHES: Pumped Heat Electrical Storage
217. PBR: Performance-Based Ratemaking
218. PEV: Plug-in Electric Vehicle
219. PJ: Petajoule
220. PNOC: Philippine National Oil Company
221. PPAs: Power Purchasing Agreements
222. PPP: Public Private Partnership
223. PSA: Power Supply Agreements
224. PV: Photovoltaic

225. PVN: PetroVietnam
226. QLD: Queensland
227. RAB: Regulated Asset Base
228. R&D: Research and Development
229. RE: Renewable Energy
230. REBA: Renewable Energy Buyers Alliance
231. REC: Renewable Energy Certificate
232. REDD+: Reduce Emissions from Deforestation and Forest Degradation
233. RGGI: Regional Greenhouse Gas Initiative
234. REJI: Renewable Energy (Jobs and Investment)
235. REP: Retail Electric Provider
236. REPPA: Renewable Energy Power Purchase Agreement
237. REPI: Retail Electricity Pricing Inquiry
238. RERT: Reliability and Emergency Reserve Trader
239. RES: Renewable Energy Sources
240. RETR: Renewable Energy Transition Roadmap
241. RET: Renewable Energy Target
242. RETF: Renewable Energy Trust Fund
243. REZ: Renewable Energy Zones
244. RIT-T: Regulatory Investment Test for Transmission
245. RPS: Renewable Portfolio Standards
246. RRO: Regional Reliability Organizations
247. RTO: Regional Transmission Organization
248. SA: Southern Australia
249. SAIDI: System Average Interruption Duration Index
250. SARE: Supply Agreement for Renewable Energy
251. SCA: Scheme of Control Agreement
252. SCADA: Supervisory Control and Data Acquisition
253. SCC: Social Cost of Carbon
254. SCEM: Singapore Certified Energy Manager
255. SEA: Southeast Asia
256. SGER: Specified Gas Emitters Regulation
257. SGIG: Smart Grid Investment Matching Grant
258. SLCP: Short-lived Climate Pollutants
259. SMOC: Streaming Media Online Charging System
260. SMR: Small Modular Reactors
261. SoC: Scheme of Control
262. SRES: Small-scale Renewable Energy Scheme
263. SSR: Summer Saver Rebate
264. S&P: Standard & Poor’s
265. TAITRA: Taiwan External Trade Development Council
266. TAS: Tasmania
267. TCF: Trillion cubic feet
268. TCI: Transportation and Climate Initiative
269. TNB: Tenaga Nasional Berhad
270. TNSP: Transmission Network Service Providers
271. ToU: Time-of-Use
272. TWh: Terawatt-hours
273. T&D: Transmission and Distribution
274. UNCED: United Nations’ Conference on Environment and Development
275. UNEP: United Nations Environment Programme
276. UNFCCC: United Nations Framework Convention on Climate Change
277. UOB: United Overseas Bank
278. USAID: United States Agency for International Development
279. US EIA: United States Energy Information Administration
280. USTDA: United States Trade and Development Agency
281. UTP: Uniform Tariff Policy
282. VES: Vehicular Emissions Scheme
283. VIC: Victoria
284. V-LEEP: Vietnam Low Emission Energy Program
285. VPP: Virtual Power Plant
286. VRE: Variable Renewable Electricity
287. VRET: Victorian Renewable Energy Target
288. VWEM: Vietnam Competitive Wholesale Electricity Market
289. WA: Western Australia
290. WESM: Wholesale Electricity Spot Market
291. WSD: Water Supplies Department
292. WTE: Waste-to-Energy
293. WTO: The World Trade Organization
294. WWII: World War II
295. YTD: Year to date
296. ZEV: Zero-Emission Vehicle

Country Abbreviations and Energy Authorities

Countries	Abbreviation	Regulators	Ministries or authorities for energy-related topics
Austria	AT	E-Control	Ministry of Agriculture, Forestry, Environment and Water Management: www.bmlfuw.gv.at/ Environment Agency: www.umweltbundesamt.at/ Competition Authority: http://www.bwb.gv.at/
Belgium	BE	CREG (national) BRUGEL (Brussels) CWAPE (Walloon) VREG (Flanders)	Ministry of Economic Affairs: http://economie.fgov.be/
Bulgaria	BG	DKER	Ministry of Economy and Energy: www.mi.government.bg/
Canada	CA	NEB	National Energy Board: www.neb-one.gc.ca Ministry of Energy: http://www.energy.gov.on.ca
Croatia	HR	HERA	Ministry of Economy, Labour and Entrepreneurship: www.mingo.hr/
Czech Republic	CZ	ERU	Ministry of Industry and Trade: www.mpo.cz/ Competition Office: www.compet.cz/
Denmark	DK	DERA NordREG	Energy Agency: www.ens.dk/ Ministry of Economic and Business Affairs: www.evm.dk/ Ministry of Environment: www.mim.dk/
Estonia	EE	ETI	Ministry of Economic Affairs: www.mkm.ee/ Competition Authority: www.konkurentsiamet.ee/
Finland	FI	EMV NordREG	Ministry of Employment and the Economy: www.tem.fi/ Ministry of Environment: www.ymparisto.fi/ Competition Authority: www.kilpailuvirasto.fi/
France	FR	CRE	Ministry of Ecology, Sustainable Development and Energy: www.developpement-durable.gouv.fr/
Germany	DE	BNetzA UNFCCC	Federal Environment Ministry: www.bmu.de/ Energy Agency: www.dena.de/ United Nations Framework Convention on Climate Change https://unfccc.int/ Competition Authority: www.bundeskartellamt.de/
Greece	GR	RAE	Ministry of Development: www.mindev.gov.gr/el/ Ministry of Environment, Energy and Climate Change: www.ypeka.gr/ Competition Commission: www.epant.gr/
Hungary	HU	MEH	Energy Office: www.mekh.hu/
Hong-Kong	HK	EMSD HKSAR	Electrical and Mechanical Services Department: www.emsd.gov.hk Hong Kong Special Administrative Region Environment Bureau: http://www.enb.gov.hk/en/
Ireland	IE	CER (Republic of Ireland)	Department of Communications, Energy & Natural Resources: www.dcenr.gov.ie/Energy/ NIAUR (Northern Ireland)
Italy	IT	AEEG	Ministry of Environment: www.minambiente.it/ Ministry of Economic Development: www.sviluppoeconomico.gov.it/ Competition Authority: www.agcm.it/
Latvia	LV	SRPK	Ministry of Economy: www.em.gov.lv/ Competition Council: www.kp.gov.lv/
Lithuania	LT	REGULA	Ministry of Economy: www.ukmin.lt/
Luxemburg	LU	ILR	Ministry of Economic Affairs: www.eco.public.lu/
Malaysia	MY	ST MESTECC MoT MESI	Energy Commission : www.st.gov.my Minister of Energy, Science, Technology, Environment and Climate Change https://www.mestecc.gov.my/web/en/ Ministry of Transport Malaysian Energy Supply Industry
Mexico	MX	SENER	Secretaría de Energía de México: www.gob.mx Comisión Federal de Electricidad: http://www.cfe.gob.mx
Netherlands	NL	DTe	Ministry of Economic Affairs: www.rijksoverheid.nl/ Energy Council: www.algemene-energieraad.nl/ Competition Authority: www.nmanet.nl/
Norway	NO	NVE NordREG	Oil and Energy Ministry: www.regjeringen.no/ Competition Authority: www.konkurransetilsynet.no/
Philippines	PH	ERC DILG ERC IEMOP DOE	Energy Regulatory Commission: www.erc.gov.ph Department of the Interior and Local Government https://www.dilg.gov.ph/ Energy Regulatory Commission https://www.erc.gov.ph/ Independent Electricity Market Operator of the Philippines http://www.iemop.ph/ Department of Energy https://www.doe.gov.ph/
Poland	PL	URE	Ministry of Economy: www.me.gov.pl
Portugal	PT	ERSE	Ministry of Economy: www.min-economia.pt/ Directorate General for Energy and Geology: www.dgeg.pt/
Romania	RO	ANRE	Ministry of Energy and Resources: www.minind.ro/
Singapore	SG	EMA HDB EDB	Energy Market Authority: www.ema.gov.sg Housing and Development Board https://www.hdb.gov.sg/cs/infoweb/homepage The Singapore Economic Development Board https://www.edb.gov.sg/
Slovakia	SK	URSO	Ministry of Economy: www.economy.gov.sk/ Ministry of Environment: www.enviro.sk/
Slovenia	SI	AGEN	Ministry of Infrastructure: www.mzip.gov.si/
Spain	ES	CNMC	Ministry of Industry, Energy and Tourism: www.minetur.gob.es/ Ministry of Agriculture, Fishing & Food: www.mapa.gob.es/ Ministry of Ecologic Transition: www.miteco.gob.es/
Sweden	SE	EI NordREG	Ministry of Energy: www.regeringen.se/ Competition Authority: www.kkv.se/
Switzerland	CH	BFE IPCC	Federal Department of Environment, Transport, Energy and Communications: www.uvek.admin.ch/ Intergovernmental Panel on Climate Change http://www.ipcc.ch/ Competition Authority: www.weko.admin.ch/

Countries	Abbreviation	Regulators	Ministries or authorities for energy-related topics
Taiwan	TW	BOE TAITRA MOEA	Bureau of Energy, Ministry of Economic Affairs: www.moeaboe.gov.tw Taiwan External Trade Development Council https://en.taitra.org.tw/ Ministry of Economic Affairs https://www.moea.gov.tw/Mns/english/home/English.aspx
United Kingdom	UK	OFGEM	Department of Energy and Climate Change: www.decc.gov.uk/ Competition Authority: www.gov.uk/government/organisations/competition-and-markets-authority
United States of America	USA	DoE EIA US Climate Alliance FERC	U.S. Department of Energy: https://www.energy.gov/ US Energy Information Administration: https://www.eia.gov/ https://www.usclimatealliance.org/ Federal Energy Regulatory Commission (FERC): https://www.ferc.gov/
Vietnam	VN	MOIT	Ministry of Industry and Trade: www.moit.gov.vn
Australia	AUS	ACCC AEMO AEMC AER APRA CSIRO COAG ARENA CER DEE	Australian Competition and Consumer Commission https://www.accc.gov.au/ Australian Energy Market Operator https://www.aemo.com.au/ Australian Energy Market Commission https://www.aemc.gov.au/ Australian Energy Regulator https://www.aer.gov.au/ Australian Prudential Regulation Authority https://www.apra.gov.au/ Commonwealth Scientific and Industrial Research Organisation https://www.csiro.au/ Council of Australian Governments Energy Council http://coagenergycouncil.gov.au/ Australian Renewable Energy Agency https://arena.gov.au/ Clean Energy Regulator http://www.cleanenergyregulator.gov.au/ Department of the Environment and Energy http://www.environment.gov.au/

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About VaasaETT

VaasaETT is a research and advisory consultancy guiding future-focused energy markets globally. We monitor and analyse energy markets, companies and consumers around the world to help our clients enter markets, develop offerings, models and policy, as well as identify future visions and take advantage of evolving opportunities and trends applying 20 years of unmatched global experience.

We help regulators make markets more competitive; retailers develop new models and offerings; network companies utilise the demand side; vendors become more relevant to the market; and large customers to get a better deal from competition.

More information at www.vaasaett.com

De Pardieu Brocas Maffei is one of France's leading independent business law firms and currently has 33 partners.

Founded in 1993, the Firm has become a key player in French business law and also has a highly regarded international practice. The firm's lawyers regularly advise on both domestic and international matters, and clients primarily include large French and overseas corporations.

In addition, the Firm works with an extensive network of referral law firms in the main financial centers in different parts of the world.

About Enerdata

Enerdata is an independent information and consulting firm specializing in global energy and carbon markets. The company has over 25 years of experience in economic issues related to midstream and downstream energy.

In addition to the global energy and carbon markets, Enerdata is specializing in detailed energy demand analysis, mid- to long term energy scenario building to assist governments, companies and stakeholders in their energy planning and development of energy and climate policies, as well as ad-hoc consulting services on all energy sources and sectors.

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About Capgemini

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