Research into renewable electricity systems

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Contact

Duncan Sinclair (Duncan.Sinclair@baringa.com +44 7887 500 856)

Matthew Grant (Matthew.Grant@baringa.com +44 7878 755 644)

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1 Purpose of the study

1.1 The National Infrastructure Commission

The National Infrastructure Commission (NIC) is the body responsible for providing independent analysis and advice to the Government to ensure the UK meets its long-term infrastructure needs. Its role is to support sustainable economic growth across all regions of the UK, improve competitiveness, and improve quality of life. In doing so, it aims to be the UK's most credible, forward-thinking and influential voice on infrastructure policy and strategy.

The NIC is set up to publish a National Infrastructure Assessment once in every Parliament setting out its assessment of long-term infrastructure needs, with recommendations to the Government – the first of which was published in July 2018.

The NIC also undertakes in-depth studies into the UK's most pressing infrastructure challenges and monitors the Government's progress in delivering infrastructure projects and programmes recommended by the Commission.

1.2 The scope of this study

The NIC commissioned Baringa to complete a study to explore how other countries and regions are addressing the challenges of integrating high levels of renewables into their electricity systems. The study is based on a set of case studies, with supporting evidence, to show progress, policy, market design and grid integration strategies. The primary aims of the study are to:

- Understand what progress comparable electricity systems to the UK have made in deploying renewables
- Synthesise evidence on how effective current policies and markets have been in deploying high levels of renewables to date
- Summarise how other regions/countries that have deployed high levels of renewables have integrated them effectively onto their electricity grids to help the NIC derive a set of insights relevant to the UK.

1.3 Structure of this document and supporting information

This document is a summary of Baringa's analysis, providing an overview of the key insights gathered during the engagement. The document structure is as follows:

- **Section 2**: Case study selection and overview
- **Section 3**: Market/region background
- **Section 4**: Key insights
- **Appendix A**: Case study reports

To support this summary, we provide a detailed set of system case study reports, one for each of the seven markets or regions included in the study. These system case studies provide the evidence base used to inform the key insights in this document. Each of the seven system case studies follows the following structure:

1 Executive Summary
- Market overview
- Key insights

2 Market overview
- Key market characteristics
- Power market structure
- Cross-border energy exchanges

3 Climate goals and subsidy mechanisms
- Energy and climate change objectives
- Renewable support schemes

4 Investment and route to market
- Capacity and generation
- Renewable routes to market

5 Grid Integration and system operation
- Transmission system operation
- System services
- Facilitating future renewable deployment

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2 Case study selection and overview

2.1 Baringa's approach

At the start of the study, Baringa and the NIC decided on the set of seven markets or regions to consider. We decided on these case studies following a selection process taking into account:

- Each region's progress in deploying renewables
- The maturity of renewable policy development and frameworks for investment
- Progress in deploying technologies and mechanisms to integrate intermittent renewables effectively
- Comparable grid implementation challenges

These are all issues that are pertinent to the UK and its current renewable growth and ambition.

Our study approach relied upon a range of information sources and data, which we have built up over a number of years of research and analysis in these markets. These included public information sources, relevant for each market, including:

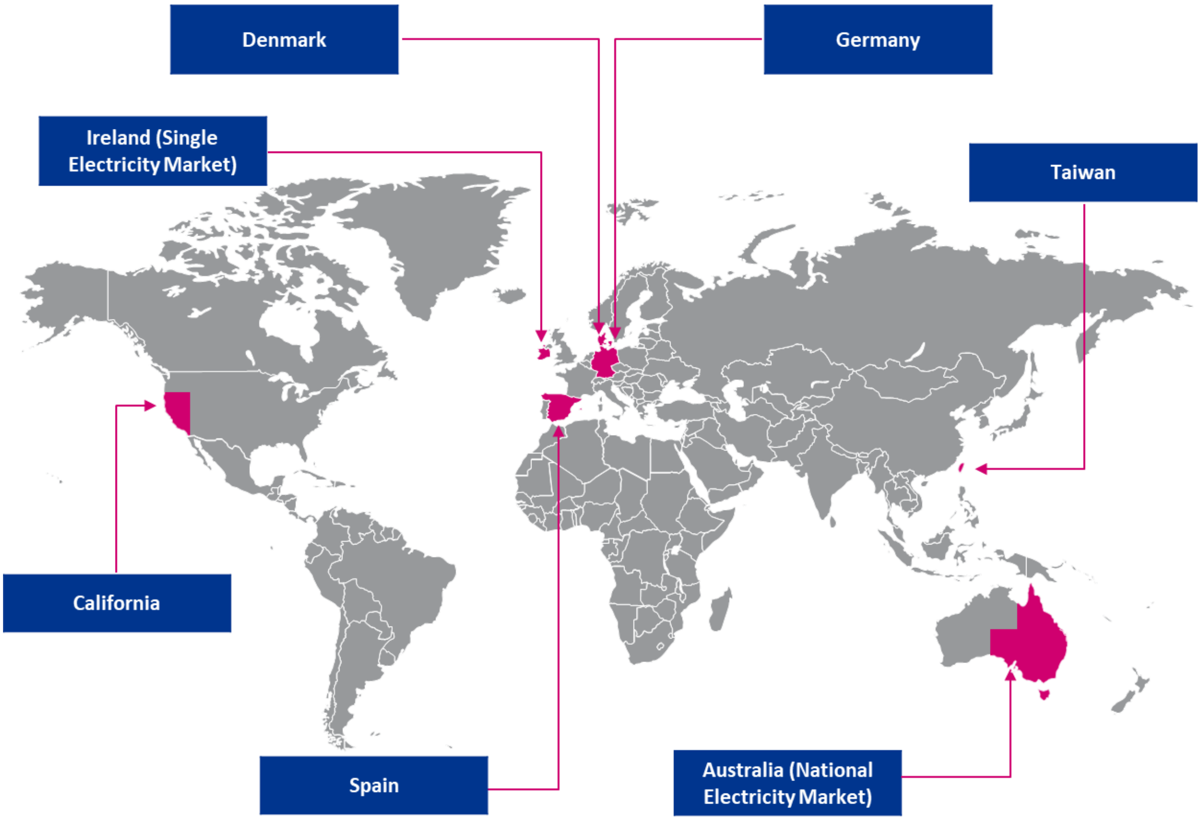
- Governments and National Regulatory Authorities
- Regional and international energy agencies
- National Transmission System Operators and Independent System Operators
- Regional network organisations (such the European Network of Transmission System Operators, ENTSO-E, in Europe)
- Regional media outlets (example reports on company level investment plans or financial decisions)
- Trade journals and news reports

We reference relevant information sources throughout the case study reports.

2.2 Case study markets/regions

Figure 1 shows the seven case study markets and regions we included in the study.

Figure 1 Overview of markets/regions included in the case study report



2.3 Comparative statistics

To understand the ambition and progress in deploying renewables in each market or region, it is important to understand the market itself, the current level of progress and the market fundamentals. We refer to this market or region information in the detailed case study reports and provide a summary in Table 1.

These comparative statistics help show, in a simple way, the difference in market dynamics and renewable deployment across the markets included in the study.

Table 1 Comparative statistics[1]

		Ireland	Germany	Denmark	Spain	Australia	California	Taiwan
Renewable electricity targets	2030	70%	50%	100%	70%	50%	60%	25%
Annual demand	TWh	40	490	35	250	192	184	264
Peak demand	GW	7	87	8	41	36	44	37
Installed capacity	GW	14	220	16	107	56	76	56
Renewable generation	TWh	16	230	31	96	47	85	15
Main renewable technology	Tech	Onshore wind	Onshore wind	Onshore wind	Onshore wind	Onshore wind	Solar	Hydro
Renewables as share of total generation	%	39%	45%	75%	39%	23%	44%	4%
Carbon intensity	gCO2/kWh	393	419	148	304	717	202	509
Cross-border capacity	GW	1	20	7	7	0	15	0
Wholesale electricity price	€/MWh	50	38	35	48	37-50	32	52

[1] **Notes**:
- **Annual and peak demand:** 2019 Baringa analysis, EirGrid and Danish Energy Agency for Europe, OpenNEM, CAISO and Taiwan Bureau of Energy
- **Renewable generation:** 2019 SEAI, ENTSO-E plus Baringa analysis, EIA, Open NEM and Taiwan Bureau of Energy
- **Renewable share**: Calculated as renewable generation / total generation 2019 (2018 for California)
- **Installed capacity:** 2019 data from ENTSO-E, plus Baringa analysis, 2018 EIA, and 2019 AEMO and Taiwan Bureau of Energy
- **Carbon intensity:** 2017 data from European Environment Agency, 2018 data for Australia Climate Transparency, 2019 data for California from CAISO and 2019 data for Taiwan from Taiwan Bureau of Energy
- **Cross-border capacity:** 2020 ENTSO-E plus various TSO website
- **Wholesale prices:** 2019 and 2020 Baringa analysis, CAISO 2019

3 Market/region background

This section of the report provides a high-level summary of the market fundamentals of each market or region in the study.

3.1 Ireland

The All-island market in Ireland, including the electricity system of the Republic of Ireland and Northern Ireland, is a small market compared to Great Britain with peak demand of approximately 7 GW and total installed capacity of around approximately 14 GW (compared to peak demand of 58 GW in GB and total installed capacity of over 100 GW). The capacity mix consists of 40% renewables (wind, solar, biomass and hydro), with approximately 40% of domestic generation coming from renewables. The Republic of Ireland will phase out coal by the end of 2025 with gas being the primary thermal technology.

Ireland is experiencing increasing deployment of small-scale flexible capacity (e.g. gas engines, batteries) to support the system services needed to accommodate significant renewable deployment.

The Irish government has set an ambitious binding target for 70% electricity from renewables by 2030, and has published its Climate Action Plan setting out an ambition to reach net-zero carbon emissions by 2050. In Northern Ireland, the UK's net-zero binding target for 2050 applies but there is currently no Northern Ireland-specific renewable policy in place to support this.

The All-island market experienced average annual wholesale price of €50/MWh in 2019, decreasing from €64MWh in 2018 (real 2020 prices). Prices have been relatively volatile over the last few years with the rise in prices in 2018 mainly driven by higher gas and carbon prices, followed by lower gas prices throughout 2019 leading to a significant drop in average annual prices.

3.2 Germany

Germany is a large central-European power market with a number of cross-border interconnectors, resulting in high imports and exports to neighbouring markets. Peak demand in Germany is close to 87 GW with installed capacity of over 200 GW. In 2020, over 45% of installed capacity is wind and solar, and approximately 32% of generation came from wind and solar in 2019. The highest increase in capacity between 2018 and 2019 was from investment in wind energy (both onshore and offshore) reflecting the renewable focus in Germany.

Nuclear exit in Germany will be completed in 2022, and over 10 GW of coal capacity will be closed between now and 2025. There are plans for an accelerated exit from coal-based generation by 2038. This is expected to put upward pressure on wholesale prices.

Germany continues to implement the 'Energiewende' – the planned transition to a low carbon, reliable energy supply. Germany is reported to be on track to achieve its 2020 renewable electricity target of 35%.

In 2019, wholesale power prices in Germany fell to €38/MWh from €45/MWh in 2018. Nuclear phase-out and coal closures will put upward pressure on prices. However, continued wind and solar deployment is likely to offset this price increase, but both price volatility, and the need for flexibility, are set to increase.

3.3 Denmark

Denmark's market and network is split in two – East Denmark and West Denmark. In total, peak demand is approximately 8 GW with total installed capacity of approximately 16 GW.

Denmark has a strong history of renewable investment dating back to the 1980s, as the country looked to renewables in response to the economic difficulties driven by the oil crises of the 1970s. Consequently, Denmark is a well-developed market for renewable investment and policy design, particularly in wind – where Denmark is a world leader. In 2018, Denmark committed to source 100% of Denmark's electricity consumption from renewables by 2030, mandating the creation of three offshore wind farms (2.4 GW in total) by 2030.

Denmark's wholesale electricity prices are around €35/MWh, comparatively low in Europe driven by high penetration of low variable cost renewables. However, Danish households pay one of the highest electricity prices in the EU, mainly due to a very high level of energy taxes and levies to support the large renewable sector.

3.4 Spain

Spain is a large market with peak demand of approximately 41 GW and installed capacity of 107 GW. The Spanish electricity system is one of the most diversified by energy source among the European Member States with a capacity mix strongly influenced by gas (31%) but with high renewable penetration (50%), in particular onshore wind (23%).

Spain built up a significant cumulative tariff deficit over the years leading up to 2013 where the total cost of running the system exceeded the approved rates and tariffs that generators, suppliers and network companies could charge customers. The government addressed this through a series of reforms in 2012-2013 introducing a tax on generation, a tax on fossil fuels and retrospective change to the feed-in tariff scheme, among other measures.

Support payments for renewables declined after the market reform. Whilst support schemes have been re-introduced, the emergence of merchant renewables, without regulated support, has marked the beginning of a new era in the market.

The average day-ahead wholesale market price in 2019 was €48/MWh, down from €58/MWh in 2018. The reduction of €10/MWh between 2018 and 2019 was mainly because of lower natural gas prices.

3.5 Australia

Peak demand in Australia's National Electricity Market (NEM)[2] is approximately 36 GW, which occurs in summer for all regions except Tasmania. Total installed capacity is 67 GW, of which around one quarter of capacity is behind the meter (from rooftop solar PV), giving total network connected capacity of around 56 GW. Coal (67%) dominates the generation mix, with the remaining 33% is made up of gas (8%), large-scale renewables (19%), rooftop solar (6%) and other (<1%).

Under the Paris Treaty, the Australian Government has committed to reduce CO_2 emissions by 26-28% on 2005 levels by 2030. Australia expects to meet its 2020 renewable target of 33 TWh, mainly from existing and committed projects. Emissions policy remains a highly contentious political issue, and is likely to remain so for some time.

Historically, annual average wholesale prices have been in the range $40-60/MWh (€25-40/MWh), driven by low domestic coal and gas prices and some over-supply since 2008. This changed in 2016-17 however, with prices increasing to around $100/MWh (over €60/MWh) on average, as the system moved rapidly from over-supply to a period of scarcity resulting from some coal plant closures.

3.6 California

Renewable energy policy dominates Californian energy policy. California has championed the development of renewable power in the US with ambitious renewable targets: 44% renewable generation by 2024, 60% by 2030 and 100% by 2045. Peak demand in California is 44 GW with total installed capacity of over 70 GW.

There has been significant progress made towards these targets over the past five years. Solar installed capacity has grown from 1 GW in 2012 to 12 GW in 2018. Wind installed capacity saw more modest growth, but still increased from 4 GW in 2012 to 6 GW in 2018 and demand response growing from close to zero to almost 4 GW in 2019. Over the same period, nuclear capacity fell from over 4 GW to just over 2 GW and gas capacity fell from around 35 GW to 30 GW.

In California, market prices averaged €32/MWh in 2019. Wholesale prices fell slightly, on average, in 2019 because of a decrease in gas prices and moderate market conditions. California is seeing increasing instances of negative prices due to high levels of subsidised renewables.

3.7 Taiwan

Peak electricity demand in Taiwan is approximately 37 GW with total installed capacity of 55 GW. Gas, from LNG, and coal-fired generation dominates the generation mix in Taiwan.

Taiwan is heavily dependent on imports for its energy supply and almost all of its gas and coal is imported. Following the Fukushima disaster in Japan, Taiwan committed to closing its 5 GW nuclear fleet by 2025. Taiwan is progressing in its planned electricity market reform, including market

[2] The five physically connected regions on the east coast of Australia, including Queensland, New South Wales, Victoria, Tasmania and South Australia.

liberalisation, and a shift towards a generation mix with significant renewable energy and gas-fired generation.

In Taiwan, the price of electricity is approximately €52/MWh.

4 Key insights

This section of the report summarises our view on the key insights from across the case studies. These insights show how each market or region has developed policy, incentives, network design and innovation to meet the needs of their system. Central to all the insights is the drive for renewable deployment at scale to meet short-, and long-term decarbonisation targets.

Figure 2 Key insights

Insight 1	**Clear and stable renewable** policy has provided the right conditions for investment and the move to competitive auctions has successfully driven cost reductions
Insight 2	**System services** are a fundamental requirement for renewable integration and clear signals, dynamic markets, and an environment that promotes **innovation** have supported a transition away from traditional service providers
Insight 3	**Cross-border connections** and **coordination** have been valuable tools in renewable integration, reducing the need for other domestic flexibility options
Insight 4	**Integrated system planning** and **innovative asset development** are helping to unlock greater levels of renewables

4.1 Insight 1: Clear and stable renewable policy has provided the right conditions for investment and the move to competitive auctions has successfully driven cost reductions

Clear and stable policy direction, along with economic incentives for renewables, have provided the right conditions for investment. Across most of the case studies, we see that renewable policy initially focused on incentivising early stage investment through Feed-in-Tariff style support. However, as markets developed, policy makers have shifted focus to reduce the cost of future subsidies by introducing competitive allocation frameworks, for example through Contracts for Difference (CfDs) auctions.

In this section, we spotlight the renewable policy progression in Ireland and California to evidence this insight. We see how clear and stable policy can help policy makers to speed up the deployment of renewables with significant growth in a short period. We compare this to Australia where a lack of coordinated policy has slowed growth in renewables deployment to date, and Spain, where policy change and retrospective action caused a plateau in renewable investment.

Ireland

Ireland's success is clear from the investment in onshore wind capacity over the last 20 years, increasing from close to zero installed capacity in 2000 to approximately 5 GW by 2020. High-level renewable policy direction in the Republic of Ireland has been clear since the Irish Government introduced its Feed-in-Tariff scheme in 2006, the Renewable Energy Feed-in-Tariff (REFIT). The Feed-in-Tariff provided a minimum price per unit of electricity exported to the grid over a 15-year period.

The Feed-in-Tariff provided stability and certainty for investors. The sustained investment under the Feed-in-Tariff scheme provided the basis for a strong renewables industry to develop in Ireland. Ireland quickly developed a strong renewable development industry, from planning advisors and consultants through to the powerful trade associations (such as the Irish Wind Energy Association, IWEA). This industry support complemented the top-down direction from Government to further back renewable projects, unlocking further growth.

In 2020, the Renewable Electricity Support Scheme (RESS) replaced the Feed-in-Tariff in the Republic of Ireland. The new renewable support scheme is a competitive, auction-based mechanism that provides a guaranteed price for each MWh of electricity generated through a Contract-for-Difference. The scheme provides support for 15 years with the first auction completed in 2020.

This trend continues with the 2020 target of generating 40% of electricity from renewables at the front and centre of Irish energy policy for the last decade. Ireland has made firm commitments post-2020 with a clear 2050 Net Zero ambition and an interim target to generate 70% of electricity from renewable sources by 2030 (referred to across the industry in Ireland as '70% by 30').

Although stable renewable policy is a key factor in Ireland's success, the generosity of the Feed-in-Tariff scheme, in terms of financial incentives for investment has also been a key driver of success. The Feed-in-Tariff, with contracts agreed for 15 years, has come at a cost to Irish consumers. The cost of renewable support under the Feed-in-Tariff scheme increased ten-fold between 2011 and 2017 to over €300m per year, with the annual customer cost of renewable support peaking at approximately €60/year in 2017-18.[3] Compared to other markets, Ireland has been relatively late in implementing competitive auctions for renewables. The introduction of the auction-based competition mechanism will improve competitiveness and should reduce the cost of support for the next generation of renewables in Ireland.

California

Consistent renewable policy is also a core theme of the Californian electricity market with renewables high on the policy agenda for the last two decades. In 2002, California introduced the Renewable Portfolio Standard, which sets the level of demand that suppliers need to meet from renewables. This has been a consistent driver of renewable investment. The Renewable Portfolio Standard requirements have increased over time as policy makers have targeted higher levels of deployment – starting at 20% renewable generation by 2020, based on the 2002 target, and increasing to a current target of 33% set as part of a 2011 target update. The recent California Senate Bill 100 has introduced

[3] Baringa approximation based on data published by the Irish regulatory authority, CRU, available here.

even more stretching objectives for California. This bill mandates that utilities source 60% of power needs from renewables by 2030, with this increasing to 100% by 2045.

Part of California's renewable success has come from a clear focus on a single technology, solar PV. California's solar resources, combined with state funded investment (such as the California Solar Initiative), has led to huge investment in distributed solar capacity in California. By the end of 2018, California had installed over 7 GW of solar capacity at over 835,000 customer sites – a demonstration of the link between clear policy and the potential speed of deployment. California's focus on a single technology shows how targeted incentives, along with clear policy direction, can deliver investment and lower future costs. Since California introduced its solar initiative in 2007, the cost of installation has fallen by 50-60%.

Australia

The Australian National Electricity Market provides an example of a market where the lack of coordinated renewable policy, along with complex governance arrangements, appears to have hampered large-scale renewable progress to date. In the absence of a federal level carbon price or renewable policy a complex array of state-level subsidies and policies have developed.

The divergence in renewable direction in Australia even exists between the regulators, policy makers and the system operator. The Policy and Rule Making Body and the Competition Regulator prefer a market-led route to renewable investment. In contrast, the market and system operator and the independent government policy advisory board favour top-down central coordination for generation and transmission.

This lack of clear ambition and route to decarbonisation has led to the reduction of the 2020 renewable target from 41 TWh set in 2015 to the current 2020 target of 33 TWh (~23% of forecast demand). Australia has seen some renewable investment success, in the form of small-scale, behind-the-meter rooftop-solar. Small-scale rooftop solar accounts for around 15-20 GW of the total installed capacity (around 6% of total generation), driven by subsidies through feed-in-tariffs. Whilst Australia has seen some renewable investment over the past decade, policy uncertainty has been a key barrier to the speed of large-scale deployment to date.

Spain

Renewable policy in Spain has been through a period of 'boom and bust' with a period of clear signals and fast renewable deployment followed by government action to reduce the cost of renewable support by retrospectively cutting subsidies. Unsurprisingly, this created an investment hiatus following a period of sustained growth in deployment of renewable generation.

The Spanish government took this action due to the tariff deficit. Since 2005, the Spanish electricity sector has been running at a significant deficit, as the costs of the system were not fully reflected in the charges that market players were allowed to recover from network users and consumers. This deficit arose when the regulated costs – the costs of transmission and distribution networks, support for renewable generators, capacity payments, levels of interruption and the payment of the accumulated debt – exceeded the regulated price for electricity (i.e. income from electricity charges, fees and taxes). This deficit did not fall to any one party but was a cumulative impact of a mismatch between revenue recovery and costs across different parties in the electricity sector, for example suppliers and network companies not able to cover costs from the revenue earned from capped, regulated tariffs.[4] As the cumulative debt of the electricity sector reached around €29bn in 2012-2013, the Spanish Government intervened to manage the debt directly, and reform the sector. Several taxes were introduced, and a retrospective reform of the Feed-In-Tariff scheme was imposed that significantly reduced support payments for renewable power generators.

The cut to tariff arrangements for existing generators led to a wave of litigation processes (mainly in international courts) against the Spanish Government that are still ongoing today.

The lack of stable and reliable subsidy schemes in Spain has put a halt on significant further development of large-scale renewables. This policy uncertainty has, however, led to a competitive project development market for smaller scale renewables as speculative, merchant project developers take advantage of low barriers to project development and network connection. For example, the current procedure for obtaining access to the network is based on a first-come-first-served approach with few pre-requisites, and, until recently, small financial guarantees to secure the permits.

Whilst the lack of a stable regulatory regime has put a halt to large-scale investment in Spain, it has meant that project developers have focussed on small-scale renewable development, leading to a long pipeline of projects.[5] As Spain embarks on a new subsidy scheme, with a five-year auction plan announced in November this year, it will be interesting to see whether this slows recent growth in merchant renewables. If we start to see renewables reaching grid parity in Spain, and support schemes clearing prices below the market, developers will look for revenue certainty from elsewhere. Medium- to long-term certainty is critical for investment and will be a key requirement of future renewable growth in Spain, whether subsidised or not.

4.2 **Insight 2:** System services are a fundamental requirement for renewable integration and clear signals, dynamic markets, and an environment that promotes innovation have supported a transition away from traditional service providers

All developed electricity systems rely on system services to manage real time supply and demand and to ensure system stability and security. System services are particularly important for energy systems with high levels of renewable penetration, providing a critical tool for system operators to manage intermittent renewables and their impact on the system. Whilst the precise details and terminology for system services differ between markets, service offerings typically provide a range of response products based on response time (i.e. within 10 seconds) and duration (from 20 seconds to a number of hours).

[4] In 2013, the Spanish Government took on this debt on behalf of the industry and recovers this cost directly through consumers bills, see FADE Fund or more details, here

[5] Note however only a small number of projects have reached maturity and are still in the development phase.

The case studies show how system services markets have developed to meet both the system needs, and the policy objectives, in each market/region. We also see how the needs of the system change with the level of renewable deployment, the type of technology deployed, and the reduction in legacy thermal system service providers. It is clear, from markets where the speed of renewable deployment is a core objective, that tailored and adaptable system services are critical to manage the cost to operating the system, and ultimately the cost to consumers.

In this section, we summarise the development of system services in Ireland and Germany and explore the ways that California has developed a market for Distributed Energy Resources to manage the impact of solar on the system.

Ireland

Ireland provides a good case study of how a centralised system services programme can help to unlock renewable investment. The system operator developed the centralised system services programme in Ireland – *DS3: Delivering a secure, sustainable electricity system* – to put the tools in place to support the realisation of 75% system non-synchronous penetration (SNSP) in Ireland by 2020.[6] This level of non-synchronous penetration, predominantly from wind, in a small system (with total demand approximately 7 GW in 2019) with low levels of interconnection, places significant pressure on the system. The volume of wind deployment in Ireland to date, and the future ambition means that the Irish system operator, EirGrid, is quite advanced compared to other system operators in its ability to manage the system with high levels of wind penetration.

A key decision for the market design for system services in Ireland was to put all 14 system services in a single regime, under a single contracting framework. These services range from voltage control and response through to reserve and ramping products. This 'one-stop-shop' for system services enables coordination between services and facilitates access for market participants by removing administrative barriers to entry. This compares to other markets where the system operator typically contracts system services bilaterally with market participants across a range of products and timeframes.

The success of the system services procurement is central to Ireland's renewable progress. In a small system with low levels of interconnection, unlike other central European markets, Ireland cannot rely heavily on cross-border exchanges to support system integration. Domestic system services are therefore critical for renewable deployment.

Germany

Facilitating market access for system services is a common theme across case studies as system operators and policy makers seek more efficient ways of managing renewable system integration. Germany has liquid ancillary services markets but, unlike Ireland, has a highly interconnected market with market and ancillary services shared cross-border.

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[6] '*SNSP is a measure of the non-synchronous generation on the system at an instant in time. It is the ratio of the real-time MW contribution from non-synchronous generation and net HVDC* [High Voltage Direct Current interconnector] *imports to demand plus net HVDC exports*' – EirGrid, here.

The German ancillary services market provides an interesting counterpoint to many other markets in Europe as demand for ancillary services has fallen at the same time as high levels of renewable growth. Technical improvements in supply and demand forecasting provides the system operators (there are four in Germany) with better system management information and has actually reduced demand for system services in recent years (notably secondary and minute reserve[7]). Alongside better information, the move to 15-minute settlement and an increase in activity in the intraday market (trading close to real time, on the day of delivery) allows responsible parties to trade out their positions more effectively, reducing the need for system balancing and system management actions.

As a result of the fall in demand for system services and a German policy direction to increase competition in reserve markets, revenues earned by reserve providers have fallen in recent years. This is a clear example of how innovation in market and service design, including through simple measures to increase competition, can help to reduce the cost of integrating renewables and the cost to consumers. Germany continues to increase competition and look for opportunities to extend the reserve markets to smaller market participants by reducing minimum bid sizes (from 5 MW to 1 MW for example for secondary and minute reserve), introducing shorter delivery periods/blocks and a proposed move to pay-as-clear auctions.

California

Whilst renewable investment is a clear success story for California, a significant volume of a single technology on the system does present system operability challenges. The level of solar penetration in California has had a significant impact on the daily generation profile. A particular phenomenon has developed in California known as the 'duck curve' – characterised by oversupply in spring midday periods, followed by a steep ramp up in the evening peak as solar output falls at the same time as evening demand increases.

The specific impact of solar penetration in California led to a policy focus to increase the role of demand response to help manage oversupply.[8] In particular, California has focussed on specific incentives for distributed resources, including demand response, and the role of non-wires alternatives (i.e. deferring traditional investment in distribution capacity through using distributed resources).

The Californian state regulator's 2017 distributed resources plan sets out a framework to make utilities neutral to distributed resources or traditional investment in new capacity. The framework allows utilities to benefit from ownership of distributed resources, and allows these resources to "stack revenues" by participating in wholesale markets (including ancillary services) and providing local grid services. Dedicated plans – 'Distributed Resource Plans' – prepared by public utilities (i.e. the network owners) help identify upgrades needed to support more renewables on the distribution grid. California introduced a formal mechanism for utilities to invite bids to provide distributed resources in certain locations in order to defer network investment (formally, this mechanism is the Distribution

[7] Secondary reserve of Automatic Frequency Restoration Reserves is a market-based service, with the system operator accepting bids to manage real-time power imbalances for delivery with 30 seconds. Minute reserve or Manual Frequency Restoration Reserves activated manually by the system operators for situation where the imbalance is as a result of large-scale outage or is likely to last for a long time.

[8] California also introduced specific ramping products to help manage the impact of the ramping requirements – we provide further detail on these products in the case study report.

Investment Deferral Framework). This places a requirement on the utilities to run the process to find alternatives to conventional network investment and reinforcement.

The Californian state regulator also adopted a specific incentive framework for utilities to contract with distributed resources as part of pilot projects to defer traditional capex-led solutions. The framework provides a 4% pre-tax incentive applied to payments to distributed resources (the "DER adder"), allowing utilities to earn a return on operational expenditure (opex) based alternatives. This helps to remove the incentives for network-based solutions in California, reducing costs for consumers by looking for the most cost effective solution to system needs. This is an example of how innovation in network design and system solutions, whether distributed resources or conventional system services, can be designed to reduce system and network costs to the benefit of consumers.

4.3 **Insight 3:** Cross-border connections and coordination have been valuable tools in renewable integration, reducing the need for other domestic flexibility options

Cross-border market access and coordinated cross-border markets provide system operators with valuable tools to help manage renewable integration. Cross-border balancing and the sharing of system services is a core theme across central European markets in Denmark, Germany and Spain, along with California, reflecting their high levels of interconnectivity with neighbouring markets. Whilst interconnection has historically been developed to manage wholesale power flows between markets and support energy balancing, interconnectors are being used increasingly to provide flexibility and system services in timeframes that support increasing levels of renewables.

Denmark

Denmark's significant levels of interconnection, within the Nordic markets of Norway and Sweden and central Europe, provides it with flexibility to manage the variability of domestic wind output and the challenges associated with managing the seasonality of renewables on the system.[9] Denmark's electricity trade profile has a strong seasonal component. During the winter, Denmark exports surplus domestic wind power. For the rest of the year Denmark typically imports electricity from Norway and Sweden who produce larger quantities than they can consume during summer months when hydro availability it at its peak.

Accommodating renewables across a larger market area reduces the actions that need to be taken domestically, reducing curtailment and maximising renewable output. This is because a large system is inherently more stable due to greater system inertia and because it provides access to a broader mix of generation sources. Denmark's cross-border market access has provided the system flexibility to enable a fast deployment of renewables without significant re-design of system services. This is a different experience to Ireland, a similar sized market, where the lack of cross-border alternatives required a step-change in the approach to domestic system services.

[9] Denmark's connection to the Nordics, and between East and West Denmark, use Voltage Source Converter technology as part of High-Voltage Direct Current interconnectors. This technology choice maximises the system services that interconnector can provide as the system operator can control the interconnector output.

Germany

In Germany, the system operators also take a coordinated approach to domestic and cross-border system operation to help maximise renewable output and minimise system costs. The four system operators coordinate system operation firstly at a national level with balancing taking place in a coordinated way across the four areas. The Germany system operators also take part in a coordinated cooperation process – International Grid Control Cooperation – that involves offsetting electricity imbalances between European system operators before balancing actions are taken in the market. The process, combining system operators from Denmark, the Netherlands, Switzerland, the Czech Republic, Belgium, Austria and France, makes use of available cross-border capacity remaining after intra-day trading, and reducing reliance on other national reserves.

California

Like Germany, in California, the system operator, the Californian Independent System Operator, also looks outside its state boundary to help manage the intermittency of vast solar penetration in California and to help the state to meet its ambitious renewable targets.

The Californian system operator launched the cross-state imbalance market in 2014 - the Western Energy Imbalance Market. This brings together system operators and network companies from across states and markets. The cross-border market now includes 11 participants across eight states. This cross-state approach avoids renewables curtailment and increases system balancing integration, by opening the Californian real-time balancing markets to entities outside of its system operation territory. This policy helps the Californian system operator and its neighbours accommodate renewables by reducing curtailment, increasing peak capacity, and ultimately reducing carbon emissions.

Maximising the efficient use of resources in this way has the joint benefit of unlocking more options to maintain system reliability, whilst also minimising system costs for consumers. The Californian system operator reports that the cross-state imbalance market has provided cost savings in the region of $1bn since 2014, because of reduced curtailment and lower overall costs of system operation.

The cross-state balancing market also offers the Californian system operator a mechanism to help manage the net load profile in California (see the description of the California ‘Duck Curve’). The system operator has developed within-state solutions to manage its load profile and ramping requirements, such as policy support for decentralised demand response. Whilst these within-state solutions help to manage periods of oversupply, the expansion of the cross-state balancing market offers an alternative solution. This expanded real-time market allows grid operators to find and move energy across a larger geographic area. Critically, for solar output management, this allows system operators to move power across different time zones to manage lumpy daily profiles.

Looking forward, the Californian system operator is also exploring the potential for full regional markets (i.e. expanding the system for all market timeframes, not just the balancing cross-state market). Consistent with European studies on the value of cross-border interconnection, the system operator studies show that greater levels of market integration can deliver significant consumer electricity cost reductions, greenhouse gas emissions reductions and macroeconomic benefits (specifically job creation).

4.4 **Insight 4:** Integrated system planning and innovative asset development are helping to unlock greater levels of renewables

Integrated system planning (combining planning decisions for networks and generation) can help to speed up renewable deployment through coordinated decision-making. In Australia, we see how integrated system planning can help to develop renewable generation and network expansion on a zonal basis. The network-led approach to Renewable Energy Zones should help to speed up renewable deployment by reducing the barriers and delays to investment within the zones themselves. In theory, this approach should also reduce costs to consumers by coordinating renewable connections and reducing the overall infrastructure requirement.

In Europe, generation and network planning are not coordinated in the same way. We have seen, however, some innovative asset specific coordination in the form of hybrid assets that help to increase renewable deployment whilst also offering a solution that addresses the need for market flexibility.

Australia

In Australia, whole system and integrated system planning for both generation and transmission provides an innovative planning framework to facilitate renewable investment. One of the key recommendations from the 2017 Finkel Review[10] was for the system and market operator to develop an Integrated System Plan to explore the least cost development of transmission alongside the strongest renewable resources.

The market and system operator released its first system plan in mid-July 2018, which introduced 33 Renewable Energy Zones, of high quality renewable projects across the Australian NEM. These Renewable Energy Zones are areas where clusters of high quality renewable projects could be delivered, along with system security services and storage, and transmission. As part of the planning process the market and system operator then undertakes long-term integrated system modelling to optimise the transmission and generation build-out in the long-term to minimise costs to consumers whilst maintaining system stability.

This new system wide approach to system planning led to the recommendation that Australian network companies focus their medium-term network development around enabling the Renewable Energy Zones.

The market and system operator's transmission planning role has historically been one of guidance and non-mandatory recommendations to network companies. This is changing. Recently, the authorities have released draft rules that force network companies to incorporate the Integrated System Plan, and Renewable Energy Zone planning, into existing national plans. Whilst this is not a universally popular move, as it takes some network planning responsibility out of the hands of the network companies, it is a significant step change in renewable integration in Australia. It puts in place

[10] According to the Australia Government, the Finkel review was '*the Blueprint for the Future Security of the National Electricity Market delivers a plan to maintain security and reliability in the National Electricity Market in light of the significant transition underway, including due to rapid technological change*', available here.

a coordinated top-down approach to the planning and development of the grid, to accommodate significant levels of renewables.

Germany and Denmark

In Europe, policy makers, regulators and network companies are also looking for ways to better plan and deliver the combined energy goals of increased market integration; trade and flexibility; renewable integration; and decarbonisation.

A specific example of these objectives working together is through innovative hybrid, or multi-purpose transmission and generation projects. These combined infrastructure assets typically combine cross-border infrastructure and offshore wind. This type of solution provides greater access to high yield offshore renewable resource and makes use of network redundancy to provide cross-border market access (beneficial for trade and helping to maintain system stability through cross-border system services). There is also the potential for infrastructure cost savings. As the cost of network investment in Europe is typically socialised, the cost savings from coordinating infrastructure could also help to reduce network costs for consumers.

The Kriegers-Flak hybrid project between Germany and Denmark is a recent multi-purpose success story. The project, developed by the German and Danish system operators (Energinet and 50Hertz), will connect two operational wind farms in Germany (Baltic 1 and 2 with a total capacity of 236MW) with the Danish Kriegers-Flak wind farm (600MW), currently under construction, via a sub-sea cable with a capacity of 400 MW.

Scheduled to start operations later this year, the project will connect the Danish and German markets via a sophisticated combination of transformers to manage the different frequencies of the Danish (Nordic) and Germany networks.

Whilst the project is considered a success, it has faced a number of challenges, mainly relating to the lack of clear regulatory arrangements for coordinated infrastructure in Europe. The project provides a possible framework to unlock greater renewable and cross-border value on a number of other European borders. There are a number of other projects and initiatives in Europe looking to develop coordinated solutions in the North Sea. Some of these projects, such as the hub-and-spoke system, developed by the North Sea Wind Power Hub[11], goes further to integrate power and hydrogen systems in the North Sea. Kriegers-Flak shows how policy makers and investors can overcome regulatory and legal barriers through innovation and regulatory coordination, combined with political support and top-down commitment.Case study reports

[11] The North Sea Wind Power Hub is a consortium of European electricity and gas system operators, Energinet, TenneT and Gasuine, and the Port of Rotterdam, more information here.

Appendix A

This pack provides the detailed case studies to support the main report: Research into renewable electricity systems

National Infrastructure Commission

November 2020

Contents

This contents navigation page allows the user to move through the Appendix by case study or by topic area by clicking on the relevant section of the report

All-island electricity market in Ireland

National Infrastructure Commission

November 2020

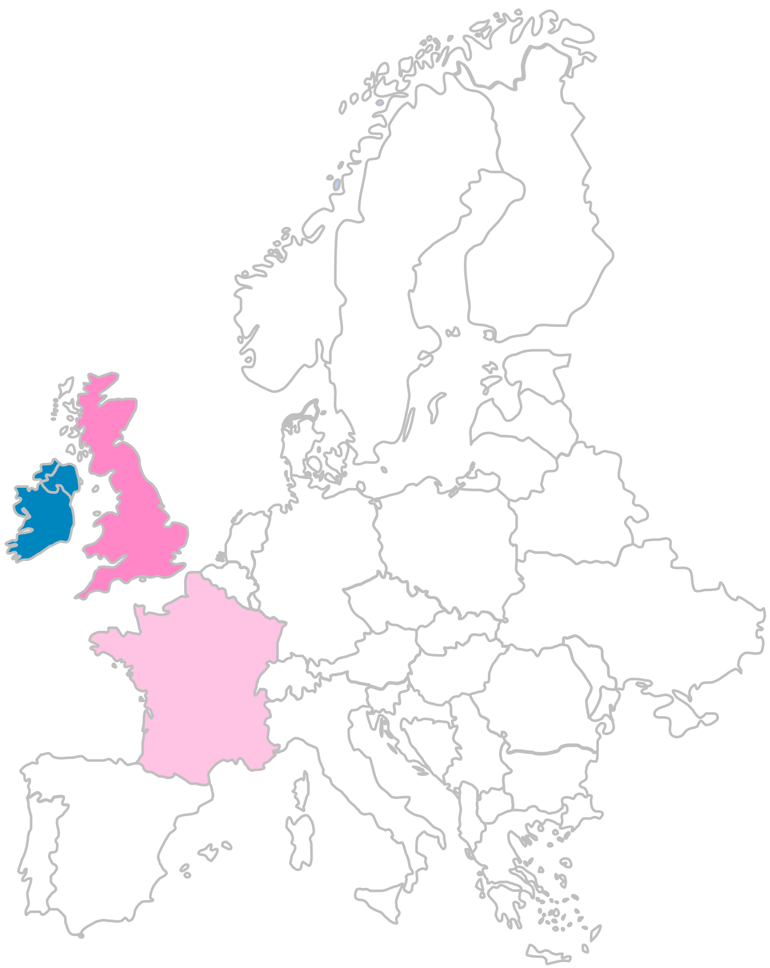
Contents

Overview of the material provided in this case study

Section		Contents
1.	**Executive Summary**	▲ Market overview – one slide summary ▲ Key insights
2.	**Market overview**	▲ Key characteristics of the Irish market ▲ Power market structure ▲ Cross-border exchanges
3.	**Climate goals and subsidy mechanisms**	▲ Energy and climate change objectives ▲ Renewable support ▲ Spotlight: RESS auctions
4.	**Investment and route to market**	▲ Renewable capacity ▲ Renewable routes to market
5.	**Grid integration and system operation**	▲ Transmission system operation in Ireland ▲ Facilitating future renewable deployment

Executive summary: Market overview

The all-island electricity market (the Integrated Single Electricity Market , or I-SEM) is a small market with large renewable ambition covering the Republic of Ireland and Northern Ireland



Existing electricity interconnection

Potential/future electricity interconnection

Energy policy

- The Irish government has set an ambitious binding target for 70% electricity from renewables by 2030, and has published its Climate Action Plan setting out an ambition to reach net-zero carbon emissions by 2050. The UK's net-zero binding target for 2050 applies in Northern Ireland but there is currently no NI-specific renewable policy in place to support this.
- The first round of the Ireland's new renewable auction (the Renewable Electricity Support Scheme) was completed in July 2020 in the Republic of Ireland which has replaced the previous Feed-in-Tariff mechanism.
- The new scheme encourages renewable deployment by awarding Contracts for Difference (CfDs) through competitive auctions.
- Ireland has a capacity mechanism , the CRM – Capacity Remuneration Mechanism which provides revenue to new and existing capacity to ensure security of supply.

Supply and demand

- Ireland is a small market with peak load of approximately 7 GW and total Installed capacity of around approximately 15 GW.
- This capacity mix consists of 40% renewables by capacity (wind, solar, biomass and hydro), with approximately 40% of domestic generation coming from renewables.
- Coal will be phased out by the close of 2025 with gas being the primary thermal technology.
- Ireland is experiencing increasing deployment of small-scale flexible capacity (e.g. gas engines, batteries) to support the system services needed to accommodate significant renewable deployment.
- Demand in Ireland has decreased slightly between 2008 and 2012 and has increased since then to approximately 40 TWh in 2019.

Wholesale prices

- Average annual wholesale price of 50 €/MWh in 2019, decreasing from 64 €/MWh in 2018 (real 2020 prices).
- After a rise in prices in 2018, mainly driven by higher gas and carbon prices, lower gas prices throughout 2019 led to a significant drop in average annual price.

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Executive summary: Key insights

Ireland has achieved significant renewables deployment, supported by a comprehensive package of system services to manage the impact of renewables on the small Irish system

Key insights from the Irish market

High-level policy direction has been clear in Ireland (slides 13 & 18)

- The 2020 target of generating 40% of electricity from renewables has been front and centre of Irish politics and the follow up target – 70% by 30 – continues this trend.
- Clear and consistent policy at the top levels of Government, and with strong support from industry bodies, creates confidence across the industry, driving investment in renewable projects; especially as the high-level policy direction has been supplemented by a stable set of subsidies which is outlined below.

Ireland has a stable regulatory and policy regime which has delivered at scale (slides 13-16, 18)

- Ireland's Feed-in Tariff, REFIT, scheme opened in 2006 and provided a minimum price per unit of electricity exported to the grid over a 15 year contract period, creating a strong incentive for investment in renewables.
- The stability and sustained investment that REFIT attracted, enabled a strong renewables industry to develop, which further supported renewable projects, unlocking further growth.
- The new auction-based scheme for renewables (RESS) replaced REFIT, but maintaining contract duration of 15 years. The first auction was completed in 2020 with the average strike price across solar and onshore wind of 74.08 €/MWh (this compares to a market price of approximately €50/MWh)

Strong focus on the system services required to facilitate a renewables (slides 22-25)

- A centralised system services programme DS3 ('Delivering a secure, sustainable electricity system') was created to put the required changes in place to support the realisation of 75% 'system non-synchronous penetration (SNSP) in Ireland by 2020 (EirGrid, the system operator is well ahead of other system operators in its ability to mange the system with high levels of wind).
- A key design decision for Ireland's system services was to put all 14 system services in a single regime, under a single contract in an aim to simply access and competition.
- As a small system with low levels of interconnection, domestic system services have been a critical facilitator of renewable deployment in Ireland.
- Ireland's system service contracts are currently undergoing a redesign to introduce a competitive element to the process (to comply with European law).

Transitioning from subsidies to merchant development could be challenging (slide 19)

- Ireland has offered generous, long-term subsidies for renewables at a significant short-term cost to consumers. Generous arrangements has reduced incentives for market participants to look for alternative merchant options for investment. Ireland has therefore not seen a significant transition towards merchant renewable development.
- Unsubsidised corporate PPAs have started to enter the market, for example to meet demand from load-intensive industry such as data-centres, however attractive subsidy schemes make these contract expensive for corporates.
- Typically, these type of arrangements in Ireland are less attractive when compared to other countries, who are able to build much larger wind farms than Ireland who typically have sub 50MW turbine limits onshore due to planning limits on tip heights.

Key insights for the UK

Clear and consistent policy is a key driver of renewable investment

- Strong and consistent policy direction, from the top-down, supplemented by a clear and reliable policy mechanism serve to provide confidence in the renewables market, creating the stimulus for investment.
- Whilst the UK Renewable Obligation scheme is not significantly different to REFIT, Ireland saw much less re-design over the years reducing uncertainty for investors (for example changes to buy-out, headroom changes etc. seen in the UK)
- Alongside government support, the Irish wind and renewable lobbies have a strong voice backed by robust analysis in support of renewable policy (for example leading the 70 by 30 campaign – now a flagship renewable plan).

Simple one-stop-shop for ancillary services

- Whilst a menu of 14 different system services appears daunting, having a single and coordinated process for service procurement provides a simple route for engagement in Ireland – compared to a more dispersed procurement approach in the UK.
- The centralised design also provides significant value for Ireland as the success of system services procurement has helped to unlock the significant levels of renewable investment in Ireland to the benefit of consumers.

Market overview

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Key characteristics of the All-Island market

Baringa

Ireland has competitive generation and supply markets, and regulated network businesses

Market structure

- The all-island markets includes the electricity market of the Republic of Ireland (RoI) and Northern Ireland (NI). The transmission and distribution networks are monopolies, owned by Electricity Supply Board (ESB Networks), a state run company. The networks are operated by EirGrid, the state owned Transmission System Operator.
- Power generation and supply are competitive sectors, following market liberalisation in 2000, though ESB maintains the greatest market share in generation (ESB generation) and supply (Electric Ireland).

Value chain	Overview
Generation	▲ Electricity Supply Board (ESB) is the state-owned electricity utility of the Republic of Ireland. It is the dominant player in generation and owns around 40% of capacity. SSE holds the second largest portfolio in the I-SEM, equivalent to 16% of the total installed capacity. EP Power Europe, a London-based subsidiary of Energetický a Průmyslový Holding (EPH), acquired Kilroot and Ballylumford power stations from AES in April 2019 and is the third largest player in the I-SEM market. ▲ Other key market participants include Viridian, Bord na Móna, Centrica, Tynagh, Aughinish Alumina.
Transmission /Distribution	▲ ESB also owns the distribution and transmission network (through ESB Networks) and is the dominant retail supplier (Electric Ireland). In the Republic of Ireland, EirGrid operates the transmission network, working closely with SONI in Northern Ireland. ▲ The network is connected to GB via the 500MW Moyle interconnector (2001, Northern Ireland to Scotland) and the 500MW East-West Interconnector (2012, Republic of Ireland to GB).
Retail	▲ The retail market in Ireland was liberalised in the early 2000s, moving away from the vertical integration of state owned ESB. ▲ Electric Ireland (ESB's retail arm) is the dominant electricity supplier in Ireland with almost half of the market. SSE Airtricity, Power Northern Ireland, Bord Gáis Power and Energia make up the majority of the remainder of the market, with PrePayPower market share at approximately 6%. ▲ The breakdown of the retail market includes: Commercial (36%), Residential (31%), Industrial (28%), Data centres (5%).
Regulator	▲ The Commissions for Regulation of Utilities (CRU) is the National Regulatory Authority (NRA) for the Republic of Ireland, with the Utility Regulator (UR) taking the same role in Northern Ireland. Unlike Ofgem in GB, the remit of the regulatory authorise in Ireland extend to electricity, gas and water, along with safety in the energy and water sectors (CRU only).

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Power market structure (1/2)

Baringa

The Irish electricity market is a centralised traded market, with the new day-ahead market intended to be the focus for the majority of physical trading and liquidity

Overview

- The Irish electricity market is a centralised trading market for electricity, including the Republic of Ireland and Northern Ireland
- The market includes centralised bilateral trading between market participants and financial forward trading
- Cross-border trade with GB takes place through financial transmission rights – a form of contract for difference based on the prices difference between two markets.
- With the new market structure, I-SEM, Ireland introduced the balancing market which means that market participants are now balance responsible (including renewables)

Day-ahead market

- The centralised day-ahead market is the exclusive route to day-ahead physical trading.
- The pan-European market coupling mechanism and algorithm is used directly for this purpose, and the day-ahead results provide the starting point from which a generation dispatch solution is centrally calculated by the system operator.
- The day-ahead market provides a robust reference price for forward traded Contracts for Differences and cross-border transmission rights. Participation in the day-ahead market is unit-based in order to increase transparency (however, gross portfolio bidding is allowed for demand-side response and for some variable renewable generation).
- A mechanism known as Agent of Last Resort (AOLR) provides a backstop route to market for wind and other small generators (AOLR is an automated data processing service provided through the market systems to facilitate participation by smaller generators – source, EirGird here)
- The requirement for market participants to bid at short-run marginal cost levels on the basis of strict bidding principles has been lifted in the I-SEM ex-ante markets (day-ahead and intra-day) under the new energy market design.

Intraday market

- Centralised intra-day trading is the exclusive route to intra-day physical trading and nominations.
- The intra-day market allows participants to adjust their nominated day-ahead position to manage imbalance exposure (see next slide).
- A pan-European platform for continuous intra-day trading (know as XBID) is currently under development, but was not ready for the I-SEM go-live. Interim intra-day arrangements have been implemented, comprising three intra-day auctions per day (two with GB power exchanges) and a local Irish-only continuous intra-day trading platform.

Power market structure (2/2)

The I-SEM energy market design is a centralised traded market, with the new day-ahead market intended to be the focus for the majority of physical trading and liquidity

Forward market

- Forward trading is financial, and not physical, in Ireland.
- This allows market participants to hedge their forward position, which is intended to mitigate exposure to spot price movements.
- The development of more liquid forward market is expected to assist in the formation of robust reference prices in later timeframes.

Balancing market

- Market participants are balance responsible – this means that they are exposed to the cost of any imbalances for which they are responsible (any difference between physical generation/demand and contractual position in day-ahead and intra-day markets) through a new imbalance pricing mechanism. There is a single marginal imbalance price that is reflective of the actual costs of energy balancing actions.
- Participants are required to provide incremental or decremental price bids/offers that the system operator can call upon to balance supply and demand across the system. Activated energy balancing actions are pay-as-cleared.
- The balancing market in Ireland incorporates administered scarcity pricing which serves to increase imbalance prices in the event of reduced operating reserve or involuntary load reduction. This mirrors recent developments in US Independent System Operator markets and the GB cash-out pricing arrangements.
- Ownership of flexible generation resources in Ireland is highly concentrated with a single incumbent player controlling hydro and pumped storage assets. To mitigate against market power in the balancing market, bidding controls are applied to non-energy actions which are priced according to 'complex' bids/offers which must be submitted by all participants on a cost-reflective basis.

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Overview of cross-border exchanges

Historically, GB-Irish interconnectors imported into the Irish system, but this trend changed in 2015/16 in response to GB Carbon Price Support adding a premium to GB wholesale prices

Cross-border capacity

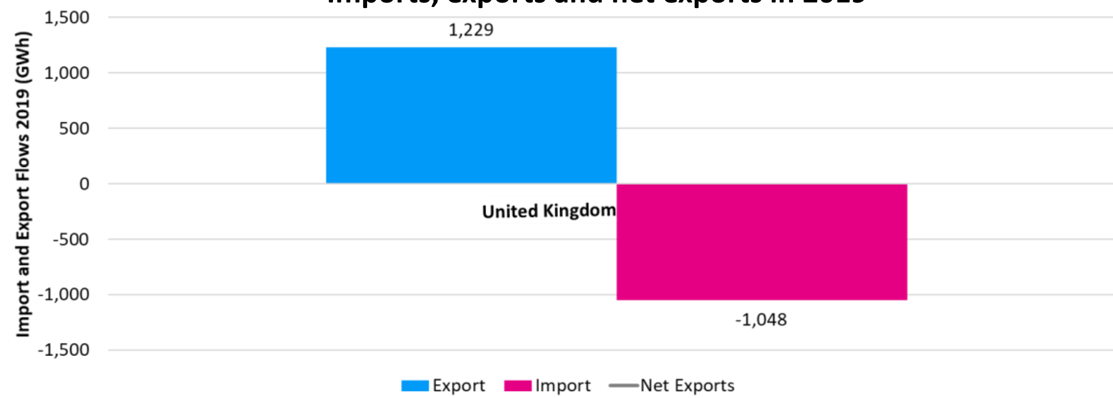
- Ireland currently has 2 cross-border connections to GB:
  - The **Moyle Interconnector** links Northern Ireland with Scotland. It is a 500 MW High Voltage Direct Current (HVDC) sub-sea cable. Usable import capacity is typically 450 MW in winter and 410 MW in summer, with export capacity to GB typically limited to about 295 MW due to constraints on the GB network.
  - The **East West Interconnector** (EWIC) was commissioned in October 2012, connecting County Dublin and Barkby Beach in North Wales with a 500 MW HVDC interconnector.
- An interconnector between Ireland and France, the Celtic interconnector, is being developed by the Irish and French system operators (EirGrid and RTE) with plans to commission in 2025. This interconnector would allow Ireland to import relatively inexpensive nuclear power from France.

Cross-border flows

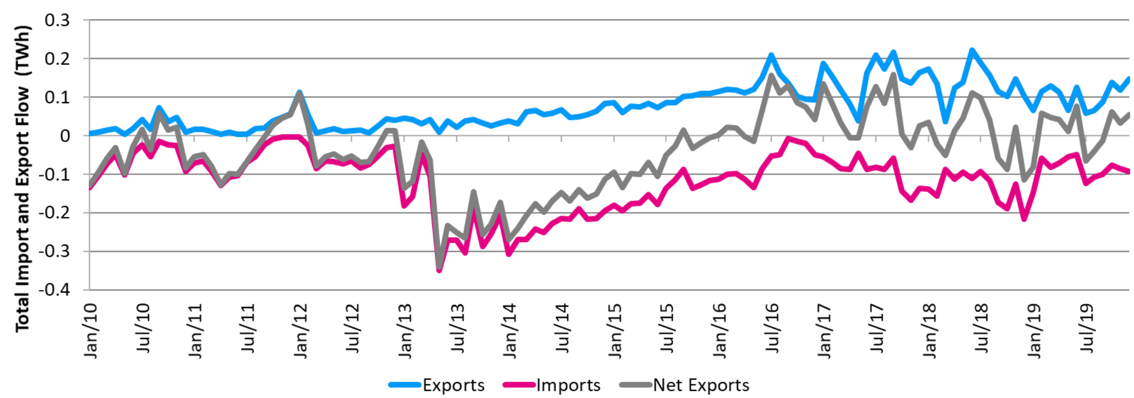
- Historically, Moyle has been used for Irish imports from Scotland. In June 2012 a fault occurred on the north cable of the interconnector, resulting in the available capacity reducing to 250 MW (50%). The cable was repaired in 2016 and returned to full operation. However, in 2017 it suffered further reliability issues.
- Since 2015, export flows from Ireland into GB have increased considerably, and 2016 was the first year that Ireland was a net exporter to GB, a status retained until 2018.
- The main driver for this trend was the GB Carbon Price Support that increased prices relative to those in Ireland, increasing the opportunity for price arbitrage.

SEM imports and exports and flow profiles

Imports, exports and net exports in 2019



Historical flow profile over the past decade



Source: ENTSO-E

Climate goals and subsidy mechanisms

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Energy and climate change objectives

Ireland is set to miss its 2020 renewable energy target but has recently made strong commitments that demonstrate a desire to move from ‘laggard to leader’

Top-down targets

	2018	2020 Target
Renewable Energy	11.3%	16%
Renewable Electricity	33% (normalised)	40%
Renewable Heat	6.8%	12%
Renewable Transport	7.1% (w/ weightings)	10%
Energy Efficiency	12.1% reduction from 2005	20% reduction from 2005
Non-ETS Emissions	6% reduction from 2005	20% reduction from 2005

Ireland is unlikely to meet it’s 2020 targets, and under EU legislation will incur an estimated €150 million of carbon costs.

Domestic policy objectives – Climate Action Plan

2030 Climate Action Plan objectives include:

- 70% renewable electricity
- 950,000 electric vehicles on the road
- An end to the sale of new petrol and diesel cars
- Retrofitting 500,000 homes
- The installation of 400,000 heat pumps in homes and businesses
- A ban on installation of new oil and gas boilers
- An increase in the carbon tax to €80 per tonne (Non-ETS sectors)

The objectives of the Climate Action Plan are yet to be endorsed by the legislature and are considered by some commentators as highly ambitious.

Ireland will focus on domestic policy to continue to increase renewable penetration and deliver long-term climate goals

- The 2015, Climate Action and Low-Carbon Development Act, established a board climate change mitigation and adaptation framework, with goals of cutting emissions from the electricity, building and transport sectors by at least 80% (compared to 1990 levels) by 2050.
- In 2018/19, an Irish cross-party committee on climate change published a dossier urging increased climate action. The recommendations were endorsed by the government and shortly after Ireland joined the UK in declaring a climate emergency.
- In June 2019, the Department of Communications, Climate Action and Environment released the Climate Action Plan. A comprehensive suite of policies to 2030, that would set Ireland on a ‘net-zero 2050’ pathway
- The Climate Action Plan states that the upcoming renewable auctions will increase renewable electricity to 55% (RES-E) with corporate PPAs expected to deliver the additional 15%.
- The recently elected Government of Ireland has clear ambition to progress green investment, including developing offshore wind, green hydrogen and continued investment in the renewable auction support scheme.
- In June 2020, a draft of the Programme for Government was released, further detailing the intended high-level policy approach to achieving the ’70 by 30’ target.
- The document details ‘A Green New Deal’ for Ireland with the objective to reduce greenhouse gas emissions by 7% per year from 2021 to 2030. Overall this will be a 51% reduction in emissions over the decade.

Source: Irish EPA 2020, here

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Renewable support: Republic of Ireland

Baringa

The Renewable Electricity Support Scheme (RESS) is the replacement for the now-closed Feed-in-Tariff scheme

Overview

- Ireland has transitioned from a Feed-in-Tariff incentive (REFIT) to an auctions based renewable auction scheme (RESS), more closely aligned to the CfD in the UK.
- EirGrid ran the fist competitive RESS auctions earlier this year, with a plan for further auctions over the next decade.

RESS auctions – high-level design

- Auctions will be held periodically in which volumes of renewable generation, as opposed to capacity, compete for subsidy support.
- By spreading out the allocation of subsidies, the Irish government aims to avoid locking in higher costs for consumers over the lifetime of the scheme.
- The scheme has been designed to promote the renewable electricity ambition in Ireland.
- The system operator is responsible for running the renewable auction and completed the first auction (RESS 1) in July 2020 (108 projects, 82 successful):
  - Community projects* cleared at a price of 104.15 €/MWh.
  - Solar projects cleared at a price 72.92 €/MWh with 'all projects' clearing at a price of 74.08 €/MWh (this category also includes onshore wind)

*This is the clearing price for all projects, the onshore specific clearing price is not provided by EriGrid, here

Current proposed timeline for RESS auctions

Auction Round	Auction Volume (GWh)**	Delivery Year (end of)
RESS 1	2,200 (approx.)	2022
RESS 2***	3,000	2025
RESS 3	4,000	2027
RESS 4	2,500	2030

**In the I-SEM network, 1,000 GWh corresponds to approximately: 356 MW of onshore wind; 253 MW of offshore wind; 134 MW of biomass; or 1,000 MW of solar PV, over one year.

***Action to confirm timetable for future auctions

DCCAE's RESS objectives

- The objective is to provide a support mechanism to incentivise the installation of additional renewable capacity by 2030.
- Increased community participation and ownership through augmented opportunity and scope for involvement. A community-led category of up to 30 GWh has been used for the first auction round. These projects can be up to 5 MW, with a majority ownership being non-profit and for community benefit.
- Increased renewable technology diversity, spurred on by inclusion of 'intervention levers'.
- Improved cost effectiveness of the competitive framework, with increased energy security and sustainability.

Renewable support: Northern Ireland

The Renewables Obligation is a UK-wide scheme, providing eligible renewable generators a stable, RPI-linked top up to wholesale prices for a 20 year period – is it now closed to new generation

Overview

- In Northern-Ireland, the Renewable Obligations remains the official support scheme for renewable subsidy, however the scheme closed to new generators in 2017.
- Energy policy is devolved in Northern Ireland and with the suspension of the Northern Ireland Assembly there is no clarity on the future subsidy arrangements in Norther Ireland.

Renewables Obligation overview

- The RO places a mandatory requirement on suppliers to source a percentage of electricity from eligible renewable generators.
  - The scheme closed to new generators in March 2017
- Renewables Obligation Certificates (ROCs), are issued for each MWh produced by eligible renewable generators, who sell them to suppliers for presentation to Ofgem, the ROC administrator, to demonstrate compliance with the RO.
  - ROCs therefore “top-up” generators’ wholesale energy revenues
  - Generators are eligible for ROCs for a 20 year period
- A requirement specific to Northern Irish generators is that they enter a PPA with an offtaker with a supply business in the province.
- Initially technology neutral, banding was subsequently introduced to the RO, whereby different technologies receive different multiples of ROCs per MWh.
  - Onshore wind generators are issued 0.9 ROCs/MWh
  - Offshore wind generators receive 1.8 ROCs/MWh

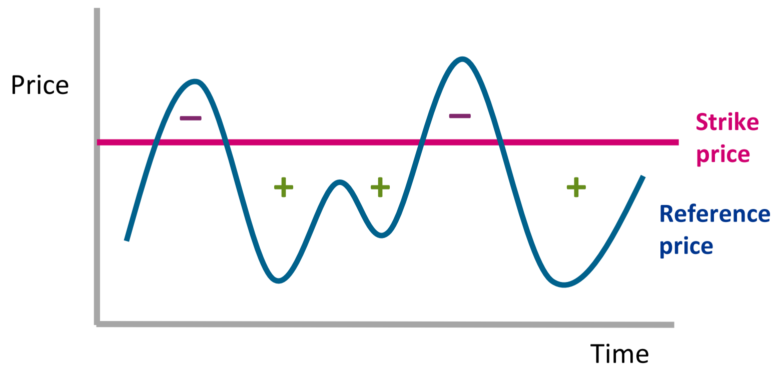
ROC pricing

- Suppliers presenting insufficient ROCs must pay a “buyout” price for each missing ROC into the buyout fund; this is redistributed to suppliers in proportion to the number of ROCs they submitted.
  - The buyout price should act as a floor, and in a short market, the value of ROCs should increase above it (noting that the redistribution of the buyout fund provides a ceiling price).
- The ROC buyout price is administratively set at 30 £/MWh (FY 2002/03 prices) and is updated annually to reflect changes in the Retail Price Index (RPI).
  - The ROC buy-out price was set at 48.78 £/MWh for FY2019/20, rising to 50.05 £/MWh in FY2020/21.
  - The equilibrium price for ROCs is the buy-out price multiplied by a factor of 1.1, representing (1 + “headroom”).
  - Under the “headroom” mechanism, the Government sets the obligation so that anticipated demand is 10% greater than anticipated supply – the market is therefore designed to be short.
  - Prices will tend to be high in years when renewable production is lower and/or demand higher than expected and vice versa, thereby providing a partial hedge to low wind years.
  - The 23rd March 2020 ROC auction on the e-ROC platform recorded an average price exceeding £55 (110% of the buyout price).

Spotlight: Renewable auction design

The new renewable auction mechanism introduces competitive auctioning, moving away from the previous Feed-in-Tariffs renewable scheme in the Republic of Ireland

Two-way CfD mechanism



- The confirmed mechanism for the RESS scheme is the floating Feed-in-Tariff with two-way payments:
  - The successful generator receives a set value per MWh produced, (known as the Strike price)
  - When the relevant market price, known as the Reference price, falls below the Strike price, the generator receives income above the market level
  - When the Reference price exceeds the Strike price, generators pay back the difference, analogously to UK CfD payments
- This mechanism guarantees a constant income for power produced, i.e. the Strike price, for generated power, removing the risks associated with price volatility.
- Irish government's preferred strategy is for technology neutral auctions, with a number of 'intervention levers' to promote diversity.
- One exception to this is the inclusion of a solar category in the first round of auction (which took placee in 2020), representing 10% of the awarded generation.

Summary and drivers

Eligibility rules	Must meet community requirements, have full planning permission and a full grid code
Bid bonds	Tied to project deadlines; community-led projects are exempted
Project milestones	To be set out and met – financial close, project development, meeting community engagement rules, construction
Two-way CfDs	Two-way contract for difference (CfD), funded by taxation Public Service Obligation
Floating feed in premium	Payments linked to the difference between a strike price and a market reference price
Pay-as-bid	All accepted bids shall receive their respective strike price, regardless of the 'highest cleared' bid
Market reference price	Based on the day-ahead all-island market price
Community fund obligation	Each project developer will be obligated to contribute 2 €/MWh to a Community Benefit Fund (CBF) for those living close to RES plant

Investment and route to market

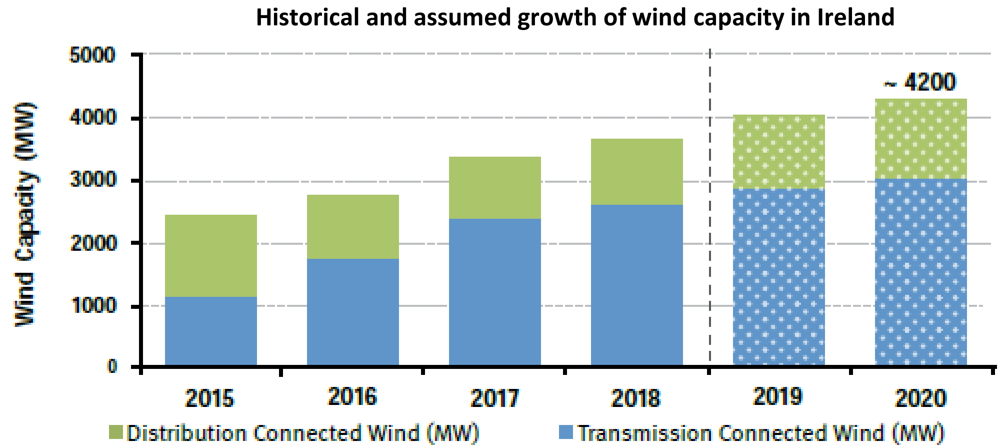
Installed capacity

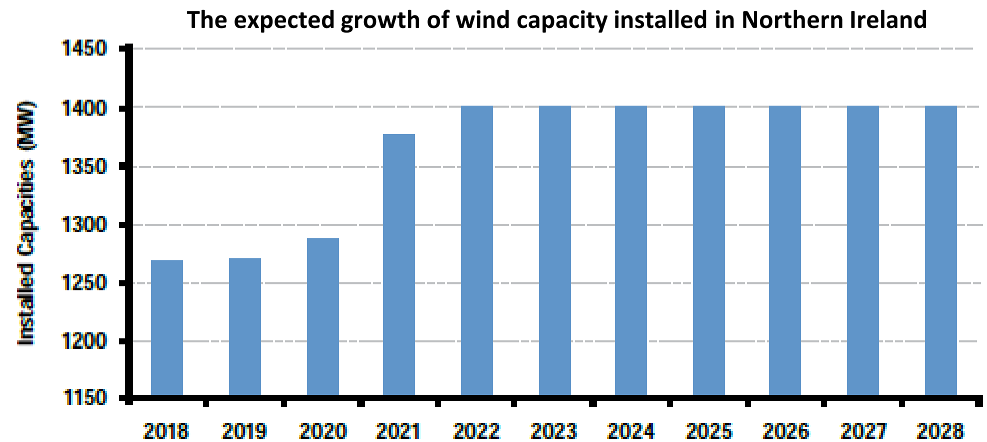
Ireland’s renewable growth has been focused on onshore wind, which is expected to continue over the coming years

Capacity Mix

- Ireland has a 40% target for renewable electricity consumption by 2020, which, alongside cost reductions in renewable technologies, has led to significant growth in renewables – particularly onshore wind
- Onshore wind installed capacity has increased significantly from only 135 MW at the end of 2002 to almost 4000MW by 2019.
- This trend in onshore wind growth is projected to continue as the cost competitiveness of renewable technologies continues to improve and it will be aided by a new competitive renewable auctions, which is expected to drive further investment in renewable energy in Ireland in the 2020s.
- Ireland's committed to achieve 55% renewable electricity by 2030, with new investment through the competition auction scheme, with the remaining 15% to be achieved outside of direct government subsidy.
- Most oil-fired capacity is expected to close in the early-2020s, replaced by more efficient gas-fired plant and other sources of flexibility, e.g. storage and interconnection. The Irish government has committed to end burning coal at Moneypoint, a 900MW generator, by 2025.
- ESB has also announced the closure of West Offaly and Lough Ree peat-fired power stations in 2020. Bord na Mona has announced they will transition away from the use of peat by 2024 (Source, Irish times, here).

Wind Capacity





Source: Eirgrid, CGA, here

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Renewable routes to market

Subsidies awarded through the new auction scheme continue to offer generous support for renewables, limiting growth in alternative non-subsidised support

<table>
<tr><th colspan="4">Routes to market for renewable generators</th></tr>
<tr><th></th><th>Onshore wind</th><th>Solar</th><th>Offshore wind</th></tr>
<tr><td>Renewable support schemes</td><td colspan="2">Generous subsidy support has been provided to date though the Feed-in-Tariff, and now continues through the renewable auction scheme
Prices in the renewable auctions are expected to fall however, as competitive pressure forces cost efficient project development.
There remains limited incentive for onshore wind developers to look for alternatives to subsidy support, particularly given recent high prices in the competitive auctions (>€70/MWh, in nominal terms, on average, for a 15 year contract, across all projects compared to a wholesale power price of approximately €40-50/MWh).</td><td>Offshore wind is eligible for the renewable auctions but does not have access to a dedicated technology pot (as the auction is technology neutral) and therefore no projects participated in the first auction earlier this year.
The Irish government are reviewing the option for new, and separate auctions for offshore wind that will reflect the specific investment needs of offshore wind compared to other technologies.
This suggests ring-fencing of the future auction volumes for offshore wind.</td></tr>
<tr><td>Corporate PPA</td><td colspan="3">Ireland has seen some developments in non-subsidised corporate PPAs, but no active projects yet in the market.
Non-competitive renewable auctions means that Ireland has not seen the significant development cost reductions that you would expect to see from competitive allocation.
Small onshore wind projects in Ireland, limited by restrictions around project tip height, have also prevented significant cost savings for the industry (in a recent report, the Irish Wind Energy Association identified tip height as the most significant policy choice that could reduce the cost of onshore wind in Ireland and enable Ireland to reach its 70 by 30 target – available here).
Without these cost savings, corporate PPA contracts continue to be expensive options for corporates as developers can still earn good value through the subsidy scheme, and at a large premium to the wholesale market price.
Industry expects competitive allocation through the renewable auction to help to increase development efficiency and increase the value of commercial corporate contracts in Ireland.</td></tr>
</table>

Grid integration and system operation

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Transmission System Operation in Ireland

The Irish transmission system is owned by ESB Networks and operated by EirGrid and SONI

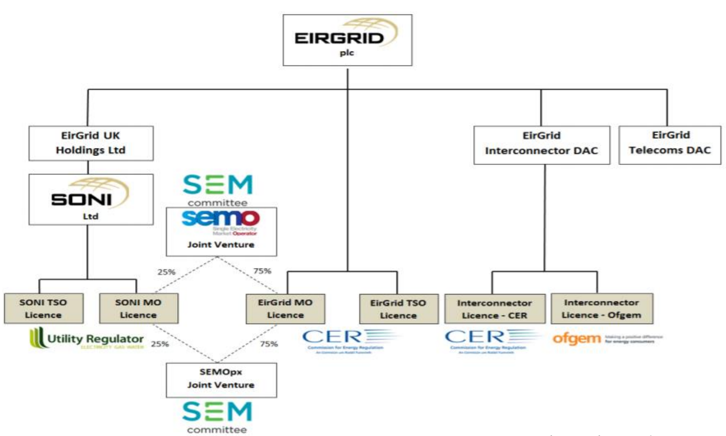
Overview

- Ownership and operation of the transmission system in Ireland is split between state owned monopolies ESBN (the single Transmission Owner) and EirGrid and SONI (Transmission System Operators).
- The Irish system connects to GB via the East-West interconnector and the Moyle interconnector (to Scotland), with a new connection to France planned between EirGrid and the French TSO, RTE.

Network planning and expansion

- EirGrid, as the system operator, is required through regulation to develop a 10 year Transmission Development Plan with the combined objectives to: Ensuring the security of electricity supply, ensuring the competitiveness of the national economy, and ensuring the long-term sustainability of electricity supply in the country.
- The Ten year plan provides EirGrid's view on the investment needs and planned network development to meet the future demand in Ireland, taking into account key strategic challenges (including renewable penetration).
- The national plan feeds into the European-wide network plan (the Ten Year Network Development Plan – TYNDP) which is a top-down view of network development across the European network.

Source: EirGrid TDP 2017, here



Source: CMA and EirGrid, 2017, here

Market and System Operation

- EirGrid and SONI entered into a Joint Venture for all-island market operation – the Single Electricity Market Operator (SEMO) – responsible for the wholesale market for electricity in Ireland (this includes bulk transfer of power, market administration, trading and settlement).
- Day to day system operation is the responsibility of EirGrid and SONI (i.e. managing system reserves, frequency and voltage).

Offshore connections

- The Climate Action Plan sets out Ireland's ambition for renewable development by 2030, including a target to develop at least 3.5GW of offshore wind capacity.
- This is a significant step for Ireland and requires coordination between generation and network infrastructure to allow for efficient offshore wind development, at scale.
- The Irish government has consulted on the connection options for offshore generation, trying to find a way to unlock grid capacity for offshore wind to meet the 3.5GW target.
- The high level options consider the trade-offs between developer-led and plan-led delivery models, with varying interfaces between the project developer, potential network owner/operator, system operators and a potential state planning body.
- The next stage of the process will see the regulator develop the regulatory framework to support the policy.

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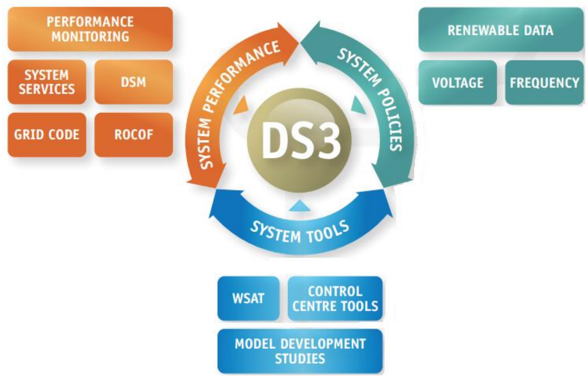
System services in Ireland (1/4)

In Ireland, system services are provided through a system operator-led programme to facilitate the integration of increasing volumes of non-synchronous renewable power onto the system

Headlines

- The DS3 programme was established in 2011 with the aim of "Delivering a Secure Sustainable Electricity System (DS3)" for the Irish market.
- The introduction of the DS3 programme was intended to enable renewable generation to increase to 40% of demand by 2020 – achieving Ireland's 2020 renewable electricity target.
- The DS3 programme has a number of elements, shown to the right, of which DS3 System Services is one component.
- Changes to the Grid Code, Rate of Change of frequency (RoCoF) requirements and updates to system operator polices and control centre tools are other key enablers of the renewable targets in Ireland.

'Pillars' of the DS3 programme



Objectives

- DS3 was introduced to facilitate Ireland's 2020 renewable target and in particular the system operator aims to increase the instantaneous penetration of non-synchronous power output (primarily wind) from ~50% in 2011 to 75% by 2022, thus allowing more renewable energy on the power system.
- This operational metric is referred to as the System Non-Synchronous Penetration (SNSP) limit.
- SNSP is a system constraint that limits the percentage of demand that can be met by non-synchronous generation. Non-synchronous generators (primarily wind and interconnectors) do not typically contribute to system inertia, hence the SNSP must be limited to manage the system.
- The SNSP limit is currently set at 65%. The system operators will trial a limit of 70% around the start of 2021, with a plan to increase the allowable SNSP limit to 75% by 2022.
- An increased SNSP limit will require enhanced DS3 System Services and budgets to maintain system stability during periods of high wind output.

Design

- To manage the increasing and changing system need, DS3 systems services were expanded and enhanced (compared to the previous system services in Ireland), with specific products designed to support frequency control and containment, as well as voltage support
- There DS3 services are broadly split into two categories:
  - **Frequency Control Services**: Designed to maintain/contain frequency at 50 Hz, including inertial response, reserve and ramping products
  - **Voltage Control Services**: Designed to maintain voltage levels through use of services such as Voltage Regulation and Transient Voltage Response
- We provide further detail on the following slide

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System services in Ireland (2/4)

Baringa

Initially procured through standard contracts and paid via regulated tariffs, system services will increasingly be procured through competitive auctions, with the first auction held in July 2019

Products and services

Inertial response

- Products that provide immediate/very fast (2 second response in the case of FFR) response to changes in frequency or voltage disturbance.
- **Products**: Synchronous Inertial Response (SIR), Fast Frequency Response (FFR), Fast Post-Fault Active Power Recovery (FPFAPR).

Reserve products

- Products required to ensure generators can respond to a sudden change in demand or unit trip to keep frequency stable and as close to 50 Hz as possible.
- For example POR must be available within 5s of an event, sustained to 15s post event whereas TOR2 must be available at 5m, sustained to 20m post event.
- **Products**: Primary Operating Reserve (POR), Secondary Operating Reserve (SOR), Tertiary Operating Reserve (TOR1, TOR2).

Ramping products

- These products allow the system operator to manage generation variability by providing a guaranteed generation margin across different notification and delivery timeframes.
- Ramping Margin must be available within 1/3/8 ours and sustained for 2/5/8 hours depending on the product.
- **Products**: Ramping Margin 1, 3 and 8 Hour (RM1, RM3, RM8), Replacement Reserve (Synchronised and De-synchronised) (RRS and RRD) .

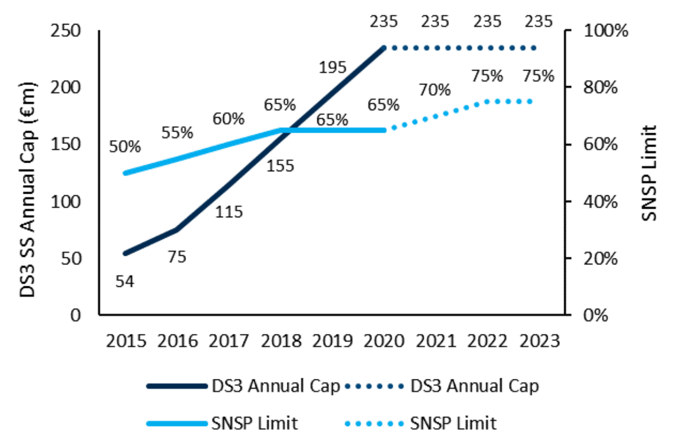
Voltage control services

- Transient voltage response: An additional product added to target increased reactive response from wind farms during disturbances. Voltage control becomes increasingly important at high levels of SNSP.
- Voltage regulation: Generators provide reactive power to maintain voltage as load varies over the course of a day.
- **Products**: Dynamic Reactive Power (DRP) and Steady-state reactive power (SSRP).

Future market design

- DS3 services were initially procured through standard contracts with providers paid regulated tariffs.
- From 2019, services will increasingly be procured through competitive auctions, with the first auction held in July 2019. Regulated tariffs would continue to apply to services where the level of competition is deemed to be insufficient.
- Service incentives, known as payment scalars, will be applied to incentivise reliability, availability, performance, scarcity and volumes (varying by service).
- The SEM Committee, who oversees the DS3 spend, will apply a total expenditure cap to system operator annual spending on DS3 system services. A budget cap of €235m per annum will be enforced from 2020 onwards.
- The ultimate long-term plan for the regulators is for entirely market-based allocation and remuneration of system services, with the eventual transition to competitive auctions for all services, if there is sufficient supply and level of competition.

Future DS3 spend and SNSP limits



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System services in Ireland (3/4)

Detail on the start and duration time, and unit of measurement, of each of the 14 system services in Ireland

Full breakdown of DS3 system services in Ireland

Category	Acronym	Service Name	Start Time and Duration	Unit
Inertial Response	SIR	Synchronous Inertial Response	Dispatch-dependent; units only receive payments when synchronised	MWs^2h
	FFR	Fast Frequency Response	Available within 2s of event, sustained up to 10s post event	MWh
	FPFAPR	Fast Post-Fault Active Power Recovery	Dispatch-dependent. Must remain connected for at least 15 minutes	MWh
Voltage Control	DRR	Dynamic Reactive Response	Dispatch-dependent. Must remain connected for at least 15 minutes	MWh
	SSRP	Steady-state reactive power	Dispatch-dependent, units only receive payments when synchronised	MVArh
Reserve	POR	Primary Operating Reserve	Available within 5s of event, sustained to 15s post event	MWh
	SOR	Secondary Operating Reserve	Available at 15s, sustained to 90s post event	MWh
	TOR1	Tertiary Operating Reserve 1	Available at 90s, sustained to 5m post event	MWh
	TOR2	Tertiary Operating Reserve 2	Available at 5m, sustained to 20m post event	MWh
	RRD	Replacement Reserve (De-Synchronised)	Available at 20m, sustained to 1 hour post event	MWh
	RRS	Replacement Reserve (Synchronised)	Available at 20m, sustained to 1 hour post event	MWh
Ramping	RM1	Ramping Margin 1 Hour	Available in 1 hour and sustainable for 2 hours duration	MWh
	RM3	Ramping Margin 3 Hour	Available in 3 hours and sustainable for 5 hours duration	MWh
	RM8	Ramping Margin 8 Hour	Available in 8 hours and sustainable for 8 hours duration	MWh

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System services in Ireland (4/4)

List of proven technologies for each of the system services in Ireland

System services proven technology list

Proven Technology List															
Type of Service Provider	**Sub-technology (fuel / operational specific)**	**FFR**	**POR**	**SOR**	**TOR1**	**TOR2**	**RR (S)**	**RRD**	**RM1**	**RM3**	**RM8**	**SSRP**	**DRR**	**SIR**	**FPFAPR**
Thermal/Hydro - Centrally Dispatched Generating Unit - CDGU	Coal	x	x	x	x	x	x	x	x	x	x	x	x	x	x
	Combined Cycle Gas Turbine - CCGT	x	x	x	x	x	x	x	x	x	x	x	x	x	x
	Open Cycle Gas Turbine - OCGT	x	x	x	x	x	x	x	x	x	x	x	x	x	x
	Distillate Oil	x	x	x	x	x	x	x	x	x	x	x	x	x	x
	Peat	x	x	x	x	x	x	x	x	x	x	x	x	x	x
	Anaerobic Digester / Waste to Energy	x	x	x	x	x	x	x	x	x	x	x	x	x	x
	Combined Heat and Power	x	x	x	x	x	x	x	x	x	x	x	x	x	x
	Biomass	x	x	x	x	x	x	x	x	x	x	x	x	x	x
	Hydro		x	x	x	x	x	x	x	x	x	x	x	x	x
Wind Power - WFPS	Wind Farm	x	x	x	x							x	x		x
Storage	Solid State Batteries e.g. Lithium Ion	x	x	x	x	x	x	x	x	x	x	x	x		x
	Flywheels (Non-Synchronous)	x	x	x	x										
	Pumped Hydro	x	x	x	x	x	x	x	x	x	x	x	x	x	x
	Compressed Air Energy Storage	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Synchronous Compensator	Synchronous Compensator	x	x	x	x	x	x	x	x	x	x	x	x	x	x
HVDC Interconnector	Direct Current – Voltage Source Converters - VSC	x	x	x	x	x						x	x		x
	Direct Current – Line Commutated Converter LCC	x	x	x	x	x									
Aggregated Service Providers	Aggregated Generation Units (fossil-fuel based) - AGU	x	x	x	x	x	x	x	x	x	x				
	Industrial Demand Side Units (demand response) - DSU	x	x	x	x	x	x	x	x	x	x				
	Residential Demand Side Mangement (demand response) - RDSM														
Solar Power	Solar Photovoltaic														
	Solar Thermal														
	Concentrated Solar														
Ocean Energy	Tidal														
	Wave														

Legend	
x	Proven
	Not Proven

Source, EirGrid, here

Germany

National Infrastructure Commission

November 2020

Contents

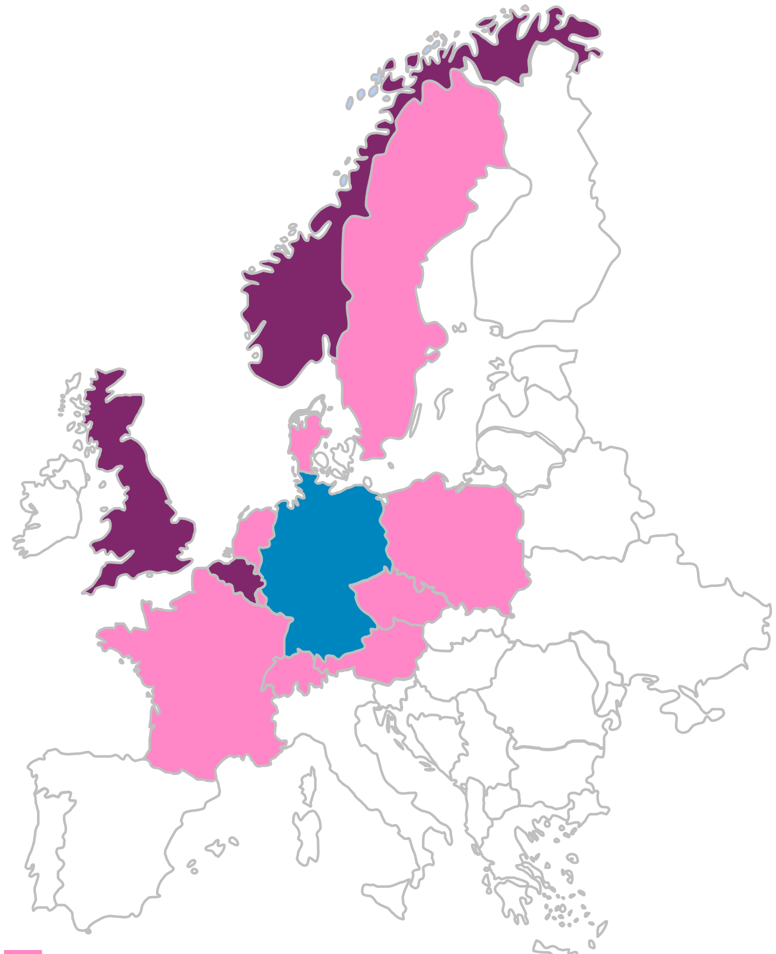
Overview of the material provided in this case study

Section		Contents
1.	**Executive Summary**	▲ Market overview ▲ Key insights
2.	**Market overview**	▲ Key characteristics of the German market ▲ Power market structure ▲ Overview of cross-border energy exchanges
3.	**Climate goals and subsidy mechanisms**	▲ Energy and climate change objectives ▲ Renewable support in Germany ▲ Spotlight: German coal exit laws ▲ Renewable policy forward look
4.	**Investment and route to market**	▲ Installed capacity and generation ▲ Renewable routes to market
5.	**Grid integration and system operation**	▲ Transmission System Operation ▲ System services in Germany ▲ Spotlight: Renewable curtailment

Executive summary: Market overview

Baringa

Over half of current German capacity is renewable with the phase-out of coal and lignite expected by the late 2030s



Existing electricity interconnection

Potential/future electricity interconnection

Energy policy

- Ongoing implementation of the 'Energiewende', the planned transition to a low carbon, reliable energy supply
- Nuclear exit will be completed in 2022, and over 10 GW of coal capacity will be closed between now and 2025
- On track to achieve 2020 renewable targets for electricity, most likely to miss energy efficiency targets
- There are plans for an accelerated exit from coal-based generation, to be completed by 2038. This is expected to put upward pressure on wholesale prices
- There are four Transmission System Operators in Germany, responsible for grid planning, development and operation, with over 800 distribution companies

Supply & demand

- Over 45% of installed capacity was-wind and solar in 2020 and about 32% of generation in Germany was came from wind and solar in 2019.
- The highest increase in capacity between 2018 to 2019 was from investment in wind energy (both onshore and offshore).

Wholesale prices

- 2019 wholesale price fell to 38 €/MWh from 45 €/MWh in 2018
- Nuclear phase-out and coal closures will put upward pressure on prices
- Wind/solar deployment during auction regime and beyond puts downward pressure on prices
- Both intermittency and need for flexibility are set to increase

Executive summary: Key insights

Germany has a well connected renewable market, with a network-led approach to develop renewables offshore leading to competitive clearing price in recent auctions (close to €0/MWh)

Key insights for Germany

Germany's grid connection policy for offshore wind provides firm connection ahead of time (slide 43)

- German system operators are required to develop the offshore grid ahead of generation build, offering connections for offshore wind developers
- This provides certainty for offshore wind, and critically, grid connection costs are socialised amongst network users
- Hybrid offshore coordinated projects are also in the pipeline in Germany, providing renewable generation and flexibility via cross-border flows

Renewable subsidies have developed from Feed-in-tariffs to auctions (slides 16 & 37)

- Like many other Member States, Germany has moved to competitive auctions for renewables, which are mostly pay-as-bid and the subsidy is in a one-way Contracts for Difference (CfD)
- Several offshore wind projects bid zero into the recent auctions meaning a significant amount of offshore wind coming online in the next years receives no subsidy other than the grid connection
- New policy options could allow negative bidding to allow developers to bid for the value of the grid connection opportunity (i.e. pay for connection)

Without streamlined planning arrangements, generous renewable subsidies are not sufficient to deliver renewable investment (slide 36)

- Recent auctions for onshore wind have been undersubscribed as a results of planning and permitting barriers and protracted regional planning arrangements

Significant network constraints (North-South) and delays to reinforcements means that Germany faces significant renewable curtailment costs (slides 43 & 48)

- North-South transmission reinforcements are in the planning process in Germany but are subject to significant delays
- With demand centres in the south, and renewable resources based in the north, these delay mean that the TSOs have to curtail renewables at significant cost (circa 6TWh in 2019)

Alongside large scale, commercial investment, Germany also has a history of investment in citizen energy projects run as cooperatives (slides 31 & 41)

- These projects face advantageous auction conditions, such as pay-as-clear participation (unlike pay-as-bid for commercial developers), and face more lenient development timeframes
- Since they were introduced in 2017, some of the rules for citizen projects have been tightened, in particular the permitting requirement ahead of auctions participation, as these were previously exploited by commercial developers

Insights for the UK

Coordinated offshore networks can help to unlock generation and flexibility, but present regulatory and commercial challenges

- Germany (with Denmark) is developing a hybrid solutions in the North Sea
- Whilst there are live opportunities to develop similar projects in the UK, the lack of central planning and multiples networks companies, introduces additional coordination and governance challenges for the UK

Clear and efficient planning processes are critical to renewable deployment

- The German experience shows the impact of planning delays on auction outcomes and overall build out of renewables
- Policy makes should take into account the planning and permitting in any renewable policy to ensure competitive and successful outcomes

Social acceptance is an important part of integrating renewables

- Some of the challenges facing onshore wind in Germany are driven by local populations who oppose developments
- They are able to delay developments by finding legal reasons to challenge onshore wind developments in their area
- Citizen projects help to overcome these issue, by providing a commercial stake for local populations

Market overview

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Key characteristics of the German market

Baringa

The German market is still dominated by 4 major players although all of them are facing major restructuring and challenges resulting from significant changes in energy policy in Germany

Market structure

In April 1998, Germany moved from a regulated regional monopoly to a liberalised power market. The German power system is dominated by four large companies, which continue to own significant generation, distribution and retail assets. Renewable technologies are supported through a support mechanism defined in the Renewable Energy Act.

Value chain	Overview
Generation	▲ The four major producers, RWE, E.ON, EnBW and Vattenfall (Swedish) dominate the generation market, and to a lesser extent, the supply market. Since Vattenfall sold its lignite business to LEAG in 2016, it also has a significant share in generation. The cumulative market share (excl. renewables) of those five companies continued its downward trend from 72.8% in 2010 to 60.8% in 2018. This decrease is mainly due the increase in retirements of older thermal capacity.
Transmission/ Distribution	▲ The transmission grid is operated by four major Transmission System Operators (TSOs): – Amprion (11,000 km): owned 25.1% by RWE, 74.9% by institutional investors, also coordinates country-wide load and frequency control – TenneT (10,700 km): owned by Dutch state-owned TSO – 50 Hertz (9,980 km): owned 80% by Belgian TSO Elia and 20% by KfW (the state-owned German Development Bank) – TransnetBW (3,200 km): owned by EnBW ▲ In comparison, the distribution network is operated by approximately 883 DSOs in 2018, the majority of them being owned by municipal utilities (Stadtwerke)
Retail	▲ The local retail landscape in Germany is quite unique in Europe, dominated by suppliers at regional level (over 1000), such as Stadtwerke. In 2018, 1485 companies sold approx. 284 TWh electricity to customers with metered load profiles and approx. 159 TWh to standardised load profile customers. In 2018, switching rates were approx. 12.3% for commercial consumers with metered load profiles and approx. 4.3% for customers with standardised load profiles. ▲ The German market has cross-ownership between suppliers, with the big four owning shares in many municipal suppliers, as well as direct ownership of the strongest retail online brands like Yello (EnBW), E Wie Einfach (E.ON) and eprimo (RWE)
Regulator	▲ The Federal Network Agency (Bundesnetzagentur) is the German regulatory office for electricity, gas, telecommunication, post and railway markets. For the energy market, it is mainly responsible for ensuring non-discriminatory third-party access to networks, regulating fees and organising renewable energy auctions

Note: 1) NewCo from E.ON and RWE respectively , operational since 2016

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Power market structure

Traded volumes on the German wholesale market have been growing along the curve during recent years with an increasing variety of products at the short-end

Overview

- In Germany, power is traded under bilateral contracts between generators and suppliers (Over-The-Counter – OTC) and through power exchanges.
- Like most European power markets, the German wholesale electricity market is broadly made up of three major exchanges: (1) a day-ahead market; (2) forward market; and (3) an intra-day market. Electricity supply deliveries in the forward market can be negotiated up to seven years in advance, but for liquidity reasons typically only look out three years, and most futures trading focuses on shorter timeframes, typically one year ahead.
- The balancing market is an auction based mechanism administered by the system operators.

Day-ahead & intra-day markets (EPEX SPOT)

- The power exchange, EPEX Spot, runs a day-ahead auction for the Germany/Luxembourg market area, closing at midday of the previous day.
- EPEX spot also offers an intra-day market for continuous trading for market participants to trade hourly and 15 minutes contracts up to 30 minutes before delivery.
- The majority of power in Germany is traded in the Day-Ahead markets, consistent with power trading across Europe, with volumes in the German day-ahead auctions approx. 225 TWh in 2018 (compared to total generation of approximately 500 TWh).

Forward market (EEX Power derivatives)

- European Energy Exchange (EEX) power derivatives provides an exchange traded market for forward contracts.
- Market liquidity for baseload products is relatively high for products up to year-ahead with lower but some liquidity 2-3 years out. In total, approximately 4,386 TWh of power derivatives were traded on the EEX in 2018.
- Phelix is the underlying index and is calculated as the average of hourly prices from auctions on the EPEX Spot Market. In 2018, about 1,950 TWh of Phelix DE Futures were traded on the EEX.

Balancing / Reserve market

- Balancing market capacity is contracted by the TSOs from pre-qualified market participants to maintain the overall balance in the system. Balancing capacity and energy is procured in auctions.
- In 2018, the TSOs procured approximately 2 GW positive and negative secondary reserve, as well as approximately 1 GW of positive and negative tertiary reserve.

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Overview of cross-border exchanges

Baringa

Germany remains a hub for electricity exchange within the central European system providing valuable cross-border flexibility to help manage the intermittency of renewables

Cross-border capacity

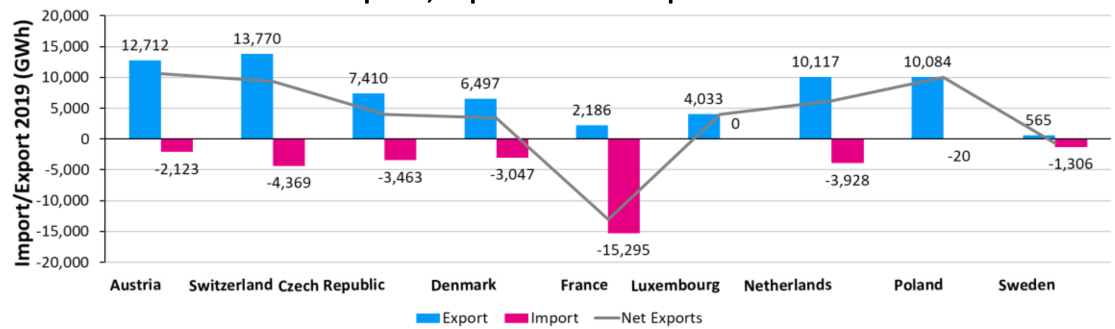
- Germany is a well connected market, with cross-border connections with all its neighbours
- These projects are typically extensions of the onshore network (typically Alternative Current) and are developed by the incumbent system operators, in collaboration with their neighbouring counterparts
- Recent activity includes a 400MW network expansion project with Denmark in 2018 (forming part of the Kriegers-Flak coordinated grid solution)

Cross-border flows

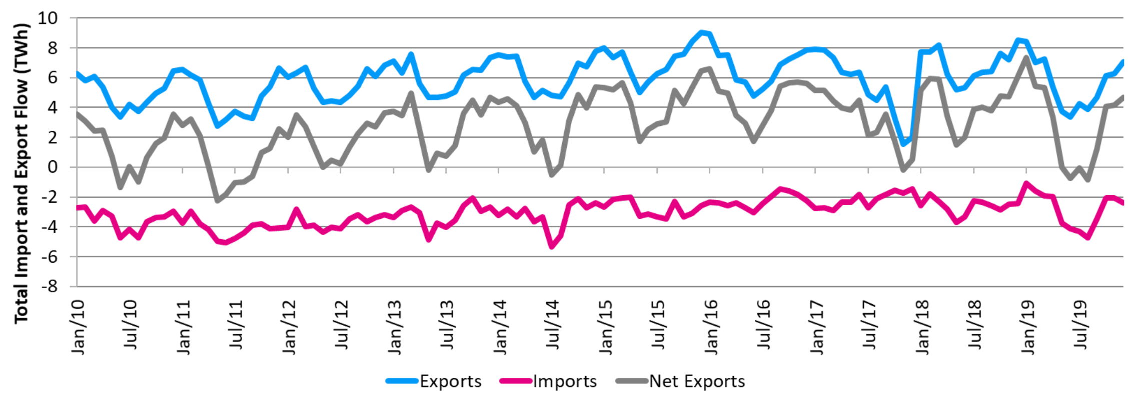
- Germany's main exports and imports are with Austria, Switzerland, the Netherlands and Poland
- A new 400MW interconnector was commissioned with Denmark in 2018. This led to a net export of 51 TWh in 2018.
- Overall, Germany is a net exporter of electricity, a trend increased by the uptake of renewables in recent years
- The electricity export profile has a strong seasonal component:
  - During winter Germany's exports are significantly higher as a result of cheap coal, over-capacity and must-run constraints for some types of generation (e.g. Combined Heat & Power)
  - Imports peak during summer months in response as prices in neighbouring markets fall more than prices in Germany

German imports and exports and flow profiles

Imports, exports and net exports in 2019



Historical flow profile over the past decade



Source: ENTSO-E

Climate goals and subsidy mechanisms

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Energy and climate change objectives

Germany shows positive progress in achieving its 20-20-20 targets with strong ambition set out for 2035 and 2050

Top-down targets

- The EU 20-20-20 targets were formulated in 2009. The targets commit the EU, by 2020, to:
  - A reduction in greenhouse gas emissions of at least 20% below 1990 levels;
  - Sourcing 20% of final energy consumption from renewable sources (RES); and
  - A 20% reduction in primary energy use compared with projected business-as-usual levels, to be achieved through improved energy efficiency
- The EU commission considers Germany to be on track to meet the renewable electricity targets, however it is likely to miss its energy efficiency and reduction of CO2-emissions targets.

Domestic policy objectives – German energy and climate targets

- Germany has the following renewable electricity targets in line with its energy transition agenda:

Target	Share of renewable energy in electricity consumption
2020	at least 35% (on track)
2030	65% (draft EEG 2021)
2050	100% (as part of a net-zero emissions target)

Germany's position in Europe, and the Internal Energy Market, is central to renewable integration in Germany

- Germany has successfully implemented coordinated cross-border trading (known as implicit and explicit capacity allocation), aligned with the electricity target model for the Internal Energy Market.
- Germany has the capability to trade power across Europe via its power exchanges. The power exchanges EPEX (Germany, France, Luxemburg, Switzerland and Austria) and APX (GB, Netherlands and Belgium) have successfully integrated by connecting their intraday markets via a coordinated trading platform providing a route for efficient dispatch of renewables in Germany, and across mainland Europe.
- This has in turn improved liquidity in the European intraday market, critical for balancing the variability of renewables in Germany
- Germany's location in central Europe and high level of connectivity with neighbouring markets, makes a core trading party in Europe and is a key driver of liquidity in German power markets.
- Germany is set to see cross-border coordination across more trading timeframes as European policy objectives, to implement cross-border balancing and reserve trading are achieved.

Source: BMUB, BMWi

Renewable support in Germany

As laid out in the Germany's Renewable Energy Act, Germany has moved from a Feed-in-Tariff system to an auction based system for all large-scale renewable installations

Overview

- The 2017 German law on renewable energy introduced an auction based system for all large-scale renewable installations in Germany (moving from a Feed-in-Tariff mechanism to date)
- Germany continues to subsidise renewables through technology-specific auctions for onshore wind, offshore wind, solar and biomass

Renewables auctions – Recent developments

- Recent onshore wind auctions have been undersubcribed as a results of a significant slowdown in the permits for new projects, and numerous legal challenges against projects in development.
- The government also plans to carry out technology neutral "innovation auctions", designed to reward innovative renewables concepts, especially with those with network and system stability benefits.
- So far there have been five technology-neutral auctions with an auction volume of 200 MW each (April 2018, November 2018, April 2019, November 2019 and April 2020).
- In these technology-neutral auctions all of the volume has been awarded to solar capacity.
- The government recently put forward a draft of a revision of the law on renewable energy (EEG 2021) setting out the auction volumes and overall framework to achieve the 2030 renewables target

Auctions design and recent auctions results in Germany

	Onshore wind			Offshore wind			Solar			Biomass		
Tender Dates in 2020	1st February; 1st March; 1st June; 1st July; 1st September; 1st October; 1st December			1st April 2017 & 2018 for existing development projects to come online 2021-2025			1st February; 1st March; 1st June; 1st July; 1st September; 1st October; 1st December			1st April 2020; 1st November 2020		
Tender volume	3,675 MW/year in 2019; 2,900 MW/ year in 2020			1,550 MW/year in 2017 & 2018			1.475 MW in 2019 1.800 MW in 2020			150 MW in 2017-2020 400 MW in 2020		
Auction type	Pay-as-bid Pay-as-cleared (cooperatives)			Pay-as-bid			Pay-as-bid			Pay-as-bid Pay-as-cleared (up to 150 kW)		
Price ceiling	6.2 ct./kWh in 2019 6.2 ct./kWh in 2020			12 ct./kWh in 2017 & 2018			8.91 ct./kWh – Feb/Mar. 2019; 7.50 ct./kWh – March 2020			14.44 ct./kWh – new build 16.40 ct./kWh – existing plant		
Recent cleared auction prices (ct./kWh)	Date	Highest	Average	Date	Highest	Average	Date	Highest	Average	Date	Highest	Average
	Feb. 20	6.20	6.18	April 17	6.00	0.44	Feb. 20	5.21	5.01	Sep. 17	16.90	14.30
	Mar. 20	6.20	6.07				Mar. 20	5.48	5.18	Sep. 18	16.73	14.73
	Jun. 20	6.20	6.14	April 18	9.86	4.66	Jun. 20	5.40	5.27	April 19	16.56	12.34
	July 20	6.20	6.14				July 20	5.36	5.18	Nov. 19	16.56	12.47
	Sep. 20	6.20	6.20	-	-	-	Sep 20	5.39	5.22	April 20	16.40	13.99
Further specifics	Limited tender volume in network constrained areas			'Central model' to start with tenders from 2021 for the period beginning from 2026			No tenders for small units up to 750 kW or projects larger than 10 MW			No tenders for new build units up to 150 kW		

Spotlight: Coal exit law

In January 2020, Germany adopted its coal exit law that will drastically change the German electricity system over the next 20 years but will provide compensation to existing generators

Lignite exit plan and compensation

- As initially suggested in the report of the Coal Commission in Germany, lignite plants in the western German mining area will be phased-out first. By 2022, around 3 GW of lignite, owned by RWE, should be closed. RWE will receive compensation of € 2.6 billion.
- The compensation takes into account the time of decommissioning, the amount of the decommissioned power and the expected and lost earnings for a certain number of years. Operating and fuel costs are also included in the calculation.
- The payment of the compensation will be in 15 equal annual tranches, starting with the decommissioning date or the end date of operations. The payment also covers the costs of re-cultivation of the land.
- Lignite plants smaller than 150 MW may receive compensation by taking part in the planned auctions for hard coal plants (see description on the right hand side).

Coal based Combined Heat and Power (CHP) plants

- CHP plants used for industrial purposes or for district heating will receive a special support if plant operators convert the plants from coal to gas or biomass.
- The coal replacement bonus is awarded only if the plant operators do not participate in the tendering process for hard coal. Further, if the operators choose to participate in the tender and are not awarded, they still can apply for the coal replacement bonus.
- The bonus is set at 180 €/kW and is calculated based on the installed capacity of the existing coal plant.

Hard coal exit plan and compensation

- The exit plan for hard coal has been established as follows:
  - Until 2022 approx. 8 GW should be phased-out, down to a total of 15 GW
  - By 2030, further approx. 8 GW should be phased-out
  - By 2038, the remaining 7-8 GW should be phased-out
- For hard coal plant operators, the new law stipulates auctions for taking capacity off the grid according to the government timetable (set until 2026). The lowest bidders will be awarded payments. After 2026, there will be forced closures depending on the age of the plant and CO2 output.
- For 2020, the law foresees approx. 4 GW to be taken off the grid through shortened tender procedures. There are doubts whether the deadlines for implementation can be met. The bids had to be submitted by the end of May 2020.
- Hard coal plants in southern Germany are exempt from the first round of auctions in 2020 as they are regarded as critical to supply security
- For 2021, the law similarly foresees a shortened tender procedure, taking a further 1.5 GW of hard coal capacity offline
- The controversial Datteln 4 hard coal power plant came online at the end of May 2020 (controversial given the timing of the investment and commissioning decision). Because of this, the Federal Government has increased the tender volumes by 1 GW for the years 2023 to 2025.
- The maximum compensation payment for the shortened round of tenders in 2020 is capped at 165,000 €/MW and in 2021 and 155,000 €/MW in 2022. The value declines gradually by approx. 25% to 49,000 €/MW by 2026. Through the declining caps, the federal government wants to increase pressure to participate in the first rounds of auctions.

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Renewable policy forward look

Baringa

The Federal Government defined 12 tasks derived from 12 major trends for the coming years which show how Germany plans to support its transition to decarbonisation

In September 2016 the Federal Government published in a Discussion Paper which sets out long-term trends for a secure, low-cost and climate friendly electricity supply system. The trends describe developments that are reflected in the current scenario studies, particularly long-term scenarios commissioned by the German Federal Ministry (BMWi). The Government derived the following tasks for the coming years.

	Trends	Tasks
1	The system is shaped by the intermittent generation of electricity from the wind and sun.	Make the electricity system more flexible.
2	There is a significant decline in the use of fossil fuels in the power plant fleet.	Reduce carbon emissions reliably, shape structural change.
3	The electricity markets are more European.	Integrate and increase flexibility in European electricity markets.
4	Security of supply is ensured within the framework of the European internal market for electricity.	Assess security of supply in a European context and develop common instruments.
5	Electricity is used far more efficiently.	Strengthen incentives for the efficient use of electricity.
6	Sector coupling: The heating sector, cars and industry use more and more renewable electricity instead of fossil fuels.	Improve competitive conditions for renewable electricity in the heating and transport sectors.
7	Modern CHP plants produce the residual electricity and contribute to the energy transition in the heating sector.	Provide incentives for modern power and heat systems.
8	Biomass is used increasingly for transport and industry.	Provide incentives so that biomass is increasingly used for transport and industry.
9	Well developed grid infrastructures create flexibility at a low cost.	Expand the grid in a timely, needs-based and cost-efficient manner.
10	System stability is guaranteed even with a large share of renewables in the energy mix.	Continue to develop and coordinate measures and processes for system stabilisation.
11	Grid financing is fair and meets the needs of the system.	Further develop regulations governing grid charges.
12	The energy sector takes advantage of the opportunities offered by digitisation	Roll out smart metering, build communication platforms, guarantee system security.

Investment and route to market

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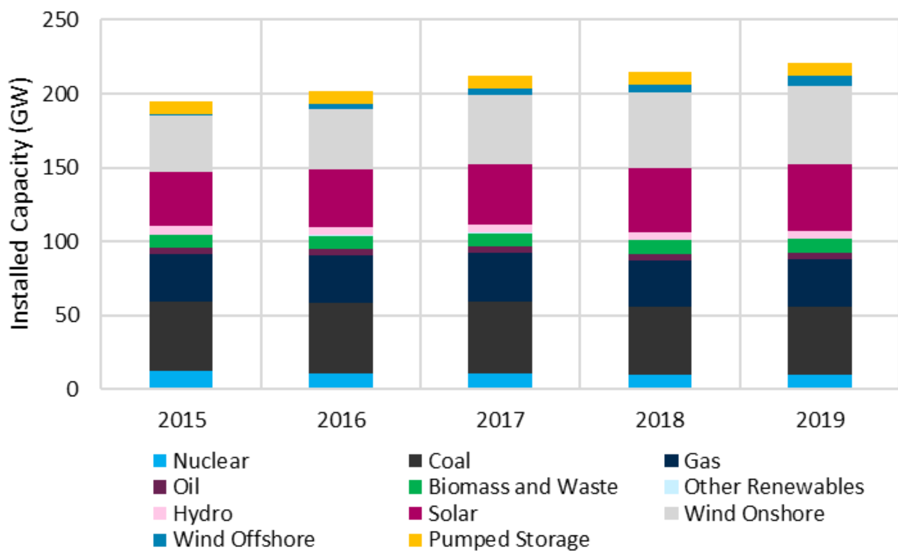
Installed capacity and generation

Baringa

There has been steady growth in renewables in recent years in Germany in response to technology specific subsidy arrangements and wider, European-wide policy goals

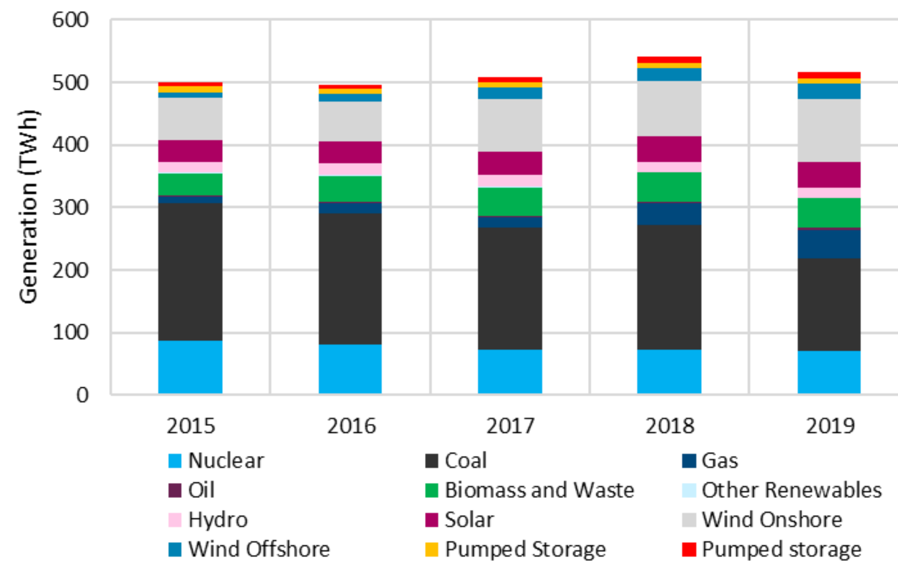
Historical Capacity Mix

- Total installed capacity has been constantly growing in Germany mainly due to attractive subsidy schemes for renewables. This trend will likely persist over the next few years although the growth in renewables is projected to slow and nuclear and coal plant are due to retire.
- Since 2015 capacity from wind and solar has increased from 39% of total capacity to 47% in 2020, moving from 76 GW to 108 GW



Historical Generation mix

- Due to favourable compensation schemes and decreasing installation costs solar and onshore wind had the strongest increase from all renewables in the years between 2015 and 2019. The combined share of PV and wind was around 22% in 2015 and 32% in 2019
- From 2015 until 2019 the share of nuclear energy dropped from 17% to 14% and will decrease further until 2022 when the last nuclear power plant will be shut down



Source: ENTSO-E

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Renewable routes to market

Baringa

The majority of German renewables still benefit from some subsidy, however low clearing prices for offshore wind has led to alternative contracting strategies

Routes to market for renewable generators

	Onshore wind	Offshore wind	Solar
Renewable support schemes	▲ 100% of onshore wind in Germany is remunerated through subsidised auctions ▲ Recent auctions have been undersubscribed as planning and permitting challenges reduce the pipeline of onshore wind projects ▲ Low demand has increased clearing prices and value to subsidised projects	▲ Supported through a one-way CfD but recent auctions (in 2018/19) have seen a large proportion of bids at €0/MWh (effectively at zero floor price). ▲ Whilst these bids suggest projects are exposed to full merchant exposure, projects receive free grid connection through participating in the CfD auction ▲ Wind farms receive the full upside, compared to capped upside in the UK	▲ Medium-sized solar (<10MW) is supported through renewable subsidy auctions
Corporate Power Purchase Agreements	▲ Not seen in Germany given capacity still available in subsidy regime	▲ Wind farms typically sign PPAs to offset risk from wholesale market exposure (i.e. full downside)	▲ Large scale (>10MW) solar cannot participate in auctions and there have been a few examples of solar corporate PPAs in Germany (i.e. where subsidies are not available)
Other revenue streams	▲ Ancillary revenue/system services: There is relatively little value to renewables from ancillary services in Germany. Questions remain around how complimentary revenues, for example from renewable support mechanisms and ancillary markets, can be coordinated effectively.		

Grid integration and system operation

Transmission System Operation in Germany

Baringa

The German transmission system, dominated by 4 system operators, benefits from close connections to neighbouring systems and coordinated national systems planning

Overview

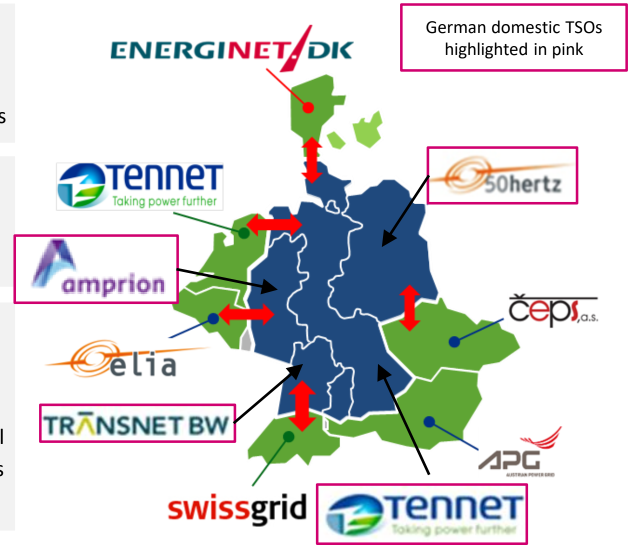
- The Germany transmission network comprises 4 system operators who work together to plan, develop and operate the network
- The German network is well connected to neighbouring networks via interconnectors and uses this connectivity to improve system operation through cross-border balancing, reducing reliance on expensive domestic balancing options

Regulation

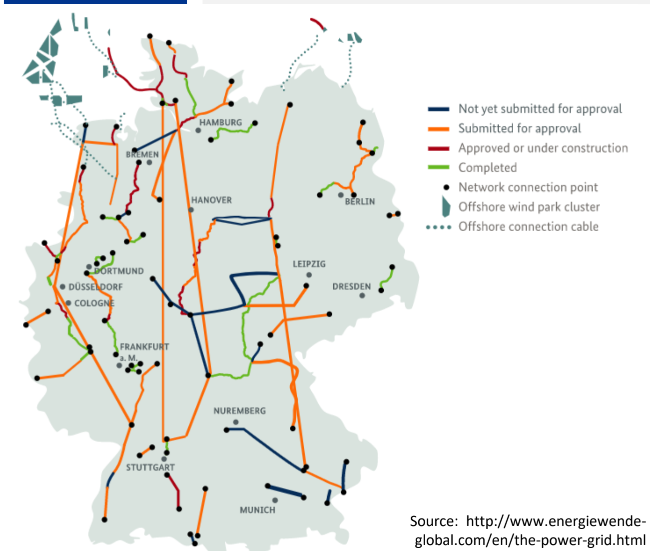
- The German system operators are subject to network price controls designed to incentive efficient investment in the network to meet network needs. This approach to network regulation is broadly consistent across Europe.
- In Germany, network charges account for approx. 25% of the total electricity price, split approx. 25% to transmission and 75% to distribution (Tennet, here).

Network planning and expansion

- Transmission network planning in Germany starts with detailed generation and demand planning by the system operators, based on scenario analysis, to consider network investment to meet future needs
- In Germany, the 4 system operators develop individual scenario plans, typically on a 2 year cycle, which are them combined into the National Development Plan
- These national plans, which is forward looking 10 year plan, are subject to public consultation and regulatory approval
- Germany also has a range of policies and laws to accelerate regional or cross-regional network needs. A key examples is the three north-south network reinforcements designed to unlock renewables in norther Germany and reduce curtailment costs.



Source: https://www.50hertz.com/en/Market/Balancingenergy



Source: http://www.energiewende-global.com/en/the-power-grid.html

System Operation

- Although Germany has 4 separate system operators, system operation takes place at a national level with balancing taking place in a coordinated way across the regional control areas
- The policy for national balancing was adopted in 2010 by the Germany regulatory authority in order to reduce the total cost of energy balancing (known as Grid Control Cooperation)
- The Germany system operators also take part in International Grid Control Cooperation, which involves offsetting electricity imbalances between European systems before balance actions are taken in the market
- The process increases the size of the balancing market, making use of cross-border capacity remaining after gate-closure, which reduces the reliance on other national reserves

Offshore connections

- Offshore wind transmission connections in Germany have developed through a transmission-led approach
- Under this mechanism, the system operators are required to develop connections between offshore wind zones and the national onshore network, based on the location of the wind connection on the system (offshore connections are typically in the northern-Germany in the transmission region of TenneT and 50 Hertz)
- This approach to offshore wind deployment provides a clear and certain connection for offshore wind, with the risk associated with network connections fully transferred (underwritten) by consumers

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System services in Germany (1/3)

Baringa

Germany expects to see an increase in demand for flexibility in future years to accommodate renewable growth, however increased competitive may limit additional cost to the system

Headlines

- Germany has highly liquid and increasingly integrated ancillary services market that is coupled with its neighbouring markets.
- Capacity mix changes in Germany are influencing demand for flexibility across Europe. With the highest renewable growth rate in Europe, and the retirement of traditional thermal capacity, it is expected that the need for flexibility will increase in the coming years.
- Despite the significant growth in renewable generation, the required volumes of system services have reduced notably over the last five years. There are various reasons for this, but key factors include:
  - Technical improvements allowing more accurate supply and demand projections, reducing the need for system operator actions
  - Changes to the market design to offer market participants for shorter lead times and delivery periods/time slices facilitating market access and competition

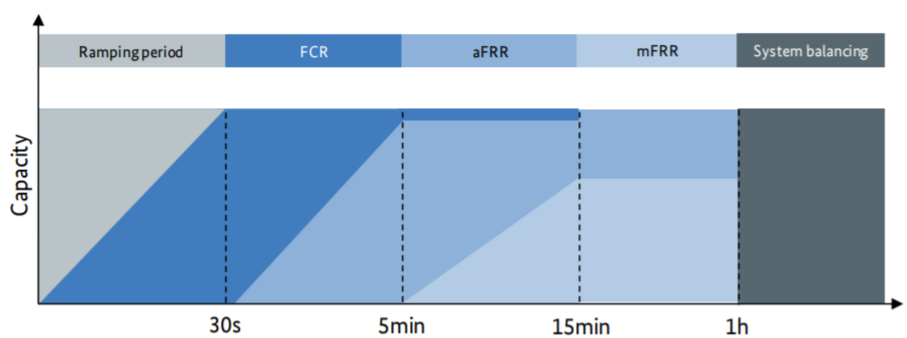
Objectives

- In Germany, like all other market, system services provide a tool for the system operators to manage system security (i.e. changes in system frequency) and balance supply and demand in real-time
- The objective of the system operators, and in particular the changes is service offerings that have occurred in Germany, is to facilitate renewable investment and manage the impact of renewables on the system at least cost
- To achieve this objective, Germany trades system services with its neighbours, and has taken steps to open the system series market to greater competition

Design

- There are three types of reserve capacity in Germany, Primary reserve, Secondary reserve and Minute reserve, increasing in response time and the duration of the reserve holding requirement
- These services are used by the system operators to provide positive as well as negative balancing energy.
- Primary Reserve, known as Frequency Containment Reserve is a fast reserve services and serves to stabilise frequency deviations in the system and is remunerated only through a capacity price
- Frequency Restoration Reserves (FRR) have separate remuneration for both capacity reserved and energy delivered/reduced

Order and timing for system services in Germany



System services in Germany (2/3)

Germany has implemented a number of changes to the ancillary services markets, aiming to increase market access and competition and provide support for the growing renewable sector

Products and services

Reserve products

- **Primary reserve – Frequency Containment Reserves (FCR)**: This is a local, automated service designed to manage frequency across the power system with a response time of <30s.
- **Secondary Reserve – Automatic Frequency Restoration Reserves (aFRR)**: This is a market based services, with the system operators accepting bids to manage real-time power imbalances. The volume of FRR is based on historical imbalances. The system operators procure aFRR through capacity contracts.
- **Minute Reserve – Manual Frequency Restoration Reserves (mFRR)**: This service is activated manually by the system operators for situation where the imbalance is as a result of large-scale outage or is likely to last for a long time.

Product	Open to battery	Open to Demand Response	Market Size (approx. MW)	Market Size 2018 (approx. €m)	Capacity prices 2018 (€/MW/h)
Primary Reserve (FCR)	Yes	Yes	650	81	12.6
Secondary Reserve (aFRR)	Yes	Yes	1900 (up/down)	147	8/1.7 (up/down)
Minute Reserve (mFRR)	Yes	Yes	1000 (up/down)	37	0.5/0.15 (up/down)
Reactive Power	Uncertain	No			

Future market design

- The revenues achieved by providers of secondary reserve and minute reserve have fallen significantly over the last years. At the same time, the volume of required and activated reserve has also decreased, despite the increase in renewables.
- There are a number of changes in market arrangements that led to this development (such as move to 15 min. gate closure), but a key aspect is the increase in competition in reserve provision.
- There are a number of further changes being brought forward to improve the accessibility of reserve for new and smaller providers, and increase the ability of plant to optimise their reserve and energy market participation.
- In the long-term, Germany is likely to implement a secondary market for reserve energy in line with Europe-wide balancing market guidelines, which will further increase competition in the reserve markets.
- We provides further detail on the system services changes in Germany on the next slide.

System services in Germany (3/3)

The landscape for system services has changed in Germany with moves to facilitate market access for new and smaller service providers

Future market design (continued)

- This table shows some of the recent changes in reserve product design in Germany.
- We see that the tender period has become more frequent, moving from weekly to daily auctions for all reserve services.
- There are now more granular product time slices and lower minimum bid sizes, offering greater market access to new and small market participants.
- In future, Germany proposes to move all auctions to pay-as-clear with a single, simple, capacity fee, simplifying access and potential gains for some market participants.

		Primary Reserve	Secondary Reserve	Minute Reserve
Tender period	Before 12 July 2018	Weekly	Weekly	Daily (Mon-Fri)
	From 12 July 2018		Daily (7 days)	Daily (7 days)
	From 1 July 2019	Daily	n/a	n/a
Product time slices	Before 12 July 2018	None - whole week (whole day from 1 July 2019)	Peak/Offpeak	6 x 4-hourly blocks
	From 12 July 2018		6 x 4-hourly blocks	6 x 4-hourly blocks
	From 1 July 2019	4 hour blocks	n/a	n/a
Product differentiation		None (symmetric product)	Positive / negative SRL	Positive / negative MRL
Min. bid size	Before 12 July 2018	1 MW	5 MW	5 MW (up to 25 MW)
	From 12 July 2018		1 MW (if only 1 submission)	1 MW (if only 1 submission)
Acceptance	Before 12 July 2018	Capacity price merit-order	Capacity price merit-order	Capacity price merit-order
	From 12 July 2018		Mixed-price method* (capacity and energy)	Mixed-price method* (capacity and energy)
	From 31 July 2019		Capacity price merit-order	Capacity price merit-order
Remuneration	Current	Pay-as-bid (Capacity fee)	Pay-as-bid (capacity fee and unit fee)	Pay-as-bid (capacity fee and unit fee)
	Proposed	Pay-as-clear (Capacity fee)	Pay-as-clear (Capacity fee)	Pay-as-clear (Capacity fee)

* overturned on legal appeal

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Spotlight: Renewable curtailment (1/2)

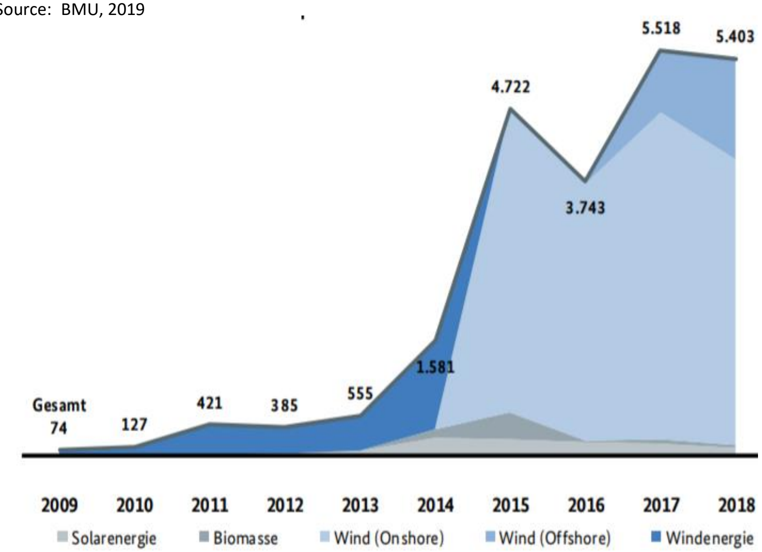
Grid management measures in Germany have increased in recent years due to the significant increase in intermittent renewable energy and delays in grid expansion

Background and Mechanisms

- Germany has very ambitious plans to increase its renewables production – by 2030, the country wants to increase renewable generation to 65% of total generation
- The system operators must take actions to ensure reliability of the electricity grid in Germany. The need and drivers for system actions are subject to change as a result of:
    - An increase in decentralised wind energy, often located far away from consumption centres
    - Changes in the thermal asset (reductions in coal and nuclear) – assets that are typically relied on by the system operators
    - Changing market physical trade with other markets (i.e. imports and exports)
- In particular the physical transmission network has struggled to cope with the level of renewable investment, resulting in significant constraints between the north and south with the system operators taking actions to manage these constraints through renewable curtailment
- The German system operators, through their network plans, are addressing the investment needs, but investment is taking longer than expected resulting in significant and sustained constraint costs in Germany
- In the interim period, there are four measures available for the system operators to manage network constraints. Reducing renewable output in the north, through 'Feed-in-Management' is the most relevant grid management method for wind power curtailment
- Curtailment volumes have increased significantly over the past decade as shown on the chart on the right hand side

Curtailment volumes by renewable tech (2009-18, GWh)

Source: BMU, 2019



Overview of grid congestion measures in Germany

1 Redispatch	2 Reserve power plants	3 Feed-in management	4 Grid Adjustments
Increase or decrease of production of a conventional power plant by the system operator	Increase of production by reserve power plants based on a contractual agreement with the system operator	Decrease of production of mainly renewable generation by the system operator	Decrease of production of renewables/CHP generators by system operator
Compensated	**Compensated**	**Compensated**	**Not compensated**

Spotlight: Renewable curtailment (2/2)

Germany has one of the highest levels of renewable deployment in Europe, but has seen the cost of reserve, to manage the system, fall as a result of better information and competition

Solving network constraint and reducing curtailment

- Renewable connections, especially wind, in Germany has been focussed on the north and east of the country. Combined with the transmission network constraints, particularly in the north-south direction, this has meant that system operation challenges have not been evenly distributed across the country.
- The regional transmission areas in the north and east, owned and operated by TenneT, has faced the most significant challenges and had to take the most costly actions (particularly around curtailment) to manage the system.
- In Germany, the nature of firm connection costs means that the cost of curtailment falls to the system operators to manage, with the ultimate costs passed back to network users and consumers through network charges.
- The German system operators are working to alleviate constraints, in part caused by renewable investment in the north, by investing in north-south transmission reinforcements. These internal network reinforcements will reduce curtailment and the cost of managing the impact of renewables on the system in Germany. The timing of this investment is critical, as delays are causing increasing costs for the system operators (as shown on the previous slide).
- Alongside network reinforcements, the German system operators continue to look outside of the German national borders to help manage intermittency and ensure system stability.
- Like many other central European Member States, the German system operators place high value on the ability to trade with neighbours to balance the system (see slide 18 on describing the International Grid Control Cooperation)
- The German ancillary services markets provides an interesting counterpoint to many other markets in Europe which are also experiencing high levels of renewable growth. Technical improvements to the way that supply and demand can be forecast provides the system operators with better information and has actually reduced demand for system services (notably secondary and minute reserve).
- Alongside better information, changes in the design of system services, for example procuring reserve for more targeted time periods, has helped to reduce demand for system services. Coupled with an increase in supply, as barriers to ancillary service have reduced, this has brought down prices and costs to the system operators.
- Whilst the cost of system security measures (re-dispatching using operational and grid reserve power plants, countertrading, feed-in management) in Germany remains a large portion of the total cost of managing the system (over 75% in 2018), the cost of system services has fallen in recent years with an overall reduction in the cost of managing the system in Germany (the total cost of system services, recovered through network charges, fell between 2017 and 2018 from €1.98bn to €1.88bn (BNETZA, here).

Denmark

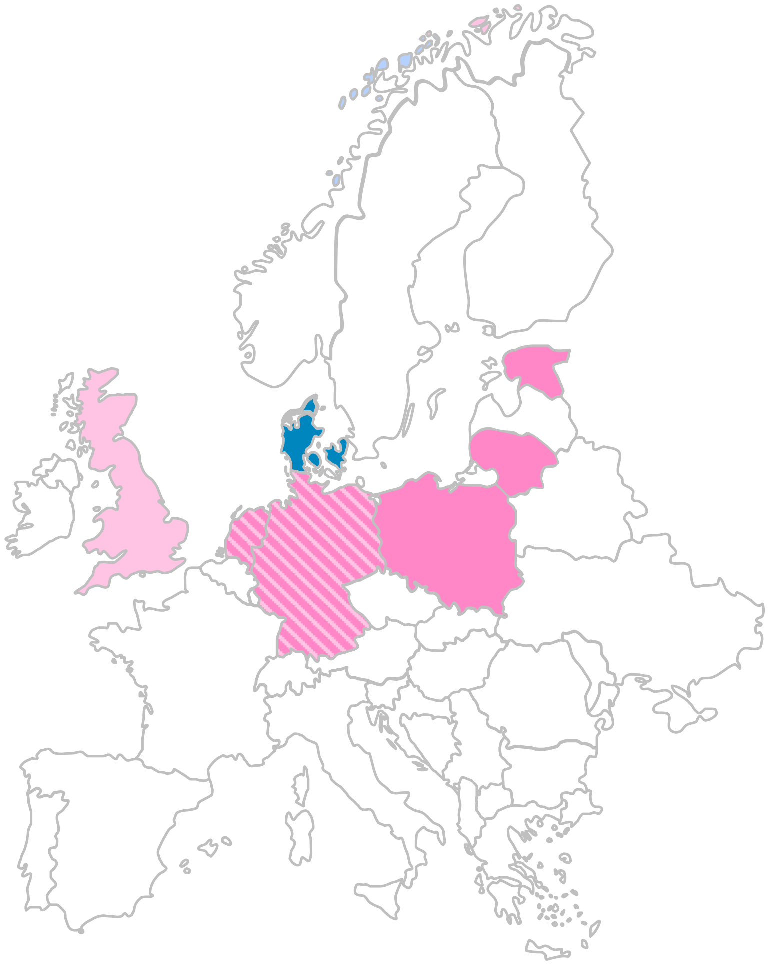
National Infrastructure Commission
November 2020

Contents

Overview of the material provided in this case study

Executive summary: Market overview

Denmark has high renewable capacity and is a highly integrated power market, forming part of the Nordic power market and is coupled with the main European synchronous grid



Existing interconnection

Planned interconnection

Planned and existing interconnection

Energy policy

- Denmark has a strong history of renewable investment dating back to the 1980s, as the country looked to renewables in response to the economic difficulties driven by the oil crises of the 1970s.
- Consequently, Denmark is a well-developed market for renewable investment and policy design, particularly in wind – where Denmark is a world leader.
- In 2018 the Danish Energy Agreement was signed, stating that 100% of Denmark's electricity consumption must be met by renewables by 2030 (100% of all *energy* needs by 2050) and mandating that 3 offshore wind farms totaling 2.4GW will be established in this timeframe.
- In 2018, technology neutral auctions were introduced, with winning bids from both the wind and solar PV. The 2019 auction also saw the emergence of solar and wind hybrid projects.
- These auctions have been significant in reducing support levels for renewables through competition.

Market

- Denmark's market and network is split into two separate markets – East Denmark and West Denmark.
- This transmission distinction determines the Danish approach to system operation and ancillary services, with the Denmark East aligned with Nordics and Denmark West connected to the European synchronous area and participating in the European harmonisation platforms for sharing of system services.

Wholesale prices

- Across Denmark, wholesale electricity prices are around €30-35/MWh driven by high penetration of low cost renewables.
- However, Danish households pay one of the highest electricity prices in the EU, mainly due to a very high level of energy taxes and levies to support the large renewable sector.

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Executive summary: Key insights

Baringa

Denmark has achieved significant renewables penetration and is starting to explore offshore coordinated infrastructure to increase renewable output and increase cross-border flexibility

Key insights for Denmark

Denmark is further along the renewables journey than most countries (slides 60, 61 & 63)

- Denmark's energy history has shaped its current capacity mix. Prior to the oil crises in the 1970s Demark sourced >90% of its energy from imported oil, which led to economic turmoil and a change in focus on their energy mix with wind power included in plans as early as the 1980s.
- This helped to cement the importance of security of supply in Denmark and led to energy policy focused on domestic generation and renewables. Reaching the levels of wind generation today (enough to power 130% of national demand for 24 hours in September 2019) is a result of this sustained energy objective over a long period of time.
- In 2018, the Danish government moved its focus from onshore to offshore wind, at the same time reducing subsidy payments in a response to tightening budget pressures.
- Renewable subsidies are now at a level that puts renewables close to grid parity, with recent examples of corporate un-subsidised Power Purchase Agreements (PPAs) providing financial support for new investment (however the uptake of un-subsidised corporate PPAs in Denmark is far below other Nordic countries, such as Finland and Sweden).

Denmark has clear geographical advantages for renewable deployment (slides 55, 57 & 58)

- Denmark has optimal wind conditions – it is sparsely populated with 134 people per square kilometre, and with long coastlines and shallow waters, conditions are ideal for onshore and offshore wind.
- Denmark's significant levels of interconnection, with the Nordics and mainland Europe, provides the Danish market with access to flexibility to manage the variability of domestic wind output and the challenges associated with managing significant levels of renewables on the system (i.e. frequency management).
- Denmark's connection to the European system, which is all one synchronous area, provides access to a large market area and cross-border balancing and system services platforms. This means that Denmark does not face the same degree of system operation challenges as other small renewable driven nations, such as Ireland.
- Denmark has also seen regulatory and commercial innovation in the roll-out of renewables offshore, for example through offshore coordinated infrastructure connecting the Danish and German markets via the Kriegers-Flak offshore wind farm. These hybrid projects offer opportunities to increase offshore wind deployment alongside increased cross-border investment in flexibility to help manage the system.

Insights for the UK

Consistent policy drives investment

- Denmark provides a clear example of how stable renewable policy (through Feed-in-tariffs) provides the necessary conditions for sustained investment.
- Kick-starting the industry in this way has delivered a well-established renewable sector, with significant levels of deployment, and a market that is pushing into merchant (un-subsidised) renewables investment.

Focusing on the right technologies

- Part of Denmark's success is a focus on technologies that it had an advantage in through geography and natural resources, i.e. onshore wind.
- The level of interconnection and ability to benefit from cross-border balancing and system services, is a key driver of successful deployment in Denmark.
- Denmark's recent innovation in coordinated offshore networks shows how policy and decision makers, along with industry, need to work together to deliver high risk, innovative pilot projects.

Market overview

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Key characteristics of the Danish market

Baringa

The Danish market is highly integrated with links to Scandinavia and Germany – Denmark itself is split into two transmission systems which are connected by the 'Great Belt Power Link'

Market structure

In 2003, the Danish electricity market was liberalised, making it possible for all Danish consumers to freely choose their electricity supplier. In 2013, Denmark took further steps to standardise data and billing information through a DataHub, providing access to suppliers and consumers to help improve transparency in consumption and increase competition. A new market model (the supplier centric model) was introduced in 2016, which simplified market engagement (for example resulting in a single consumer bill) in an attempt to further increase competition and support the development of new consumer products and services.

Value chain	Description
Generation	▲ Generation in Denmark is dominated by wind, which accounted for 47% of power in 2019. Key players within wind generation in Denmark are: Vattenfall, Orsted and wind turbine giant Vestas ▲ Denmark has been reducing reliance on Oil and Gas over the past 10 years ▲ The large reliance on wind, and being heavily interconnected, results in Denmark often being a net importer of energy
Transmission/ Distribution	▲ Denmark has two transmission systems, one in the east and one in the west, which are connected by the 'Great Belt Power Link' ▲ The transmission grid as a whole is operated by Energinet, the Danish Transmission System Operator, who is an independent public enterprise owned by the Danish Ministry of Climate, Energy and Utilities. ▲ The distribution network is operated by over 17 different companies ▲ Denmark is also characterised by interconnection with links to Germany and Scandinavia in place and work starting on the 'Viking Link' which will connect Denmark to the UK with a planned commissioning date in 2023
Retail	▲ Denmark has approximately 2,750,000 residential customers and roughly 500,000 non-residential customers ▲ There are approximately 50 active energy suppliers in the Danish market, with SEAS-NVE, HOFOR, SE Energy and Climate and Orsted acting as the main market participants ▲ Danish households pay one of the highest electricity prices in the EU, mainly due to a very high level of energy taxes and levies (household consumer prices in Denmark in 2019 were €0.29/KWh compared to €0.22/KWh in UK – Eurostat, here) ▲ The main utilities in Denmark are: HOFOR, Orsted (although they are in the process of selling their residential customer business to SEAS-NVE for circa €2.85bn), SEAS-NVE and SE Energy and Climate
Regulator	▲ The Danish Energy Regulator is Forsyningstilsynet, who were established in 2018 taking over from the Danish Energy Regulatory Authority (DERA)

Sources: Baringa research

Spotlight: Denmark in the Nordic market

Denmark is part of one of the most integrated and liquid power markets in Europe – the Nordic power market

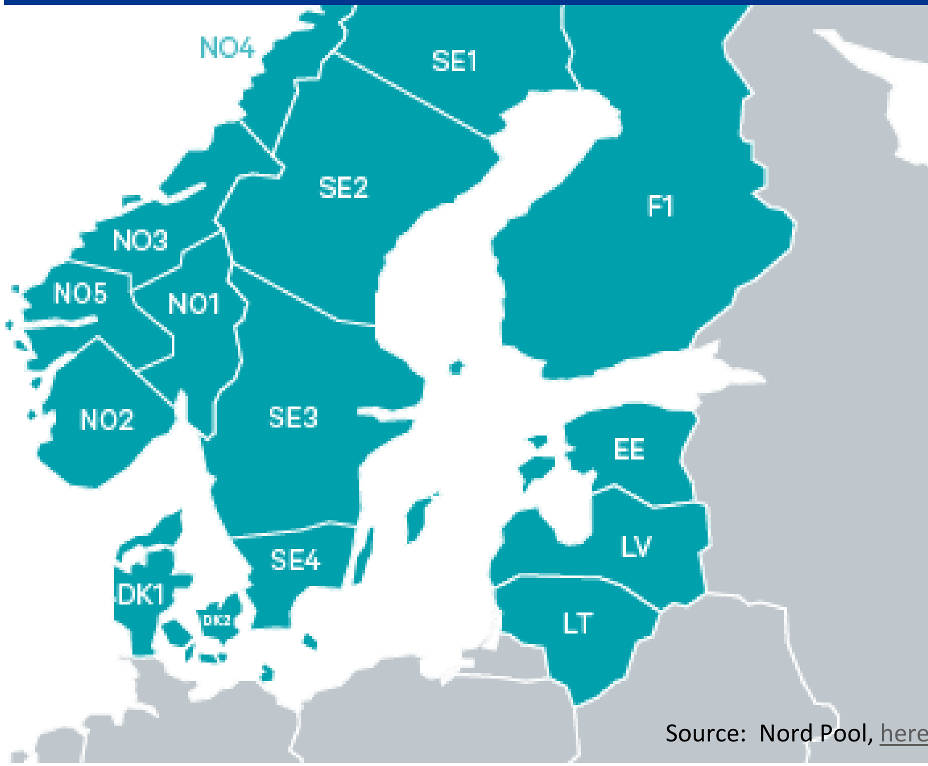
Nordics overview

- The electricity markets in the Nordic countries have undergone major changes since the middle of 1990s. All Nordic countries have liberalised their electricity markets, opening electricity production and distribution to competition through energy-only markets.
- 75% of the region's wholesale electricity is traded on the power exchange, Nord Pool, making it one of the most competitive and liquid markets for wholesale electricity in the world.
- More recently, increasing renewable penetration, further development of interconnection within the Nordic countries and with Continental Europe and changes in consumption – driven by climate change policies, technology advancement and a common European framework for markets, operation and planning – have created more challenges and opportunities for the Nordic power sector and its stakeholders.

Networks across the Nordics

- The high voltage transmission systems are publically owned and regulated monopolies. Alongside Energinet in Denmark, the Nordic system operators include Fingrid (Finland), Statnett (Norway), and Svenska Kraftnät (Sweden).
- The Nordic system operators share the ownership of Nord Pool, which runs the power market for the Nordic countries offering trading and associated services in both day-ahead and intraday markets across nine European countries.

Nord Pool Day-Ahead market bidding areas



Source: Nord Pool, here

- There is significant differences in the cost of generaton between the northern Nordic regions dominated by hydro capacity and the southern regions which consist of thermal capacity in combination with increasing renewables.
- In addition the southern zones are connected to other markets further south (e.g. Germany) which has a varied mix of thermal and intermittent renewables generation.

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Power market structure

Nord Pool is one of the most competitive and liquid markets for wholesale electricity in the world with volume turnover in 2019 of over 800TWh

Overview

- Nord Pool remains one of the most competitive and liquid markets for wholesale electricity in the world although over the past decade there has been a decline in forward traded volumes on the Nordic forward market with traders disagreeing on the precise reason for the reduction (tightening regulation, lower prices, changes in volatility).
- Traded volume in 2019 was 814 TWh, which means that the volume turnover has decreased for eight consecutive years (in 2008, volume turnover peaked at 2,535 TWh)
- During 2019 a total of 494 TWh of power was traded through Nord Pool, including the Nordic and Baltic day-ahead market (382 TWh), the UK day-ahead market (94 TWh), and record volume from Nord Pool's intraday markets (16 TWh).
- A total of 380 companies from 20 countries trade on Nord Pool Spot.

Day-ahead market

- The Day-Ahead market is a core Nord Pool market, with bids and offers coupled as part of the pan-European Market Coupling mechanism (known as Single Day-Ahead Coupling – the mechanism used across Europe for Day-Ahead power trading).
- This takes place through the common European Market Coupling algorithm applied across Europe
- The Nordic market has separate bidding zones which take into account the network constraints between different parts of the grid. This market design, limited to the Nordic markets in Europe, results in different prices within the Nordic regions (including East and West-Denmark).

Intra-day market

- The Intra-day market offer market participants the opportunity to trade closer to real-time, and is valuable in Denmark and the Nordics given the significant volume of intermittent generation on the system
- The Intra-day market is a continuous market, which means that trading takes place in all time periods up to an hour ahead of delivery, with prices matched on a first-come-fist-served basis
- Nord pool offers a range of products to give market participants the ability to manage their positions (15 minutes, 30 minutes, hourly and block bids)

Forward market

- Forward trading takes place through the trading platforms (Nasdaq and EEX) offering financial future, options, Demand Settled Futures and Electricity Price Areas Differentials (i.e. capturing the risk of different market prices between price zones in the Nordics)
- Nasdaq offers yearly, quarterly and monthly products

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Overview of cross-border exchanges

Baringa

Denmark is a net importer of electricity with reliance on flexibility from Germany, Norway and Sweden to help manage renewables on the Danish system

Cross-border capacity

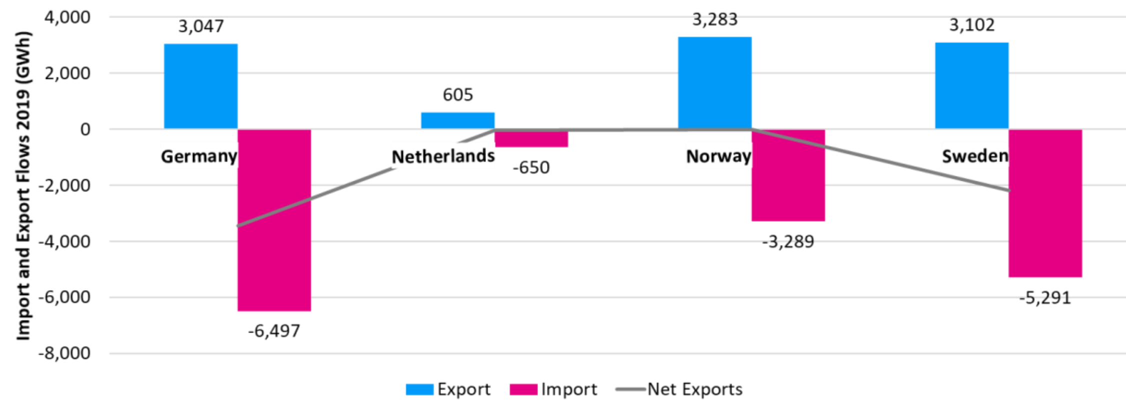
- Denmark is well connected to its neighbours through existing onshore and sub-sea cables (1.7GW to Norway, 2.4GW (export) to Sweden, >2GW to Germany)
- The Danish system operator has a number of projects in the pipeline/recently commissioned to increase cross-border capacity including:
  - A new 700MW sub-sea cable to the Netherlands, which commissioned in 2019
  - A new 400kV overhead line with Germany, commissioning in 2023
  - A new 400MW sub-sea interconnector with Germany, forming part of the Kriegers-Flak combined grid solution, and commissioning in 2020
  - A 1.4GW sub-sea connection to the UK (Viking link) developed with National Grid Ventures to commission in 2023

Cross-border flows

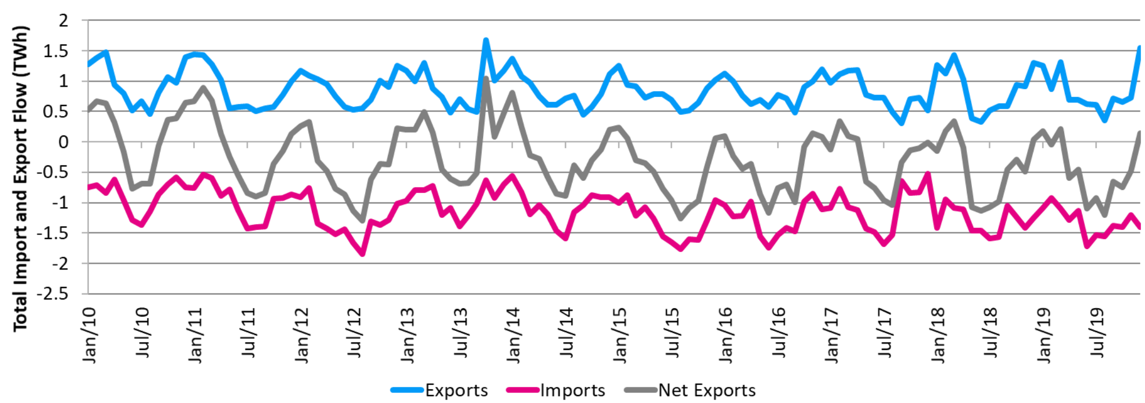
- Denmark had net imports from Germany, Norway, Sweden and the Netherlands in 2019.
- Denmark's trade profile has a strong seasonal component:
  - During the winter season, Denmark exports the wind power surplus
  - For the rest of the year, Denmark imports electricity mainly from Norway and Sweden who produce larger quantities than they can consume during summer (high hydro availability).
- The relatively low exports to Germany are also affected by internal grid constraints on the German network, limiting available capacity

Danish imports and exports and flow profiles

Imports, exports and net exports in 2019



Historical flow profile over the past decade



Source: ENTSO-E

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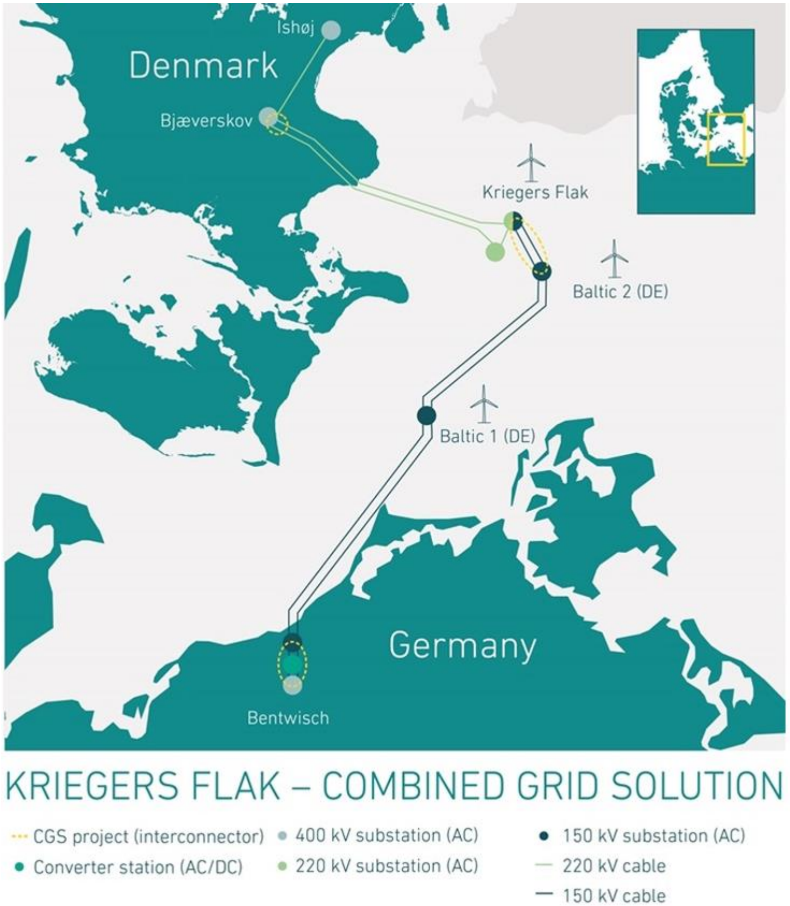
Spotlight: Coordinated infrastructure investment

Denmark and Germany have led the way by developing the commercial, regulatory and technical solutions for a hybrid offshore wind/interconnector project in the Baltic Sea

The Kriegers-Flak Combined Grid Solution

- The Kriegers-Flak combined grid solution will be a first-of-its-kind project that combines offshore wind and cross-border interconnection.
- The project has been developed by the Danish, and one of the German, system operators.
- The project will connect 2 operational wind farms in Germany (Baltic 1 and 2 with a total capacity of 236MW) with the Danish Kriegers-Flak wind farm (600MW), currently under construction, via a 2 sub-sea cables with a capacity of 400MW.
- Scheduled to start operations later this year, the project will connect the Danish and German market via a sophisticated combination of transformers to manage the different frequencies of the Danish (Nordic) and Germany networks.
- The European Commission’s European Energy Programme for Recovery (EEPR) awarded the project €150m.
- The primary purpose of the project is to provide a route for renewable export to both the Danish and German markets, with remaining capacity on the network used for cross-border exchange between markets (in response to economic price signals) – this agreement has been subject to extensive legal and regulatory discussions between the national system operators, regulators and the European Commission.
- Whilst the project is considered a success, it has faced a number of challenges, mainly relating to the lack of clear regulatory arrangements for coordinated infrastructure in Europe.
- Regulatory coordination, innovation and the need for political support/commitment are key success factors identified by the project partners for any first-of-a-kind project, along with an understanding that the project should be defined as a ‘pilot project’ (paving the way for some bespoke arrangements or solutions).



Source: Energinet, here

Climate goals and subsidy mechanisms

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Energy and climate change objectives

Baringa

Denmark is on track to achieve its RES 2020 targets but relies heavily on cross-border flows to manage intermittency from high levels of renewable integration

European energy strategy – 2030 targets

- The EU Commission's winter package reinforces the targets to be achieved in the period 2020-2030 through a range of initiatives:
  - A reduction in greenhouse gas emissions of at least 40% below 1990 levels
  - Sourcing 32% of final energy consumption from renewable sources (RES) by 2030
  - A 30% reduction in primary energy use compared with projected business-as-usual levels, to be achieved through improved energy efficiency and by phasing out coal power plants
- Denmark is taking domestic policy action to help incentivise renewables over other generation sources. As an example, Demark is phasing out its Public Service Obligation, originally intended to support thermal generation, and redirecting funds towards renewable investment.
- Part of Denmark's focus is on domestic and commercial heating – re-directing tax on electric heating to incentivise renewables heating options
- Denmark has ambitious 2050 targets, with the aim to become a carbon neutral society by 2050

Country	RES share in gross final energy consumption		RES share of electricity consumption	
	2020	2030	2020	2030
Denmark	30%	55%	52%	>100%

Internal Energy Market

- Part of Denmark's strategy for managing renewables and intermittency is through interconnection and trading with its neighbours
- Denmark has successfully implemented implicit and explicit capacity allocation (the European rules designed to improve efficiency and harmonise cross-border trading across Europe).
- Participation in the internal energy market provides a valuable source of imports for Denmark, offering a source of flexibility to manage renewable integration

"The parties in the energy agreement have allocated funding that sets a course towards a RE (renewable energy) share of approximately 55% by 2030. The agreement also aims to give Denmark a RE share in electricity above 100% of consumption, and ensure that at least 90% of district heating consumption is based on energy sources other than coal, oil or gas by 2030"
- Denmark's Integrated National Energy and Climate Plan, December 2018, here

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Renewable support in Denmark

Denmark is committed to 100% renewable electricity, by consumption, by 2030 extending this target to all energy consumption by 2050

Overview

- The new energy agreement signed by the Danish parliament in June 2018 puts a focus on the large scale development of offshore wind while support for other renewables will continue to be allocated through technology-neutral tenders as part of the Feed-in-premium mechanism.

Renewable auctions – Feed-in-premium

- Denmark runs technology neutral tenders, with eligible technologies including onshore wind, solar PV and “open door” offshore wind (sitting outside the tenders announced by the Danish state – see description on right).
- The tender is capped by a budget, meaning that the number of successful tenderers depend on tenderers’ size (MWh) and bid (øre/kWh), with the potential that all tenderers could be successful if the budget cap is not exceeded.
- Bidders will bid in the support they require (subject to caps) and support is granted for maximum of 20 years from grid connection.
- The support will be in the form of premium paid on top of the electricity price on the spot market (with exceptions for when spot price is negative).
- The government extended the tendering system to 2020-2024 and to additional technologies such as wave power and hydro power.
- The technology neutral tenders in 2020 and 2021 will take the form of a hybrid CfD model with a bid cap of 25 øre/kWh (roughly 34 €/MWh) and a budget cap of DKK 600 million (roughly €80 million). This new tender format is currently undergoing public consultation.

Tenders for offshore wind in Denmark

- Alongside the feed-in-premium support scheme, the Danish Energy Agency has been running offshore wind auctions for three new offshore wind farms that will supply at least 2,400 MW by 2030.
- All energy auctions are pay-as-bid.
- Before 2015 single-site auctions had been used to develop 4 wind farms: Horns Rev 2, Rødsand 2, Anholt and Horns Rev 3.
- Sliding premiums are awarded which are hourly two-way CfD contracts. Prospective tenders have the opportunity to influence tender conditions to help mange allocation of risk between parties which has resulted in competitive outcomes to date.
- These contracts include project specific conditions, for example for Anholt and Horns Rev 3 subsidies are not paid when spot prices are negative.
- The nearshore auction in 2016 resulted in Vattenfall being awarded contracts for Vesterhav Nord and Vesterhav Syd totalling 340 MW. The 600 MW Kriegers Flak tender in the same year was also awarded to Vattenfall.
- Three further offshore wind tenders have been confirmed, with the first one, Thor (800-1000 MW), launched in September 2020.

Investment and route to market

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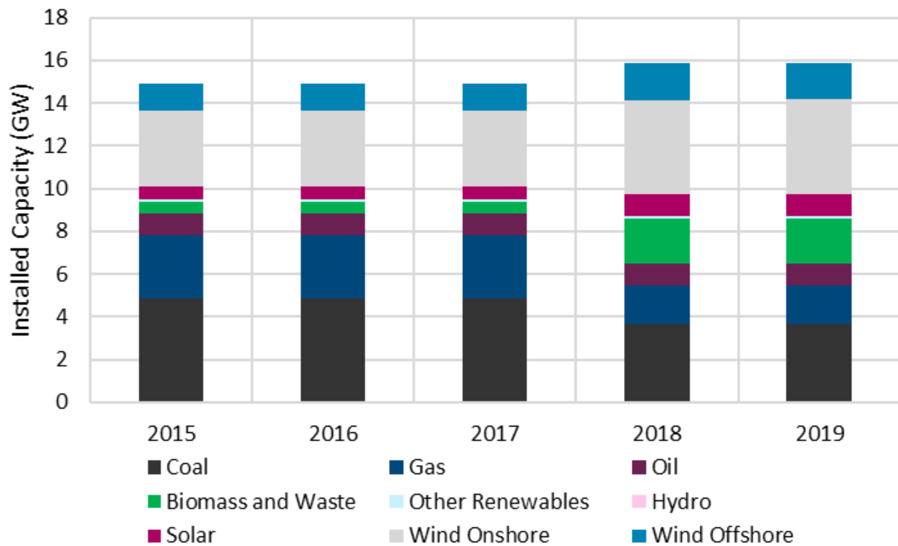
Electricity capacity and generation

Denmark has doubled its electricity generation from wind in the past nine years, with slower investment over the past 5 years

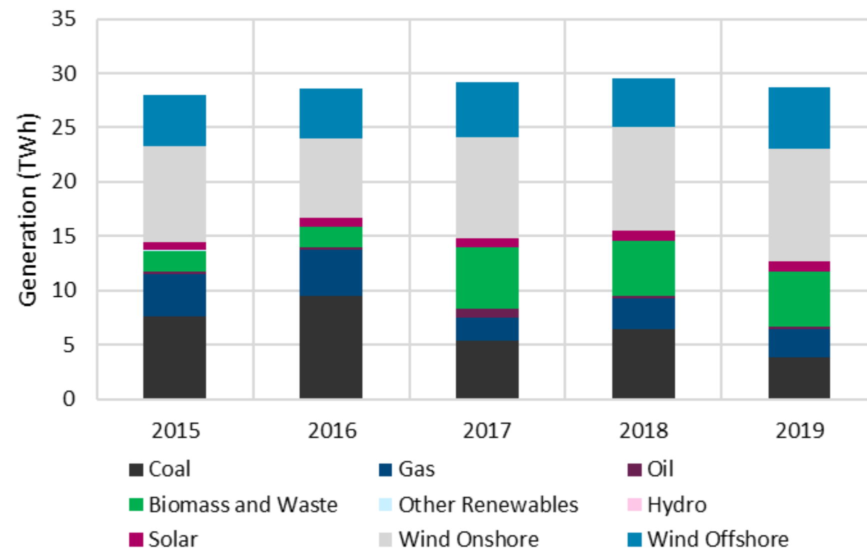
Historical capacity mix

- Denmark is a leader in terms of energy produced from Biomass and Waste with a total installed capacity in 2020 of 2.1 GW.
- A large portion of conventional power generation is connected to the district heating system – with the possibility of co-generating electricity and heat.
- Wind power accounts for more than one-third of installed power capacity – 38%. In 2019 there were more than 6 GW of installed onshore and offshore wind.



Historical generation mix

- Electricity generation from wind turbines has grown from 49% in 2015 to 56% of generation in 2019.
- Generation from coal and gas has fallen significantly since 2015. From approximately 41% of total generation to only 22% of total generation in 2019.
- Unlike other Nordic regions, Denmark has almost no hydro power given the lack of the right geographical conditions (in contrast to Norway, for example, where hydro power dominates the wholesale market).



Notes: We note that the ENTSO-E data shows a discrepancy in the timing of capacity and generation output for Biomass and Waste which we understand to be a results of a lag in the reporting in the ENTSO-E dataset.

Source: ENTSO-E

Renewable routes to market

Baringa

A successful auction in late 2019, with low bids, led to speculation that Denmark may stop holding auctions and led to an increase in activity around unsubsidised corporate PPAs in Denmark

Routes to market for renewable generators

	Onshore wind	Solar	Offshore wind
Renewable support schemes	▶ Denmark runs renewable energy auctions which provide a feed-in-premium on top of the wholesale price of power. ▶ The price premium is granted as pay-as-bid meaning that each winning tenderer will receive the price premium that was included in their bid on top of the market price for electricity. ▶ Low bids in the 2019 auction, resulted in speculation that Denmark may be ready for unsubsidised green power. ▶ The last auction in December 2019 received 7 bids totaling 271MW of solar and wind, with 252MW allocated. ▶ The average price premium was DKK 0.0154/kWh, far below the ceiling of DKK 0.06/kWh and a large decrease on the previous year (DKK 0.0228/kWh).		▶ Offshore wind farms that have been subject to competitive tender also have access to project specific 20-year CfD arrangements (note that tender includes the cost of constructing and operating the onshore connection assets) ▶ The Danish Energy Agency consults on the CfD design and rates for the project specific CfD ▶ Prospective tenders have the opportunity to influence tender conditions to help mange allocation of risk between parties which has resulted in competitive outcomes to date ▶ Recent tenders include the current tender for the Thor offshore wind farm where parties bid for a CfD (800MW offshore wind farm commissioning in 2025-27) *Source: DEA, here*
Unsubsidised corporate PPA	▶ Denmark has a reasonably advanced market for unsubsidised corporate PPAs, but corporate PPAs are less common than in other Nordic markets. ▶ This is in part due to lack of investment in renewables in Denmark compared to other Nordics, Finland and Sweden in particular, which is in turn, not driving demand for these type of contracts (Sweden, for example has significant industrial demand which provides strong incentives for merchant PPA solutions outside of the market). ▶ Recent activity includes Better Energy and Best Seller who announced a small 25 MW solar PPA (February 2019), and Apple developing a 50 MW solar project to support its Viborg data centre (September 2020)		

Grid integration and system operation

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System services in Denmark (1/2)

Baringa

Since Western Denmark (DK1) and Eastern Denmark (DK2) are part of their respective synchronous areas, there are also differences in the use of and the need for system services

Headlines

- The Danish system operator procures a number of system services to help it maintain balance and stability of the electricity system
- The vast majority of system operator's system services consist of reserves (including Fast Frequency Reserve and Frequency Containment Reserve) and regulating power (for example voltage regulation)
- These are procured through market-based arrangements, in a mix of short-term and long-term tenders
- Since Western Denmark (DK1) and Eastern Denmark (DK2) are part of their respective synchronous areas, there are also differences in the use of and the need for system services
- Harmonization across system boundaries is expected in future in the Nordics and in Europe for system services such as Automatic Frequency Restoration Reserve (through a European system called PICASSO), Manual Frequency Restoration Reserve (through MARI) and Replacement Reserve (through TERRE)

Product	DK1 – East	DK2 – West
Frequency stabilisation / Primary reserve	FCR +/- 20 MW	FCR-N +/- 18 MW FCR-D +/- 44 MW
Frequency recovery / Secondary reserve	aFRR +/- 100 MW	
Balancing equalisation / Tertiary reserve	mFRR + 282 MW	mFRR + 623 MW

Design

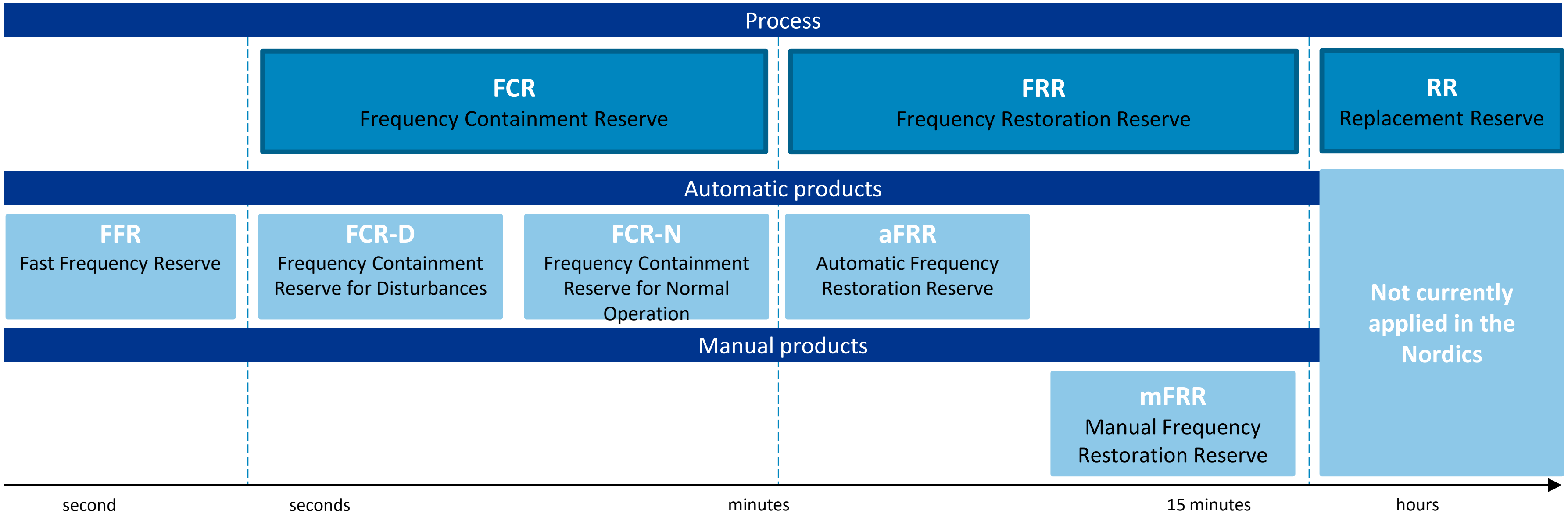
- The synchronous grid in the Nordics consist of Denmark East, Norway, Sweden and Finland, operating at a nominal frequency of 50.0 Hz (the frequency range in Denmark is 49.9 - 50.1 Hz)
- Balancing frequency on this synchronous grid is carried out under a joint Nordic system with procurement of standardised products by the transmission system operators of each country, based on relative annual electricity consumption. Requirements are met by a mix of cross-border (normally up to 1/3 of their total obligation) and domestic resources (normally at least 2/3).
- A range of balancing products are used, from those that respond in seconds (e.g. Fast Frequency Reserve and Frequency Containment Reserve), which help arrest an initial sudden change in frequency and manager system inertia, to those that respond in minutes (Frequency Restoration Reserve), which help restore system frequency to 50 Hz over longer timeframes.
- In particular, Frequency Containment Reserve for Normal Operation (FCR-N) is used to maintain system frequency between 49.9 and 50.1 Hz during normal operation
- Currently the Nordic FCR-N requirement is around 600 MW, which is derived from 1% of demand variation of the peak Nordic load (around 60 GW)
- Whilst the products are largely standardised, system operators can add specific features to suit the need of their grid, and use different procurement mechanisms that they deem the most appropriate based on local supply/demand and market dynamics

Baringa

System services in Denmark (2/2)

System balancing is carried out in a joint Nordic system whereby each system operators has an annual obligation to maintain a certain reserve, using a number of products to balance the system

Products and services



Addition services

- In addition, there is a smaller need for "system bearing properties" including inertia, short-circuit power and voltage, and other system services, such as emergency start-up.
- The reason this need is small in Denmark is that a lot of the services are provided for free due to the way the system operates (still a fair amount of synchronous generation), due to grid connection technical requirements (minimum standards regarding fault ride through etc.), or due to the nature of the product itself (e.g. black start requires a few large power stations in strategic locations).
- The need for such services is not constant, and the system operator makes ad-hoc purchases of system-bearing properties when a need arises, e.g. due to predictable events such as summer maintenance outages of large thermal units, or due to unpredictable events such as unplanned outages of generators or network elements.
- The services can often only be provided by plants of a certain size (>150 MW) that are directly connected to the transmission network (>100 kV).

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Facilitating future renewable deployment

Baringa

High integration with neighbouring markets, flexible operation of domestic generators and use of innovative technologies to provide ancillary services supports the integration of wind in Denmark

The importance of cross-border connections

- Denmark is highly interconnected with other countries including Sweden, Germany, Norway and the Netherlands, with a total of around 7 GW export and import capacity.
- In addition, the east and the west are also interconnected with via a 600 MW HVDC link.
- The interconnectors provide a valuable trade route for excess electricity from Denmark to be exported (and electricity to be imported when Denmark faces an electricity deficit due to intermittency of wind). Interconnection also allows sharing of ancillary services that enable a relatively small system such as Denmark to be supported by larger electricity systems such as the Nordic grid and the Continental Europe synchronous grid.

The role of CHPs is changing with increased renewables

- Denmark also has significant volumes of Combined Heat & Power (CHP) plants.
- As wind penetration increased in Denmark, electricity generation from these plants started to reduce.
- This is a market based outcome, as different generators compete in the market based on price for dispatch – plants with lower short-run marginal costs (SRMC) i.e. wind and solar, displace those with higher SRMC, fossil fuels and CHP.
- In response to competition from wind, CHPs are switching from baseload operation (which is usually dictated by heat load) to a combination of baseload and peaking operation, with some of the electricity used to complement heat production (through electric boilers) rather than being exported to the grid.

Denmark is innovating, and relying on renewables, to support the system

- The Danish system operator has also been investigating the use of innovative technologies to provide reserve capacity, inertia, frequency control and voltage control that were traditionally supplied by large, central power generators.
- Technologies such as Static Var Compensators (SVC), static synchronous compensator (STATCOM) equipment and synchronous condensers are tested or implemented in the grid to provide continuous voltage support during fault without the need to generate electricity (i.e. as standalone system service providers).
- These technologies provide benefits to the system as they provide system services without the need for co-generation and can help to reduce the need for costly must-run units.
- Denmark also benefits from system services provided by High-Voltage Direct Current (HVDC) connection between East and West Denmark and with the Nordics. HVDC connections that use Voltage Source Converter (VSC) technology can provide a full set of system services (from inertia to continuous voltage control).
- In light of these technology advancements, the need for must-run capacity has been reduced from 3 large units to around 1 unit in Western Denmark; and in Eastern Denmark the requirement has been reduced from 2-3 to 1-2 units.
- In addition, newly installed wind turbines are required to have fault ride through capability to be able to contribute to system stability during faults in the grid and some wind turbines can supply secondary reserve (Manual Frequency Restoration Reserve).

Source: Energinet and DEA, here

Spain

National Infrastructure Commission
November 2020

Contents

Overview of the material provided in this case study

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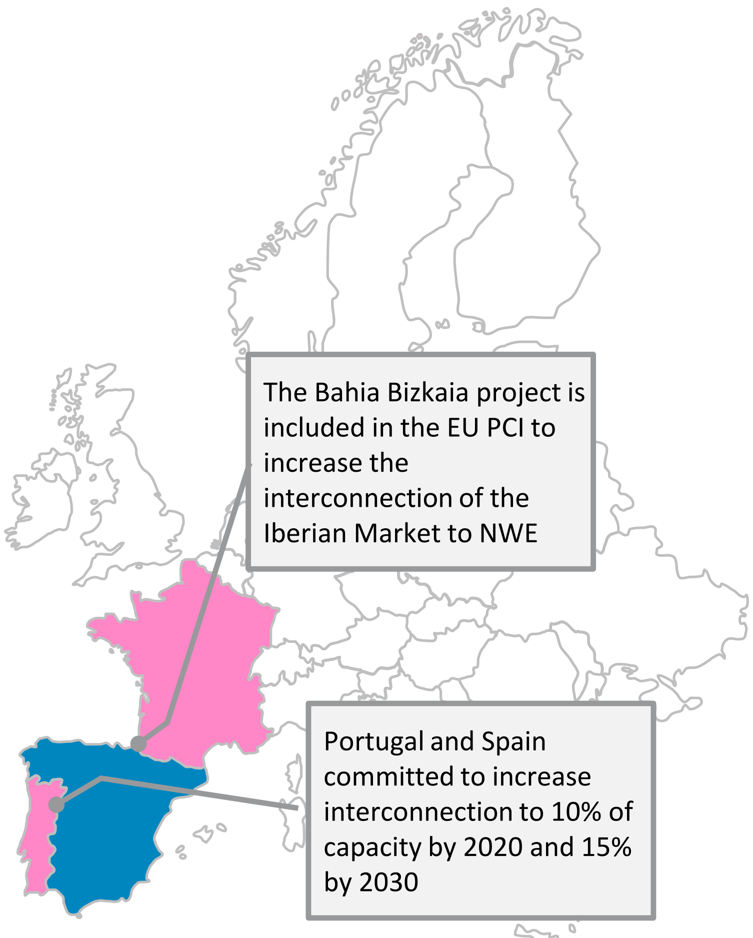
Executive summary: Market overview

Baringa

Spain and Portugal are integrated into a single Iberian Electricity Market with significant volumes of gas and renewables, but a relatively low level of interconnection with Central Western Europe



Existing electricity interconnection

Energy policy

- Spain built up a significant cumulative tariff deficit over the years prior to 2013 – where the cost of running the system exceeded regulated revenues that could be earned. The government addressed this through a series of reforms in 2012-2013 introducing a tax on generation, a tax on fossil fuels and retroactive suppression of the feed-in tariff scheme, among other measures.
- Support payments for renewables declined after the market reform, and the support regime changed to an allowed return allocated through competitive tenders for new-build capacity. Tenders stopped in 2017, although new renewables auctions are expected in 2020/2021. However, the emergence of merchant renewables without regulated incomes has marked the beginning of a new era in the market.

Supply and demand

- Spain is a large market with installed capacity of 107 GW. The Spanish electricity system is one of the most diversified by energy source among the European member countries, currently with a high installed capacity margin and a relatively low CO_2 intensity.
- The Spanish capacity mix is strongly influenced by gas (31%) but also contains a high renewable penetration (50%), in particular onshore wind (23%).
- Annual power generation in 2019 was 246 TWh of which approximately 35-40% came from renewable sources (solar, wind and biomass).
- Imports are sensitive to specific conditions such as the level of hydro generation and the 7% generation tax (putting upward pressure on Spanish prices).

Wholesale prices

- The average day-ahead wholesale market price in 2019 was €48/MWh, down from €58/MWh in 2018. The average price reached a six year low of €42/MWh in 2016.
- The reduction of €10/MWh between 2018 and 2019 was mainly as a result of lower natural gas prices.

Executive summary: Key insights

Baringa

Spain's renewable journey includes significant policy uncertainty driving speculative project development and a challenging connections queue for the system operator to manage

Key insights from Spain

Tariff deficits in the electricity sector created a turbulent path for renewables (slide 79)

- In 2012-2013, the debt of the electricity sector was approximately €29bn, which led to the Spanish Government intervening to reform the sector.
- Several taxes were introduced and a retroactive reform of the Feed-In-Tariff scheme was imposed that significantly reduced the support payments available for existing renewable power generators.
- These measures have been legally challenged in national courts and international arbitration, with national courts backing the measures introduced by the Government and not ruling against the Feed-in-Tariff reform.
- Numerous international renewable energy investors however have resorted to international arbitration which is still ongoing today.

Accommodating the pipeline of renewable projects trying to secure a connection point is currently a major challenge (slides 80, 81 & 87)

- The current procedure for applying for access to the network is based on a first-come-first-served approach with few pre-requisites, and, until recently, small financial guarantees to secure the permits.
- This relaxed regulation led to an over-request of permits, as investors realised that grid connection was the largest constraint to project development and began applying for connections speculatively.
- A large secondary market for grid access developed, resulting in Spain having far greater capacity than required to meet its 2030 targets (Spain has over 130 GW of approved renewable connection requests to date)
- The Government is addressing this as part of the June Royal Decree, which imposes strict milestones based on timings for development, construction and permitting, and failing projects will lose the connection rights and bond payments. However, there is a concern of what to do with the 130 GW which have already been granted rights.
- The Government will provide a moratorium period of 3 months for connection owners to decide if they want to keep their connection offers (and accept the new milestones) or renounce them and receive their bonds.

Spain has seen an uptake of corporate Power Purchase Agreement (PPAs) and merchant investment, supported by government funding of counterparty risk (slide 84)

- A combination of a lack in stable and reliable subsidy schemes for renewables, a lack of structured auctions, and low barriers to project connection has led to project development outside the regulated schemes.
- 2016/17 auctions cleared with large discounts to the wholesale market price making corporate PPAs, with long-term rights, attractive options for developers.
- Close to 8 GW of renewable energy projects have recently signed PPAs in Spain, the majority with utilities/traders or energy suppliers
- The Spanish government has recently stated it will force large energy users to sign long-term PPA with renewable producers to cover at least 10% of its annual consumption. The government will create a fund with over €800m (the Reserve Fund) to cover part of the counterparty PPA risk, in an effort to further incentivise the corporate PPA market in Spain.

Insights for the UK

Competition can find a route to market in the absence of clear policy

- Spain shows how competitive project development markets can develop even in spite of a clear policy objective, however, with a focus on smaller renewable projects.
- However, as the excess grid applications have demonstrated, allowing the market to operate in this way could have unintended consequences as inefficiencies drive higher bills for end-users as policy makers try to deal with the connection queue.

Clarity and simplicity should not be underestimated in policy design

- Simple and easy-to-follow processes are important drivers of policy adoption. Complicated and changing policy and subsidy processes can create confusion and drive unexpected behaviours.
- Spain is now in the process of designing a new, simple mechanism to incentivise investment in renewables.

Market overview

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Key characteristics of the Spanish market

The Spanish power market is diversified and currently has a large capacity margin but with relatively low interconnection capacity to North-West Europe

Market structure

- **The Spanish electricity sector was liberalised in 1997**. The regulatory authority is the Comisión Nacional de Mecardos y Competencia (CNMC). The Regulator is responsible for promoting competition, protecting consumers, regulating network tariffs and advising the government on energy laws and new regulation.
- Portugal and Spain are integrated into a **single Iberian Electricity Market** known as MIBEL (Mercado Ibérico de Electricidad)
- Traditionally an **oligopolistic market**, where the "big five" Endesa, Iberdrola, Naturgy (formerly Gas Natural Fenosa), EDP (who recently acquired Viesgo) account for around 60% of the generation and over 95% of the retail sector.

Value chain	Overview
Generation	▲ The "big five" hold a dominant position in the market, but smaller new entrant players have entered the supply market in recent years and now account for a third of the market. ▲ The largest companies in terms of installed capacity in Spain are Iberdrola, Endesa and Naturgy (former Gas Natural Fenosa). They hold around 52% of installed capacity, including wind and solar capacity. EDP and Viesgo together hold around 7% of installed capacity. ▲ Market concentration increases significantly if only price-setting technologies (hydro, coal and gas) are taken into account.
Transmission /Distribution	▲ The system operator is Red Eléctrica de España (REE). REE owns, operates and maintains the transmission network. REE is responsible for the technical management of the power system and security of supply, including balancing markets and international co-ordination. ▲ Spain has limited cross-border electricity interconnection (below 5% of demand) with Portugal (up to 3.8 GW), France (up to 3.5 GW) and Morocco (600 MW). There are plans to develop new interconnection capacity to Portugal and France and to increase interconnection capacity with Morocco. ▲ 5 distribution companies are responsible for the operation of distribution networks in their historical distribution regions. There are over 300 small local distribution companies.
Retail	▲ The retail electricity market was fully liberalised in 2009 and all consumers can choose their supplier. Supplier switching rates are monitored by the Regulator and have been quite stable in recent years at an annual switching rate of 11%. ▲ There are eight Reseller Companies (Comercializador de Referencia) that supply electricity at a regulated price (Precio Voluntario para el Pequeño Consumidor) for small consumers. Around 42% of consumers with a capacity lower than 10kW are currently supplied through this arrangement. ▲ Spain is a European leader in smart meter deployment, having reportedly reached 100% rollout at the end of 2018 following a government mandate. A small levy is added to consumer bills to cover the costs of the smart metering programme and consumers buy or rent smart meters off their utilities (rental costs are approximately €0.50/month).

Power market structure

Baringa

Following a series of measures to deregulate the market, the Spanish system evolved to become a comprehensive pool including intraday, day-ahead and ancillary services

Overview

- Portugal and Spain are integrated in a single electricity market, the Iberian Electricity Market. On 13 May 2014, the coupling of the Iberian market with the North-West Europe region came into force, and has operated successfully since then.
- The prices between Spain and Portugal are very similar – day-ahead prices had a price difference lower than 1 €/MWh for 96% of the hours in 2019 and 2018.

Day-ahead and intraday markets (OMIE)

- OMIE – The Spanish division of the Iberian Market Operator (Operador del Mercado Ibérico de Energia, SA) is the managing entity for the spot electricity market with daily transactions and intraday adjustments (intraday markets).
- Spain participates in the European Day-ahead market (Single Day-Ahead Coupling). Transactions in Spain and Portugal take place through OMIE.
- OMIE is responsible for the settlement of the day-ahead and intraday markets. The total traded volume in day-ahead and intraday markets in recent years has been between 270-280 TWh/year (total generation in just under 250 TWh).

Forward Market (OMIP)

- OMIP – The Portuguese division of the Iberian Energy Market Operator manages the Iberian futures market.
- OMIClear provides clearing and settlement services as a clearing house and central counterparty of energy derivatives traded in OMIP. OMIP is a regulated market supervised by the financial regulator, the Portuguese Securities Market Commission.
- In January 2019, OMIP launched the trading of future contracts with maturity of 6 and 7 years, and in June 2020 it launched forward contracts with maturities of 8, 9 and 10 years.
- These contracts, traded through a recognised trading platform, provide a standardised and bankable contract for renewable developers and help to address the need for financing renewable projects

Balancing and Ancillary Services market

- The system operator purchases and sells power to balance the networks in real-time.
- In Spain, there are four types of ancillary services: Primary regulation, Secondary regulation, Tertiary regulation and Interruptible loads (see slide 18 for more details).

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Overview of cross-border exchanges

Historically, Spain has been a net exporter of electricity, however since 2016 it has been a net importer, mainly from France, as Spanish prices have risen above prices in France

Cross-border capacity

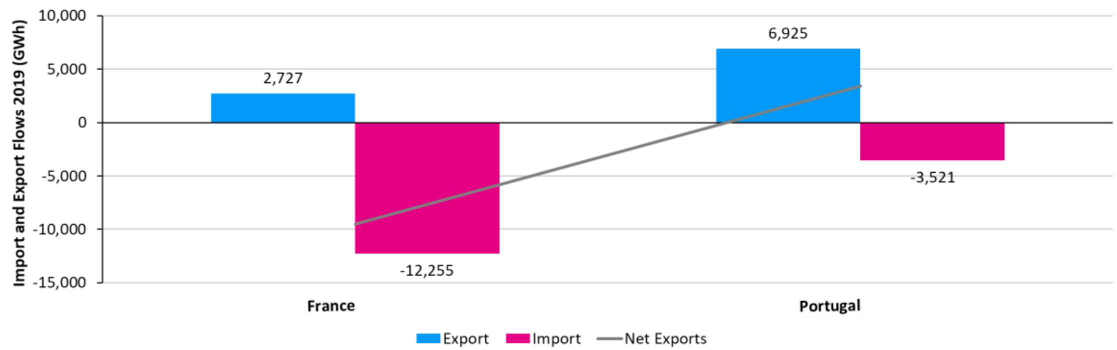
- The key electricity trading partners for Spain are France and Portugal, reflecting investments in recent years to increase cross-border interconnection capacity between the markets.
- These new interconnectors increased the net transfer capacity to 6.4 GW in 2018 and to 7.5 GW today (this takes into account any restrictions on flows cross border as a results of domestic network constraints).
- To support an efficient integration of renewables and meet electricity interconnection targets, further plans for new interconnectors (particularly with France and Portugal) are also in development.
- The Spanish-French border in particular presents construction and planning challenges, as the projects must cross the Pyrenees, which extends the planning and construction time for projects on this border (for example, the project commissioned in 2015, at the time, included the world's longest underground high-voltage

Cross-border flows

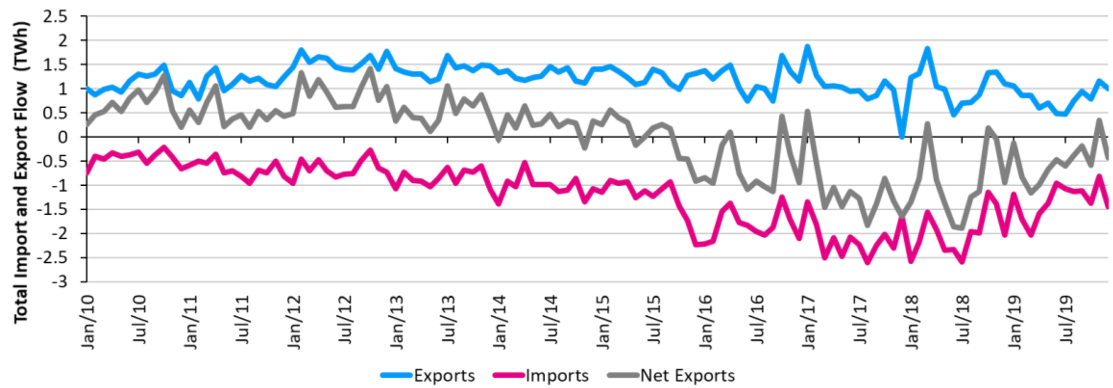
- The Imports from France in particular increased significantly with the commissioning of the new (2015) HVDC Santa Llogaia-Baixas line (doubling the capacity between France and Spain) and as a result Spain has recently become a net importer of electricity.
- The border remains congested, with high price differentials between Spain and France, signalling the value of additional interconnection on the border (the Spanish price is higher than the French price resulting in Spanish imports).

Spanish market imports and exports and flow profiles

Imports, exports and net exports in 2019



Historical flow profile over the past decade



Source: ENTSO-E

Climate goals and subsidy mechanisms

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Energy and climate change objectives

The Law for Climate Change and Energy Transition, approved in May 2020, includes a 35% renewable electricity target for 2030 and 100% renewable electricity target by 2050

Top-down targets

- Like all European Member States, Spain is bound by the EU 20-20-20 targets, formulated in 2009. The targets commit the EU, by 2020, to:
    - A reduction in greenhouse gas emissions of at least 20% below 1990 levels
    - Sourcing 20% of final energy consumption from renewable sources (RES)
    - A 20% reduction in primary energy use compared with projected business-as-usual levels, to be achieved through improved energy efficiency
- The EU commission expects that Spain will meet its targets and possibly slightly exceed them.

Spanish energy and climate targets

- The new National Integrated Energy and Climate Plan was submitted in January 2020, and an updated Law for Climate Change and Energy Transition was approved in May 2020
- The new proposed climate law includes:
    - 70% renewable sources to meet **electricity** demand by 2030 rising to 100% by 2050
    - 35% of total **energy** from renewable sources by 2030 and 100% by 2050
    - Total energy consumption to be 35% lower due to energy efficiency measures
    - Vehicles based on fossil fuels will not be allowed to be sold or registered from 2040 onwards, banned from circulation by 2050
    - A 20% reduction of CO_2 emissions by 2030 compared to 1990 levels.

Spain is a key market in the Internal Energy Market with plans to expand trading opportunities with Europe (via France)

- For Spain, which will meet its 2020 targets and has already seen considerable renewable capacity investment, network companies are looking to European integration to foster more efficient deployment of renewables across Europe and to benefit from lower priced French power.
- As explained in the previous section, limited interconnection capacity due to geographical and other cost considerations has resulted in relatively low levels of market integration between the Iberian market (Spain and Portugal) and the French market.
- Both Spain and France are committed to increasing cross-border interconnection capacity to better facilitate renewable integration and to facilitate trade within the Internal Energy Market.

Spotlight: Regulatory reform targeting the tariff deficit

The 2012/13 reform introduced several taxes and imposed a retrospective reform of the Feed-In-Tariff scheme that significantly reduced renewable support payments

Why was there a tariff deficit in Spain?

Since 2005, the Spanish electricity sector has been running at a significant deficit as the costs of the system were not fully passed on to consumers. This is usually referred to as the “tariff deficit”:

- This deficit arose when the combined regulated costs of the system (i.e. costs related to transmission and distribution networks, support for renewable generators, capacity payments, interruptbility and the payment of the accumulated debt) exceeded the regulated price for electricity (i.e. income that market operators could earn from electricity charges, fees and taxes).
- As the debt of the electricity sector reached approximately €29bn in 2012-2013, the Spanish Government intervened to reform the sector. Several taxes were introduced and a retroactive reform of the Feed-In-Tariff scheme was imposed that significantly reduced support payments available for renewable power generators.

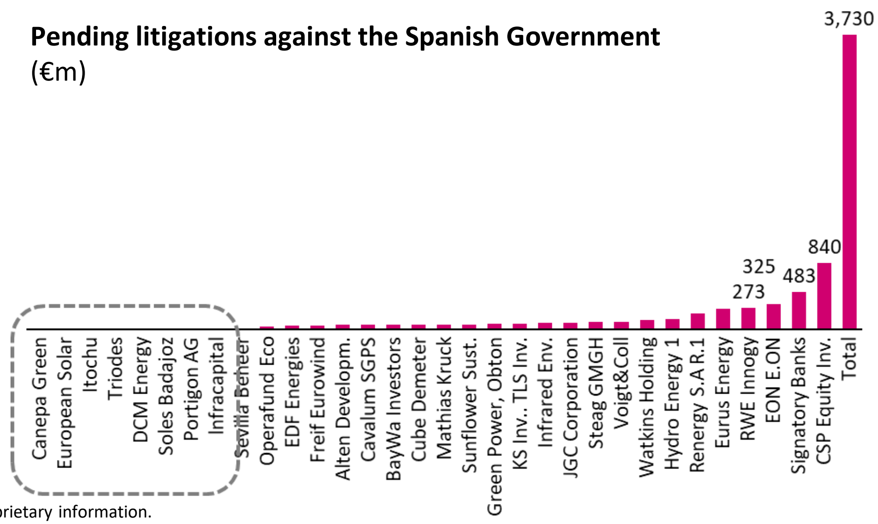
What initial measures did the government take?

The Spanish Government intervened in 2012/13 to reform the sector and introduced the following changes:

- A 7% tax on all revenues received by electricity generators (including capacity payments and renewable support payments)
- A tax on nuclear waste
- A tax on hydro generation
- A tax on all fossil fuels (“green cent”) of 0.234 c€/kWh used for power generation and heating
- A tariff charge on behind-the-meter generation (“solar tax”)
- Very controversially, a retrospective reform of the Feed-In-Tariff regime which changed the support mechanism for renewables

What was the consequence of the FIT retrospective reform?

- The cut to tariff arrangements for existing generators led to a wave of litigation processes (mainly in international courts) against the Spanish Government that are still ongoing today and virtually stopped international investment.
- As of Q3 2020, the Spanish government had only won two cases and had lost at least 13, with the amount it was sentenced to pay totaling €923m. The developer awarded the largest sum was NexTera, an American developer, and was awarded €291m (a small cost compared to the €4.1bn claimed in these proceedings).
- The Spanish government has fought off some claims, in particular a solar investors consortium made up of 16 international funds, claimed €1.9bn (including costs and interests) and received just €91m
- There are however still over 30 additional pending litigation cases against the Spanish Government, and the total amount currently claimed is estimated at almost €4bn. This amount however excludes the 8 investors highlighted in the chart below, who are still assessing the final amount to claim in court. Combined, it is estimated that the total amount claimed could be as high as €8bn.
- In response the Spanish government has offered the claimants the option to maintain a stable regulated rate of return of 7.4% if they remove their litigation by December 2020.



Renewable support in Spain (1/2)

Baringa

Spain allocates renewable support payments based on competitive tenders for new biomass, wind and solar capacity

Overview

- The Feed-In-Tariff scheme ("Régimen Especial"), operating from 2007-2012, originally attracted large volumes of investment in renewable generation, particularly onshore wind and solar. The electricity market reform of 2013 however replaced the existing scheme with a new support regime for all existing units
- The new scheme ("Régimen Retributivo Específico") was announced in 2013, with final parameters established in 2014. The scheme is designed to ensure a certain "reasonable return" for renewable generation plants based on their "standard investment costs", "standard operation costs" and "expected revenues"
- The Royal Decree in June 2020 announced a new renewable auction planned for the end of 2020, the details are still being developed but it appears that the scheme will be based on a guaranteed price for electricity (€/kWh) bid into the market (either day-ahead or intraday) based on the successful outcome of a pay-as-bid auction (specific auction arrangements will be determined ahead of each auction).

Competitive support scheme – progress to date

The allocation of renewable support for new plants is carried out through a competitive call for tenders where projects bid a discount on the reasonable rate of return of the investment to be targeted by the support scheme:

- The scheme was open to new and existing generators, comprising an investment incentive (Rinv) and an operating incentive (Ro), designed to grant renewable generators a certain rate of return during their lifetime, provided that a production threshold (number of hours) is met.
- Auctions in May and July 2017 included wind, biomass and solar and had a cap of 70% on the maximum discount to be offered on the bid. The awarded capacity comprised 4.1 GW of wind, 3.9 GW of solar and 20 MW of other technologies.

Eligibility

Wind	• Wind plants with a capacity up to 500 MW are eligible • **4.6 GW of new wind** projects have cleared the auctions for the Régimen Retributivo Específico
Solar	• Solar plants have been able to take part in auctions offering a higher maximum discount on rate of return • **3.9 GW of new solar projects** have cleared the auctions for the Régimen Retributivo Específico
Biomass/ Biogas	• Biomass plants with a capacity up to 200 MW are eligible • **220MW of new biomass projects** have cleared the auctions for the Régimen Retributivo Específico

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Renewable support in Spain (2/2)

A new Royal Decree and the decommissioning of over half of its coal in June 2020 put Spain on the right path for a zero carbon power sector

Overview

The Spanish Government approved a Royal Decree in June 2020 to ensure a transition to a green electricity sector. This provides a legal framework to allow Spain to achieve its ambitious decarbonisation goals, and the key measures specified in the Royal Decree are presented here

New renewable auctions

- The Degree include provision for a new renewable energy auctions to be held in late 2020.
- The auction design will be adjusted based on the need, ahead of each auction, but based on a guaranteed price for electricity sold to the market and guaranteed for 20 years. As the auction is pay-as-bid the value to each participant will be different.
- This moves renewable subsidies in Spain to a scheme based on the cost of energy, rather than the reasonable rate of return method used for the previous round of auctions.
- It will also consider different technologies, hybrid projects (with storage or a mix of technologies), project location and flexibility.
- The Spanish government has agreed a 5-year auction plan with minimum auction volumes of 2 GW in 2020 rising to almost 20 GW by 2025 split across all renewable technology but with a focus on wind and solar.

Reducing speculative grid applications

- The Decree will also seek to stop speculative grid applications, which have led to over 130 GW of solar and wind projects with approved grid connections as of June 2020.
- This is increasing the costs for all renewable projects, and some developers are auctioning their grid connection points to the highest bidder, having reached prices of €150,000/MW.
- This Decree will impose strict milestones based on timings for development, construction and permitting, and failing projects will lose the connection rights and bond payments.
- However, there is a concern around how to handle the 130 GW of connection which have already been granted rights.
- In an effort to avoid a new wave of international litigations, the government will provide a moratorium period of 3 months for connection owners to decide if they want to keep their connection offers (and accept the new milestones) or renounce them and receive their bonds.
- The new process will also simplify and streamline processing renewable projects connections and corresponding infrastructure. This includes reviewing the instances where the promoter does not need to renew certain authorisations, for example when the project doesn't change substantially, and simplifying the authorisation for upgrading mobile infrastructure (such as transformers).

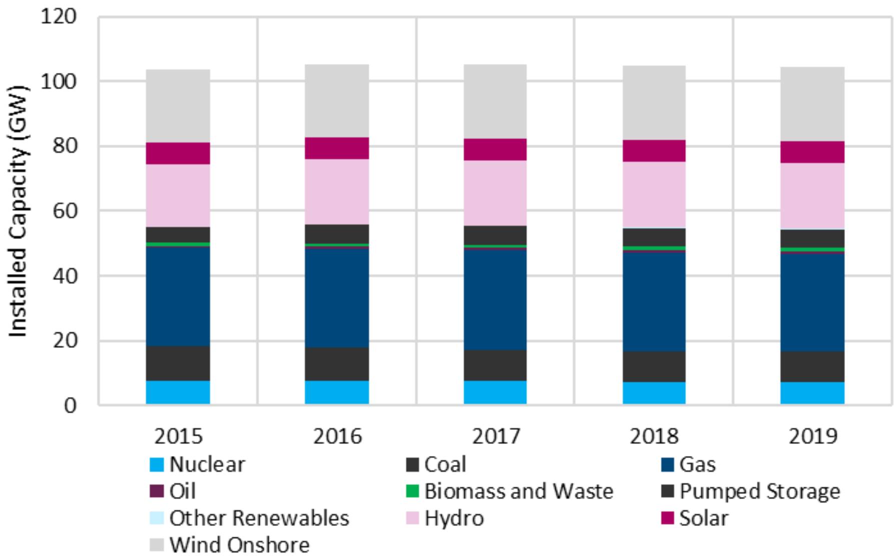
Investment and route to market

Installed capacity and generation

The capacity mix in Spain has been stable in recent years with limited investment in renewable capacity due to cuts in support payments, but some uptake in merchant investment

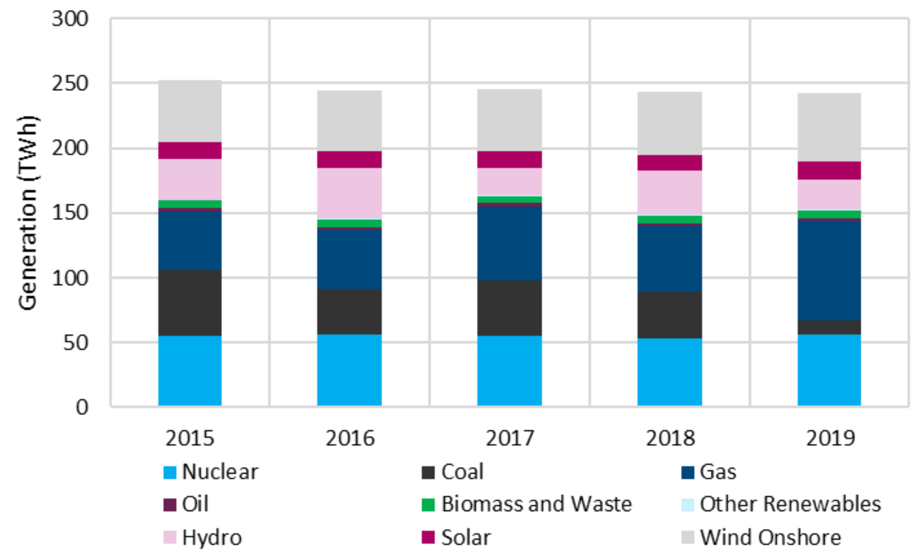
Historical Capacity Mix

- Total installed capacity in Spain has remained relatively stable in recent years, due to the policy measures that were implemented by the Spanish Government reducing certainty in the Spanish renewable investment market.
- Whilst project developers have continued to develop projects in the absence of policy certainty, the majority of these projects remain in the planning/development phase and are yet to make it to market in any volume.
- The composition of installed capacity has also remained relatively stable in recent years, with only some small variations registered in onshore wind capacity and the decommissioning of some gas-fired power stations.



Historical Generation mix

- Electricity generation has declined over the past five years.
- In 2019 almost a third of the generation came from natural gas and close to a quarter from nuclear.
- Generation from renewables has been relatively stable in recent years given limited renewable capacity additions, and even declined for some years when hydro and wind yields were low. In particular, 2017 was a historically very dry year. In 2018 renewable generation increased to previous levels with an average wind and hydro output displacing thermal generation, and in 2019 gas generation has displaced coal-fired plants, whilst renewable generation remained at similar levels.



Source: ENTSO-E

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Renewable routes to market

Baringa

The lack of stable subsidy mechanisms, and limited value in recent auctions, has led to a well developed market for corporate PPAs, with a focus on solar

Routes to market for renewable generators	Onshore wind	Solar
Renewable support schemes	▲ Following the government's retrospective change to the subsidy arrangements for renewables, coupled with low returns under the new competitive auction scheme (where projects bid a discount to the rate of return), investor confidence and investment in subsidised renewables has been low ▲ The Royal Decree and the provision for new renewable auctions provides a clearer route to market for new renewable investment in Spain with the potential for a 20-year fixed price for delivered power.	
Merchant projects and corporate PPAs	▲ The lack of clear route to market for renewables, and low connection cost, has led to lots of speculative project development in Spain ▲ There is a large pipeline of projects in Spain currently under development, with close to 130 GW of renewable generation capacity having been granted connection agreement from the system operator. Around 70% of that capacity (92 GW) represents solar PV projects. ▲ Approximately 2.4 GW out of 8 GW of projects with capacity awarded in the recent auctions failed to meet the required development criteria by the end of 2019, and may therefore seek a PPA route-to-market option instead. ▲ Whilst failing to meet the deadline could cost some developers up to €60/kW (from losing the bid bond), the high discounts observed in the auctions relative to the wholesale market price means it may be possible to achieve more favourable terms under a long-term corporate PPA. Therefore, it is possible that some developers have purposely failed to meet the 2019 deadline in order to pursue a more profitable route to market option. ▲ Approximately 8 GW of renewable energy projects have recently signed PPAs in Spain, the majority with utilities/traders or energy suppliers as offtakers rather than directly with large energy users. However, the Spanish government has recently stated it will force large energy users to sign long-term PPAs with renewable producers to cover at least 10% of their annual consumption. The government will create a fund with over €800m (the Reserve Fund) to cover part of the counterparty PPA risk (for example providing support in case of counterparty bankruptcy), in an effort to further incentivise the corporate PPA market in Spain.	

Grid integration and system operation

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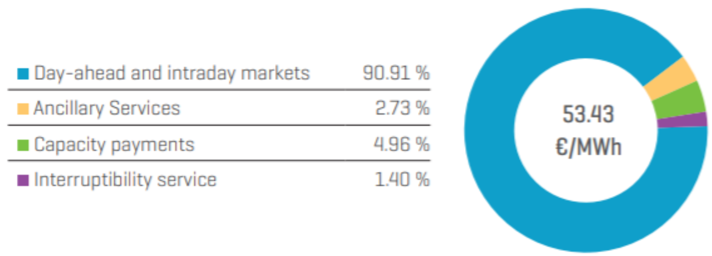
System services in Spain

The cost of ancillary services in Spain decreased from €595m in 2018 to €363m in 2019, driven by lower gas costs observed in 2019

Headlines

- In Spain, like most other European Member States, the system operator (REE) purchases and sells power to balance the networks in real-time and manages the system through a suite of system or ancillary services.
- In Spain, there are four types of ancillary services: technical constraints, secondary control, tertiary control and deviation management.
- System services in Spain are typically provided by gas capacity, and therefore the costs are sensitive to commodity price fluctuations.
- Spain has taken measures to help integrate renewables through coordinated control systems, along with a plan to invest in new hybrid projects and flexibility to help manage intermittency.

Components of the average final electricity price

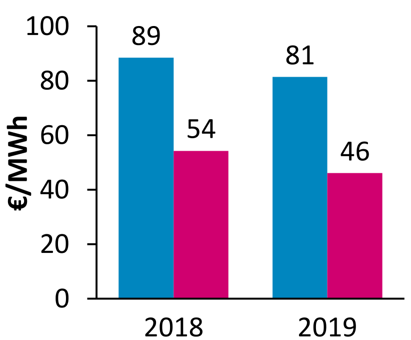


Source: REE, Ancillary Service report 2019, here

Products and services and average weighted prices

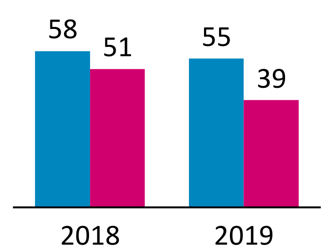
Technical constraints

- The system operators adjusts the schedule of power stations on the system to manage technical constraints at the lowest cost.



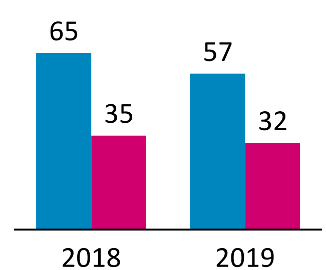
Secondary control

- An optional, automatic ancillary service designed to maintain the generation-demand balance (20s to 15m) and remunerated via a market mechanism (equivalent to Automatic Frequency Restoration Reserve, as defined in other European markets).



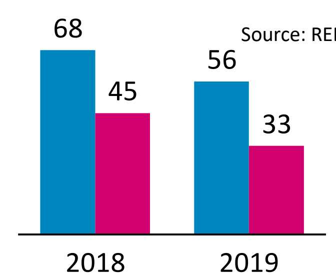
Tertiary control

- An optional, but manual, service defined as the maximum response within 15 minutes, and maintained for 2 hours (equivalent to Manual Frequency Restoration Reserve, as defined in other markets).



Deviation management

- An optional, market based service, for a longer-term period, to cover the period between the end of one intraday market and the beginning of the next intraday market period.



Source: REE

Negative Positive

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Spotlight: Grid connection applications in Spain

Baringa

Accommodating the pipeline of renewable projects trying to secure a connection point is currently a major challenge for the Spanish transmission and distribution network operators

Grid connection applications for renewables are significant over-subscribed in Spain

- Renewable asset development in Spain is currently comprised of three major stages: 1) obtain permission for network access; 2) obtain a connection agreement; 3) commence construction, obtain operational permission (PES) and operation.
- The current procedure for obtaining access to the network dates back to 2000 and is based on a first-come-first-served approach with few pre-requisites, and, until recently, small financial guarantees to secure the permits. This relaxed regulation has led to an over-request of permits, in some cases with speculative purposes. Key data for wind and solar PV from the Spanish system as of August 2020:
  - 35.4 GW of wind and solar PV in operation, of which 26.1 GW is wind and 9.3 GW solar PV
  - 130.0 GW of wind and solar PV with access and/or connection agreement but pre-commissioning, of which 30.3 GW is wind and 99.7 GW is solar PV
  - 60.0 GW of wind and solar PV have requested access, of which 23.4 GW is wind and 35.7 GW is solar PV
  - 117.5 GW of wind and solar PV access applications have been rejected, of which 17.2 GW is wind and 100.3 GW is solar PV
- The development of grid infrastructure is a lengthy process, with new transmission lines (underground cables or overhead lines) and new substations taking 3 to 10 years from the government planning procedure, approval of the investment, and permitting phase until the assets are operational.
- The very significant development pipeline in Spain described above is also putting pressure on public administration, especially at the regional level. As a result, administrative procedures do not always meet the legal deadlines, extending beyond what would be desirable for project developers.

Secondary market for grid connection rights

- This overwhelming demand for connections has led to a secondary market for grid rights in Spain. This market has few clear rules and rising prices, partly due to speculators obtaining permits without the corresponding capacity and in some cases, in locations where there is no infrastructure. The Spanish government has stated that it is currently considering a new law to govern the access permits, which would allow for the creation of an official secondary market for grid permits.
- The government and regulator recognise this issue and are overseeing the possible auctioning of connection points at sites where nuclear and coal plants are due for closure.
- The regulator has also approved a new methodology for evaluating new grid applications, after the current surge in applications has saturated connection nodes, in particular in locations with good wind and solar load factors.

Facilitating future renewable deployment in Spain

Spain has taken measures to help to integrate renewables through coordinated control systems, along with a plan to invest in new hybrid projects and flexibility to help manage intermittency

What else is Spain doing to help manage the impact of renewables on the system?

Alongside the suite of system services, used to manage renewable integration, the Spanish system operator has also taken a number of steps to integrate renewables at least cost to the system:

Hybridisation – Combining renewables and storage

- The Royal Decree, passed in June this year, provides an opportunity for hybrid projects to participate, combining, for example renewables and storage. This has a number of benefits for the project developer, who can increase market offerings through a more stable and reliable supply source. It can also help alleviate some of the system operation challenges presented by renewable intermittency.
- Whilst there is limited electricity storage in Spain to date, the commercial opportunities presented by hybridisation may open the market to increased storage and the benefits these can provide for system operation.

Control Centre for Renewable Energies (CECRE)

- In 2016, the Spanish system operator, put in place state of the art renewable monitoring and control system to help manage the integration of renewables.
- The CECRE monitors and controls renewable facilities greater that 5MW with each unit providing information to the CECRE every 12 seconds using real time telemetry. The information exchanges included the status of the connection, the active and reactive power, and voltage at the connection location.
- This information helps the control centre to predict system needs and effectively manage the system, enabling increasing integration of renewables without impacts on the safe operation of the system.
- The success of this system relies on effective two-way communication between generators and the system operator, via Generation Control Centres. Information is provided to the CECRE through a set of accredited Generation Control Centre, with the accredited list published by the system operator. These control centres actively manage renewables on the system and communicate with the system operator who has overall system operation responsibility.

The role of green hydrogen

- The Spanish Government has recently published its 'Route to Green Hydrogen', with a commitment to 4 GW of hydrogen from electrolysers, powered by renewables, by 2030.
- Green hydrogen provides a flexible, low carbon, power supply (when burned through hydrogen turbines), which can help manage the output of renewables on the system, particularly in periods of high renewables output.
- This decision puts Spain alongside Germany and France as early movers in the European drive to deploy 40GW of renewable hydrogen electrolysers by 2030 (see the European Commission hydrogen strategy, here).

Australia (National Electricity Market)

National Infrastructure Commission

November 2020

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Overview of the material provided in this case study

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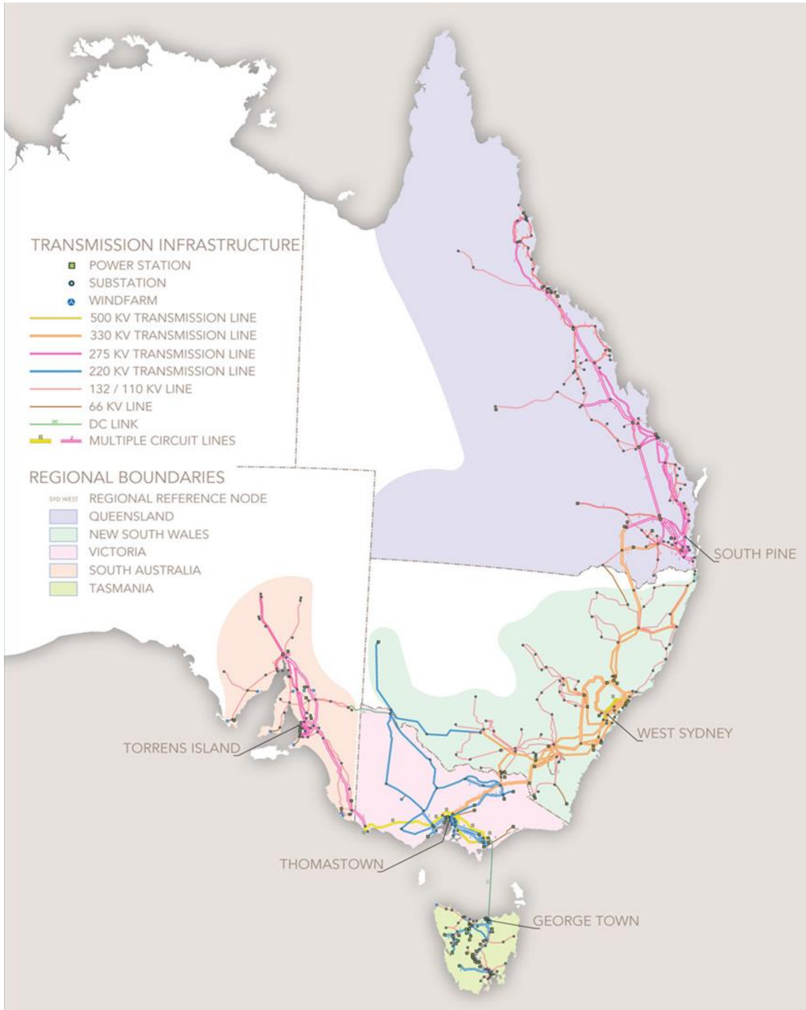
Executive summary: Market overview

Coal capacity still dominates the Australian National Electricity Market (NEM), and even though Australia has extensive renewable resources, renewable policy remains a contentious issue



Source: AEMO, OpenNEM, APVI & AER

Energy policy

- The Australian energy regulator (Clean Energy Regulator, CER) indicates that the 2020 Renewable Target of 33TWh from large-scale projects has been met with existing and committed projects.
- Under the Paris Treaty, the Australian Government has committed to reduce CO2 emissions by 26-28% on 2005 levels by 2030.
- Emissions policy remains a highly contentious political issue, and is likely to remain so for some time.

Supply & demand

- Total electricity demand of 204 TWh in FY 19/20 (around 6% of which is met by rooftop solar PV).
- Peak load of around 36 GW in FY19/20, which occurred in summer for all regions except Tasmania.
- Total current installed capacity of 67 GW connected to the grid, of which around one quarter (15-20 GW) of capacity is behind the meter (rooftop solar PV).
- Current generation mix is dominated by coal (67%), with the remaining 33% made up of gas (8%), large-scale renewables (19%), rooftop solar (6%) and other (<1%).

Wholesale prices

- Historically, annual average wholesale prices have been in the range \$40-60/MWh (with some tight years), driven by low domestic coal and gas prices and some over-supply since 2008.
- This changed in 2016-17 however, with prices increasing to around \$100/MWh on average, as the system moved rapidly from over-supply to a period of scarcity and some coal plant closures.

Executive summary: Key insights

Australia has had a turbulent renewable journey but is benefitting from coordination on generation and transmission investment through integrated system planning and renewable zones

Key insights from Australia

Australia has a different market set-up than the UK (slides 94-97)

- A large proportion of capacity in Australia is provided by 'gentailers' with integrated generation and retail businesses providing a natural hedge.
- The wholesale market is an energy only central pool, operated by the market and system operator (the Australian Energy Market Operator, AEMO) with no capacity market.
- Locational, market based loss factors provide a strong incentive for renewable investment, directly affecting generator revenues.

Complex governance arrangements and a range of Government bodies has led to disparate renewables policy in Australia (95 & 99)

- There is no carbon price at the federal level in Australia which has led to different state-level subsidies, resulting in a complex system of different policies.
- Even within the market bodies there are different views, with the Policy and Rule Making Body (AEMC) and the Regulator (AER) preferring a market-led route to investment and the Market Operator (AEMO) and the independent Government Policy Advisor (ESB) favouring top-down central planning (generation and transmission).
- Lack of clear ambition and route to decarbonisation has led to the reduction of the 2020 renewable target from 41TWh set in 2015 to the current 2020 target of 33TWh (~23% of forecast demand)

Australia has experienced an increase in frequency control challenges (slide 108)

- Australia relies on generator response, outside of a commercial market, for primary frequency response and has a commercial market for secondary frequency response.
- Recent increases in frequency deviation has been driven by increased intermittent generation, coupled with a decline in primary frequency response by synchronous generators as large thermal units have closed.
- Following a review by the policy making body, the AEMC, in 2018, additional obligations have been placed on generators in the NEM to provide mandatory primary frequency response, however this is a temporary solution, put in place to address an immediate need and is subject to review within 3 years.

Integrated system planning and Renewable Energy Zones (REZ) provide useful frameworks to facilitate renewable investment (slides 101 & 109)

- Australia is trying solve the challenges of integrating generation and transmission investment by planning and developing renewables through renewable energy zones.
- These zones identify areas where clusters of high quality renewable projects could be delivered. The market and system operator then undertakes long-term integrated system modelling to optimise the transmission and generation build-out in the long-term so as to minimise costs to consumers whilst maintaining system stability.
- This led to the recommendation that Australian network companies must focus their medium-term network development around enabling the renewable zones (for example, the latest 2020 Integrated System Plan identifies 35 candidate zones).
- Critically, the market and system operator's transmission planning role has historically been one of guidance and non-mandatory recommendations to network companies, but recently the authorities have released draft rules that force network companies to incorporate the system plan, and zone planning, into existing national plans thereby formalising the links between each element.

Key insights for the UK

Market based location investment signals can provide a valuable tool to help manage the impact of renewables on the system, but impacts on risk must be considered

- System issues can be managed through both wholesale market and network reform. For example, how do you provide locational investment signals to new generation? In Australia this is managed through wholesale market prices, MLFs. More locational granular wholesale prices (regional => nodal) and dynamic loss factors (annual => 5 minute updates) have been proposed in Australia.

Conflicting aims between political bodies can stifle investment

- Australia has experienced a lack of policy direction and inconsistency between the regional and federal-level approach to integrating renewables, which has led to uncertain investment signals for renewables (the carbon price, for example).
- But this is being redressed by improvements in planning and coordination of renewable connections and network investment which provides a roadmap for significant volumes of renewable development going forward.

Market overview

Key characteristics of the Australian market

The market is vertically disaggregated between competitive (generation, retail) and natural monopoly (transmission, distribution) sections of the market

Market structure

- The NEM is a liberalised gross mandatory pool market covering the east coast of Australia, with five interconnected regions and regional pricing
- It is an energy-only market, with 5 minute physical dispatch under the instruction of the market and system operator, and half-hourly financial settlement (note that 5-minute settlement will be introduced in 2021)
- The NEM is a liberalised power market, which has a high degree of vertical integration between generation and retail. The 'Big Three' players (AGL, Origin and EnergyAustralia) control 46% of the generation and supply 66% of the small retail electricity customers. The degree of government participation varies by state, with generation and retail in Victoria, New South Wales and South Australia predominantly private, and a greater state participation in Queensland and Tasmania.

Value chain	Description
Generation	▲ The ownership of generation in the NEM is highly competitive and diverse, with over 300 generators registered to sell electricity in the spot market. Private entities own most generation in Victoria, New South Wales and South Australia, whereas government owned corporations own or control the majority of capacity in Queensland and Tasmania.
Transmission/ Distribution	▲ The transmission network is operated by six transmission network service providers (TNSPs) which are split by region of coverage, and regulated by the Australian Energy Regulator. – These network companies are TransGrid (NSW), Powerlink (QLD), ElectraNet (SA), TasNetworks (TAS), and in Victoria, AEMO and AusNet Services have split functions in this region for legacy reasons (AEMO is also the system operator). ▲ The number of distribution network service providers ranges between 1 and 5 per state, for legacy reasons, with 13 distribution companies servicing the NEM.
Retail	▲ Retail price deregulation occurred in Australia when the authorities determined a market to be effectively competitive. Victoria was the first to deregulate (2009) followed by South Australia (2013), NSW (2014) and south-east Queensland (July 2016). Regional Queensland , Australia Capital Territory and Tasmania retain retail price regulation and have dominant incumbent suppliers. In 2019, retail price regulation was partially reintroduced in the other states after several reviews found the expected benefits of competition were not being fully realised. ▲ The retail energy market is dominated by the 'Big Three' retailers, who supply 63% of small electricity customers in NEM regions in 2019.
Regulator	▲ Regulation and rule making is split between two key institutions in Australia. The Australian Energy Regulator (AER) is the NEM market monitor and regulator, whereas the Australian Energy Market Commission (AEMC) is the NEM policy and rule-making body.

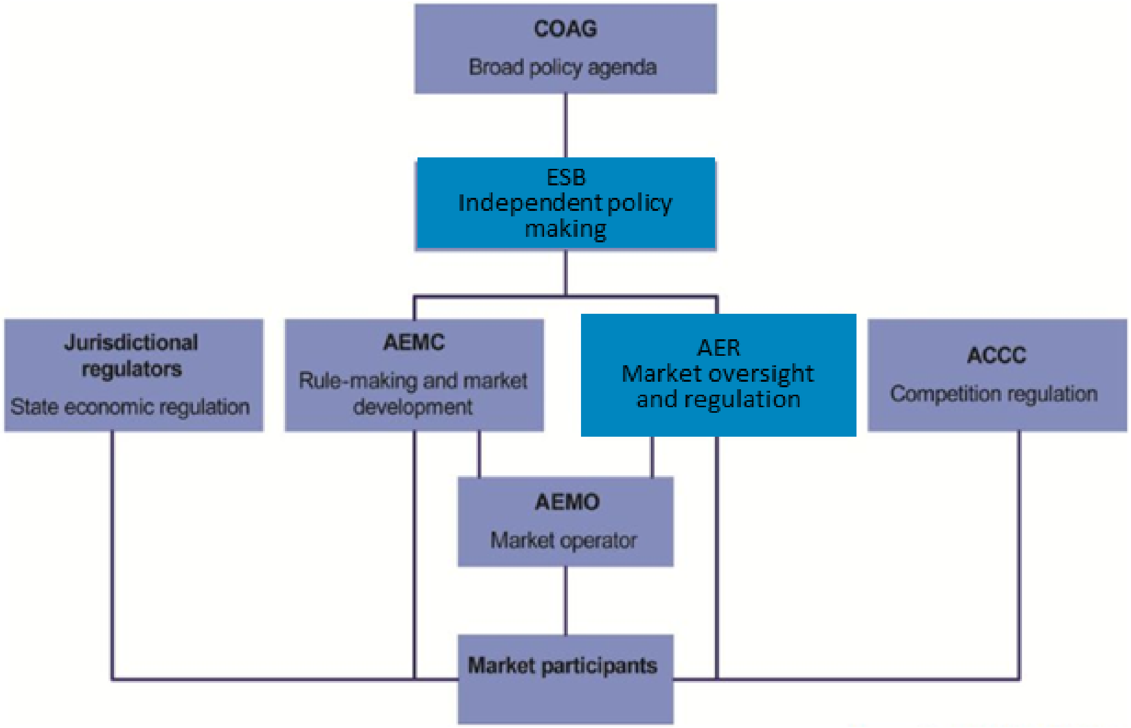
Sources: AER State of the Energy Market Report 2020

Spotlight: Key government institutions

The NEM has a unique governance structure with a number of parties with relevant roles in renewables policy, regulation and rule making

Key government bodies and regulators

- **Council of Australian Governments** (COAG) and COAG Energy Council: high-level policy with Prime Minister and state Premiers, and state and federal energy Ministers, respectively. Currently being replacement with new (but similar) arrangements.
- **Energy Security Board** (ESB): Independent policy-making and advisory body to government, with representative from the AEMC, AER and AEMO.
- **Australian Energy Market Commission** (AEMC): NEM policy and rule-making body.
- **Australian Energy Regulator** (AER): NEM market monitor and regulator.
- **Australian Energy Market Operator** (AEMO): NEM market and transmission system operator.
- **Australian competition and Consumer Commission** (ACCC) cross-sector competition regulation.



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Power market structure

Exchange-traded volumes have increased over the last few years, despite an increase in renewable generation share

Overview

- As Australia has a gross mandatory pool, all generators bid into the spot market and physical dispatch is determined by the system operator.
- Financial instruments are used by participants to provide price certainty, and these are traded under bilateral contracts between generators and suppliers (Over-The-Counter, OTC) and via the Australian Securities Exchange (ASX)
- There is no dedicated balancing market in the NEM but the system operator takes actions to balance the system via frequency control and reserve products. The costs of this are partially socialised, with an element being passed directly to generators which causes the imbalance

Spot market

- The market and system operator operates a mandatory gross pool spot market, in which all large-scale generators bid in price-volume pairs required for dispatch at the day-ahead stage. These bids may be re-optimised within day under certain circumstances.
- The market and system operator operator forecasts required supply and reserve, and sends dispatch instructions to plant which provide the least-cost supply mix, respecting certain operational constraints. All generators receive the trading price for the intervals in which they generate, and similarly customers pay the trading price for demand in that interval.

Forward market (ASX derivatives, OTC)

- The ASX provides a market for electricity derivatives.
- Products offered are quarterly or annual futures and options or caps. The large majority of liquidity is found in quarterly baseload products, in Victoria, New South Wales and Queensland, but liquidity is poor in South Australia. Total traded volumes for FY 18-19 were around 3 times underlying demand (of which 2.5 times were ASX Futures, and 0.5 times Over-The-Counter)*.
- ASX Contracts are structured as cash-settled Contract for Difference against the regional reference nodes in the Australian National Electricity Market.
- OTC contracts typically have a similar structure, but are bespoke by nature.

Balancing market

- Large-scale intermittent renewables are classified as "semi-scheduled" and not currently required to submit granular generation forecasts (the market and system operator forecasts solar and wind generation). The market and system operator will then use the ancillary services market (the Frequency Control Ancillary Services) to balance the system in real-time, and pass some of this cost back to renewables via an assumption on a given participant's contribution to the imbalance.
- The market and system operator also procures reserve products through direct contracting with flexible generation or load under the Reliability and Reserve Emergency Trader. These costs are recovered from customers.

*AER, State of the Energy Market 2020

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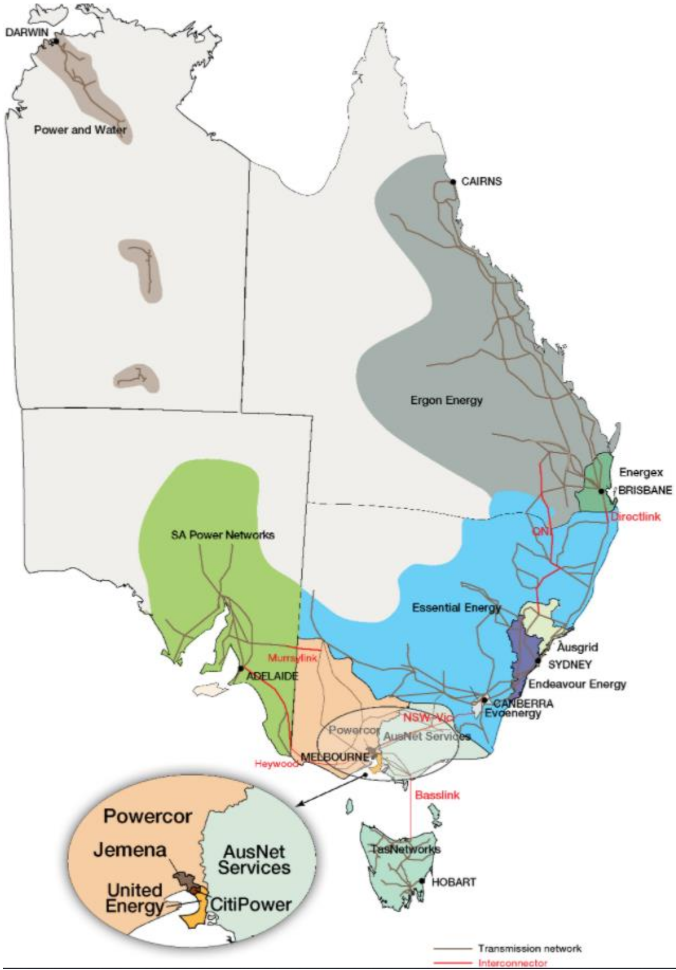
Overview of cross-border exchange

There are no cross-border exchanges between the NEM and other countries, however the NEM is nonetheless one of the largest interconnected electricity systems in the world

The transmission network in the NEM



Sources: AER, here

- The NEM is one of the largest interconnected electricity systems in the world. It covers around 40,000 km of transmission lines and cables.
- The NEM includes an undersea connection between the state of Tasmania and the Australian mainland. However, there are no cross-border electricity exchanges with other countries.
- Within the NEM itself, the current inter-state connections include:
  - Terranora and QNI interconnectors (New South Wales and Queensland)
  - Victoria to New South Wales interconnector
  - Basslink (Victoria and Tasmania)
  - Heywood and Murraylink interconnectors (South Australia and Victoria)

Climate goals and subsidy mechanisms

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Energy and climate change objectives – Federal targets

Baringa

Australian energy policy includes federal and state level targets, with an increasing emphasis on state level targets set above federal level minimum requirements

Latest federal policy

Carbon tax:

- The previous Labour government in Australia introduced an emissions trading scheme with an initial fixed price (carbon tax) period at AUD $23/t, but it was subsequently removed in 2014 by the Liberal Coalition government.

The National Energy Guarantee:

- In November 2017, the newly formed independent advisory board to the government, the Energy Security Board, put forward the National Energy Guarantee (NEG) – an emissions intensity scheme – to oblige suppliers to meet obligations in relation to both emissions and reliability.
- The advisory board published a detailed consultation on NEG design in March 2018, and the policy received broad support with the states as well as the Labour federal opposition.
- However, the level of the carbon emissions target under the NEG remained subject to intense debate within the Coalition Government's own party, and was subsequently dropped in August 2018 with a change in leadership.

Federal policy post-election

- Following the re-election of the Coalition Government, there is now not expected to be significant new policy with respect to CO2 emissions from the NEM.
- The government is however pushing ahead with the implementation of the reliability limb of the NEG (called the Retailer Reliability Obligation) as well as the Underwriting New Generation Investments initiative, both focused on ensuring adequacy and security of supply.
- In May 2020, the Coalition Government published a Technology Investment Roadmap discussion paper as part of its 'technology not taxes' approach to reducing emissions.

The Finkel Review – a key driver for change

- In Oct 2016, the Liberal government commissioned an independent review of the Australian energy market, to be conducted by chief scientist Dr Alan Finkel.
- The final report, published in June 2017, contained a wide-ranging review of all aspects of the energy system, and contained a total of 50 recommendations.
- Among the key recommendations was a Clean Energy Target to meet emissions targets, the establishment of a new government advisory group, Energy Security Board, and a strategic reserve to cover potential capacity shortfalls during summer peak.
- The government accepted 49 of the 50 recommendations from the Finkel Review, however the Clean Energy Target proved politically divisive.

2020 Renewables electricity target

- The NEM has a 2020 renewable electricity target of 33 TWh (~23% of forecast demand).
- This was revised down from 41 TWh in 2015 following a prolonged period of political stalemate and uncertainty.
- One large-scale generation certificate is created for each MWh of eligible renewable energy produced. The scheme places an obligation on electricity suppliers to source a growing volume of electricity from accredited renewable generators through the exchange of certificates.
- The certificate scheme provide an additional revenue stream to accredited generators, capped at a penalty price of $93/MWh.
- The regulator now indicates that the target has been met with existing and committed projects.

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Energy and climate change objectives – State targets

The current federal support scheme for large-scale renewables is the Renewable Energy Target – some states have more ambitious targets, procuring renewables through long-term contracts

- A number of states have legislated for higher renewables targets than the federal Renewable Energy Target (RET).
- Reverse auctions have been the procurement mechanism of choice to date, with long-term government backed contracts-for-difference on offer (see below for details).
- However, given that these mechanisms require government intervention, they are exposed to some policy risk.

Victoria

- Targets (Victoria RET, VRET): 25% by 2020, 40% by 2025.
- The first Victoria renewable energy auction was held in February 2018, and winners announced in September 2018 included over 900 MW of large-scale projects (including 3 onshore wind and 3 solar projects).
- Further auction rounds are planned, with the current Victorian government now in place until 2022 providing some political certainty.

Queensland

- Target (Queensland RET, QRET): 50% by 2030.
- First auction round will procure 400 MW of renewables alongside 100 MW of storage.
- Progress has been slow, however with CleanCo (the new Government Owned Corporation for clean electricity generation and trading company) in place, a shortlist of projects was published in July 2019.

New South Wales

- In March 2020, the New South Wales Government released their Net Zero Plan Stage 1: 2020-2030 setting the short-term roadmap to reach net zero emission by 2050.
- The New South Wales Government does not intend to impose a state-wide renewables target. Instead, it has adopted an emissions target of 35% below 2005 levels by 2030.
- It is also keen to support the development of new transmission to support both Snowy 2.0 as well as the development of Central West New South Wales pilot Renewable Energy Zone, to unlock up to 3,000 MW of renewable capacity by 2030.

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Spotlight: AEMO's Integrated System Plan

AEMO's system plan represents an important signal to the transmission network companies to build out their transmission systems to accommodate the least cost mix of renewables

AEMO's ISP – key elements and implications

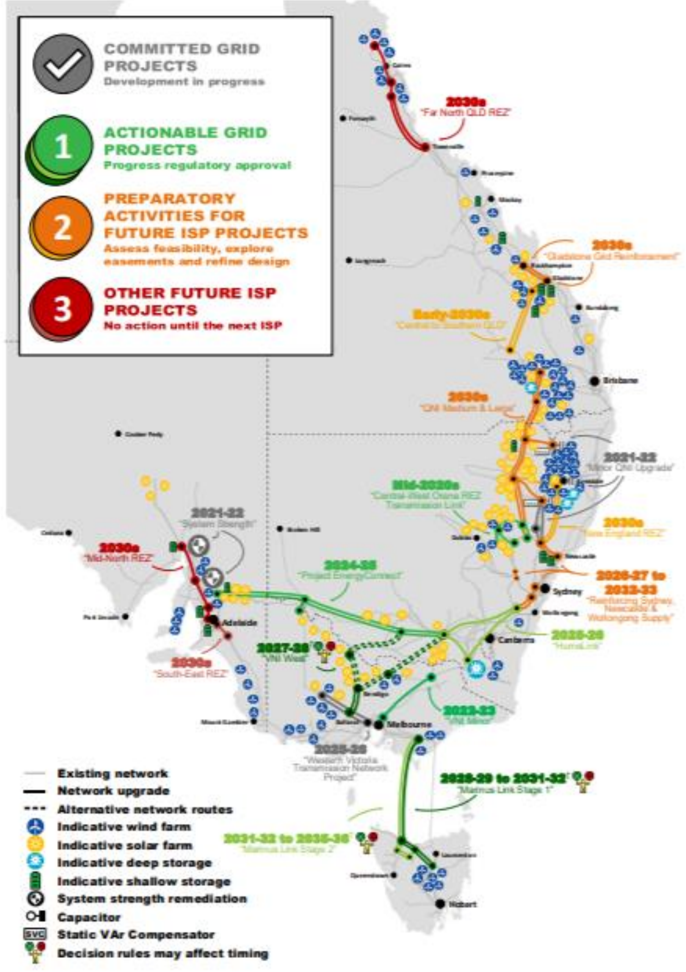
Background

- One of the key recommendations from the Finkel Review from 2017 was for the market and system operator to develop an Integrated System Plan to explore the least cost development of transmission alongside the strongest renewable resources.
- The market and system operator released its much-awaited first plan in mid-July 2018, which introduced 33 (now 35) Renewable Energy Zones, where clusters of high quality renewable projects can be observed.
- The market and system operator then carried out long-term integrated system modelling to optimise the transmission and generation build-out in the long-term so as to minimize costs to consumers whilst maintaining system stability.
- The final report for 2018 contained recommendations on both new interconnection as well as intra-regional transmission reinforcements that facilitate the build-out of generation with the Renewable Energy Zones.
- While the market and system operator's transmission planning role has historically been one of guidance and non-mandatory recommendations to network companies via the national development plan (except for Victoria, where it has a mandatory function), the government advisory board (ESB) and the rule making body (AEMC) have released draft requirements to integrate the integrated system plan with existing planning process, formalising its role.

Key implications

- The most immediate implications of the Integrated System Plan are the recommendations around new interconnection augmentation, with specific capacity upgrades and timing.
- Secondly, the market and system operator has recommended that network companies focus their medium-term network augmentation around enabling the Renewable Energy Zones, which will be critical for renewable developers and investors exposed to potential reductions in Marginal Loss Factors and local curtailment due to network constraints
- The market and system operator has now released its 2020 update to the Integrated System Plan.

ISP Renewable Energy Zones (REZs)



Sources: AEMO ISP 2020, here

Investment and route to market

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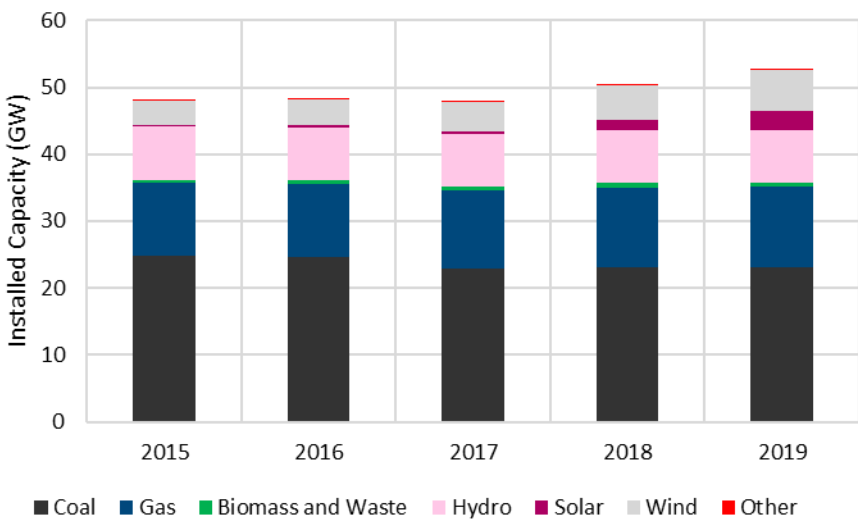
Electricity capacity and generation

Coal dominates the capacity and generation mix in Australia, with a small but rapidly increasing renewable investment pipeline

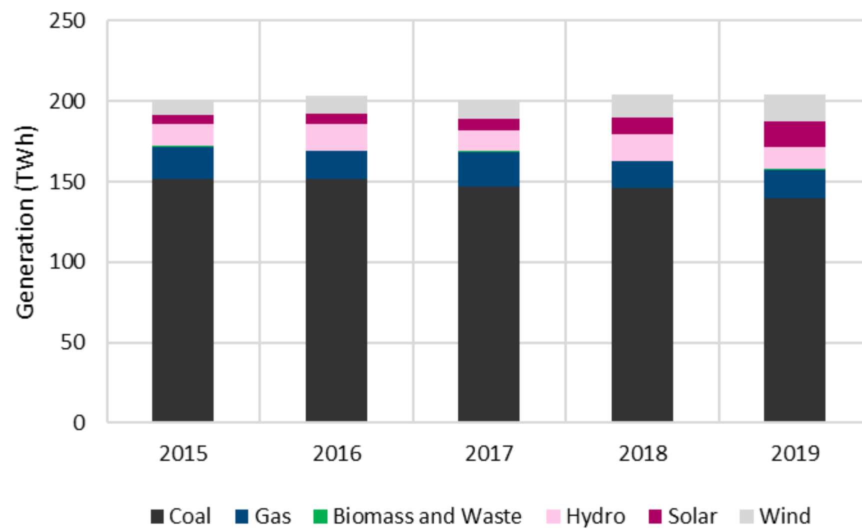
Historical capacity mix

- The majority of electricity capacity in the NEM is made up of black and brown coal (23 GW) and gas (12 GW).
- There is also significant hydro (8 GW), wind capacity (7 GW), and utility scale solar generation (4 GW).
- The NEM has a high level of rooftop solar penetration with approximately 15-20 GW of small scale solar installed (note that this capacity is not shown on this chart as it is behind the meter capacity).
- A rapid increased in installed capacity of solar and wind occurred in the period to 2020.



Historical generation mix

- The estimated total electricity generation in 2019 was 204 TWh, and total annual generation in Australia has remained relatively flat since 2014.
- Current generation mix comprises 67% from coal, whilst renewables generation (including hydro and rooftop solar) representing approximately 25%.
- Gas represents approximately 8% of generation, and gas plant is often on the margin.



Source: AEMO and OpenNEM

Renewable routes to market

Baringa

Typically, new build projects will seek a combination of longer-term offtake and merchant exposure to achieve an attractive risk-return profile

Routes to market for renewable generators	Onshore wind	Solar	Offshore wind
Renewable support schemes	▲ The Australian Capital Territory (ACT) and Victoria have run reverse auctions, with auctions in Queensland currently underway, providing developers have certainty from long-term 15-20 year government-backed contracts. ▲ These reverse auction schemes offer the lowest risk route to market currently available, but competition has driven down prices. ▲ Recent State processes (e.g. the Queensland RET) focused on both renewables and storage. ▲ In 2019, some State Governments opened their retail supply contracts to renewable generators, offering offtake opportunity (New South Wales and South Australia).		
Corporate Power Purchase Agreements (PPAs)	▲ With power prices high, large corporates are becoming increasingly engaged in direct PPAs. Contract lengths vary from 5 years (e.g. Adelaide Brighton – cement manufacturer) up to 20 years (e.g. Mars). ▲ The volume of Corporate PPAs increased rapidly over 2017-18, with a few examples of PPAs signed with buying groups to facilitate smaller corporate purchase. ▲ Through 2019 an increase in ‘firmed’ PPAs (i.e. flat volume or matching customer load) or separate ‘firming’ products came to market which help the corporate match their demand profile with the PPA, provided by retailers, or pure financial players.		
Merchant renewables	▲ There is an increasing appetite for merchant opportunities in Australia, both due to the lack of long-term offtake, but also upside potential. Contract lengths are short, with either fully merchant exposure bidding into the centralised pool market, or short-term contracts (< 5 years). ▲ A number of wind and solar projects already take an element of merchant risk, and this trend is likely to increase. Developers and investors typically structure deals with a mix of longer-term (options above) and higher risk (merchant) offtake contracts. ▲ Some availability of 3-5 year fixed price contracts with new offtakers.		
Retailer PPAs	▲ Some activity from the Big Three (AGL, Origin, EA) and new entrants are also now more active. Limited appetite for PPAs in order to meet requirements under the Renewable Energy Target scheme, but some activity due to expected cost savings from renewable PPAs. ▲ Retail PPA contract lengths are typically longer-term (10-15 year) contracts thank corporates, with timing mostly linked to the expiry of Large-scale Generator Certificate payments in 2030. ▲ The Big Three retailers (AGL, Origin, EA) continue to be dominant in the PPA market. They have been developing less volumes of new renewables themselves, in favour of PPAs to minimise the cost of meeting their Renewable Energy Target obligations and reduce the price paid for power. ▲ More recent new entrants, such as Flow Power and ERM Power, are also now active, with a focus on large Commercial and Industrial and corporate PPAs. ▲ Current retailer ‘pay-as-produced’ renewable PPA prices are very low ($40-50/MWh), which may be more reflective of their strong negotiating position in a crowded developer market, than underlying fundamentals. ▲ The NEM has seen an increase in offtake agreements announced with batteries (e.g. AGL / Maoneng, EA / Edify).		

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Spotlight: Thermal closures present renewable opportunity

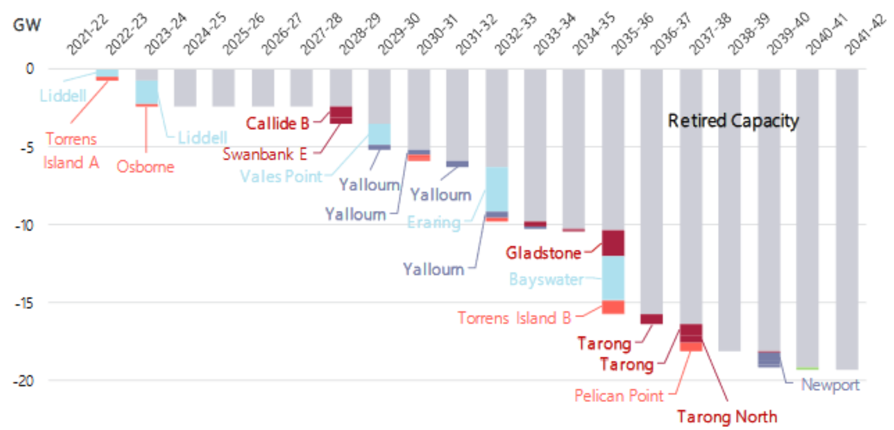
Baringa

Closure of thermal generation for end-of-life reasons opens up significant growth opportunities for renewables despite flat demand forecasts

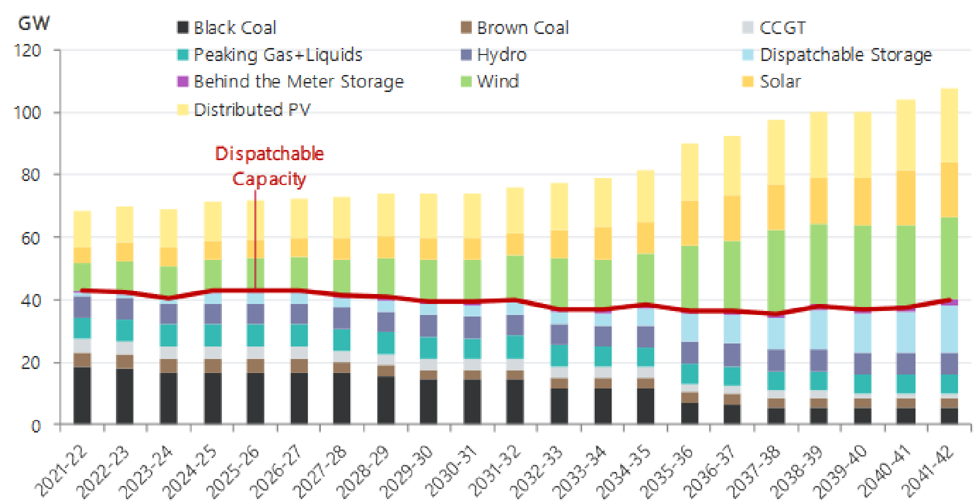
Renewables as a replacements for an ageing thermal fleet

- Rising behind the meter generation, primarily rooftop solar, means that forecasts of grid-supplied consumption in the NEM are relatively stable.
- This contrasts with the supply, where significant retirement of coal and gas fired generation is projected due to existing plant reaching end-of-life. No new coal fired generation is expected to be built, though there may be some new gas fired generation.
- To replace these retiring thermal plants, the market and system operator forecasts that there should be further investment in new large scale variable renewable generation of between 26-50 GW. This amount is in addition to existing, committed and anticipated projects.
- This new renewable energy generation would most optimally occur in Renewable Energy Zones – to lower the total system cost taking into account both generation and transmission network costs. This variable renewable generation investment would be supported by new investment in storage, gas fired generation, demand side response and transmission investment.

Forecast coal and gas generation retirements



ISP optimal development path – dispatchable and variable generation



Sources: AEMO

Grid integration and system operation

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System services in the NEM (1/2)

Frequency Control Ancillary Services are procured by the market and system operator at the day-ahead stage, and co-optimised with energy in the 5-minute dispatch

Headlines

- Frequency Control Ancillary Services are procured at day-ahead stage in the NEM.
- The response requirements are categorised as:
  - **Regulation** (Raise/Lower): used via Automatic Generator Control to correct minor frequency deviations.
  - **Contingency** (Raise/Lower): Used less frequently for major change in frequency events (e.g. loss of major plant or transmission asset).
- Ancillary Service costs are recovered via payments from:
  - The plant that cased the frequency deviation, in the case of Regulation services
  - Generators, in the case of Contingency Raise; Consumers, in the case of Contingency Lower.
  - Market customers, in the case of Network Support Control Ancillary Services (e.g. Voltage Control); Generators and consumers on a 50/50 basis, in the case of System restart Ancillary Services.
- To date, Frequency Control services have largely been provided by large thermal and hydro plant which are synchronous and have headroom to withhold for FCAS provision.
- Recently, new technologies have begun offering FCAS availability, such as wind plants which now make up a notable percentage of registered FCAS capacity.
- Although batteries still represent only a small percentage of total registered FCAS capacity, as demonstrated in the registration data, below, they represent a growing percentage of FCAS provision.

Design

- To participate in the system services markets, plants bid in MW of response:
  - The electricity pool, through the National Electricity Market Dispatch Engine sets requirements for each of the 8 FCAS products for each period.
  - Offers are evaluated in a merit order, and the highest cost offer to be enabled will set the marginal price for the system service category.
  - Offers are submitted for up to 10 continuous MW/price bands and are fixed at 12:30 at the day-ahead. Band availabilities and can be re-bid under rules similar to those of the energy market.
- It is possible for a registered Ancillary Service Facility to be enabled to provide either or all regulation / contingency services at once (i.e. no mutual exclusivities).

Service Type		Service name / function
Frequency Control Ancillary Services (FCAS) (AUD $220m / annum)	Regulation	Regulation Raise
	Regulation	Regulation Lower
	Contingency	Fast Raise / Lower *(6 sec response time)*
	Contingency	Slow Raise / Lower *(60 sec response time)*
	Contingency	Delayed Raise / Lower *(5 min response time)*
Network Support & Control Ancillary Services (NSCAS)		► Voltage control ► Reserve control (following major power system events)
System Restart Ancillary Services (SRAS)		► Complete or partial system blackout

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System services in the NEM (2/2)

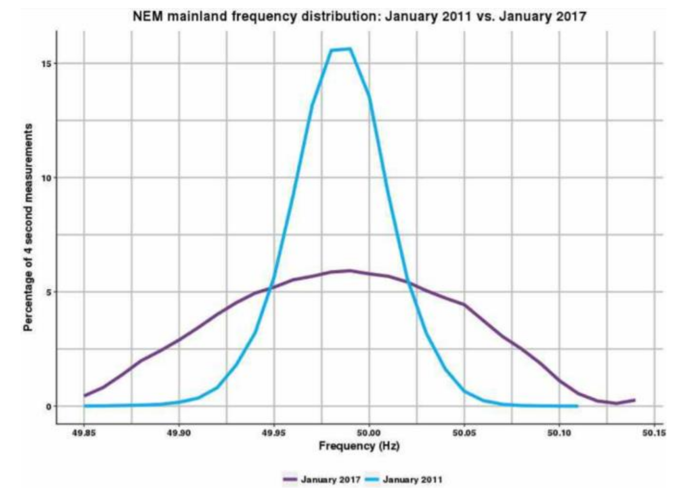
Baringa

Australia has seen increasing frequency deviations within normal operations. Additional commercial and non-market frequency response has been required to manage this.

Current challenges

- Under current market structures, Australia has a commercial market for secondary frequency response within the normal operational frequency band ('NOFB') but relies on generator response outside of a commercial market for primary frequency response within the NOFB.
- AEMC reviewed the system services market in 2018, driven in part by an observed increase in frequency deviations within the NOFB, and an increased occurrence of breaching of the normal operations frequency limits.
- At the time, the reasons for this were noted as:
  - An increase in intermittent generation increasing requirement for frequency control within NOFB
  - A reduction in provision of primary frequency response by synchronous generators. This is driven by factors including the costs of providing a primary frequency response not being financially valued, and a lack of strong incentives to provide more frequency response than is required to meet the generators own dispatch targets through the current 'causer pays' cost recovery arrangements for regulating FCAS.

Frequency distribution 2011 vs 2017



Source: AEMC, here

Future market design

- Measures have been taken to manage this change in frequency distribution including:
  - An increase of commercially-procured secondary frequency response from current products (Regulation FCAS) minimum procurement from 130/120MW raise/lower to 220/210MW through 2019.
  - A new mandatory obligation for Primary Frequency Response for all generators in the NEM within the NOFB.
- The new mandatory obligation requires all scheduled and semi-scheduled generators that receive a dispatch instruction greater than 0MW to provide Primary Frequency Response in accordance with a requirement to be published by market and system operator.
- The response requirement will define the technical requirements of generators providing Primary Frequency Response.
- The new rule has a sunset of 3 years meaning it will expire in June 2023. This reflects the fact that the rule was introduced as an interim measure in order to assist in the immediacy of the system stability issue associated with lower levels of PFR in the NOFB.
- It is expected that a longer-term solution that provides appropriate distribution of costs and revenues for generators, and incentivises an appropriate level of system stability will be developed and actioned while the mandatory requirement is in place.

Spotlight: Grid operation challenges and REZ development

Baringa

Renewable Energy Zones seek to co-ordinate generation and transmission investment and provide more certainty to generators

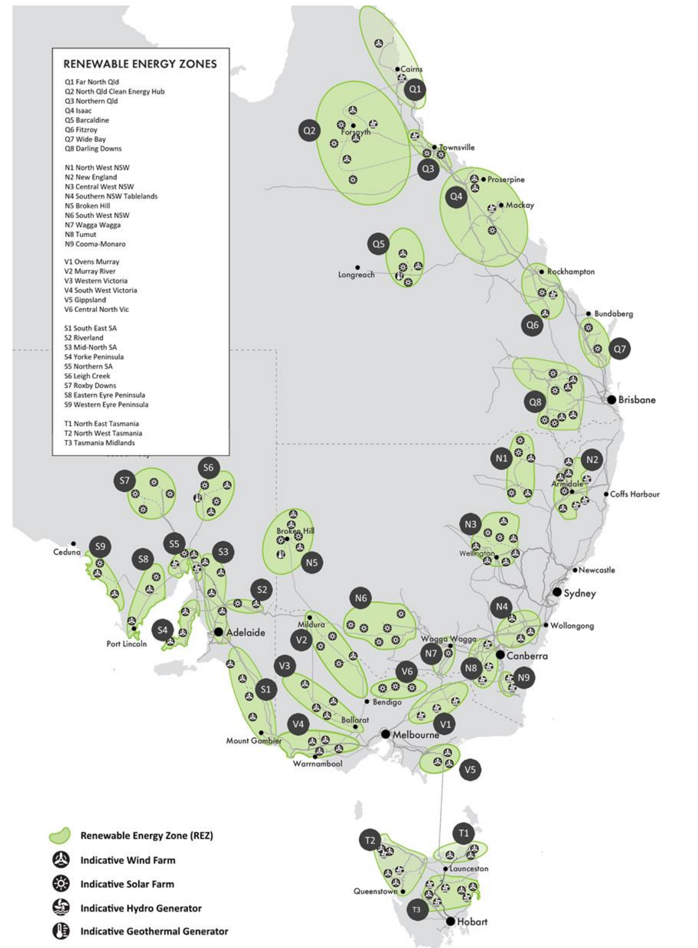
Current grid operation challenges

- Subsidy schemes for large scale renewables have driven some investment in wind generation in Australia, and in more recent years, solar. Significant increases in rooftop solar PV has also been driven by small scale subsidy schemes (e.g. feed-in tariffs).
- Private investment continued after early subsidy schemes ran out, as technology costs fell making development more cost effective. Some new subsidy schemes have also been introduced by state governments.
- The grid is experiencing capacity, frequency and voltage management issues in integrating this new investment.
- A series of short term, and possibly inefficient, measures are being put in place to manage the system while longer-term measures are being developed and implemented.
- For example, in September 2019, the market and system operator directed solar farms in north-west Victoria and south-west New South Wales to be constrained to 50% maximum output at all times – a loss of 170MW – to manage voltage instability risk. These limits were lifted in April 2020 following changes to inverter settings.

Developing Renewable Energy Zones

- Examples of longer-term measures to tackle grid constraints include the creation of Renewable Energy Zones, as explained in the previous section. These zones seek to:
  - Optimise the mix of generation, storage and transmission investment across multiple connecting parties.
  - Co-locate and optimise the otherwise 'lumpy' investments in network and system support infrastructure.
  - Realise benefits of capital scale in all those investments.
- Some state governments are looking at adopting state specific frameworks for the development of Renewable Energy Zones. New South Wales plans to establish Renewable Energy Zones that would:
  - Provide value to generators through creating a firm (to a degree) access right and streamlined planning in return for generation financial contributions to transmission costs
  - Start a 3000MW pilot Renewable Energy Zones in central west New South Wales.

System Plan – Renewable Energy Zones



California

National Infrastructure Commission

November 2020

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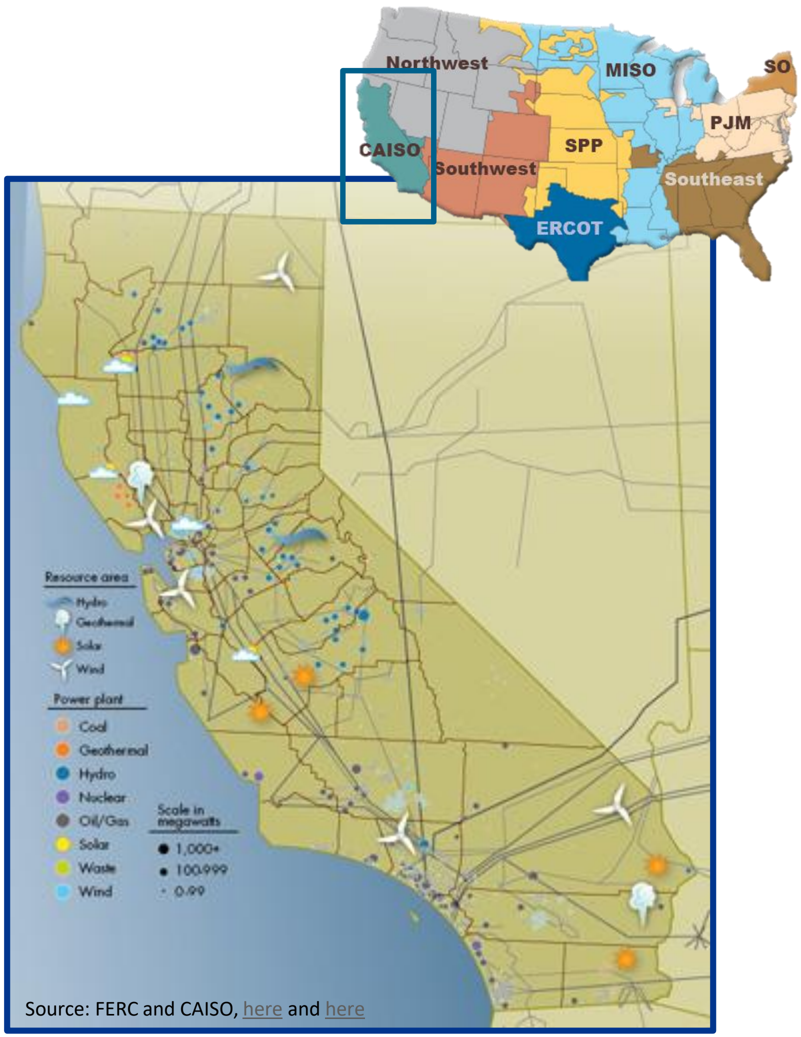
Overview of the material provided in this case study

Executive summary: Market overview

Baringa

California has a well developed renewable sector and strong renewable ambition centred on the continued deployment on solar capacity and onshore wind



Source: FERC and CAISO, here and here

Energy policy

- Renewable energy policy dominates California energy policy at the moment with legislators committing to 100% renewable electricity targets by 2045 (previously set for 2050).
- The short-term 2030 targets have increased to 60% to put the state on the trajectory to meet the deep decarbonisation targets 15 years later.

Supply and demand

- California has championed the development of renewable power in the US with ambitious renewable targets: 44% renewable generation by 2024 and 60% by 2030 according to the state level renewable mechanism (the Renewable Portfolio Standard).
- There has been significant progress made towards these targets over the past five years.
- Solar installed capacity has grown from 1 GW in 2012 to 12 GW in 2018. Wind installed capacity saw more modest growth, but still increased from 4 GW in 2012 to 6 GW in 2018 and demand response growing from almost zero to almost 4 GW in 2019.
- Peak demand in California was 44 GW in 2019.

Wholesale prices

- Wholesale prices fell slightly, on average, in 2019 as a result of a decrease in gas prices and moderate market conditions.
- Day-ahead market prices averaged €38/MWh (€32/MWh) in 2019 according to the system operator.
- California is seeing increasing negative prices as results of high levels of renewables.
- In 2019, California experienced 1% (130 hours) of negative prices at the Day-Ahead stage (up from 90 hours in 2018 and only 3 hours in 2017).
- These prices typically occurred during period of high renewable generation (around midday) and on weekend, when demand was low.

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Executive summary: Key insights

California is an innovative energy market with a clear focus on decarbonisation, but also faces integration challenges as a result of successful solar growth leading to oversupply in some periods

Key insight from California

Renewables have been on the policy agenda in California for 2 decades (slides 119-121)

- California introduced the Renewable Portfolio Standard – which sets the level of demand that suppliers must meet from renewables –this has been a consistent driver for renewable investment since its introduction in 2002.
- California leads the way across the US with legal renewable requirements. Current targets require reaching 100% by 2045.

California's solar success story (slides 119 & 129)

- California's solar resources, combined with state funded investment funds (such as the California Solar Initiative), has led to huge investment in distributed solar capacity in California.
- To the end of 2018, California installed over 7GW of solar capacity at over 835,000 customer sites across the state (source: CPUC, here).
- As a result of dedicated solar funding, introduced in 2007, the cost of installation has reportedly fallen by 50-60% (with greater cost savings for larger solar installations).

There is a cost to accommodating high volumes of solar in California (slides 129 & 130)

- Meeting California's renewable ambitions comes with system implications as solar penetration significantly changes the generation profile in the state.
- The independent system operator (CAISO – the Californian Independent System Operator) is responsible for managing real-time supply and demand
- The system operator was forward thinking in its assessment of the impact of solar on the system in California.
- CAISO recognised the need to manage this 'duck curve' caused by high solar penetration – characterised by oversupply in spring midday periods, followed by a steep ramp in the evening peak as solar generation drops as demand rise.

Avoiding oversupply in California (slides 129 & 130)

- To manage this challenging net load profile, California has taken policy action to support decentralised demand response (i.e. load reduction), offering a solution to periods of oversupply.
- Whilst the market does provide a route to manage oversupply through negative pricing, this is not seen as a long-term solution as this is often managed through renewable curtailment.
- The system operator has taken steps to expand its balancing area by developing a cross-state balancing market (the Western Energy Imbalance Market) which increases the size of the balancing market by connecting states and market regions (currently 11 regions with a further 10 set to join by 2022).
- This expanded real-time market allows system and grid operators to find and move energy across a larger geographic area – and different time zones – allowing for more flexibility in scheduling and dispatching.
- This cross-state scheme avoids renewable curtailment and reduces the overall cost of system operation (estimated economic benefits of $1bn since 2014 according to the system operator).

Key insights for the UK

Single technology focus

- The success of the solar industry in California is an example of how targeted subsidy schemes can deliver renewable technology at scale.
- Some argue that the solar schemes have been too successful, as solar output and profiles are now driving system impacts causing costs for the system.
- This shows the importance of taking into account the full system impact of incentive mechanisms, alongside the core benefit of renewable low cost generation capacity and the low carbon benefit this provides.

Value of cross-border integration

- The value of cross-border integration is clear from the Californian example, and is one of the core tools used by the system operator to manage the impact of renewables on the system.
- This reinforces the value of multijurisdictional exchanges as a tool to manage renewable integration (as well as improving generation diversity and resilience).

Market overview

Key characteristics of the Californian market

Three large utilities dominate the Californian market – each owning generation, transmission and supply – with regulation split between the federal and state regulators

Market structure

Following a re-structuring of the US market which began in the mid-1990s, several markets have shifted from collections of regulated vertically-integrated utilities – with one party owning generation, supply and the network – to partially decentralised systems with separation of system operation activities.

Value chain	Description
Generation	▲ California has three large Investor Owned Utilities (IOUs) who own approximately 70% of generation: – San Diego Gas & Electric, Southern California Edison, Pacific Gas & Electric
Transmission/ Distribution	▲ In California the system operator is independent from the network owners with responsibility for administering wholesale energy markets, conducting system planning, operating the transmission network and ensuring balance of supply and demand on the system. ▲ The system operator is not a government agency and has no remit on resource policy, nor does it own any physical assets. ▲ Alongside the “Big Three” utilities who own the majority of the transmission network, there are 15 smaller transmission owners. ▲ The majority of the distribution network in California is managed by the main three utilities, while six other smaller, municipal utilities manage the rest of the distribution network. ▲ PGE, California’s largest utility, filed for bankruptcy in January 2019, facing an estimated liability of $30 billion for a series of wildfires blamed on PGE’s equipment, including one in 2018 that destroyed the town of Paradise, killing 85 people and burning 18,000 buildings. Since then, PGE has periodically shut down electricity supply to certain areas during hot, dry, windy spells for fear of a repetition. A process to take PGE into public ownership is under considerations.
Retail	▲ Consumers in California are served by their local utility, with limited retail competition ▲ The five largest utilities in California supply 82% of the states residential consumers. These include the “Big Three” utilities, as well as two publicly-owned companies (Los Angeles Department of Water & Power, and Sacramento Municipal Utility District)
Regulators	▲ At the federal level the regulatory authority, the Federal Energy Regulatory Commission (FERC), regulates the system operator and utilities network activities, and the sale of electricity with a focus on interstate networks (i.e. the transmission network) and issues around mergers. ▲ The state regulator is the California Public Utilities Commission (CPUC) who sets the amount each state utility can recover from customers and separately regulates the state distribution networks (i.e. setting regulated network charges). ▲ The primary energy policy and planning agency is the California Energy Commission who administers the state renewable mechanisms. ▲ A separate organisation, the North American Electric Reliability Corporation, is responsible for ensuring the reliability of the power system (both power adequacy and security) by developing a 10-year adequacy assessment, auditing generation and network owners and training market parties to ensure a good understanding of requirements.

Power market structure (1/2)

The system operator in California operates the wholesale power market through a combination of day-ahead and intraday trading, and is responsible for supply/demand balance and system stability

Overview

- The system operator maintains and operates the Californian market and network (along with parts of the network in Nevada). It is a not for profit entity separate to the network owners.
- The system operator operates the wholesale electricity market, running day-ahead and real-time markets, dispatching generation to meet demand every 5 minutes.

Day-ahead market

- The day-ahead market in California is made up of three market processes that run sequentially.
  - First, the system operators runs a market power mitigation test to test the competiveness of the market based on an assessment of pivotality. Bids that fail the test are revised to predetermined limits.
  - Then the integrated forward market establishes the generation needed to meet forecast demand.
  - And last, the system operator designates any additional power plants that will be needed for the next day and must be ready to generate electricity.
- A major component of the market is the system operator's full network model, which analyses the active transmission and generation resources to find the least cost energy to serve demand.
- The model produces prices that show the cost of producing and delivering energy from individual nodes, or locations on the grid where transmission lines and generation interconnect.
- Market participants can buy or sell energy in the day-ahead market with the explicit requirement to buy or sell it back in the real-time market. There is no requirement for such bids to be backed by physical assets.
- This type of bidding, also called virtual bidding, pressures prices in the day-ahead and real-time markets to converge reducing incentives for buyers and sellers to wait to bid physical schedules in the real time market.

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Power market structure (2/2)

Baringa

The system operator operates the wholesale power market in California through a combination of day-ahead and intraday trading

Real-time market

- The real-time market is a spot market in which utilities can buy power to meet the last few increments of demand not covered in their day-ahead schedules.
- It is also the market that secures energy reserves, held ready and available for the system operator use if needed, and the energy needed to regulate transmission line stability.

Energy Imbalance Market

- The system operator is part of, and manages, the Western Energy Imbalance Market which is an automated balancing market across the Western states of the US (see slide 17 for more details).
- The market offers real-time market participation, with 5-minute dispatch, to serve customer demand and to improve integration of renewables cross-state.
- The cross-state imbalance markets is credited as one of the reasons that California is able to accommodate such high levels of renewables on the system.
- The Californian system operator operates the cross-state imbalance market on behalf of the participants.

Source: CAISO, here

Climate goals and subsidy mechanisms

Energy and climate change objectives (1/2)

Baringa

Renewable policy in California is well developed with a combination of Federal level requirements and state-level Bills which provide ambitious, but clear, renewable electricity targets

Two of the most significant developments in California's renewable sector are:

- **The Renewable Portfolio Standard**: Setting the basis for a renewable target based on a renewable supply obligation on suppliers through a certificate scheme
- **Senate Bill 100**: Setting even more ambitious 2030 and 2045 targets for renewable energy sources in the supply of retail electricity

Federal level renewable targets – The Renewables Portfolio Standard (RPS)

- The Renewables Portfolio Standard was introduced at a Federal level and stipulates that each state must have a renewable energy penetration target.
- These targets place an obligation on energy suppliers to procure a certain amount of their electricity from renewable sources, which suppliers demonstrate by acquiring renewable energy certificates.
- The mechanisms was established in 2002 by Senate Bill 1078, with the initial requirement that 20% of electricity retail sales must be served by renewable resources by 2017.
- The programme was accelerated in 2015 by the Clean Energy and Pollution Reduction Act – Senate Bill 350, which:
  - Increased California's renewable electricity procurement goal from 33% by 2020 to 50% by 2030
  - Required the state to double energy efficiency savings in electricity and natural gas end uses by 2030
- In 2018, Senate Bill 100 was signed into law, further increasing the renewable electricity procurement goal to 60% by 2030
- All electricity retail sellers had an interim target between compliance periods to serve at least 27% of their load with RPS-eligible resources by December 31, 2017. In general, retail sellers either met or exceeded the interim 27% target and are on track to achieve their compliance requirements.

Source: California Public Utilities Commission

Senate Bill 100

The 2018 Bill 100 is a pivotal piece of legislation that pushed California towards it's 2030 and 2045 renewable targets:

- *"This bill would state that it is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers and 100% of electricity procured to serve all state agencies by December 31, 2045"*
- The Bill also mandates that utilities source 60% of power needs from renewables by 2030 (increased from a previous requirement of 50%)
- Estimates by the system operator suggest that California is already on track to meet its 2020 target of 33% of energy coming from renewables.
- At least every 4 years, the joint authorities (California Energy Commission, California Public Utilities Commission, and California Air Resources Board) must complete a joint report evaluating the 100% zero-carbon electricity policy, taking into account:
  - Technology progress, including transmission, safety, affordability and system and local reliability
  - Benefits and impacts on system and local reliability associated with achieving the policy
  - Anticipated financial costs and benefits on customer bills
  - Barriers to achieving the policy objectives
  - Alternative scenarios to achieve the policy objectives

Source: Senate Bill No. 100 CHAPTER 312 and CEC website

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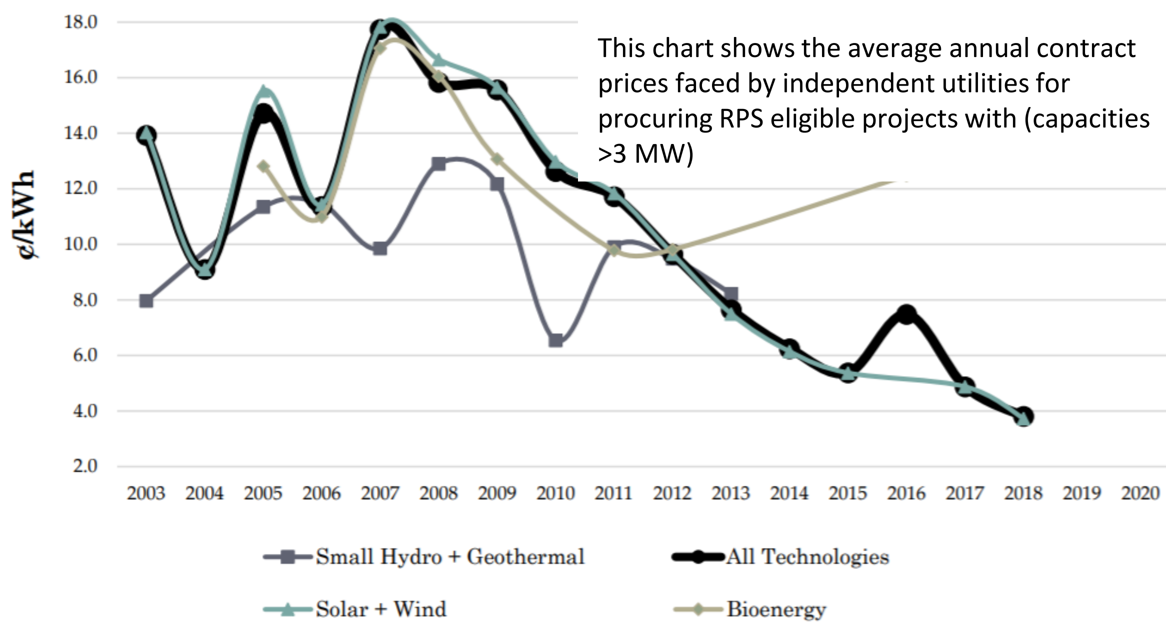
Energy and climate change objectives (2/2)

High concentration of renewables and significant reduction in wind and solar technology costs has led a sustained reduction in cost of procuring renewable projects in California

Historical trend of Large independent utility RPS contract costs by Technology (Real $)



Source: CPUC Annual Report, here

The RPS

- The RPS is a renewable certificate scheme targeting renewables electricity generation.
- There are currently no federal level RPS policies, but individual states, including California, have legislated to impose minimum requirements on RPS procurement for their public utilities.
- The RPS is a traded scheme, such that a supplier or utility can sell additional credit to other market participants.
- In 2010, the state regulator approved rules to allow for trade in renewable energy credits for the Californian RPS. This allows parties to meet their RPS requirement by purchasing Tradable Renewable Energy Certificates (TRECs) that are not associated with a specific renewable generator (i.e. unbundled).
- If a supplier does not meet their RPS requirement they face a penalty of $50 per certificate shortfall.
- The general technology cost reduction for solar in particular is a key factor in the solar growth in California over the last decade.
- California is seeing a slow down in renewable development, in part due to the reducing value, and phase-out, of Production Tax Credit (a federal policy to support the renewable industry).

Source: CPUC, here

Spotlight: Distributed resource and non-wire alternatives

The state regulator has been a leader in innovating the utility regulatory framework, but is also dealing with disaster and bankruptcy of the state's largest utility

California is well known for its ambitious decarbonisation goals, with a focus on distributed energy. To support this growth, California has looked to demand response and storage to provide the flexibility accommodate renewable deployment:

- California has ambitious targets for distribution-led decarbonisation
- Utilities in California also have an energy storage mandate, with targets for deployment of energy storage by 2020, broken down by transmission, distribution and behind the meter connection
- Increased deployment of Distributed Energy Resource (DERs), including demand side response, are seen as a key component of managing the system and delivering these targets at least cost

Incentives for DER

The state regulator has adopted a ruling creating an incentive framework for utilities to contract with DERs in pilot projects for deferring traditional capex led solutions

- The framework provides a 4% pre-tax incentive applied to payments for distributed resources (the 'DER adder'), allowing utilities to earn a degree of profit on opex based alternatives.
- The intention is to incentivise utilities to contract with a DER, for example Demand Side Response, and earn a small return, compared to investing in a network solution and earning a regulated return.
- This mechanism is less generous than that available in other parts of the US. For example in New York the costs associated with DER contracts are capitalised so that utilities can earn the full rate of return as part of their regulated settlement.
- California is however progressive in its approach to distributed resources, especially demand side response, which provides a valuable course of flexibly to manage the growing output from intermittent renewables.

Non-wires alternatives

California, alongside New York, has been an early mover in considering **Non Wire Alternatives** (i.e. deferring traditional investment in distribution capacity through using distributed resources):

- The state regulator's 2017 DER Action Plan set out a framework where utilities are neutral to distributed resources or traditional investment in new capacity, are themselves able to benefit from ownership of distributed resources, and where distributed resources can 'stack revenues' by participating in wholesale markets (including ancillary services) and providing local grid services.
- Early actions associated with delivering this vision included development of formalised Distributed Resource Plans by utilities to help identify upgrades needed to support more renewables on the distribution grid, and the Integrated Distributed Energy Resources strategy to help pay for distributed energy projects.
- Alongside these planning activities, a formal mechanism was introduced (the Distribution Investment Deferral Framework) for utilities to invite bids to provide distributed solutions in certain locations in order to defer network investment. This places the requirement on the public utilities, i.e. the network owners, to run the process to find alternatives to conventional network investment and reinforcement (see, for example, PG&E's 2020 Request for Offers here).

Investment and route to market

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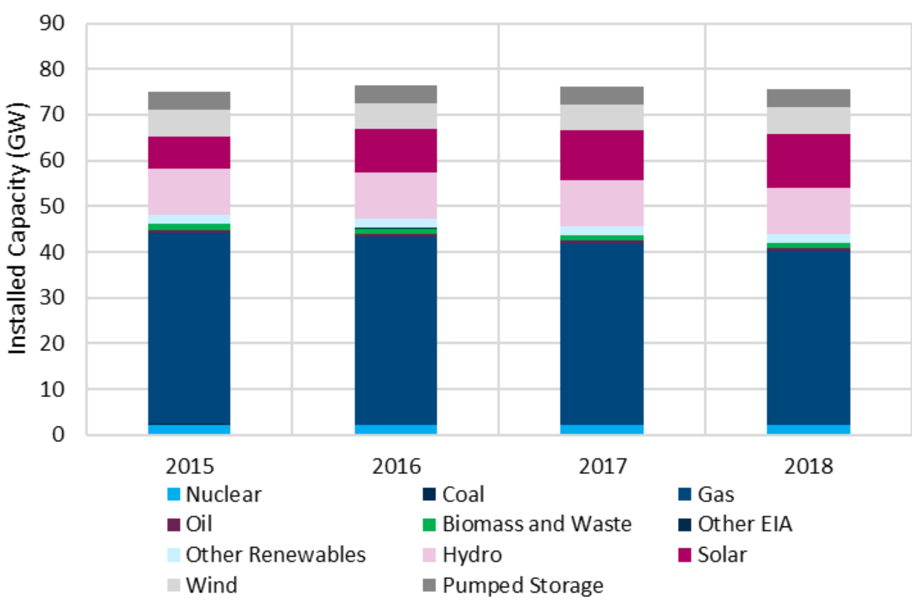
Installed capacity and generation

Hydro, solar and wind represent a large proportion of installed capacity and generation but gas remains as the key contributor

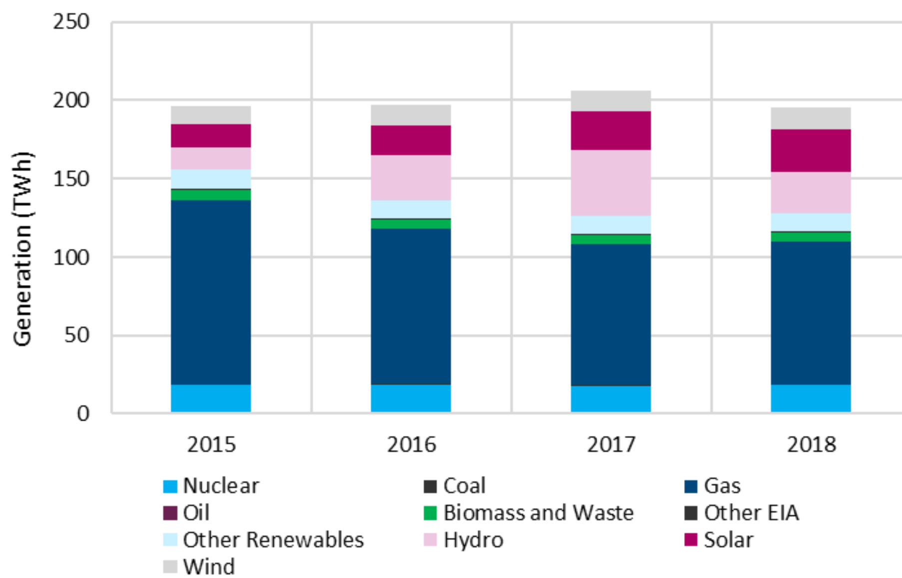
Historical Capacity Mix

- Total installed capacity has been flat in California in the past few years, with gas remaining as the main source of capacity, representing approximately 50% of installed capacity in 2018.
- Wind, solar and hydro capacity accounted for around 37% of installed capacity in 2018, contributing 8%, 15% and 13% respectively.
- Solar capacity has seen a steady increases since 2015, growing from 7GW in 2015 to 12GW in 2018 .



Historical Generation mix

- Gas is the enduring key component of the generation mix, representing approximately 47% of generation in 2018.
- Generation from hydro resources increased significantly from approximately 14TWh in 2015 to over 26TWh in 2018, with a spike in 2017 of over 42TW.
- Solar generation has also seen large increases between 2015-2018 from circa 15TWh to 27TWh in line with capacity expansion.



Source: US Energy Information Administration

Renewable routes to market

Power Purchase Agreements remain the route to market for onshore wind and solar, however the offshore wind lobby is building support to harness the large offshore resource potential

Routes to market for renewable generators

	Onshore wind / Solar	Offshore wind
Renewable support schemes	▲ Renewable support in California comprises a number of elements, including tax relief and direct cash incentives (like the California Solar Initiative). ▲ The Renewable Portfolio Standard offers a top-up to market prices, but requires renewables developers to access the market via commercial contract with offtakers. ▲ Solar capacity dominates the Californian market, with projects developers looking for PPAs (alongside RPS support) to provide long-term offtakes certainty in the form of a long-term contract. ▲ California is seeing a slow down in renewable development, in part due to the reducing value of support, and phase-out, of the Production Tax Credit (a federal policy to support the renewable industry). ▲ Even with the slow down in project development, PPA prices continue to fall, but PPAs remain the main route for renewable contract in California. ▲ Long-term PPAs are, however, becoming harder to access, leaving a merchant-tail – where projects are exposed to full merchant risk when the PPA ends, increasing risk for investors.	▲ Offshore wind is not part of the current renewable capacity mix in California. ▲ The state regulator, and other research bodies, have indicated the potential value that offshore wind can bring to California, and importantly, reduce the cost of meeting the ambitious 2045 targets. ▲ There are a handful of development projects in California, with some media outlets suggests that auctions for offshore wind seabed leases could be as early as 2021. ▲ In 2019, a group of interested parties joined to make the Offshore Wind California group who propose minimum targets for offshore wind in California by 2040 (10GW). ▲ In total, based on a 2016 report, the National Renewable Energy Laboratory estimates that there is 112GW of technical offshore wind resource potential over the entire California coastline, but note that '*ninety-six percent of the technical offshore wind resource is in waters deeper than 60m indicating that floating wind technology will likely be the most viable option in California*'. Source: NREL, here

Grid integration and system operation

Transmission System Operation in California

CAISO is the not-for-profit, Independent System Operator in California, regulated at the federal level, with an overarching objective to manage supply and demand in the state

Overview

- California is characterised by a powerful system operator responsible for network planning and system operation.
- Core functions of the system operator include: Network management through network modelling (system management, including frequency), managing wholesale markets by offering an integrated service taking into account transmission capacity constraints and reserve requirements, and locational marginal pricing.

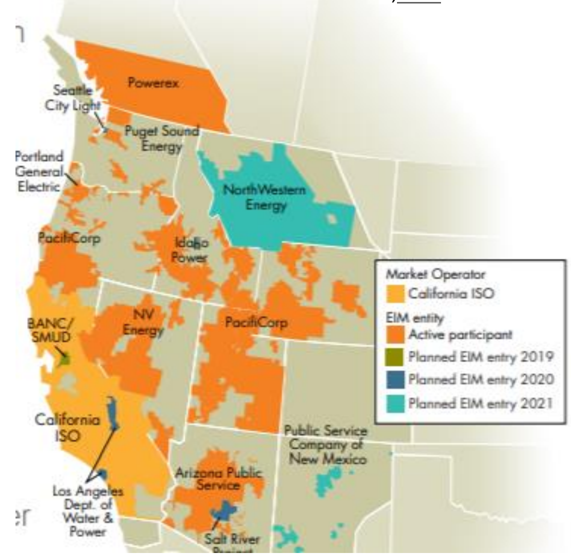
Regulation

- The system operator is under the jurisdiction of the federal regulator.
- FERC approves new rules proposed by the system operator and adjudicates all complaints or appeals filed by market participants, states, or interested parties.
- The line between state jurisdiction (energy policy, local energy distribution grids) and federal jurisdiction (transmission lines and wholesale markets) used to be fairly clear, but has been slightly blurred by new market participants such as batteries, which are often mandated by state energy policy and implemented on local distribution grids, but directly affect wholesale energy prices.

Network planning and expansion

- The system operator is responsible for transmission planning, and must 'identify any grid expansions necessary to maintain reliability, lower costs or meet future infrastructure needs based on public policies'.
- The system operator produces a long-term transmission plan every 15 months, taking into account the planned generation and demand growth across the network and works with other western state entities in inter-regional planning.

Source: CAISO, here



System Operation

- The system operator's role includes both system planning and real-time system operation covering approximately 80% of the Californian transmission system (the system operator does not own any infrastructure).
- The system operator operates the markets and is responsible for Ancillary Service procurement and management – ultimately responsible for keeping the lights on.

Connections and interregional connections

- New generators must apply to the system operator for a grid connection, who will then undertake various modelling exercises, studies and analyses to validate the application, which can take between 10 weeks and 2.5 years.
- Utilities are required to provide estimates of the costs of new connections to their sections of the network, but they are not bound to their initial estimates, posing a risk to developers who cannot be certain of final cost of a project.
- There continues to be debate as to the value of further connections between California and neighbouring states. Proponents argue such a move would bring lower prices, as excess renewable energy could be exported rather than curtailed, and help meet renewable targets, as more renewable energy could also be imported to meet demand. Opponent suggest that the system operator currently benefits from autonomy and should focus on progress in-state and avoid having to work to different state policies, potentially diluting progress and decision making.

System services in California (1/2)

The system operator is responsible for managing power flows and procuring system services in California

Headlines

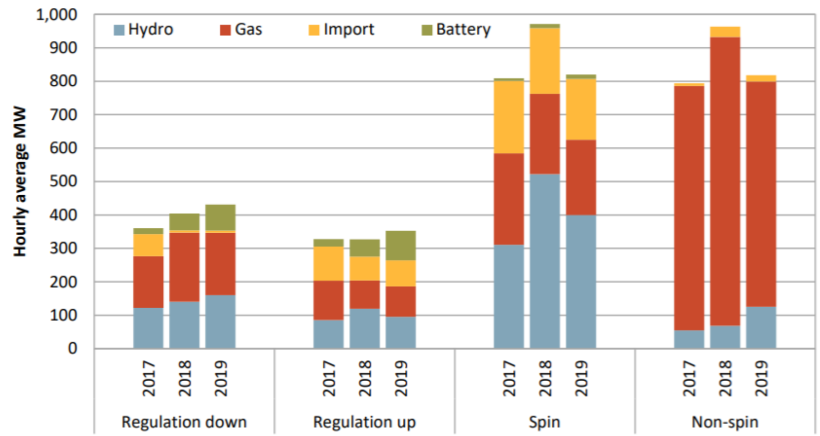
- The system operator is responsible for procuring sufficient ancillary services through the Day-Ahead and Real-Time markets.
- The system operator does this through either self-scheduling resources in its territory or through its ancillary services market (which includes the interconnected markets of neighboring states).
- Ancillary services are procured for different ancillary service regions, which are network partitions used to explicitly impose regional constraints in the procurement of ancillary services.
- There are two main ancillary service regions in California: 1) the CAISO System Region, and 2) the CAISO Expanded System Region.
- The ancillary service market has been increasingly valuable in recent years, driven mainly by increasing levels of intermittent generation from renewable sources.

Products and services

Regulation services

- Regulation services are based on reserved capacity provided by generators on the system (and therefore synchronised), so that the operating levels can be increased/decreased automatically by the system operator
- There are two products available for Regulation:
  - **Regulation-up**: Immediate increase in output in response to automated signals (approximately 50% from gas, 40% hydro and 10% battery storage)
  - **Regulation-down**: Immediate decrease in output in response to automated signals (approximately 40% hydro, then split equally between gas, imports and battery storage)
- Since October 2016, the system operator has calculated the regulation requirements based on observed levels of system regulation required during the same time period the year before.
- The system requirement for each product is approximately 300-400 MW; this target is based on either a percentage of peak load or a fixed number to satisfy reliability standards.
- Requirements for regulation-down were typically highest in the morning and evening hours when solar is ramping on and off; requirements for regulation-up were greatest during afternoon hours.

Ancillary services average requirements in California



System services in California (2/2)

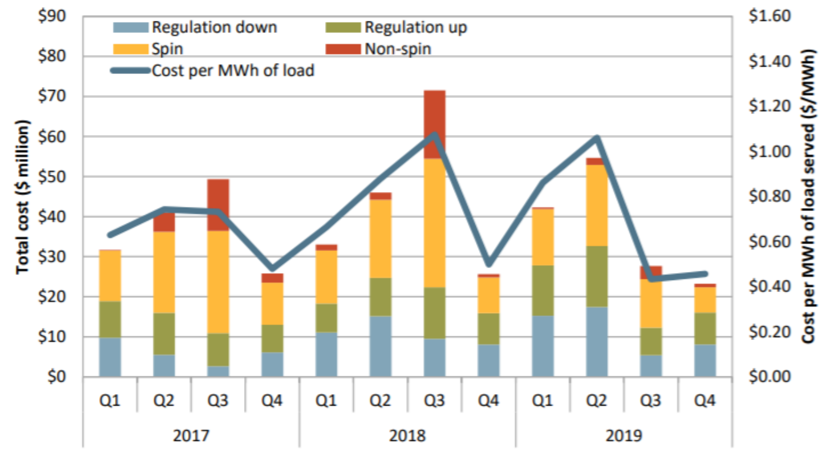
Regulation and reserve are the two main types of ancillary service in California

Products and services

Reserve services

- There are two main reserve products available in California:
  - **Spinning reserves** must be synchronised to the grid, able to respond within 10 minutes and able to run for at least two hours (roughly 50% hydro, 25% gas, 25% imports)
  - **Non-spinning reserves** must be able to respond within 10 minutes and able to run for at least two hours (almost entirely provided by gas generation)
- Spinning reserve requirements are calculated as 50% of the total Contingency Reserve requirement, where Contingency Reserve represents the sum total of spinning and non-spinning reserves (note: in other markets this is referred to as Primary Reserve)
- Contingency reserves are procured in the day-ahead market to meet the full requirement defined by the regional reliability standards. If additional resources are required to provide reserve, they are purchased through the real-time market.
- Load Serving Entities (LSEs) in CAISO must procure ancillary services through self-scheduling or the system operator-led market. They can also bid excess ancillary services into the market.
- In California reserve is typically provided by thermal units.

Historical trends in service costs



Future market design

- In 2016 California introduced two ramping products – flexible ramp-up and flexible ramp-down in the 15-minute and 5-minute markets.
- The products were designed to account for the increase in renewable deployment, particularly solar capacity, and the uncertainty this created for system operation (particularly from forecasting errors).
- Providers of the ramping service were paid their marginal opportunity cost.
- Since implementation, the system operator has continued to make adjustments to the ramping products to improve operability and ensure that the services continues to deliver required ramping in the face of changing system needs.

Spotlight: Solar success and system costs

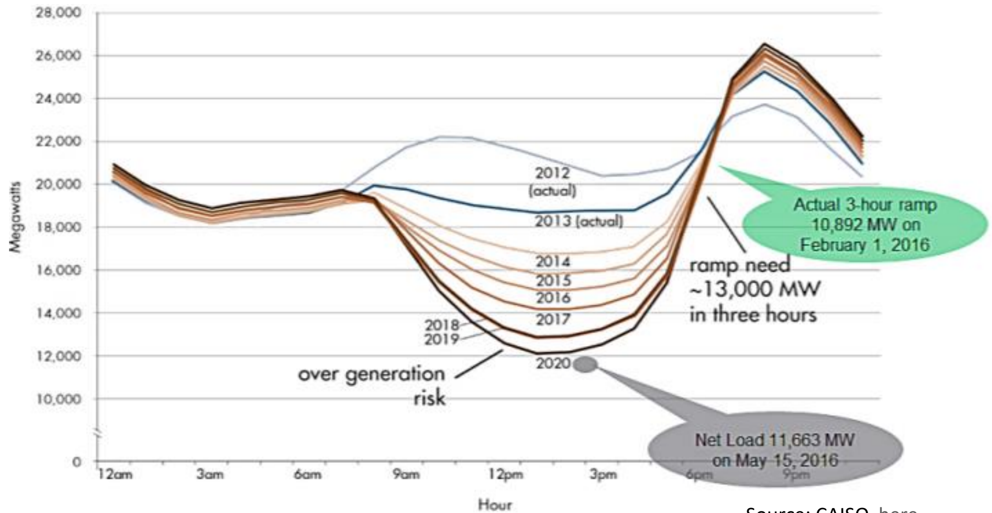
Baringa

California is experiencing challenges with renewable curtailment and capacity shortfalls due to the rapid increase in renewables penetration since 2010

Key considerations for future renewable integration

- The demand for flexible generation in California has dramatically changed since 2010, shown by the famous Californian ‘duck curve’.
- This shows how the net-load shape – calculated by taking the forecast load and subtracting the forecasted electricity production from variable generation resources (wind and solar) – over the day results in significant ramps requirements (i.e. where generation needs to be brought onto the system quickly to meet demand).
- These ramping requirements are particularly problematic in the evening peak when solar output falls as demand increases.
- The system operator needs flexible ramping resources to manage this demand shape (up to 13,00MW ramp in 3 hours to replace the lost solar for the evening peak). As explained on the previous slide, the system operator continues to adapt its ramping product design to respond to this system need.
- The level of solar penetration in California also has a significant impact on wholesale prices – with very low spot prices in the day and more expensive evening peaks.
- For example, in 2010 spot prices were fairly flat between 8am and 8pm, but in 2017 with the significant increase in solar over the past decade, spot prices nearly doubled on average between 3pm and 7pm, relative to 2010.
- Whilst fast ramping generation can support the net load profile seen in California, the system operator also has to take curtailment action to manage the net load profile and ensure there is sufficient capacity ready to meet the swing in net load.

California ‘Duck curve’ (estimated by CAISO in 2011) - Net load curves*



Source: CAISO, here

*The net load is calculated by taking the forecast load and subtracting the forecasted electricity production from variable generation resources (wind and solar)

Facilitating future renewable deployment

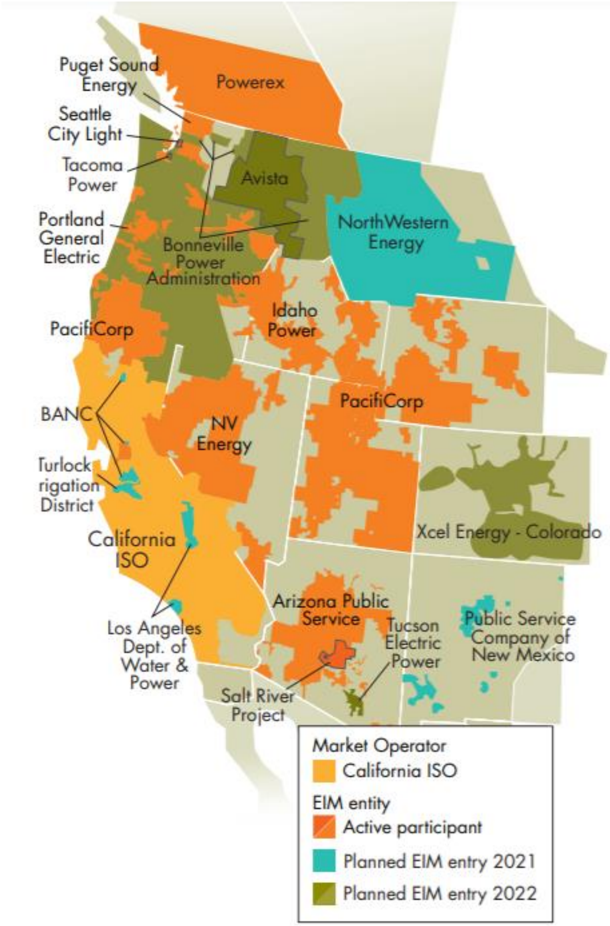
Baringa

With ambitious targets, the system operator, along with other organisations, are looking for ways to manage intermittency to facilitate deployment

Initiatives to improve integration and deployment

California is taking steps to manage the intermittency of renewables to allow the state to meet its ambitious targets:

- **Expansion of the Western Energy Imbalance Market:** Launched by the system operator in 2014, the market now includes 11 participants**.** The imbalance market avoids renewables curtailment and increases system balancing integration, by opening California's real-time balancing markets to entities outside of its territories. This policy helps the Californian system operator, and its neighbours, accommodate renewables by reducing curtailment and increasing peak capacity, and reduce carbon emissions.
- **Regional markets**: The Californian system operators is also exploring expanding the system for all market timeframes, not just balancing. Studies for the system operator show that '*by expanding the energy grid, California would reach its 50 percent renewable energy goal while saving consumers up to $1.5 billion annually by 2030, lowering greenhouse gas emissions and adding jobs in California*' (Source: CAISO, here).
- **Removing barriers for electricity storage**: The federal regulatory authority (Order 841, 2018) required system operators across the US to create a framework to remove barriers to the participation of storage in wholesale markets. Storage is viewed as key part of the future energy mix that will address concerns of capacity shortfalls and price volatility. California had already provided strong incentives for storage, and other non-wires solutions and is currently finalising its plan to allow storage to compete in its spot market.



Source: Western EIM, here

Taiwan

National Infrastructure Commission
November 2020

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Executive summary: Market overview

Baringa

Fossil fuel generation continues to dominate Taiwan's power sector, but ambitious targets pave the way for a rapid ramp up in renewables over the next decade

Energy policy

- Taiwan is heavily dependent on imports for its energy supply: almost all of its gas and coal is imported.
- Following Fukushima, Taiwan has committed to closing its >5 GW nuclear fleet by 2025.
- Taiwan is progressing its planned electricity market reform and shift towards a generation mix with significant renewable energy and gas-fired generation.

Supply & demand

- Electricity demand in 2019 was ~264 TWh; over 50% of this was industrial demand. Peak demand was ~37 GW.
- Installed capacity was just below 56 GW in December 2019 and was dominated by LNG and coal-fired capacity.
- A Feed-in tariff ("FiT") has been in place since 2009, with prices historically higher than international average to support development of the local supply chain.
- Auction rounds in April and June 2019 resulted in 3,836 MW of allocated grid connection and FiTs for 2020-2024 and a further 1,664 MW of capacity awarded grid connection in 2025 respectively.

Prices

- In the absence of a wholesale market in Taiwan, pricing has historically been based on the average cost of domestic fossil fuel power production ("avoided cost") as an indication of FiT prices receivable by renewable generators.
- If a wholesale market existed today, prices would be mainly set by existing CCGTs.
- This is equivalent to a wholesale power for electricity of approximately €52/MWh

*Includes low voltage ride through (LVRT)

Executive summary: Key insights

Baringa

Taiwan is yet to liberalise its power sector, but has seen international corporates look to meet decarbonisation targets through signing PPAs with renewable developers

Key insights from Taiwan

Bankable Feed-in-Tariffs with a PPA, with single buyer, transfers risk away from developers providing an attractive route for investment (slides 136, 137 & 145)

- Taiwan does not yet have a competitive market with Taipower still the single buyer utility. However, there are also lots of PPAs (tolling agreements) with independent generators.
- As Taiwan is going through the process of market reform and liberalisation, there is a degree of uncertainty as to the future market design and route to market for renewables.
- Even with this uncertainty, Taiwan has continued to make significant progress in renewable deployment (including large scale offshore wind deployment with major global players) sustained by the centrally contracted market, with a generous Feed-in-Tariff scheme for renewables providing a defined route to market.
- Under this model, which ultimately transfers risk from developers to consumers, provides an attractive investment opportunity for renewable developers, even with the uncertainty of market liberalisation on the horizon.

Competition can develop even in a market which is not yet liberalised (slides 140, 141 & 145)

- Although Taiwan is yet to introduce a competitive wholesale electricity market, market participants (large users) have sought alternative supply contracts through corporate Power Purchase Agreements.
- These contracts, bilaterally negotiated, reduce offtaker reliance on Taipower as the Vertically Integrated Utility.
- Taiwan's market reform Act has provided the opportunity for this market behaviour, specifically by removing the requirements to purchase power solely from Taipower.

Taiwan has made headlines as international corporates look to meet decarbonisation targets (slide 145)

- Large international corporates have looked to Taiwan, and particularly offshore wind opportunities, to procure large renewable contracts to meet their decarbonisation objectives.
- Recent example include Orsted's recent Power Purchase Agreement with Taiwanese semiconductor manufacturer TSMC (2020), reportedly the largest renewable PPA in the world to date, along with Google who signed its first Asian PPA in Taiwan to meet its data centre load (2019).

Key insights for the UK

- As the UK energy market transitions towards net zero, it is likely to see significant changes to price formation, returns for all generators, including renewable developers, and significant power price risk as the market becomes saturated with zero, or low marginal cost generation.
- A number of commentators have said that this will require a redesign of the wholesale market. Taiwan shows that an alternative is to protect generators from wholesale price risk/design through commercial contracts, whilst maintaining competition between projects.
- In the UK, as renewable support falls and renewable technology reaches grid parity, renewable developers will look for revenue certainty, or risk higher cost of capital or an investment hiatus.
- Whilst Taiwan is in a very different stage of market development and liberalisation, it does provide an example of a system where price risk has been transferred away from market participant and enabled a significant change in investment in a short period of time.

Market Overview

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Key characteristics of Taiwan's power sector

Baringa

Taipower – the vertically integrated and state owned electricity utility – dominates Taiwan's power sector

Market structure

Since 1998, alongside Taipower, the role of Independent Power Producers (IPPs) has gradually increased, contributing to 26% of generation capacity in 2018. Market reform, passed as an amendment to the Electricity Act in January 2017, intends to establish a new Electricity Regulatory Authority, following the example of other liberalised energy markets around the world. This has yet to be established as an independent entity

Value chain	Overview
Generation	▲ Most generation capacity remains under Taipower's ownership. ▲ Since the late 1990s a growing number of independent Power Producers have developed capacity, initially coal-fired, gas-fired, and some oil-fired units; more recently these independent providers have also been involved in developing renewables capacity, predominantly onshore wind and solar PV. ▲ Taiwan's power generation mix remains dominated by thermal power plants, particularly coal-fired, but gas-fired plants (using liquefied natural gas – LNG) and renewables are gaining market share. ▲ Taiwan plans to phase out nuclear by 2025
Transmission and Distribution	▲ Taipower owns all of the transmission and distribution infrastructure in Taiwan. ▲ The Electricity Act amendments will result in some unbundling of the networks activities of Taipower from its generation activities, although the two entities are likely to initially remain under common ownership.
Retail	▲ In practice Taipower remains the single supplier of electricity to consumers (14.2m customers at the end of 2019) across Taiwan. ▲ However, the Electricity Act amendment in theory paves the way towards greater liberalisation in the sale of retail electricity: communities, municipal governments, renewable energy vendors, and other organisations will be permitted to create energy enterprises that can sell electricity to consumers. ▲ These reforms are likely to only impact large consumers of energy that want to buy power directly from renewable energy projects; further market reforms will be needed to provide energy retailers with the market access required to set up energy retailers that offer a genuine alternative to Taipower.

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Power market structure

Taipower will roll out four electricity trading markets and products under a liberalised market

Overview

- According to Taipower's announcement in early 2019, the future Taiwan power market is likely to consist of four markets as outlined below.
- The trading platform is expected to begin early pilots shortly, with a full testing phase by 2023, and the official launch planned in 2024.
- Based on observations from European markets, the introduction of a capacity market is expected to become an important source of revenue for thermal capacities to recover capital investment and fixed costs when the average baseload power price is expected to fall under increased renewable penetration.
- Participation in balancing and the imbalance market is also expected to become a source of revenue for flexible assets. Wind and solar would potentially face imbalance costs, although there may be some revenue opportunity for actions in the Balancing Mechanism.

Day-ahead market	The Taipower Transmission and Distribution Company is responsible for executing the day-ahead market based on forecast hourly demand for the following day. Generators, storage providers, and aggregators would be able to bid into the market, which is optimised on an economic basis. Ancillary services would also be traded in this market.
Intraday market (hour-ahead balancing mechanism)	Taipower manages the balance between power demand and supply in 15-minute intervals through an Hour-Ahead balancing mechanism.
Imbalance Market	Taipower operates an imbalance market to ensure instantaneous balance in power supply and demand. The market operates in 5-minute intervals through a bid and offer mechanism for increase and reduction of generation volume. This market observes the highest price volatility.
Capacity market	To ensure security of supply, the Electricity Act requires generator and retailers to have appropriate level of electricity reserve capacity for their electricity sales. To meet the required capacity, they may use resources from their own generation, purchase from other generators, or demand response providers. The methodology for calculating the required reserve capacity and corresponding procedures would be determined by the electricity industry regulatory authority. The intended Capacity Market would likely be opened for contracting 1 to 3 years ahead of delivery. Gas-powered Independent Power Plants, cogeneration plants, and part-loaded renewables could be considered for participation in the Capacity Market.

Source: Bureau of Energy, here

Climate goals and subsidy mechanisms

Energy and climate change objectives

With a planned rapid expansion of renewable capacity in the energy system, Taiwan aims for less energy imports and to phase out nuclear generation

History of renewable policy in Taiwan

- Taiwan does not have indigenous fossil fuel supply, and therefore has historically been dependent on imports (98% of fuel for electricity was imported in 2017). In the past it has developed nuclear capacity to address this import dependence.
- However in 2009, authorities passed the Renewable Energy Act to increase the installed capacity of renewables to 9.95 GW by 2030. A Feed-in-Tariff was introduced for solar, wind (onshore and offshore), biomass and hydro.

2012	2014	2015	2015	2016	2017	2018	2019
"Million Rooftop PV" and "Thousand Wind Turbines" programs were initiated	**Rising Green Energy Industry Program** was initated	**Intended Nationally Determined Contribution** → 2030 GHG decreased by 50%	**GHG Reduction & Mgmt. Act** → 2050 GHG 50% decrease vs. 2005 level	**Energy Transition Policy** → Nuclear free energy supply by 2025	**Amended Electricity Act** → Open market for RES → Ability to procure renewable energy directly	**Amended 2025 Targets** → Increased offshore wind target from 3 GW to 5.5 GW by 2025 (auction)	**Amendments to RES Act** → Increased renewable targets → Easier application process

It was not until 2017 that Taiwan formalised its renewable energy targets – The Energy Transition Pathway

In May 2017 Taiwan published the Energy Transition Pathway, the forward-looking Green Energy Infrastructure and Stable Electricity Supply, aiming to increase the generation share of renewables and natural-gas to 20% and 50% respectively, and to decrease the coal-fired electricity generation share to 30%. The key components of the strategy include:

- **Renewables**: the strategy aims to increase the electricity generation share from renewables from 4.8% in 2016 to 9% by 2020, reaching 20% by 2025:
  - **Solar PV**: 1.52 GW from 2016 to 2018 with the "Two-year Promotion Project", then reaching 6.5 GW by 2020 and 20 GW by 2025
  - **Wind Power**: "Thousand Wind Turbines" Project (1) onshore wind is already fairly well developed and will increase from 721 MW in 2019, to 800 MW and 1,200 MW in 2020 and 2025 respectively; (2) offshore wind had 8 MW of installed demonstration capacity in 2016. However, the strategic aim is to increase this to 3 GW by 2025.
- **Greenhouse gas (GHG) emissions**: should be reduced by 50% in 2050 compared to 2005 emissions.

The Electricity Act serves as the market mechanism and legal basis for energy transition and electricity market reform: the Act grants priority access to the grid for green power and allows wheeling and direct supply from renewable energy generators. The Act also allows for renewable energy retailers to be established.

A further amendment in Taiwan's Renewables Policy was approved in March 2018 with the increase of the offshore wind target from 3 to 5.5 GW. A total of 3.8 GW was awarded to seven pre-qualified wind farm developers under Feed-in-Tariff, and a further 1.6 GW awarded to two developers in May's auction.

Renewable support in Taiwan (1/2)

Various support has been implemented since the Renewable Energy Act came into force – the most important for renewable investment is the Feed-in-Tariff

Overview

- Taiwan's main economic incentive for renewable investment is through a Feed-in-Tariff, introduced in 2009
- The FITs apply to all renewable technologies and are fixed for 20 years.
- Alongside the FITs, Taiwan has a suite of other, smaller and specific regulations, designed to incentivise renewable through easing regulatory and commercial barriers to project development.

Feed-in-Tariff scheme

- FiTs are available for onshore and offshore wind, Solar PV (rooftop, small scale ground mounted), hydropower, geothermal, biomass and energy from waste and is valid to be applied for 20 years.
- A committee has formed to decide the calculation formula for the FiTs. Tariffs and formulas should be reviewed annually (for new installations), referring to technical advancement, cost variation and goal achievement status. A previous requirement for FiT to be no lower than the average cost for fossil-fired power of domestic power utilities has been removed in a recent amendment.
- PV rates are set on the date on which generation equipment installations are completed with the PV capacity quota announced every year.
- PV systems >50 kW are subject to a bidding procedure to decide tariffs. Developers proposing higher discount rates receive the priority in the quota assignment.
- All other technologies have tariff rates set on the Power Purchase Agreements, which are the offtakes agreement that sit alongside the FIT, signing date.
- The formula to calculate FiT levels is based on an estimate of the levelised cost of electricity, using estimates of cost items and cost of capital.

Wider incentives for renewable deployment

There are a range of other incentives, designed to support renewable development across the sector. These include:

- Regulations allowing staged payments for or custom duty exemptions from renewable energy generation equipment imports
- Regulations subsidising building that include integrated photovoltaic generation equipment demonstration projects
- Subsidies for the promotion of photovoltaic community
- Incentive regulations for geothermal generation demonstration projects
- Subsidies for the promotion of biogas generation projects
- Subsidies for small wind generation system demonstration projects
- Subsidies for research institutions promoting industrial innovation and research development
- Requirements for industry participation in research and development of energy technology projects/initiatives
- An incentive for offshore wind power demonstration projects

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Renewable support in Taiwan (2/2)

Recent amendments to the Renewable Energy Development Act place renewable sourcing requirements on large energy users

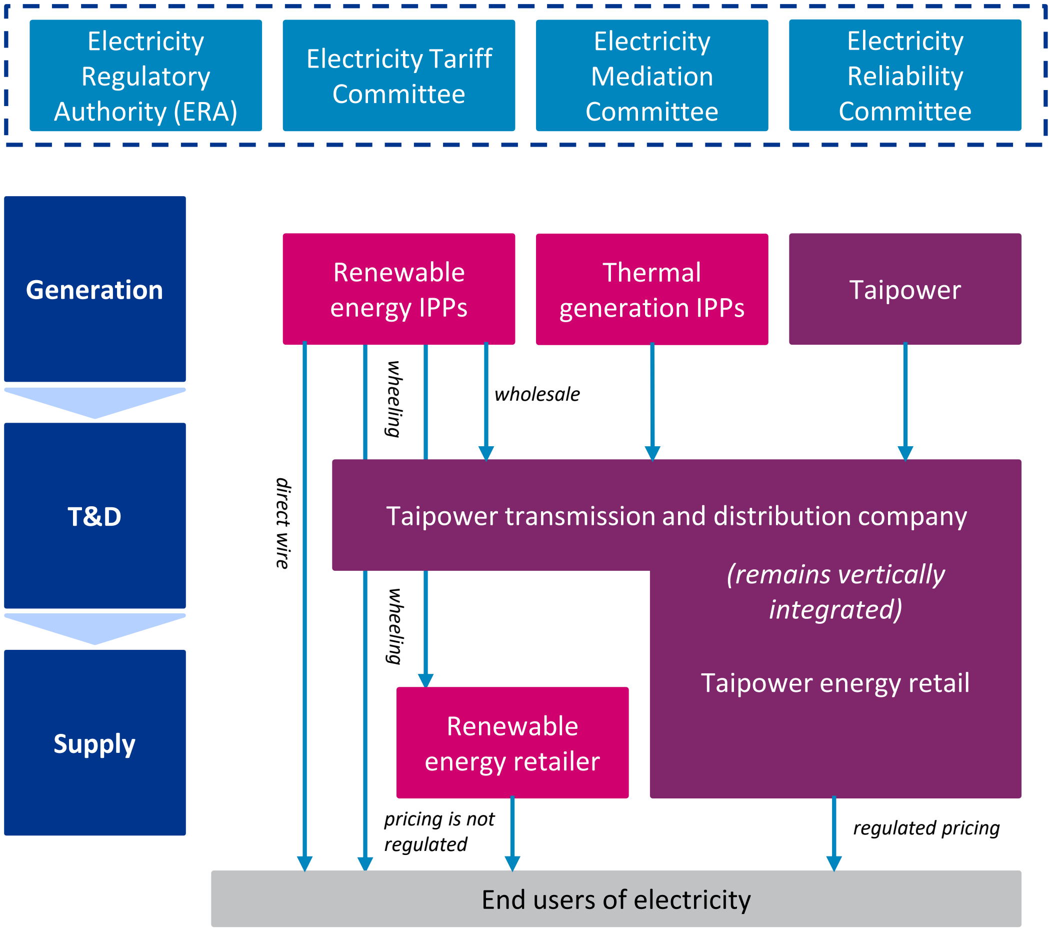
Renewable Energy Development Act

- The Renewable Energy Development Act is another key, forward looking, regulation that sets out a clear framework for development of renewable assets in Taiwan.
- This considers issues such as eligibility of renewable subsidies, entities responsible for determination of Feed-in-Tariffs, cost recovery mechanism for grid connection.
- In April 2019, Taiwan made some key amendments to the Act:
  - Incorporating a 27 GW renewable capacity target by 2025
  - Simplifying the application process for small scale renewable assets below 2MW (to be handled directly by local authorities)
  - Removing a clause offering a lower bound to Feed-in-Tariff payment (avoided system cost) considering falling costs of renewables
  - Requiring large energy users to build renewable or storage capacity as part of their portfolio, or alternatively purchase Taiwanese Renewable Energy Certificates (T-RECs) or pay compensation that contributes towards development of renewable energy.
- As a result of the recent amendments, Taipower is reviewing current Power Purchase Agreements with renewable generators and aims to introduce a mechanism allowing new renewable generators, locked-in under existing FiT, to choose freely between alternative routes to market (e.g. corporate PPA) or selling to Taipower, as well as reviewing the exit clauses of existing contracts to provide reasonable means of exit.
- A recent example if this polity change in action is the corporate Power Purchase Agreement signed between renewable power developer Orsted and Taiwan-based TSMC for the Greater Changhua offshore wind farm, agreed in July 2020 to become the world's largest ever corporate PPA of its kind. Under the terms of the PPA, Orsted will receive a price for the 20-year contract period higher than the feed-in tariff originally agreed in 2018 during Taiwan's first offshore wind auction.
- The regulatory change aims to accelerate renewable deployment through simplification of procedures and facilitating demand-driven development of renewable assets with multiple routes to market.

Spotlight: Market reform in Taiwan

In January 2017 an amendment to the Electricity Act started the liberalisation process – the practical implications of the amendment are likely to be limited in the near-term

Electricity sector structure after implementation of the amendment



Introduction of a regulatory authority

- The Electricity Act amendment requires Taiwanese authorities to designate a regulatory authority, although there appears to have been little progress in setting up this regulatory body to date.
- The regulator is charged with approving rates charged by "public power sales enterprises" (i.e. Taipower), ensuring that wheeling charges result in fair access to the grid, and establishing an "energy price stabilisation fund" to minimise price volatility for end users.

New route to market for renewables

- The amendment will also establish new routes to market for renewable energy generators – largely to meet the requirements of enterprises (such as datacentres) who wish to source all of their power from renewable energy sources.
- Power could be sold through a 'direct wire', or could be wheeled across the Taipower network at regulated rates. This power could also be procured (and then sold on to end consumers) by a renewable energy retail company.

Investment and route to market

Installed capacity and generation

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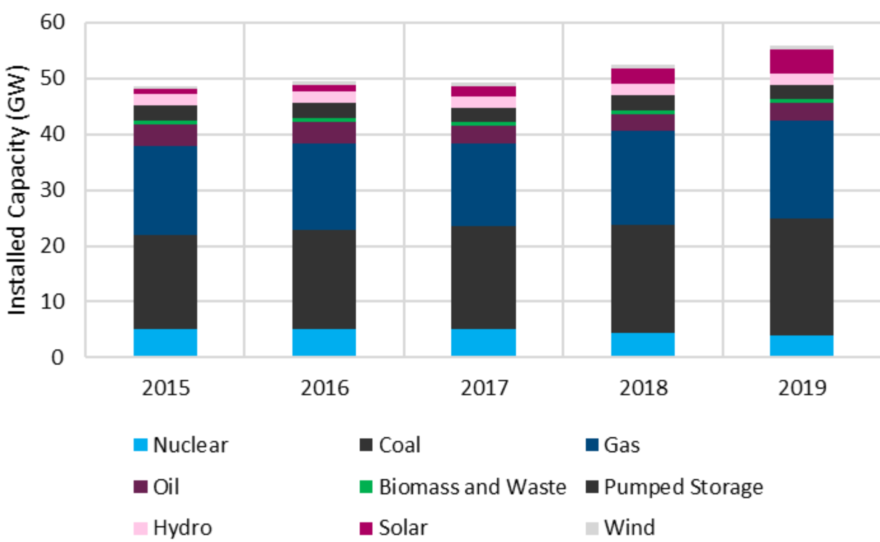
Between 2015 and 2019, installed renewable capacity increased from 4 GW to almost 8 GW, generating over 15 TWh, 6% of the total power produced

Capacity Mix

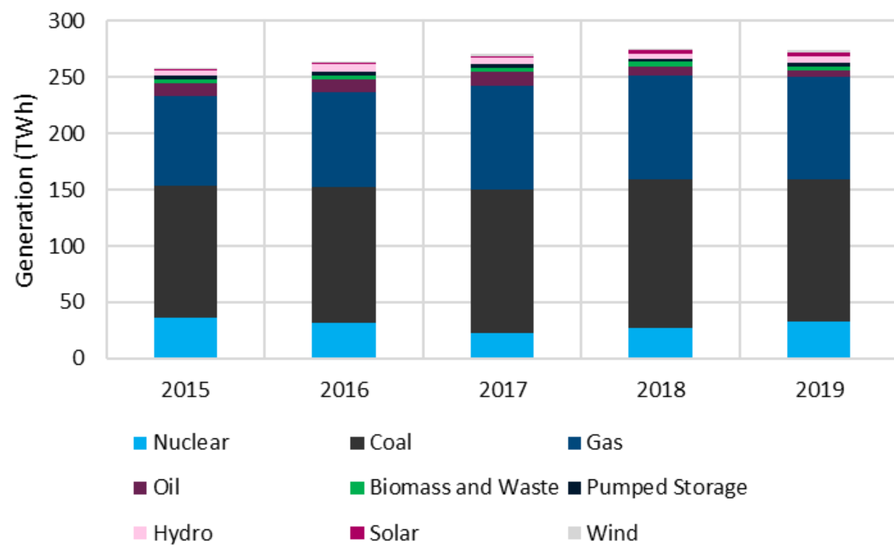
- As of 2019 Taiwan has approximately 56 GW of installed capacity, including Taipower, Independent Power Producers, and self-use capacities (including co-generation)*.
- Of this, almost 14% is based on renewables (excluding pumped hydro).
- The capacity mix is dominated by thermal and nuclear power plants with main technologies being Coal (38%) followed by LNG (31%), Nuclear (7%), and Oil (5%).
- The renewable electricity mix in 2019 was dominated by Solar PV (53%) followed by conventional hydro (27%) and Wind (11%).
- Taiwan does not have any cross-border electricity interconnectors, however the island relies, almost exclusively, on imports for its primary energy sources (LNG, oil, coal and nuclear).



* 53GW total installed capacity in Taiwan, of which 50GW is either owned or contracted with Taipower

Generation mix

- The total gross electricity generation in 2019 was 274 TWh
- 81% of total electricity comes from thermal power – almost half of the generation is coal (46%), followed by LNG (33%).
- Generation from renewables had a 6% (15.2 TWh) share of generation, of which conventional hydro power contributed for 36% of the total, followed by waste (24%).
- Solar and Wind energy have a combined share of 39% of renewable generation.
- Since 2015 total annual demand in Taiwan has grown by 1.8% p.a. on average.



Source: Taiwan Bureau of Energy, here

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Renewable routes to market

Corporate Power Purchase Agreements and trading of renewable certificates are expected to grow in significance in Taiwan, alongside the Feed-in-Tariff regime

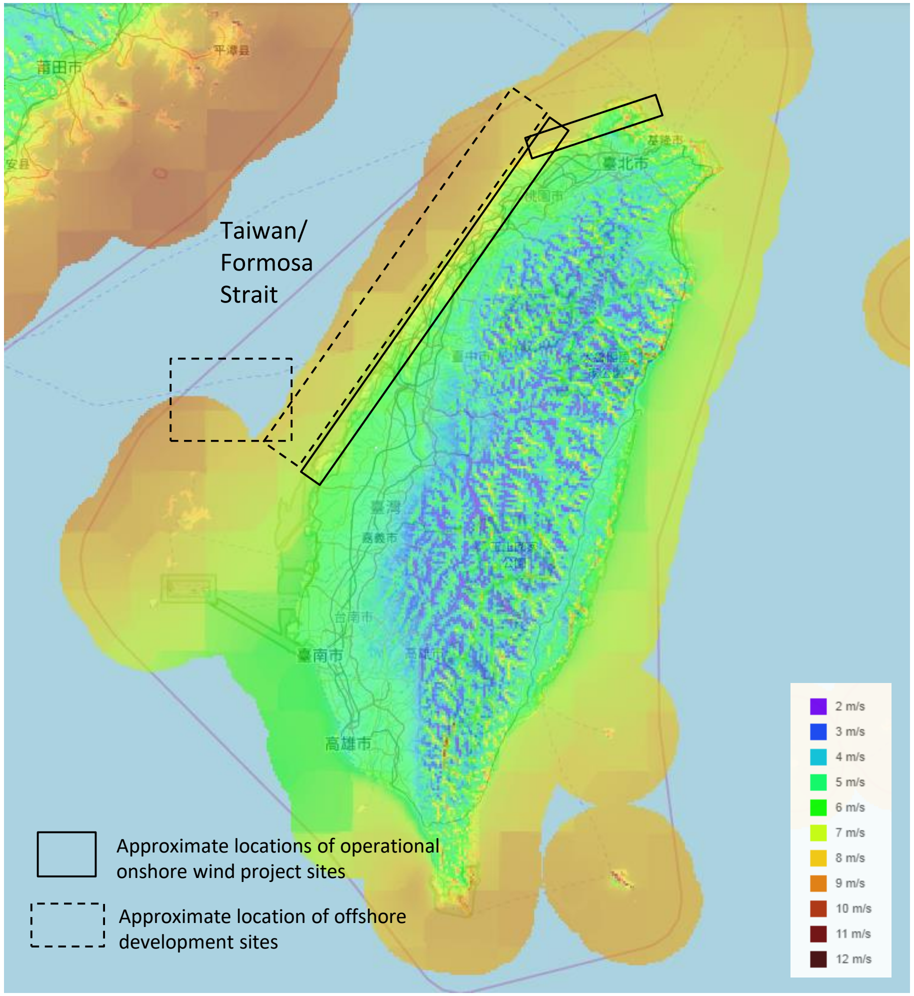
Routes to market for renewable generators

	Onshore wind	Solar	Offshore wind
PPAs with Taipower or Private retailers	▲ When Feed-in-Tariffs expire, renewable generators may negotiate new agreements with Taipower with an extension of at least 5 years. A PPA with Taipower is likely to be in similar format to existing arrangement with Independent Power Producers. ▲ Similar PPA arrangement could also be agreed with private renewable energy retailers. ▲ Taipower's review of contract exit clauses, essentially reducing barriers to contract changes, would facilitate flexibility around generators' route to market.		
Renewable Certificates (demonstration)	▲ Taiwanese authorities launched the National Renewable Energy Certification (T-REC) in April 2017 and issued its first batch of T-RECs during demonstration phase of the scheme. Currently the certificate system is a bundled system consisting of one-time transactions with 57,939 certificates issued and 2,745 traded to date, each certificate representing 1 MWh of renewable electricity. Transfer of certificates could accompany all other routes to market (except projects under Feed-in-Tariffs). ▲ The pricing and implementation of certificates are still at an early stage. However this presents a potential revenue stream for otherwise unsupported renewables in the future. ▲ Recent changes to renewable legislation now requires large energy users to build renewable or alternatively purchase certificates (or pay compensation fee) and is expected to drive demand in certificates. Supply for certificates is also expected to rise with an increase in alternative routes to market.		
Corporate PPAs	▲ This arrangement would see direct bilateral contract agreements between renewable generators, retailer, and energy users, where power generated is sold to users at agreed rate, with excess or deficit bought or met by the retailer. ▲ Power could be transferred through the grid to end users, with a fee payable for dispatching and ancillary services and wheeling. Alternatively power could be sold directly to end users through private wires. ▲ Google signed the first PPA with a 10 MW solar PV installation in January 2019. With requirements on renewable portfolios for large energy users, demand for corporate PPAs is likely to increase.		
Wholesale electricity market	▲ Under the wholesale electricity market proposals, generators and large energy users would be able to trade electricity in near real-time. The Taipower Transmission & Distribution Company would act as the system operator to match demand and supply. ▲ Exact mechanism of wholesale market to be decided with official launch in 2024.		

Spotlight: Wind Resources

Baringa

Good resources for wind power in Taiwan means that wind power has been a focus for the development of renewables, with offshore wind now dominating development



Source: IRENA, DTU wind speed @100m, 1km resolution, here

Onshore wind

- Wind speeds in Taiwan are relatively high, particularly along the western coast of the island, with speeds from 5-7 m/s.
- Due to the mountainous geography of the island, there is limited land suitable for onshore wind development, and the vast majority of development to date has been along the west coast.

Offshore wind

- The highest wind speeds are seen to the north west of the country, in the Taiwan Strait.
- This is the location of potential development locations for the 1,000 Wind Turbines Project.

Thousand Wind Turbines Project announced in 2012 to achieve offshore wind target

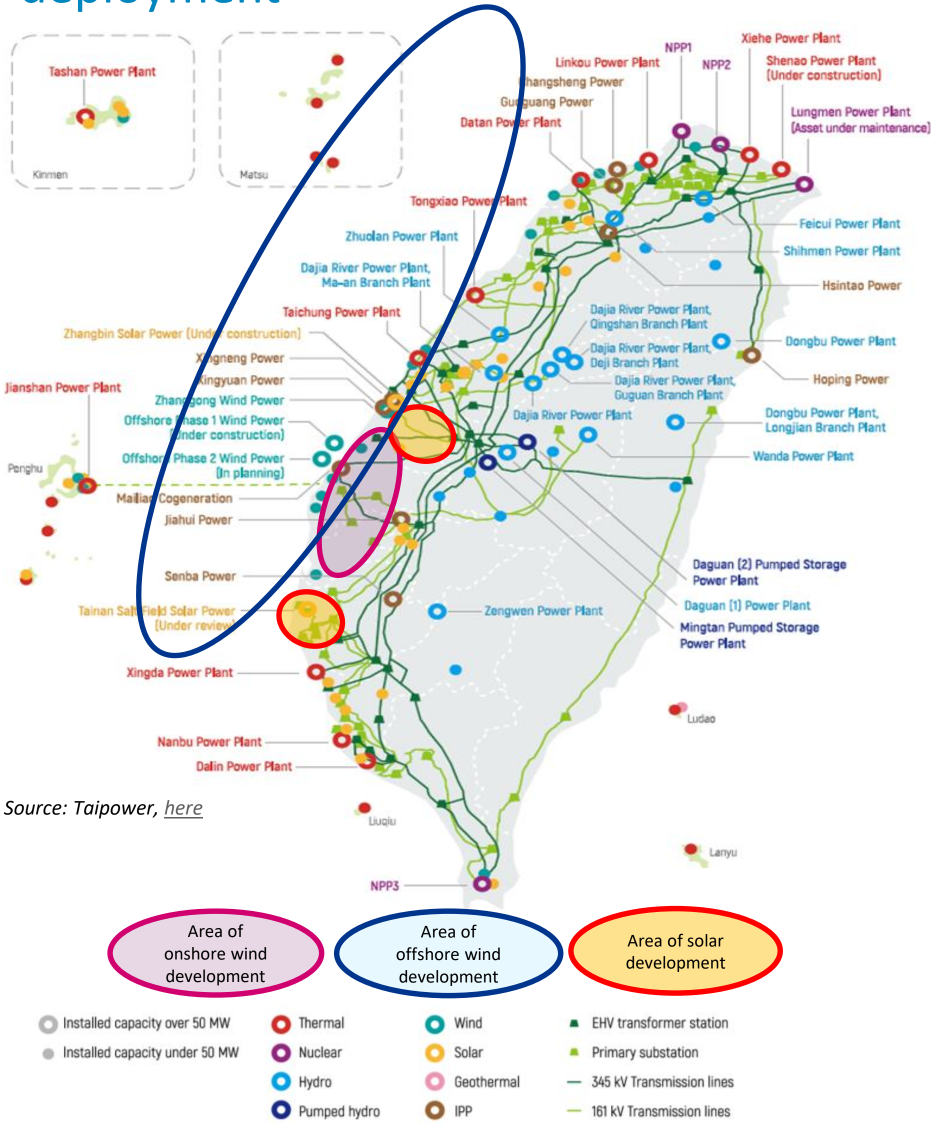
Phase 1 (2016-2020) Demonstration Round	**Phase 2 (2019-2020)** Transition Rounds	**Phase 3 (2021-2025)** Zonal development (ZD)
3 demonstration Wind Farm Projects selected. Phase 1 of Formosa 1 operational (8 MW). Demonstration Wind Farm Projects to be operational by 2020 (360 MW).	5.5 GW capacity allocated to project developers for offshore wind farm developments. 36 potential sites to be investigated with completed environmental assessment until Dec `19. 0.5 GW of capacity with FiT to be operational by 2020.	Remaining Offshore wind energy projects selected during Transition Round will be developed. 5 GW of capacity with 3 GW FiT and 2 GW competitive auction to be operational by 2025.

- Over 10 GW of offshore wind capacity has received environmental approval for development in Taiwan, 5.5 GW of which have been allocated under Phase I and II development. Taiwanese authorities have announced a further target of 1 GW additional offshore wind capacity each year from 2026 to 2030, bringing the total capacity to over 10 GW by 2030.

Grid Integration and system operation

Transmission system operation in Taiwan

Taiwan plans to increase grid connection capacity to support further renewable deployment



Source: Taipower, here

Overview

- The northern region accounts for around 40% of total demand in Taiwan, of which around 6% has been met by generation from the southern region. With the decommissioning of nuclear plants, the trend is likely to continue in the short-term and be partially alleviated with the commissioning of new thermal plants.
- In central Taiwan, a planned expansion and construction of LNG import terminals at the Port of Taichung is expected to support a net increase in CCGT capacity in the area.

Offshore wind

- Across the region, planned development of intermittent renewables is currently limited in scale. As of 2018, Taipower estimated 27 GW of grid connection capacity is available for renewables across Taiwan.
- Taipower plans to increase available grid connection capacity for offshore wind to 11 GW by 2025, in line with the regions ambition of reaching 6 GW by 2025 and 11 GW by 2030.

System operation

- Taiwan faces similar challenges to other island systems trying to integrate renewables into a closed system, reliant on just that systems response services to manage the system.
- As a vertically integrated utility, Taipower has full control and responsibility for system operation and dispatch of flexible assets.

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System services in Taiwan

Taiwan has a typical set of system services to help manage intermittency and system frequency, mainly reliant on gas generation to offer flexibility

Headlines

- Taipower operates the system and has now implemented a set of ancillary services to help manage renewable intermittency (see next slide)
- Alongside these system services, Taipower procures other energy sources for the island (such as storage systems, demand response and other fast response power generation resources) to increase system flexibility. Taipower reports that 3 batteries, with total capacity of 3 MW, were installed in 2019 to offer system services.
- As a vertically integrated utility, Taipower has full control and responsibility for system operation and dispatch of flexible assets.

Products and services

Fast response reserve	Regulation reserve	Spinning reserve	Supplemental reserve
Response time: <1 second **Duration**: 3-15 minutes **Providers**: Energy storage, demand response (with Under Frequency relay used to match load with available generation) and thermal generators with primary frequency response **Procurement target (2025)**: 1000-1200 MW	**Response time**: 3 minutes **Duration**: 15 minutes **Providers**: Energy storage, demand response (with storage) and thermal generators with automatic generation control **Procurement target (2025)**: +/- 1300 MW	**Response time**: 10 minutes (target) from current requirement of 30 minutes **Duration**: 1 hour **Providers**: Energy storage, demand response (with load curtailment), generators **Procurement target (2025)**: 1100 MW	**Response time**: 30 minutes (target) from current requirement of 60 minutes **Duration**: 1 hour **Providers**: Demand response (with load curtailment), generators **Procurement target (2025)**: 1100 MW

Source: Taipower, here

Future market

- In 2020, Enel X, a subsidiary of Enel joined Taipower's Demand Response programme to manage system reliability.
- Reports suggest that Enel X will offer Demand Response services to energy intensive users, such as food processing factories, cold storage units and industrial sector energy users.
- Enel X's offering will be through it's Virtual Power Plan.
- Participants in the scheme will be paid by Enel X to adjust demand in response to the system needs in Taiwan.
- Whilst we see that Taiwan has a number of comparable system services, and a growing Demand Response market, there is no evidence to suggest that Taiwan is struggling to support the current levels of renewable investment on the transmission system
- With the extensive investment in intermittent renewables, planned for the next decade, and the lack of alternative sources of flexibility (i.e. cross-border infrastructure), we expect the see system operation (particularly frequency contract and inertia) to become increasingly challenging in Taiwan

Source: Enel, here