Power-Industry Transition, Here and Now

Wind and Solar Won't Break the Grid: Nine Case Studies

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This report is the result of a collaborative effort drawing upon experts in the drafting of the individual country sections. These experts were:

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Executive Summary

In this study, we show how nine leading countries and regions have adapted to high market shares of wind and solar power using existing integration technologies and policy measures to improve their diversity of domestic generation without compromising reliability or undercutting supply.

This research is timely, given rapidly growing levels of renewables globally, concerns about climate change and air pollution, and the renewable energy sector's growing competitiveness with fossil fuels.

Renewable sources of electricity can be divided between variable sources, notably wind and solar power, and firm sources available on demand, such as biomass, geothermal, concentrated solar power (CSP) and hydropower. The focus of this study is grid stability and the challenges for grid operators posed by variable wind and solar power.

Our nine case studies are among the top 15 countries/markets worldwide by wind and solar market share, ranging from 14% to 53% of total electricity generation, compared with a global average of 5%. The case studies span the globe: four are from Europe, two from the U.S., one from South America, one from Asia, and one from Australia. They are, in descending order of wind and solar market share of total net generation in 2017: Denmark (52.8%); South Australia (48.4%); Uruguay (32.2%); Germany (26%); Ireland (24.6%); Spain (23.2%); Texas (18%); California (15%); and the state of Tamil Nadu, India (14.3%).

Data for major cities in the national case studies indicate that none have suffered major grid problems. If anything, power outage data suggest that these are among the world's most robust electric grids and are performing better than their peers by national income.

This report focuses on the practical changes in market rules and resources required to manage the shift to higher levels of wind and solar power. All of the grid integration solutions discussed below are available and proven today. The broad use of emerging technologies, particularly battery storage, that could enable even higher levels of variable renewables is not considered. But we note that battery storage is an emerging solution among the leaders, notably in South Australia.

We draw attention to nine options for system operators to consider, all of which can help ease the integration process and assure supply security and grid reliability. Countries can select from these, according to their circumstances, and so avoid radical redesigns of their power markets. Our view is that solutions are tied to specific conditions and that a broad sharing of state-of-the-art solutions is the best way to encourage market growth. The nine options are listed below, with examples drawn from our case studies.

1. **Timely investment in the transmission grid**: Texas is the lead example of a highly organized program of transmission network investment connecting wind farm regions with cities.
2. **Boosting transmission interconnections and cooperation between neighboring countries and power markets**: In 2014, the California independent system operator (CAISO) and PacifiCorp launched the western energy imbalance market, which extended into seven states the area that CAISO could call upon to balance variability in demand and supply, thus reducing renewables curtailment.

3. **Ensuring flexibility in domestic generation**: In Uruguay, domestic hydropower provides flexibility for wind generation that has grown more than 30-fold in the past five years.
4. **Market reform to boost flexible back-up**: Ireland is in the process of introducing real-time balancing and intraday markets to provide important price signals to potential investors in flexible generation, demand-side response, and storage, aiding the development of a more flexible grid to respond better to increased renewables penetration.
5. **Supporting demand-side flexibility**: Following a one-in-a-100-year storm that caused a statewide blackout in 2016, South Australia devised an energy plan backing new sources of flexibility, including 1,000 megawatts (MW) of contracted demand-side management.
6. **Better wind and solar forecasting**: In Spain, modelling advances at the national wind power forecaster, Sipreolico, have halved day-ahead forecasting errors.
7. **Enhancing the responsiveness of the distribution grid**: Germany has changed grid codes for household solar inverters to make them responsive to variations in grid frequency and thus stabilize the grid, while avoiding any prospect of sudden, large-scale disconnection.
8. **Making renewables more responsible for grid balancing**: Beginning this year, wind power aggregators in Denmark will have to provide firm power from across their portfolios, including the oldest turbines, meaning they will pay for inaccurate forecasts.
9. **National leadership:** India's ambition to drive five-fold national growth in variable renewables over the next decade has spurred initiatives such as its Interstate Green Power Corridor, favoring local integration of solar power in the state of Tamil Nadu

Our findings are particularly relevant against the backdrop of the rapidly rising global market share for wind and solar generation. As the market share of variable renewables grows, system integration issues will become even more important. Our case studies provide valuable lessons, documenting how national or regional market share of wind and solar power is up to 10 times the world average. Significant market share has been achieved in a handful of years, defying decades-long transitions projected by some analysts. For example, Uruguay's wind and solar share of generation rose to 32% in 2017, from 1% in 2013.

This report is timely also in the context of political and industry pushback against renewables. Political resistance has been particularly pronounced in the U.S., with the Trump administration looking for ways to bolster coal and nuclear power. But resistance has been raised elsewhere as well. We note that Germany in 2018, for instance, gave in to the coal lobby and abandoned its 2020 carbon emissions goals. Fossil fuel firms have spun a false narrative around the supposedly negative impacts of renewables growth on electric reliability and affordability.

Regions trends have outpaced national trends in three of our case studies: South Australia, California and Texas. These examples show how regional markets can play leadership roles as early adopters of wind and solar power. When national governments are on board, as in India, regional growth can be even faster, as in the state of Tamil Nadu.

Finally, our report finds that concerns about the impact of wind and solar power on grid reliability are over-stated. We show that grid operators can assure security of supply at levels of wind and solar power of at least 50% of total generation by boosting system flexibility and grid interconnection and by ensuring strong price signals. Operators can achieve this through a series of technical engineering adjustments, investments and reforms to power market design and without resorting to new out-of-energy market subsidies for conventional generation.

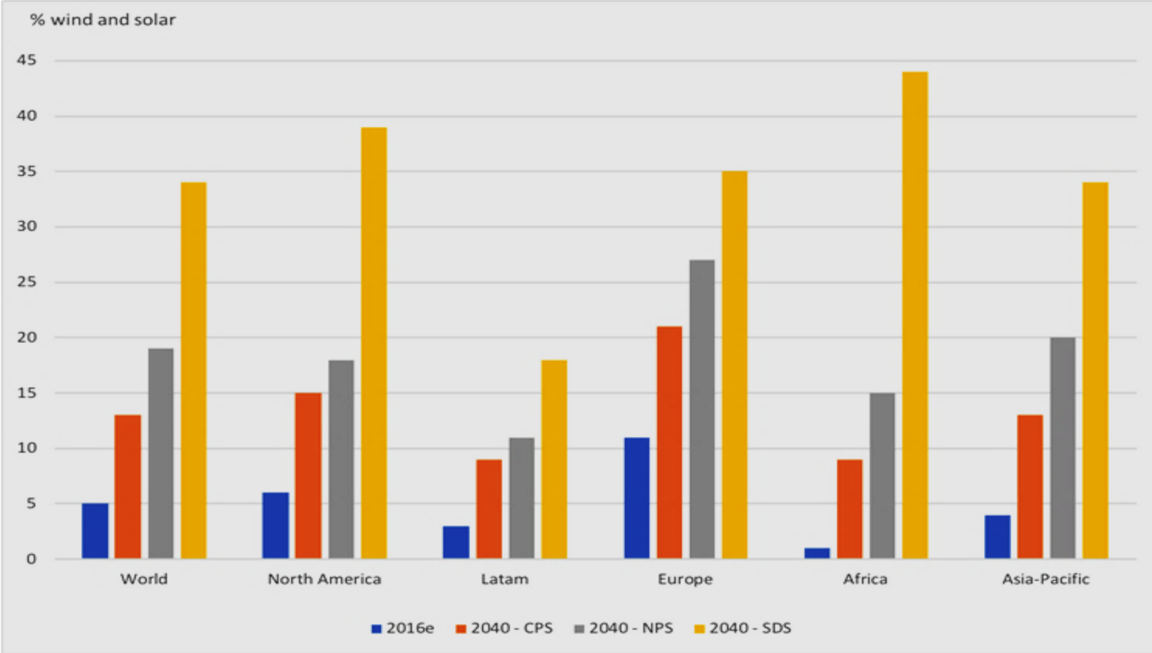
Introduction

Growth in Wind and Solar Power

According to the International Energy Agency (IEA), the global average wind and solar penetration today is 5%, and will rise to 13-34% by 2040, depending on the ambition of energy policies adopted (see Figure 1 below).[1] The IEA scenarios range from 13% of global power generation under a current policies scenario (CPS, in Figure 1); to 19% under additional climate action plans (its new policies scenario or NPS); and 34% market share under more aggressive policies consistent with climate and air pollution targets (its sustainable development scenario or SDS).

Importantly, all nine of the countries/markets described in this report already achieve far higher levels of solar and wind than the global average today, with two near or above 50%. Our case studies therefore provide lessons for the world at large in how to prepare for a high-renewables future.

Figure 1: IEA Projections for Wind and Solar Market Share (% of total generation)



Source: IEA 2017

[1] https://www.iea.org/weo2017/

New Challenges for the Power Grid

In conventional power market models, electricity generation is broadly divided between baseload (around-the-clock), mid-merit (on-demand) and peaking (short-term balancing) capacity. Under a traditional merit order approach, operators dispatch electricity according to least marginal cost to minimize system costs. Marginal cost refers to the cost of running a power plant, moment to moment, rather than the upfront, capital cost to build it.

Traditionally, baseload power plants would have the lowest marginal cost, starting with hydropower and nuclear power, which would be dispatched first. Mid-merit plants would be dispatched next, for example coal or gas, depending on fuel prices, followed by peaking capacity.

Baseload power refers to the base (or minimum) load (demand) that customers require around the clock. Baseload power plants would generally supply this minimum level of electricity. Generally, it is only convenient or economical for these power plants to ramp up and down quite slowly. Mid-merit power plants operate more flexibly, according to daily variation in demand. They would traditionally be served by gas or modern, more flexible coal plants, depending on fuel sourcing and hence prices, with the lower marginal cost generation despatched first. Peaking power plants respond to infrequent, short-duration demand peaks, and include fast-response gas turbines or diesel engines. Pumped hydro storage, batteries and demand-side response can also fill this role.

Growth in wind and solar power is changing this traditional power dispatch model. Both wind and solar power have near-zero operating costs. As a result, they are delivered first, pushing other forms of generation further down the merit order, meaning they operate less often and make less money. In many European countries, wind and solar power have also had priority feed-in to the grid. Consequently, wind and solar power are both displacing conventional generation and depressing wholesale power prices generally, putting economic pressure on traditional mid-merit plants.

There are several fundamental differences between variable renewables, including how they are paid for and delivered, and conventional generation, that must be addressed to integrate wind and solar power effectively into the electric grid.

These characteristics include:

1. Their daily variability may not be perfectly predictable, adding uncertainty regarding meeting electricity demand. Such variability puts more importance on incentivizing additional, flexible sources of generation that can respond quickly when variable power is less available or demand surges. That may mean preferring fast-responding hydropower, storage and fast-ramp gas generation over less flexible alternatives.
2. Variable renewables are often located on local distribution grids, e.g. residential solar roof-tops, rather than on high-voltage transmission lines. This generation is therefore effectively invisible to and beyond the control of grid operators, who can only see its impact on net demand. This low visibility and lack of control may add to the challenge of forecasting and managing their variability.

3. Even where variability is predictable, the rate of change may cause difficulties. For example, solar generation typically declines rapidly around sunset just as power demand is peaking (i.e. the much-discussed California duck curve). This requires a grid operator to bring on substantial back-up resources over a short, ramp-up period.

4. Some renewables vary seasonally, such as solar power in temperate climates. Such generation will require long-term seasonal balancing, which may be beyond the scope of most storage options and require instead some standby flexible generation.

5. The strength of renewable energy resources is site-specific, and the best resources may be far from demand centers, with offshore wind one example in some countries. This may increase transmission costs.

6. Because wind and solar have zero fuel costs, they have very low marginal costs, and will displace conventional fossil fuel generation when they are available. They may therefore undermine the economic viability of conventional generation which may still be needed when wind and solar are unavailable. Contracting renewables through out-of-market payments, such as subsidies or power purchase agreements, may further suppress wholesale power prices, adding to this effect.

7. Because the output of wind turbines (and solar modules) is highly correlated at any one location, according to the prevailing weather (time of day), additional variable generation added at that location will tend to be progressively less useful to a national electricity system. This issue places greater importance on load shifting, which means moving demand to match supply, instead of the other way around, and storage, which allows operators to store excess renewable power until it is needed.

8. Conventional coal, gas, nuclear and hydropower generate electricity with massive turbines that spin synchronously in line with grid frequency. The momentum of these turbines helps balance changes in grid frequency, and a steady grid frequency is essential to protect consumer appliances. As asynchronous generation, wind and solar do not provide such operational benefit. This has placed new emphasis on frequency control.

A Political Backlash

The economic dislocation linked to rising levels of solar and wind generation has become particularly contentious in the United States, where the Trump administration has sought to bolster the coal industry, at the expense of growth in wind and solar generation, by arguing that variable renewables undermine grid security.

In April 2017, U.S. Energy Secretary Rick Perry requested his department to investigate the impact of "regulatory burdens, as well as mandates and tax and subsidy policies" on energy security and reliability.[2] The "burdens" referred to new pollution controls on coal, and the "subsidies" to tax credits for wind and solar power. In his memo, Senator Perry stated that baseload power, such as coal, natural gas, nuclear and hydro, was necessary to a well-functioning electric grid, and he cited concerns from "grid experts" that such baseload power was now being eroded by these coal burdens and renewables subsidies.

[2] https://geoharvey.com/text-of-rick-perrys-memo-of-april-14-2017/

In its response, U.S. Department of Energy staff published a report which concluded that the emergence of cheap natural gas was the main factor behind recent coal and nuclear retirements, rather than growth in variable renewables.[3] Notwithstanding changes in power markets, the report concluded that markets were achieving reliable wholesale electricity delivery. It found that hydropower, nuclear, coal and natural gas power plants provided essential reliability services, but that wind and solar power and demand response were also capable of providing many of these services, and that regulations increasingly required them to do so. It acknowledged that markets need reform, over time, to cope with potential future challenges, including growth in variable renewables. Already, growth in variable renewables had increased the "premium on flexible output rather than the steady output of traditional baseload power plants", it said, contradicting Perry's argument that baseload per se was an essential part of the energy mix going forward.

Despite these findings of his own staff, Secretary Perry proposed that the Federal Energy Regulatory Commission (FERC) make a significant power market intervention, to provide additional out-of-market revenues to recover full costs for coal and nuclear baseload resources that stored on-site fuel.[4] Perry stated that the measure would help provide grid balancing services such as frequency and voltage support, even though many other technologies provide such services. In January 2018, FERC commissioners unanimously rejected Perry's proposal, instead asking regional grid operators to review more thoroughly issues around improving power system resilience.[5]

This result was interesting, as an example of expert regulators striking down political doubts about the grid reliability impacts of changes in power markets including the growth in variable renewables. FERC agreed that the new U.S. administration had identified a useful and important issue, namely reliability, and said that it would work to figure out how best to address it. But FERC found that the administration's proposal failed because it did not improve reliability, resilience or correct imbalances in the pricing system.

Structural Worries About High Solar and Wind Generation Levels

Elsewhere, market participants have voiced concern that lower running times and lower wholesale power prices will deter investment in flexible, mid-merit generation. That has led to calls for market design that explicitly rewards flexible generation for the "flexibility services" that they provide. One example of such market reform has been the establishment of capacity markets, which provide an additional revenue stream outside energy-only markets. In such capacity markets, operators are paid for their power plants simply to be available, even if they don't generate any electricity, as an insurance policy or back-up in case variable renewables are unavailable.

Capacity markets, discussed in detail in the following box (Box 1), are likely to remain a source of disagreement among industry participants in the years ahead. It is worth noting that of the nine case studies in this report, only Spain has a comprehensive capacity market,

[3] https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf

[4] https://energy.gov/sites/prod/files/2017/09/f37/Secretary%20Rick%20Perry%27s%20Letter%20to%20the%20Federal%20Energy%20Regulatory%20Commission.pdf

[5] https://www.utilitydive.com/news/ferc-rejects-doe-nopr-kicking-resilience-issue-to-grid-operators/514334/

while the others have adapted to higher wind and solar generation levels largely using an energy-only market approach. We note that the Spanish capacity market has been unsatisfactory: its lacks transparency; is inefficiently applied; and has added new subsidies to an energy system before addressing existing flawed policies, such as a cap on wholesale power prices, and a regulation preventing mothballing of idle power plants. As a result, the scheme has helped create wasteful over-capacity, and may have undermined system flexibility.[6] We conclude that there is no evidence yet that capacity markets are needed to adapt to high levels of renewables.

It is beyond the scope of this paper to delve into the details of how market operators run their grids, but Box 2 presents an overview of how demand and supply are balanced, and how rising levels of variable renewables affect those operating procedures.

Box 1. Use of Capacity Markets in High-Penetration Wind and Solar Markets

Growth in wind and solar power has displaced other generation because they have lower running costs, with the effect of lowering power prices and reducing running times for conventional generation. That has reduced incentives to invest in conventional generation, including flexible generation, which is sometimes termed the "missing money" problem. As the running time of competing, conventional generation falls, ever-higher prices are required when wind and solar power are unavailable to incentivize new investment.
This "missing money" arises from the assumption that prices would have to rise to very high levels, say $100,000 per megawatt-hour (MWh), or even higher, to incentivize long-term investment in merchant generation in energy-only markets. Regulators may not allow that to happen, for example because of fear of market abuse. And even if they did allow such high scarcity prices, there would still be uncertainty about exactly when or how often generators might reap such revenues, given this would depend on infrequent scarcity events that may be entirely absent for months or years.

The argument is that generators therefore may need some additional revenue stream to balance variable renewables in regular, energy-only markets. One such additional revenue stream could come via capacity markets. Under a capacity market, a central system operator decides on the planning requirement for future capacity, up to several years ahead, to assure security of supply. The operator then holds auctions inviting bids to provide that capacity. Successful bidders will receive a certain sum per unit of capacity that they make available in the target year. That revenue will be in addition to sales of energy in wholesale power markets. Such planning several years ahead of actual delivery could incentivize more back-up generation. It may also favor more flexible assets, for example if units are favored according to their ramping ability. In the United States, some operators have introduced such flexible ramping products.

However, we note weaknesses of capacity markets. Over-cautious public officials may play it safe, creating a tendency toward over-capacity. Pre-planning also risks creating a static, sclerotic energy system, through the picking of long-term winners. And it invites government intervention. We note that fossil fuel utilities have driven present political support for capacity markets in Europe. Capacity markets also distort regular, energy-only markets, by creating additional income streams that dilute energy market price signals, and so risk creating a self-perpetuating system (lower power prices will perpetuate calls for additional income streams such as capacity payments). In this report, we present many alternative approaches to balancing the grid which may better avoid these problems.

[6] http://ieefa.org/wp-content/uploads/2017/11/Spains-Capacity-Market-Energy-Security-or-Subsidy_December-2016.pdf

Box 2. The Basics of Balancing Demand and Supply

Wholesale power markets

Liberalized wholesale power markets account for most of markets described in this report. In such markets, participants buy and sell electricity across various time scales, from years to minutes ahead, in futures, day-ahead and intraday markets, up until a certain number of minutes or hours before real time. On the day of delivery, trade is divided into chunks according to the time of day, sometimes called settlement periods. For any given settlement period, participants responsible for matching demand and supply (so-called balance responsible parties) must submit their estimates for demand and supply. Market participants can only trade up to a certain point beforehand, called gate closure. In Germany, gate closure is 30 minutes before the start of the 15-minute settlement period. In Britain, it is one hour before a half-hour settlement period. A narrower gate closure will reduce forecasting errors, and so minimize the amount of reserve generation that must be increased or decreased to match demand. Shortening the gate closure period is an example of adaptation to deal with more variable renewables.

Balancing markets

After gate closure, the balancing market takes over. The balancing market is a real-time mechanism used by the grid operator to match actual demand and supply. The operator typically will invite offers from generators to increase the supply of electricity if the system is short (excess demand) or seek bids to reduce supply if the system is long (excess supply). When the system is more seriously short, the operator may call up reserve generation. Most recently, these resources have included contracts with consumers to use less electricity at times of stress, called demand-side response (DSR). In extreme cases, the operator can forcibly reduce demand by reducing voltage levels or by load-shedding (causing brownouts or blackouts). After the end of the settlement period, the balancing market operator will calculate the cost of these balancing activities. The net cost can then be used to calculate an imbalance charge; this charge is then passed through to parties responsible for causing the imbalances, i.e. those that incorrectly forecast their demand or supply through the settlement period. The higher the imbalance charge and the more directly it is passed through to market participants (perhaps including renewables generators), the greater the incentive for those participants to keep the system in balance. For renewables, this would include efforts to improve weather forecasting (and, by extension, expected generation), and for suppliers, investment in flexible back-up including peaking generation and demand-side response.

Ancillary services market

As well as matching demand and supply in general, grid operators must handle unexpected changes that affect network stability, including grid frequency. Grid operators have an arsenal of tools to deal with such instability. In the first instance, over a period of seconds, they rely on automated controls to maintain grid frequency. In the second instance, over a period of minutes to hours, they will manually instruct reserve generation to increase or decrease supply as required. Such provision of frequency control and reserve power are known as ancillary services, which refer to both energy and non-energy services.

Main Findings

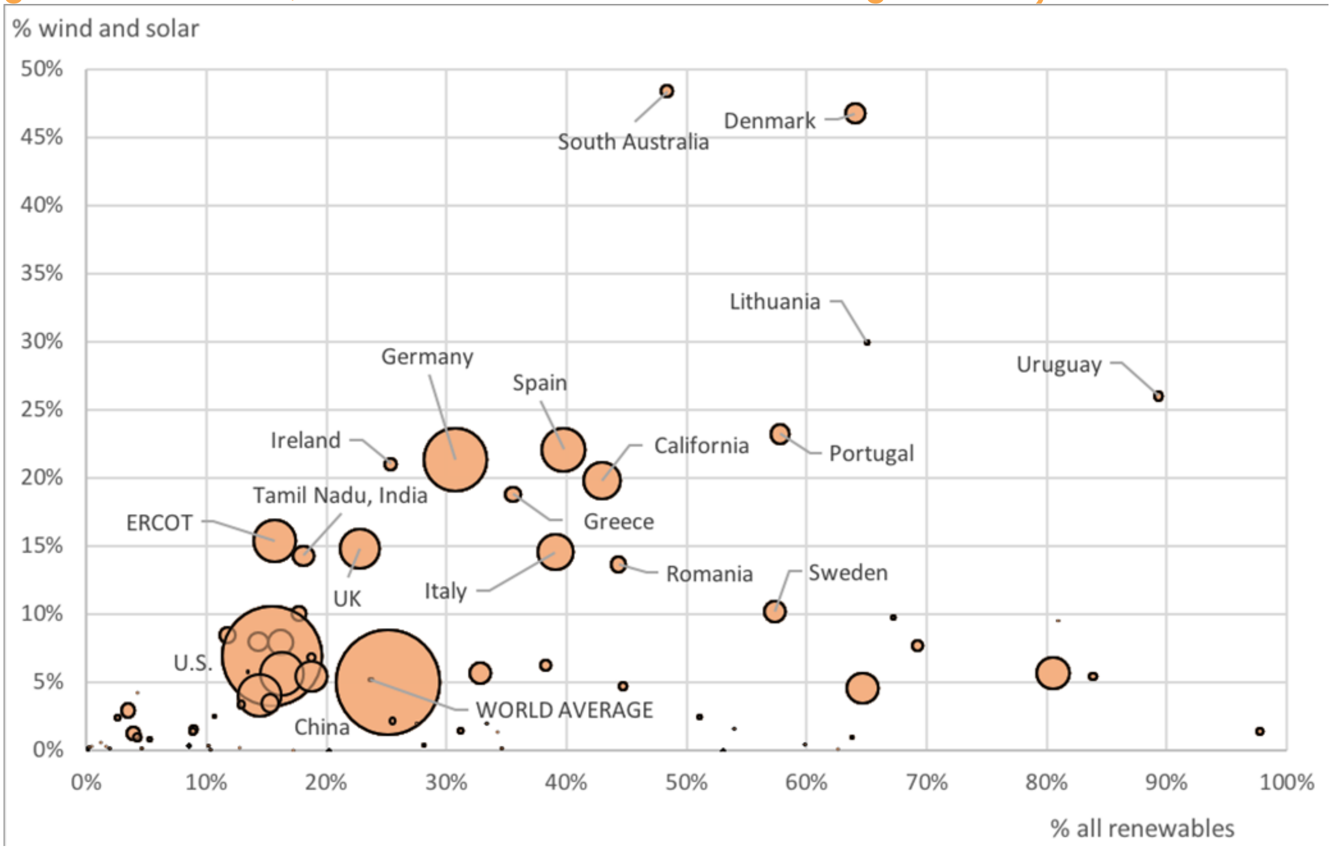
For our case studies, we selected nine of the top 15 countries/power markets worldwide by wind and solar power market share. We defined market share as the percentage of net electricity generation met by wind and solar. These target markets were, in descending order of variable wind and solar market share, in 2017: Denmark, South Australia, Uruguay, Germany, Ireland, Spain, Texas (where the market is run by ERCOT), California (where the system operator is CAISO), and the state of Tamil Nadu, India. These entities range from fully liberalized, energy-only markets, to markets with some state intervention, to full state regulation. Participants range from private to vertically integrated, state-owned monopolies. In scale, they range from very small to very large. As a result, there are some useful, applicable lessons for all power markets around the world.

Case Study Characteristics

Figure 2 below shows our case studies by market share of variable renewables and of all renewables. The graphic uses 2016 rather than 2017 data, to allow comparison across a broad range of countries worldwide. It allows some immediate observations:

1. Some of the top markets for variable renewables also have high levels of other, non-variable renewables (hydropower, geothermal, biomass and CSP), which can serve as a valuable buffer. For example, Denmark, Uruguay and Spain all have high levels of hydro, CSP and/or biomass power.
2. The reverse does not hold true: markets with very high levels of 24/7, on-demand renewables, such as Norway (98% of generation, mostly hydropower) and Iceland (100%, mostly geothermal power), may have very low levels of variable renewables.
3. Very high levels of wind and solar have to date been the energy choice of industrialized nations, with 16 of the top 20 markets by country all members of the Organization for Economic Cooperation and Development (OECD). The exceptions are Lithuania, Uruguay, Romania and Croatia.

Figure 2: Market Share of Wind and Solar, and all Renewables (% of total power generation in 2016; bubble size = TWh of wind and solar generation)



Sources: IEEFA interpretation of European Network of Transmission System Operators for Electricity (ENTSOE) [7]; Electric Reliability Council of Texas (ERCOT)[8]; Uruguay Ministry of Industry, Energy and Mining (MIEM) [9]; BP Statistical Review of World Energy 2017.[10]

Wind and Solar Curtailment: An Indicator of Grid Integration Challenges

One important indicator that wind and solar power may be affecting grid reliability is the use of curtailment or "dispatch down" by network operators to force wind or solar farms to generate less power at times of excess output. Curtailment increases the cost of variable renewables by reducing the output and revenue per unit of installed capacity.

We should note that there are various definitions for curtailment, according to the different rules among our nine case studies. Generally, curtailment in Europe refers to an order from the grid operator for a generator to reduce output. In Ireland, the operator further distinguishes between curtailment to address grid congestion (curtailment), or to address voltage and frequency levels (dispatch down). In California, a broader definition of

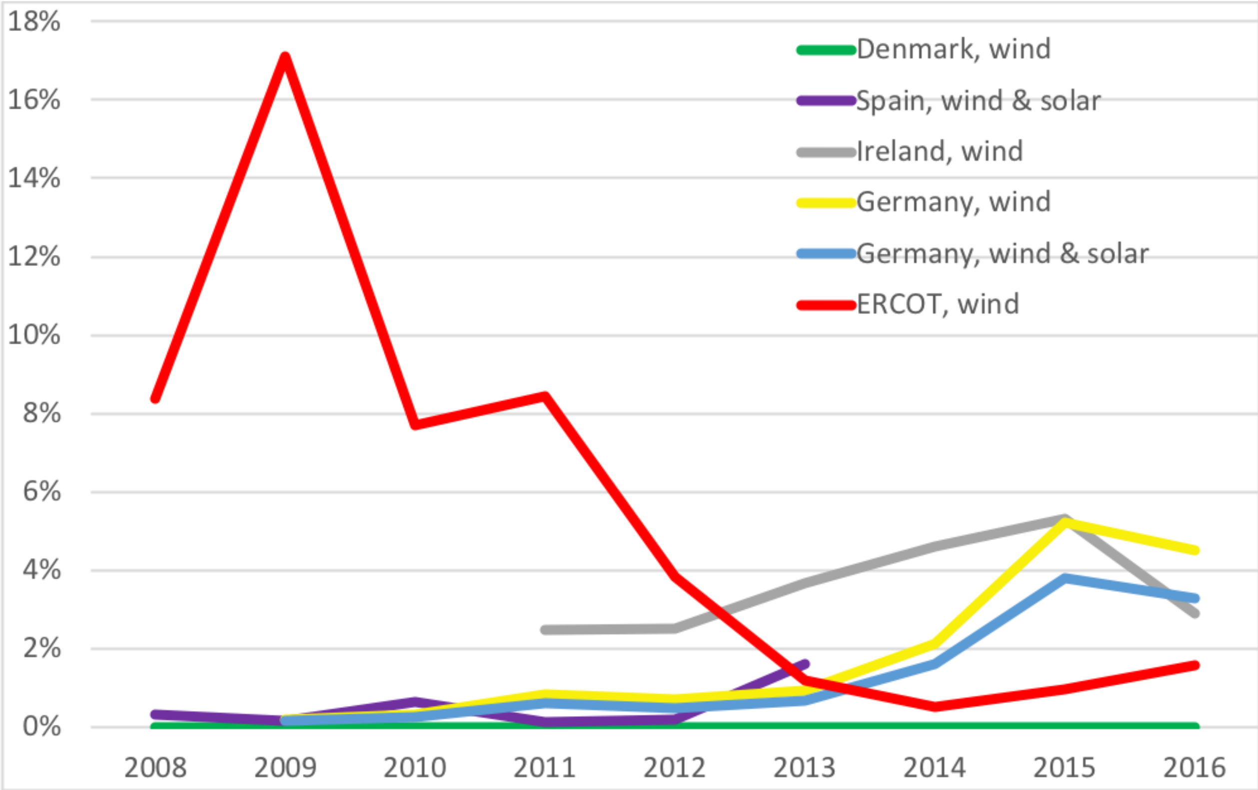
[7] https://www.entsoe.eu/Documents/Publications/Statistics/Factsheet/entsoe_sfs_2016_web.pdf
[8] http://www.ercot.com/content/wcm/lists/89476/ERCOT2016D_E.xlsx
[9] http://www.miem.gub.uy/web/energia/publicaciones-y-estadisticas/energia-electrica
[10] https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html

curtailment is used, to include the economic choice by generators to produce less power because of low electricity prices, as well as instructions from the operator.

The reasons for curtailment can be divided broadly between system security and grid constraints.[11] System security limits typically refer to minimum thresholds for synchronous generation, for example the minimum level of conventional generation required on the grid to maintain frequency and voltage control. Grid constraints refer to local grid capacity limits, for example because of inadequate transmission capacity between a large wind farm and the buyers of its electricity, for example to supply a city perhaps far away.

Figure 3 below compares percentage curtailment across our case study power markets.

Figure 3: Wind and/or Solar Power Curtailment (as a percentage of wind or solar generation)



Sources: Various [12]

Growth in curtailment over time in some countries (Ireland, Germany, Spain) mainly reflects growth in variable renewables generation, because of rising installed capacity of wind and

[11] http://www.eirgrid.ie/site-files/library/EirGrid/Annual-Renewable-Constraint-and-Curtailment-Report-2016-v1.0.pdf

[12] Germany: https://www.bundesnetzagentur.de/EN/Areas/Energy/Companies/RenewableEnergy/Facts_Figures_EEG/FactsFiguresEEG_node.html;

Ireland: http://www.eirgrid.ie/site-files/library/EirGrid/Annual-Renewable-Constraint-and-Curtailment-Report-2016-v1.0.pdf

Denmark: Various sources describe wind curtailment in Denmark as near zero, however there is no easily publicly available data on precise number of gigawatt hours curtailed, which we therefore assume to be zero solar farms. Small blips between years (e.g. the drop in 2016) reflects how some years are windier than others. The exception to this general growth trend is ERCOT, where curtailment has collapsed despite very rapid growth in installed wind capacity and generation. This collapse is due to the build-out of transmission capacity between the west and north, where most of the state's wind resources are located, and demand centers such as Dallas and Houston (see below, in "Menu of Approaches").

Variation in curtailment between countries reflects differences in transmission capacity. Germany has a relatively high curtailment rate, and an over-budget, long-delayed transmission upgrade between the windy north and demand centers in the south. Similarly, Ireland is an island grid whose only interconnection is to the United Kingdom. Denmark is the stand-out leader, with near-zero curtailment despite having by far the highest market share of wind power. This is due to its grid interconnections to big neighboring markets like Germany, Sweden and Norway. Regarding interconnection in 2017, Denmark had cross-border connections equivalent to 51% of its totalled installed generating capacity, far above our other European case studies—where Spain was at 6%, Ireland 7% and Germany 9%.[13]

Customer Outages: An Indicator that Grids are Coping

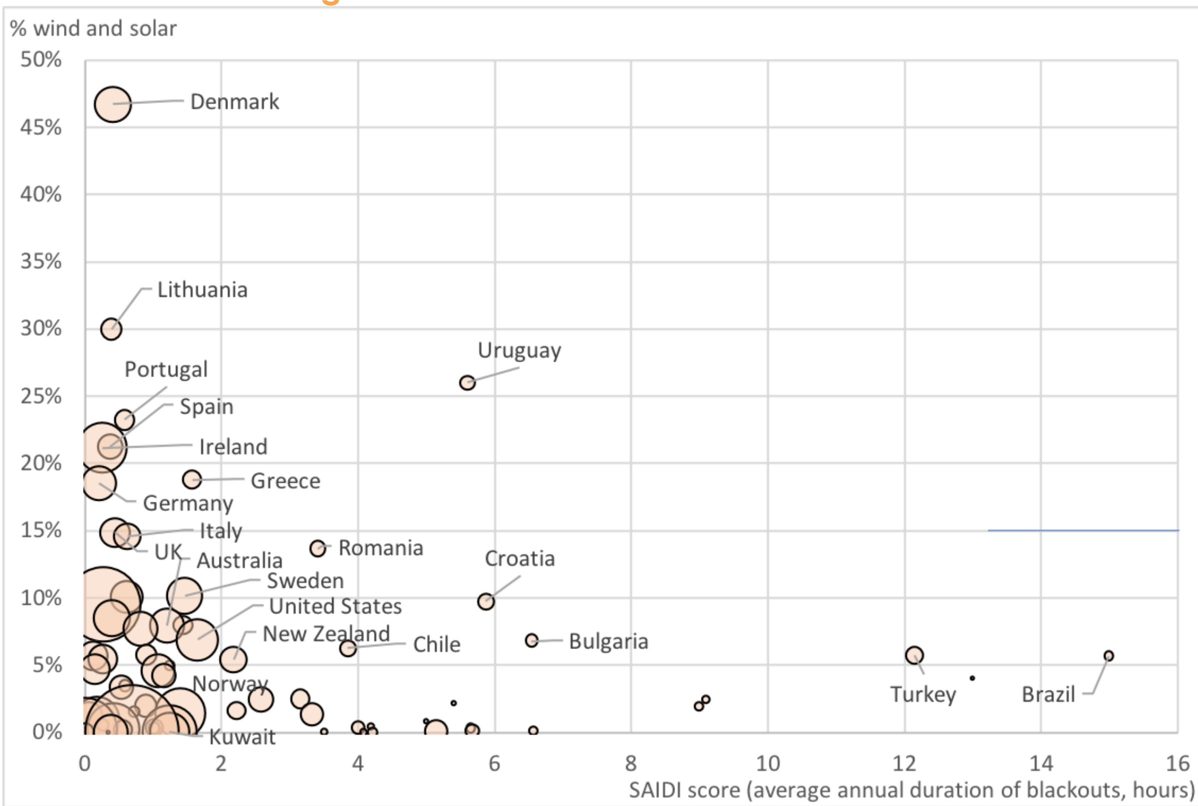
Here we compare the market share of wind and solar power with security of electricity supply, and specifically the duration of blackouts in major cities. We also look at per capita income.

World Bank data for global power outages use global comparative data for electricity outages for residential and non-residential customers, based on each country's largest business city.[14] Using these data, the World Bank derives a score for quality of electricity service, called SAIDI (system average interruption duration index). SAIDI measures the average duration of power outages per year per customer, including planned and unplanned outages. The duration of blackouts is measured in hours.

Figure 4 below plots wind and solar market share against power outage score. Bubble size represents per capita income. The figure confirms a general view that power outages are closely related with per capita income (the smaller bubbles tend to have longer outages). The figure shows no obvious link between wind and solar market share and longer outages. If anything, the opposite is the case: we note that richer nations with power outages of more than 1 hour, such as Sweden, the United States, Australia, New Zealand, Norway and Kuwait, also have a lower market share of variable renewables. We can speculate that this may be because the steps that operators take to handle higher levels of variable renewables also improve security of supply more generally.

[13] https://ec.europa.eu/energy/sites/ener/files/documents/communication_on_infrastructure_17.pdf
[14] http://pubdocs.worldbank.org/en/444681490076354657/Electricity-Tariffs-Power-Outages-and-Firm-Performance.pdf

Figure 4: Outage Duration and Per Capita Income (bubble size) for Countries with Above Global Average Wind and Solar Market Share



Source: IEEFA interpretation of World Bank GDP/ outage data, and various energy data

A Menu for Integrating Higher Levels of Wind and Solar Power

Our case studies show that there are straightforward, practical steps that countries can take to adapt existing power markets to much higher levels of variable renewable generation. These measures can help assure security of supply and grid reliability without the need for new, costly subsidies for back-up generation, for example via additional markets for capacity. We note that the only example of the use of capacity markets among our case studies, in Spain, lacks transparency and has driven over-capacity, and may, if anything, have undermined system flexibility.[15]

There is no single prescription for a high renewables grid. We describe nine approaches from our case studies, noting that no individual country would have to adopt every measure, rather a selection according to their circumstances. We argue that emerging countries should consider taking similar steps, rather than embarking on a radical redesign of their power markets. These measures are described in more detail under the individual country and power market sections.

[15] http://ieefa.org/wp-content/uploads/2017/11/Spains-Capacity-Market-Energy-Security-or-Subsidy_December-2016.pdf

1. Timely investment in the transmission grid

Making well-planned investment in high-voltage transmission systems is one of the most critical steps to prepare for higher levels of variable renewables. Such investment in transmission systems can bring the best renewables resources to demand centers like major cities, and so reduce curtailment because of grid congestion.

- ERCOT is a stand-out example of transmission network forward planning, where a systematic approach followed some initial blunders. In 2002, for example, 758 MW of wind were interconnected to a substation with only 400 MW of transmission, according to a report by the National Renewable Energy Laboratory, "Integrating Variable Renewable Energy in Electric Power Markets". That underscored the need for a centralized, coordinated approach. In 2005, the Texas legislature passed Senate Bill 20, which established the Texas renewable energy program and directed the Public Utilities Commission of Texas (PUCT) to develop competitive renewable energy zones (CREZ). The PUCT designated zones in 2008, and a number of transmission projects were selected to transmit 18,500 MW of wind power from the CREZs to the eastern, more populated area of the state, along 3,600 miles of new transmission lines. Curtailment of wind power in Texas fell from 17% in 2009 to just 0.5% in 2014.[16]
- The ERCOT example is a lesson for some leading energy transformation countries, such as Germany and China, where a rapid rollout of variable renewables has raced ahead of supporting high-voltage grid infrastructure.

2. Boosting transmission interconnections and cooperation between neighboring countries and power markets

A related way to boost grid flexibility, and so balance variable renewables, is to improve grid interconnections and cooperation between neighboring electric systems. Such cooperation enables the sharing of power capacity across countries and regions, boosting security of supply. Sharing of capacity across wide geographic areas can exploit time lags in demand (eastern regions will turn their lights on first), as well as wind power (as weather fronts pass) and solar generation (according to the movement of the sun and cloud cover).

- Across central Europe, countries have worked together to integrate new technologies and enable greater cross-border collaboration, allowing for more efficient trading of electricity between countries and power markets. Specifically, Germany, France and the Benelux countries have worked to couple their markets, a process that bundles interconnection capacity and electricity into a single product, thereby ensuring that the available interconnection capacity is used most cost-effectively. Algorithms ensure that power usually flows from cheaper to more expensive markets, further boosting efficient allocation.
- Denmark has the highest wind power market share in the world, but the lowest wind power curtailment among our case studies, at near-zero, and one of the lowest average outage hours per customer per year. Part of the explanation is exceptional interconnection to its neighbors. The country's interconnection capacity today accounts for more than half of installed generating capacity, at 51%, and that is expected to rise to 59% by 2020. Using this interconnection capacity, Denmark exploits the diversity of

[16] IEA World Energy Outlook 2016 page 520

generation of its bigger neighbors, especially hydropower in Scandinavia and thermal and renewable generation in Germany.

- Denmark's transmission system operator (TSO), Energinet.dk, has implemented a proactive grid planning approach on a national level, strengthening the network in parallel with new generation, not afterward. In this spirit, the TSO is now working to expand its export capacity in response to anticipated growth in Germany's wind capacity, which has sometimes limited exports by Denmark. In March 2016, Denmark approved a series of additional interconnections, including the 1.4 GW Viking Link to the United Kingdom. This new submarine cable, which will be 740 kilometers long, will be capable of transporting the annual electricity consumption of an estimated 2.7 million households.
- In Germany, the four transmission system operators (TSOs) have shared a common balancing area since 2009, giving them a much wider array of generating resources to call upon to match demand, before calling on more expensive back-up capacity. This cooperation may be one explanation for a rapid drop in the use of such back-up reserves, notwithstanding a trebling in installed capacity of wind and solar power.
- Ireland is developing hedging products in its wholesale power markets, to reduce the wasteful use of its limited, and therefore valuable, cross-border interconnection as a hedging tool by some market participants. Ireland is undergoing a transition from its so-called Single Electricity Market (SEM) toward an Integrated Single Electricity Market (I-SEM).[17] The SEM consisted of a single day-ahead wholesale spot market, with no forward market. The introduction of forward markets, ex-ante markets and other hedging products under the I-SEM should minimize the incentive to use the interconnector for hedging activity. Data show that efficient use of Ireland's interconnection can reduce domestic wind power curtailment by half.

3. Ensuring flexibility in domestic generation

A flexible electricity system is critical to balance the variability of wind and solar power. Suitable technologies include gas, hydropower including pumped hydro storage, power to heat technologies, CSP, rooftop solar with behind-the-meter battery storage, demand-side response (DSR, also called demand side management or DSM) and other battery storage, including electric vehicles (EVs).

Power to heat technologies use electricity to generate heat and can be used to store surplus renewable power. One existing power to heat technology is combined heat and power (CHP). CHP plants can either buy or generate electricity to produce and store heat, for example as steam, for use in district heating networks. DSR refers to the option for energy consumers to profit from reducing consumption at times of peak prices, usually associated with system stress, which may be a result of low availability of variable renewables. Consumers might sign up for time-of-use DSR contracts, where they pay less for their electricity overall, in return for shifting their consumption to off-peak times. Key enabling technologies include smart metering, which in theory allows utilities to manage energy use remotely.

[17] Di Cosmo, V. and M.Á. Lynch, *Competition and the single electricity market: Which lessons for Ireland?* Utilities Policy, 2016. 41: p. 40-47

Meanwhile, EVs potentially create an entirely new tool for grid management. EVs, like all cars, spend much of their time standing still, waiting for people to come and drive them. As such, they could be a distributed storage system that network operators access to manage the grid.

- In Uruguay, hydropower is the main buffer for wind power variability. We find wind power runs first, as the lowest marginal cost option whenever it is available, balanced by hydropower when wind is short, and by exports via interconnectors to Brazil and Argentina when wind power is in surplus. The combination of hydropower and interconnection meets most of Uruguay's flexibility needs, resulting from its high and rapidly growing wind power.
- Denmark anticipated the need for power system flexibility a decade ago by optimizing its conventional coal power plants to allow very steep ramp-up gradients, shorter start-up times and low but stable minimum generation levels: in short, to be more flexible. Modifications, in both control software and equipment, allow hard coal plants in Denmark today to ramp at rates up to 3-4% of rated output per minute, which is unprecedented among coal plants globally. Furthermore, coal plants in Denmark can cycle down to a minimum 10-20% of rated output, compared to typical levels of 60-70% elsewhere.
- In addition, Denmark benefits from very close coupling of its electricity and heating sectors, through its district heating and CHP network. Today, half of all Denmark's electricity and two-thirds of its heat is produced by small CHP plants. These plants feed into district heat-supply networks that include large water tanks for thermal energy storage. The system was designed with flexibility in mind, to achieve a varying proportion of heat and electricity output, and heat storage. Today, that means that CHP plants can optimize their output in according to changes in wind output, and thus provide balancing services.
- As in Denmark, Germany's coal plants have been designed or modified for flexible output. They can now ramp on an hourly basis to much less than full output, and cycle on and off daily. Germany's lignite power plants are still less flexible than hard coal, but they also have been modified recently to enable ramping down to 40% of their maximum output, compared to only 60% previously.

4. Market reform to boost flexible back-up

In countries with liberalized power markets, electricity suppliers and generators trade power across various timeframes, from years to minutes ahead of real-time delivery. In an age of variable renewables, there is growing emphasis on nearer term, day-ahead, intraday and balancing markets, to integrate this less-predictable supply as efficiently as possible.

One way to reform markets to adapt to growth in variable renewables is to shorten balancing markets used to match supply and demand in real time, and to schedule these more often, for example as often as every five minutes, instead of every hour. A second example of power market reform is to introduce non-energy payments for back-up generation, for example via capacity markets or a reserve fleet (see Box 1 above). A third way to incentivize flexible generation is to encourage "spikier" power markets by raising or scrapping ceilings on power prices. Finally, a fourth example of power market reform is to introduce negative pricing.

- Ireland is in the process of market reform to allow participants to trade at different time scales. This new system will introduce a balancing and intraday market. This will provide important price signals to potential investors in flexible generation, demand-side response and storage, aiding the development of a flexible grid to better respond to increased renewables penetration.

- In Germany, the energy regulator in 2011 reduced the duration of intraday market auctions to 15 minutes from 1 hour, to create more market opportunities for conventional and renewable generators that can ramp faster, and so help handle imbalances created by wind forecast errors.

- Spain has used capacity payments to support coal, gas and hydropower for several years. However, we note that there is significant over-capacity in Spain, and under-use of its most flexible generation, its combined cycle gas turbines (CCGTs). It appears therefore that these supplementary, out-of-energy market capacity payments are unnecessary and may even have undermined the flexibility of the energy system.

- The leading European Spot Power Exchange (EPEXSPOT)[18] introduced negative spot electricity prices in 2007 and 2008 in the German intraday market and German-Austrian day-ahead market respectively to incentivize generators to reduce production at times of renewable electricity over-supply. Negative pricing was subsequently introduced in more of Germany's neighbors, in the French price zone in 2010, and in the Austrian and Swiss intraday markets in 2012 and 2013.[19] Negative pricing affects other neighboring countries, such as the Netherlands, because generation from conventional sources like coal and gas will seek higher market prices in other countries. In this way, the combination of negative pricing and high renewable generation penetration in Germany has reduced electricity wholesale market prices across central-western Europe.

- The Nordic power exchange including Denmark introduced negative pricing in 2009. Negative pricing has facilitated wind power integration in Denmark by motivating wind turbines to dispatch down when wind power is in excess, given that offshore turbines do not receive feed-in tariff prices when wholesale power prices are negative.[20] In addition, negative pricing is an obvious bonus for flexible storage options, such as Nordic pumped storage hydropower (PSH) and Danish CHP, which are effectively paid to take electricity and then sell it when power prices are higher, or use it for district heating.

- In Australia, the Australian Energy Market Commission announced in 2017 a move to a 5 minute market for pricing, effective July 2021.[21] This builds on a regulatory framework including negative wholesale market pricing and highly differentiated time-of-use pricing for solar customers to incentivize the rapid deployment of CSP, grid interconnections, pumped hydro storage and to-date the largest lithium-ion battery storage plant globally (100 MW/128 MWh) by Tesla, commissioned in South Australia in December 2017.

[18] www.epexspot.com
[19] EPEX Spot (2016): Negative Prices – Q&A, online: https://www.epexspot.com/en/company-info/basics_of_the_power_market/negative_prices
[20] http://orbit.dtu.dk/files/134034514/60245.pdf
[21] http://www.aemc.gov.au/Rule-Changes/Five-Minute-Settlement

5. Supporting demand-side flexibility

DSR, which refers to paying consumers to reduce demand at times or peak prices or system stress, cannot provide some system services, such as voltage and frequency control. Critically, however, it can shift demand to when variable renewables are available. To date, uptake has been poor outside the United States.

- Following the political backlash after a state-wide blackout in September 2016, South Australia devised an energy plan that included plans for new sources of flexibility, including some 1,000 MW of contracted demand management.
- Germany has sought to overcome low DSR uptake both by reducing size thresholds for participation in balancing markets and increasing the frequency of auctions. Until recently, grid operators ran auctions for ancillary services to maintain grid stability on a weekly or bi-weekly basis. However, renewables and some demand response struggle to bid on that basis, due to forecast uncertainties. In mid-2017, the German regulator Bundesnetzagentur announced it would roll out daily tenders to make it easier for wind and solar generators to submit bids based on forecasted power output. There are other ways to increase the participation of DSR and renewables in such markets. At present, the system requires reserve power to be activated for a duration of four hours for "minute reserves." However, the service is normally only required for much shorter periods. Markets in Austria, Belgium, the Nordic region and the U.K. already have lowered the required activation period to allow DSR and renewables to compete.[22]
- Denmark has also taken initial steps to incorporate the demand-side into power markets, although still largely in a pilot phase. For example, the READY pilot project demonstrated how a large number of small heat pumps can be controlled remotely.[23] This flexibility can be predicted and used in both the day-ahead market and as regulation power. The concept was tested with the direct control of heat pumps (in contrast to indirect control, sending a price signal and allowing the end user to act). The test was performed with 100 active heat pumps and, in general, end user acceptance was high.[24]

6. Better wind and solar forecasting

Another way to reduce the need for back-up of variable wind and solar, and so cut curtailment and other balancing costs, is to reduce forecast errors. Considering the case of wind along the western Danish coast, a small change in wind speed of 1 meter per second triggers a difference of 500 MW in electricity production in the country.[25] That is equivalent to the size of a large thermal power plant. This difference in generation must be balanced by other power plants or by interconnectors.

The more accurate and further ahead wind power forecasts are, the better prepared are system operators. Specifically, grid operators can use better forecasts, further in advance, to call upon a wider suite of slower-responding, cheaper generation, as opposed to the limited fleet of exceptionally fast-responding, peaking power plants that must deal with last-minute surprises.

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[22] Stede, Jan (2016).
[23] EA Energy Analyses (2014): READY project: Summary of main findings with a focus on market aspects and local grid constraints, Copenhagen, 10.12.2014.
[24] Ea Energy Analyses (2015): p. 3.
[25] http://regridintegrationindia.org/wp-content/uploads/sites/3/2017/09/6A_3_GIZ17_xxx_paper_Orths_170731.pdf

- In Denmark, the TSO constantly monitors output of renewables in real time and compares this with modelled forecasts. The modelled forecasts are based on wind speed forecasts and an understanding of the output of individual turbines. The actual, near-real-time output data come from monitors on the turbines.[26]
- In Spain, the national wind power forecasting system, Sipreolico, provides hourly wind production forecasts for up to 10 days ahead. According to the system operator, REE, the percentage error of wind power forecasts 24 hours ahead has halved from 18% to 9%, between 2008 and 2015. This was partly attributable to more advanced modelling techniques.

7. Enhancing the responsiveness of the distribution grid

Renewable generation is often installed on a small scale and distributed widely, for example at the level of individual homes in the case of rooftop solar, in contrast to conventional thermal generation, which is traditionally centralized in large thermal gas, coal or nuclear power plants. Denmark, Germany and South Australia are all examples of power markets with high levels of distributed renewables generation, with prosumers who both produce their own electricity as well as consuming power from the grid.

- In Germany, the technical grid code for solar inverters has been changed to ensure that they do not all trip at the same frequency, thus increasing system resilience.
- With high solar radiation plus very high and rapidly rising residential electricity tariffs, Australia is already a world leader in terms of distributed residential rooftop solar. 2017 saw the rapid scaling up of rooftop solar with storage system installations, incentivized by time-of-use pricing structures for solar users to encourage time-shifting of production.[27]

8. Making renewables more responsible for balancing electricity demand and supply

Policymakers and regulators exempted renewable generation from certain grid balancing responsibilities when the technologies were first introduced. For example, variable renewables were exempt from so-called balancing charges applied to other suppliers and generators that failed to meet expected demand or supply in real time. And they were exempt from the requirement to provide inertial response, which is used to control grid frequency and voltage levels.

Countries are now changing grid codes to require variable renewables to provide reliability services as a condition of grid connection, and to participate in regular power markets. Variable renewables can provide many grid balancing services in the same way as conventional generation.

- In Denmark, variable renewables pay balancing charges if they fail to meet scheduled output, thus forcing wind farm operators themselves to invest in better forecasting. This requirement is being extended this year to operators of all wind turbines, including older models for the first time.

[26] Martinot, Eric (2015).
[27] http://reneweconomy.com.au/battery-storage-australias-rooftop-solar-boom-has-only-just-begun-85122/

- In Germany, wind and solar power producers were previously paid a fixed feed-in tariff for every unit of power produced. They are now paid the average monthly spot price, plus the difference to the feed-in tariff. As a result, they still earn the same as before if they don't participate in the power market. But they can earn more if they gear their generation toward peak prices, and so beat the monthly average price. In this way, operators are incentivized to respond to market signals and help balance demand.

In South Australia, a statewide blackout triggered by a storm in 2016 threw new focus on the importance of frequency control, following the tripping of an interstate grid connection. In response, the regulator concluded that variable renewables would have to be used for frequency control increasingly in future. This, in turn, has led to rising interest in adding battery storage at wind farms. In late 2017, for example, Tesla completed the installation of a 100 MW battery at the 315 MW Hornsdale wind farm; the project was designed to provide frequency control as well as other grid balancing services. Singapore's Nexif Energy also is planning a 125 MW wind farm with a 10 MW battery project at Port Augusta. And in February 2018, South Australian Premier Jay Weatherill announced a plan to build the world's largest virtual power plant in suburban Adelaide, giving 50,000 households free solar panels and Tesla storage batteries.

9. **National Leadership**

When national governments are committed to growth in renewables, this will result in policies that favor grid integration at the local level. A clear example here is the commitment to expanding grid infrastructure that connects local variable renewables into a national network.

India has made an exceptional commitment to renewables as part of broader effort to transform its electricity sector. India's main motivation is economic, looking to spur energy price deflation through the use of fixed-price, long-term power purchase agreements. The country's 10-year national electricity plan released in 2016 envisages 275 GW of variable renewable energy capacity in place by 2026/27, a fivefold expansion in absolute terms from the 57 GW of variable renewables operational today. India's energy minister R.K. Singh in February 2018 suggested that this plan might be conservative, noting that the country planned to tender 30-40 GW annually of wind and solar in the next two years.[28]

- India's national renewables ambition has spurred initiatives such as its Interstate Green Power Corridor, which will help foster local renewables integration. In January 2018, Union Coal Minister Piyush Goyal told the Lok Sabha (India's lower House of Parliament) that work on a US$2 billion upgrade of this corridor should be operational by May 2019.
- The corridor enables the export of surplus renewables generation from leading states such as Tamil Nadu. Such exports have a growing market given the failure of many states to meet their renewable power obligation targets. The corridor initiative has motivated the ongoing rapid deployment of renewable energy infrastructure, including more than 2,000 MW currently under construction in Tamil Nadu.

[28] https://energy.economictimes.indiatimes.com/news/power/indian-economy-to-grow-at-8-5-per-cent-in-2018-19-power-minister/62740037

CASE STUDIES

Denmark

Denmark's energy transition began with the oil shocks of the 1970s. The initial focus was energy independence, but it evolved to include low-carbon energy, in a planned transition involving the government, grid operator and utilities.[29] In 1976, Denmark established a nationwide natural-gas system, required local heating, and shifted from oil to coal generation. In 1981, it added efficiency mandates. In 1985, Denmark targeted wind power with a grant program to support the installation of 100 MW of new capacity It then established a target to cut carbon emissions by 20% by 2005, compared with 1990 levels. In 2012, it established a goal to be fossil fuel-free by 2050.

Denmark has introduced various support schemes to foster growth in renewables. These schemes are paid for by energy consumers, via the so-called public service obligation (PSO)-tariff, introduced in 1998 as an addition to electricity bills. By the end of 2016, the PSO charge amounted to €0.297/kWh. It has helped drive rapid growth in wind power, but also played its part in making Danish residential power prices some of the costliest in Europe. Revenues from the PSO tariff are spent on support for renewables generation, research and development into green energy innovation, and support for combined heat and power (CHP) plants. Under plans to increase the integration of renewables, the government has decided to phase out the PSO by 2022. Going forward, price support for renewable energy will be made as a supplement to the market price. As a result of the PSO scheme, and the development of turbine-maker Vestas, Denmark became a global wind energy leader. It has set international records, for example generating 140% of its electricity demand across two days in July 2016.

Denmark's successful approach to the integration of renewables relies on three core factors:

1. Strong interconnection with neighboring countries
2. The use of CHP plants to store excess wind power as heat
3. Advanced market structures in the Nord Pool exchange.

The development of these framework conditions started decades ago, showing the importance of forward planning to integrate high market shares of variable renewable energy.

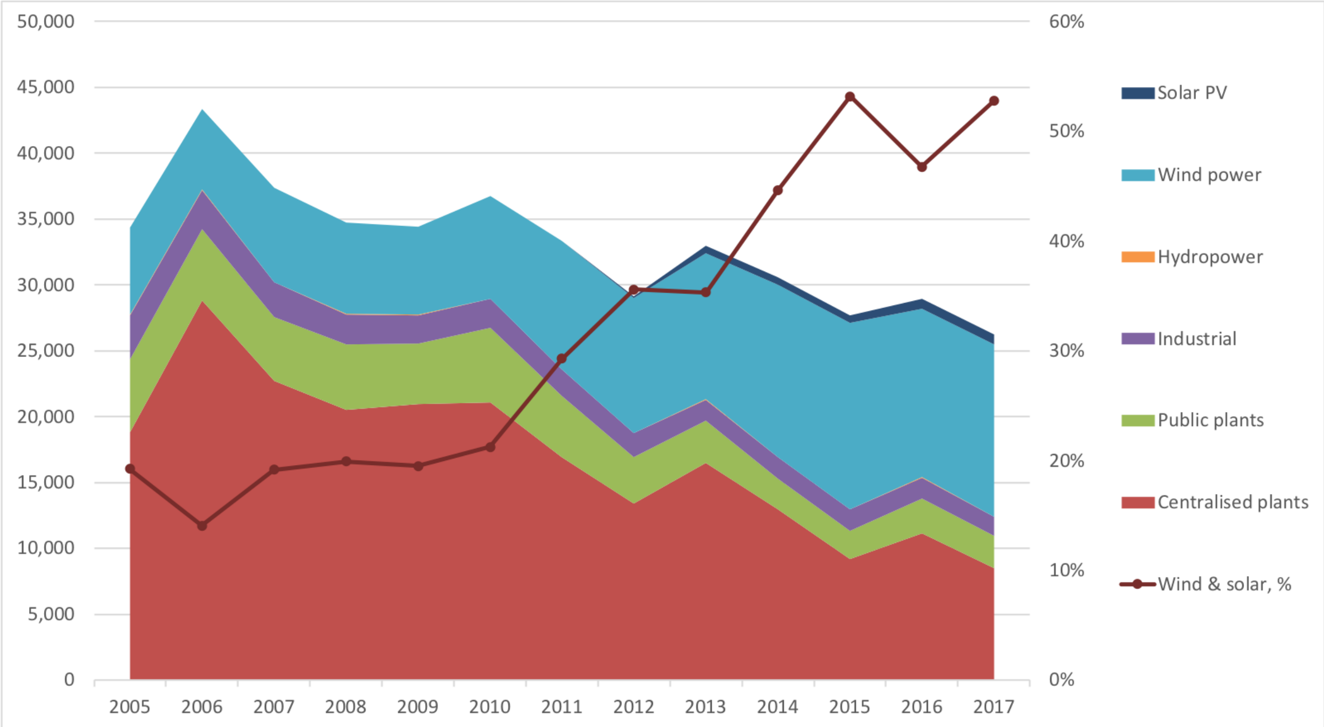
Market Share of Renewables

On an annual basis, wind and solar generation combined have accounted for more than 40% of Denmark's net electricity generation since 2014. National wind power generation fell

[29] Marcacci, Silvio (2016): Denmark May Hold the Key to Integrating Large Amounts of Intermittent Renewables: How DERs and grid flexibility empower Denmark to lead the world in wind, Greentech Media, July 27, 2016; online: https://www.greentechmedia.com/articles/read/does-denmark-hold-the-key-to-integrating-large-amounts-of-intermittent-rene#gs.dhWRWv8

in 2016, because of a less windy year, but last year recovered to 53% of net generation, matching a similar peak in 2015.[30]

Figure 5: Electricity Generation by Source (GWh) & Wind & Solar Market Share (%, through November 2017



Source: Danish Energy Agency (2017) [31]

Indicators of Integration Challenges

Wind Curtailment

Given wind power's high market share, one might also expect high levels of wind curtailment. But this is not the case. Denmark's wind generation is curtailed infrequently because of two factors, negative pricing and strong interconnection:

1. Negative pricing was introduced into the Nordic power exchange in 2009. Negative pricing has facilitated wind power integration by motivating wind turbine operators to dispatch down when wind power is in excess since offshore turbines do not receive feed-in tariff guaranteed prices when wholesale power prices are negative.[32] In addition, flexible storage options, including Nordic pumped storage hydropower (PSH) and Danish

[30] 2017 data: https://stateofgreen.com/en/profiles/state-of-green/news/denmark-set-new-wind-record-in-2017 & https://www.entsoe.eu/data/statistics/Pages/monthly_domestic_values.aspx

[31] Danish Energy Agency (2017): Monthly Energy Production and Consumption Statistics, September 2017, online: https://ens.dk/en/our-services/statistics-data-key-figures-and-energy-maps/annual-and-monthly-statistics

[32] http://orbit.dtu.dk/files/134034514/60245.pdf

CHP facilities, can purchase electricity at negative prices (i.e. be paid) for subsequent power generation and district heating respectively.

2. Strong grid interconnection is the main reason for Denmark's low levels of wind power curtailment. Nordic countries can use Danish wind power to replace hydro generation and conserve water in their hydro reservoirs or store surplus wind power using PSH. There have been just two cases of curtailment of Danish wind turbines, in 2010 and in 2008, and in both cases this happened because of interconnector outages.[33] Denmark's interconnection capacity today is equivalent to 51% of domestic generation, and that is expected to rise to 59% by 2020.[34]

Re-Dispatch

Re-dispatch is another indicator of grid congestion, closely related to curtailment. Re-dispatch refers to measures by the grid operator to respond to congestion in one part of the grid, by increasing generation locally to continue to serve customers. Given that curtailment is so infrequent in Denmark, it is not surprising that the number of re-dispatch hours because of national grid congestion is also very limited.

However, there is a cross-border transmission issue with Germany that can lead to increased re-dispatch in Denmark. Germany sometimes struggles to transmit wind power generated in northern Germany, due to internal transmission bottlenecks. In this case the German TSO, Tennet, may ask for permission to export to Denmark. To balance such imports with its own national surplus, Denmark can reduce domestic power generation, while continuing to export through its remaining interconnectors. In these so-called counter-trades, importing TSOs do not incur any financial cost, and facilities that agree to reduce production are compensated by the exporting operator.

Indicators That Denmark's Grid Is Coping

According to a study by the Danish Energy Agency, the national grid is stable and needs limited emergency measures.[35] The study defines security of supply as the likelihood that electricity is available as required, and notes that average long-term outages are around 40 minutes per customer per year. That is in line with World Bank findings (see section above, "Customer outages: One indicator that grids are coping") and appears superior to most peer countries by income and renewables market share.

Factors That Have Favored Integration

Long-Term Power System Planning: Heat Storage

As noted above, Denmark embarked on an energy transition in the 1980s. It was at this time that heating and electricity supply were integrated. Today, half of all Denmark's electricity

33 https://ens.dk/sites/ens.dk/files/Globalcooperation/system_integration_of_wp.pdf
34 https://ec.europa.eu/energy/sites/ener/files/documents/communication_on_infrastructure_17.pdf
35 Danish Energy Agency (2016): Security of electricity supply in Denmark (1st edition 2015; translated 2016), Copenhagen 2016; online: https://ens.dk/sites/ens.dk/files/Globalcooperation/security_of_electricity_supply_in_denmark.pdf

and two-thirds of its heat is produced by CHP plants. These plants feed into district heat-supply networks that include large water tanks for thermal energy storage. The system was designed with flexibility in mind, to achieve a varying proportion of heat and electricity output, and heat storage. Today, that means CHP plants can optimize their output according to changes in wind output, and thus provide balancing services. Many of these CHP plants are fueled by biomass, which thus provides a long-term pathway for balancing variable renewables like wind and solar with a non-variable but still-renewable resource.[36]

Since 2006, all CHP plants above 5 MW have been required to settle at market prices (e.g. rather than via long-term bilateral contracts), which means they are now incentivized to respond to wind output. At times of excess wind generation and low power prices, they will bypass their steam turbines to produce heat exclusively. When prices recover, they can quickly switch back into a co-generation model, producing combined heat and power. The approach works seasonally, as wind power surpluses and grid constraints can be greater in winter, when heat is also more in demand, thus incentivizing CHP units to consume cheap excess electricity to produce heat.

Grid Measures

Denmark's transmission network is divided into two separate zones; western and eastern. The western zone is connected to the European continental grid, and the eastern zone to the Nordic grid. In turn, the two zones are connected through a 600 MW connection across the "Great Belt." East Denmark is connected to Sweden by four AC interconnections with a total transmission capacity of 1,900 MW, and to Germany by a DC interconnection with a total transmission capacity of 600 MW. West Denmark is connected to Germany by AC connections where the total transmission capacity is determined by congestion in the surrounding grids and is normally 1,500 MW in the southbound direction and 950 MW in the northbound direction. West Denmark is connected to Sweden with a DC connection with a total capacity of 740 MW, and to Norway with a DC connection of 1,040 MW.[37]

Due to grid bottlenecks across the Nord Pool Spot bidding zone, this wider Nordic area is divided into several price areas, including two in Denmark: West Denmark and East Denmark. Due to market coupling arrangements across central-western Europe, Denmark can freely buy and sell power from its neighbors to balance its renewables.

Investment in the Grid Network

Historically, the Danish TSO, Energinet.dk, has implemented a proactive grid planning approach on a national level, strengthening the network in parallel with new generation, not afterward. Transmission capacity planning anticipates the future interconnection of wind farms, based on project development plans and actual consented projects. In this spirit, the TSO is now preparing for further growth in German wind capacity, which has sometimes limited exports by Denmark via the 2.4-gigawatt net transfer capacity interconnector between the two countries. The TSO has moved to expand export capacity: In March 2016, it approved a series of additional interconnections to Germany and the United Kingdom,

[36] Martinot, Eric (2015).

[37] Sorknæs, Peter / Mæng, Henning / Weiss, Thomas Weiss / Andersen, Anders N. (2015): Overview of the Danish Power system and RES integration, Final Report, July 2015, p. 9; online: http://www.store-project.eu/documents/target-country-results/en_GB/energy-needs-in-denmark-executive-summary

including the 1.4-gigawatt capacity UK-Viking Link, which will be the world's largest submarine cable at 740 kilometers. In addition to balancing wind supplies, Energinet.dk predicts the investment will "make billions in export profits for Denmark." [38]

Improved Weather Forecasting

The Danish TSO has integrated advanced weather forecasting into its power system control and dispatch operations, helping it enhance grid reliability while also integrating and balancing high shares of renewables on the system. The TSO monitors output of renewables in real-time and compares this with modelled forecasts. The modelled forecasts are based on wind speed forecasts and an understanding of the output of individual turbines. These forecasts are improved using near real-time wind speed and turbine output data, to reduce forecasting error.[39] Based on these calculations, the power control center updates its forecast every 5 minutes.

DSO Measures

In many parts of Denmark, installed wind and CHP generation surpass local demand, turning local networks into net power exporters, raising the potential for local curtailment and grid instability. The so-called EcoGrid project sought to address this problem, and drew some international attention, winning various awards.[40] EcoGrid started in 2011, under a strategy established by the Bornholm municipality, with local industry, the public and other authorities, to source 100 % renewable energy. The Bornholm distribution grid is operated by the local DSO, Østkraft, which is owned by the Bornholm municipality.

The idea behind EcoGrid was to use market-based mechanisms close to real time to release balancing capacity, and especially flexible demand. A five-minute balancing market helped reduce forecast errors, by requiring frequent, near real time scheduling of demand and supply.[41] A successor EcoGrid 2.0 initiative, begun in January 2016, focused on new challenges, including the integration of electric vehicles and local battery storage systems. Such distributed system initiatives will only become more important, given that Denmark is expected to hit 55% wind power market share by 2020, requiring new distributed options for wind balancing, including electric heat pumps, EVs, and water electrolysis converting electricity into synthetic natural gas." [42]

Power Market Measures

To help balance supply and demand, TSOs sign balancing agreements with balance responsible parties (BRPs), namely the generators, traders and suppliers involved in generating and supplying electricity on a day-to-day basis. These BRPs provide the TSO with their plans for electricity generation, supply and trade for each hour of the day. They first do this on the day before real time, via day-ahead markets (Nord Pool Spot) and through bilateral trades. Gate closure of the day-ahead market, Elspot, is at 12:00 CET (Central

[38] Marcacci, Silvio (2016).
[39] Martinot, Eric (2015).
[40] EcoGrid (2016a): Media Information – EcoGrid is winner of the EUSEW Award 2016, 20th of June, 2016; online: http://www.eu-ecogrid.net/events-and-news
[41] http://www.eu-ecogrid.net/
[42] Marcacci, Silvio (2016).

European Time) prior to the day of delivery. On the day of delivery, participants can alter their plans via intraday trade (via Nord Pool Elbas or bilateral trades) until one hour before real time. From that moment, the TSO has responsibility for balancing the system for the one-hour period.[43]

Nord Pool

To increase flexibility to balance demand and supply, Denmark helped create the Nord Pool market-based power exchange in 1999-2000, which now includes nine northern European countries. Electricity moves freely between these market-coupled markets, using algorithms to assign transmission capacity to transport power from cheaper to more expensive markets. Nord Pool plays an important role in the successful integration of renewables. Denmark has 6.4 GW of net transfer capacity to Norway, Sweden and Germany, and the high liquidity of the Nord Pool market offers Denmark the opportunity to sell wind power to its neighbors when oversupplied. In addition, Denmark can buy solar or hydropower when wind output is low. Nord Pool also increases the economic value of wind. By selling excess generation to other nations at market-determined prices, Denmark's wind generation becomes an export product.

More Balancing Responsibility for Wind Power

Denmark recently decided to phase out its PSO charge by 2022, under plans to increase the market integration of renewables. This move echoes Germany's new direct marketing of renewables in wholesale power markets.

In another move to increase market integration of wind power, beginning this year commercial wind power aggregators will be responsible for providing firm power from their entire portfolios of wind units, and to pay for imbalances. Until now, only operators of newer turbines had such balancing responsibility.[44]

Increasing Flexibility of Conventional Generation, Motivated by Balancing Markets

Denmark anticipated the need for power system flexibility a decade ago, adjusting its conventional generation fleet much earlier than most other countries.[45] Danish coal power plants have been optimized to allow very steep ramp-up gradients, shorter start-up times and low but stable minimum generation levels: in a word, they are more flexible.[46] Modifications, in both control software and equipment, allow hard coal plants in Denmark to ramp at rates up to 3-4% of rated output per minute, which is unprecedented among coal plants globally. Further, coal plants in Denmark can cycle down to a minimum 10-20% of rated output, compared to 45-55% in Germany and typical 60-70% levels elsewhere.[47] While the country has committed to a coal phase-out, these power plants may remain, through conversion to biomass; DONG Energy has said its power stations would replace coal with sustainable

[43] Ea Energy Analyses (2015): p. 1.

[44] Energinet (2015): News from Energinet.dk, 13 May 2015: "Energinet.dk udliciterer balanceansvar for vindmøller og små kraftvarmeværker", online: http://energinet.dk/DA/El/Nyheder/Sider/Energinet-dk-udlicitererbalanceansvar-for-vindmoller-og-smaa-kraftvarmevaerker.aspx

[45] Martinot, Eric (2015).

[46] Ea Energy Analyses (2015): p. 1.

[47] Martinot, Eric (2015).

biomass by 2023.[48] High flexibility of conventional generation allows them also to participate in the balancing markets and to take advantage of higher prices there compared to the spot market.

The Danish TSO exploits such thermal power flexibility with a must-run directive, keeping some power plants online and available, but producing as little energy as technically possible to provide short-term balancing power when needed.[49]

Changes in Balancing and Intraday Markets

The Nordic market adopted a common approach for bids and offers in balancing markets across all participating countries and TSOs back in 2002. All bids for delivering regulating power are collected in the common Nordic NOIS list (Nordic Operational Information System - NOIS) and are sorted in a list with increasing prices for up-regulation (above spot price) and decreasing prices for down-regulation (below spot price). These bids can be submitted, adjusted, or removed until 45 minutes before the operation hour. If transmission capacity is available, the lowest bid can be activated. Because it is a common market, an up-regulation bid from Sweden may be applied for up-regulation in Denmark.

In Denmark, there are four ancillary/balancing markets. There are two forms of manual balancing for time frames of 15 minutes to 1 hour, in which balancing power providers are called upon when needed, and two forms of automatic balancing, for both sub 15-minute and sub 30-second time frames. In both cases, power generators can choose the day before how much of their power capacity to sell into the normal day-ahead wholesale market, and how much to hold back to sell into the real-time ancillary/balancing market. In three out of four of these markets, balancing power providers are also paid a capacity payment, based on the reserve capacity they make available, for agreeing to participate in the next day's ancillary/balancing market, even if they don't provide any electricity.[50] They also receive an energy payment for any kWh of power they sell to the balancing market, based on different tariff regimes.

Denmark's TSO also has introduced the use of a fixed amount of trans-national secondary reserves, which can be activated quickly (e.g. within 30 seconds). Typically, this reserve was delivered by power plants running below their full capacity. However, in 2015, Energinet.dk entered a five-year agreement with the Norwegian TSO Statnett, for the delivery of +/-100 MW secondary reserves. This is delivered over the new DC line from Norway to Denmark.

First Steps in Demand-Side Flexibility

Use of demand response for integrating and balancing renewables has significant potential in Denmark, but projects are still largely in the pilot phase. The FlexPower project proposed an alternative market for regulating power, with a special focus on making it attractive for the demand-side.[51] A key feature was that the end user should receive a price signal every five minutes. When this system is applied to a large number of households as well as small and medium-sized industrial end users (many with automated control systems) the desired up or

[48] https://www.cnbc.com/2017/02/02/denmarks-largest-energy-company-to-stop-using-coal-by-2023.html
[49] Martinot, Eric (2015).
[50] https://www.energidataservice.dk/en/group/ancillaryservices
[51] Ea Energy Analyses (2013): Activating electricity demand as regulating power – Flexpower, Testing a Market Design Proposal, Copenhagen, 30.11.2013; online: http://www.ea-energianalyse.dk/reports/1027_flexpower_activating_electricity_demand_as_regulating_power.pdf

down regulation can be realized.[52] The READY project demonstrated how many small heat pumps can be controlled remotely.[53] This flexibility can be predicted and used in both the day-ahead market and as regulating power. The concept was tested with the direct control of heat pumps (in contrast to indirect control, sending a price signal and allowing the end user to act). The test was performed with 100 active heat pumps and, in general, end user acceptance was high.[54]

South Australia

The Australian electricity industry is controlled by the states. There is a national electricity market (NEM) that ensures all the states (except for Western Australia) are connected and electricity is traded between markets, however each state is responsible for its energy policy. Generally speaking. Australia is a coal-powered nation, with the most populous states of New South Wales and Victoria predominantly coal-powered. Tasmania has since the 1970s been the state with the highest level of renewable energy with the development of its large-scale hydroelectricity plants.

The energy transition from high carbon to low carbon electricity that is occurring in South Australia is unique in the Australian context. It has not been easy politically, as Australian politics and media is dominated by the fossil fuel lobby. The problems that occurred following severe storms in South Australia in September 2016 were dissected in the media, and many commentators were very critical of the path to renewables. Energy policy uncertainty at the national level caused a major investment hiatus into any sort of generation capacity, either renewable or non-renewable, from 2015-2016. As renewable generation costs continue their relentless march down, South Australia is increasingly seen as forging the way for an electricity system in transition. With more capacity coming on stream in South Australia, the short-term downward trend in prices may be a medium-term trend. Generation investment in South Australia continues to be focussed on renewables and natural gas, plus electricity storage. As of June 2017, an additional 1,515 MW of large scale solar farms and 3,178 MW of new wind projects were either committed or proposed. Rooftop PV installations are expected to continue to be popular as high electricity prices make pay-back periods short.

Market Share of Renewables

Wind and Solar Near 50%

South Australia has among the highest market share for wind and solar worldwide. Wind power accounts for 39.2% of generation, and rooftop solar for 9.2% (see Figure 6 below).[55] Rooftop solar is extremely popular in South Australia, with more than 30% of households having a system installed. In total 48.4% of the state's power came from these two sources

[52] Ea Energy Analyses (2015) p. 3.

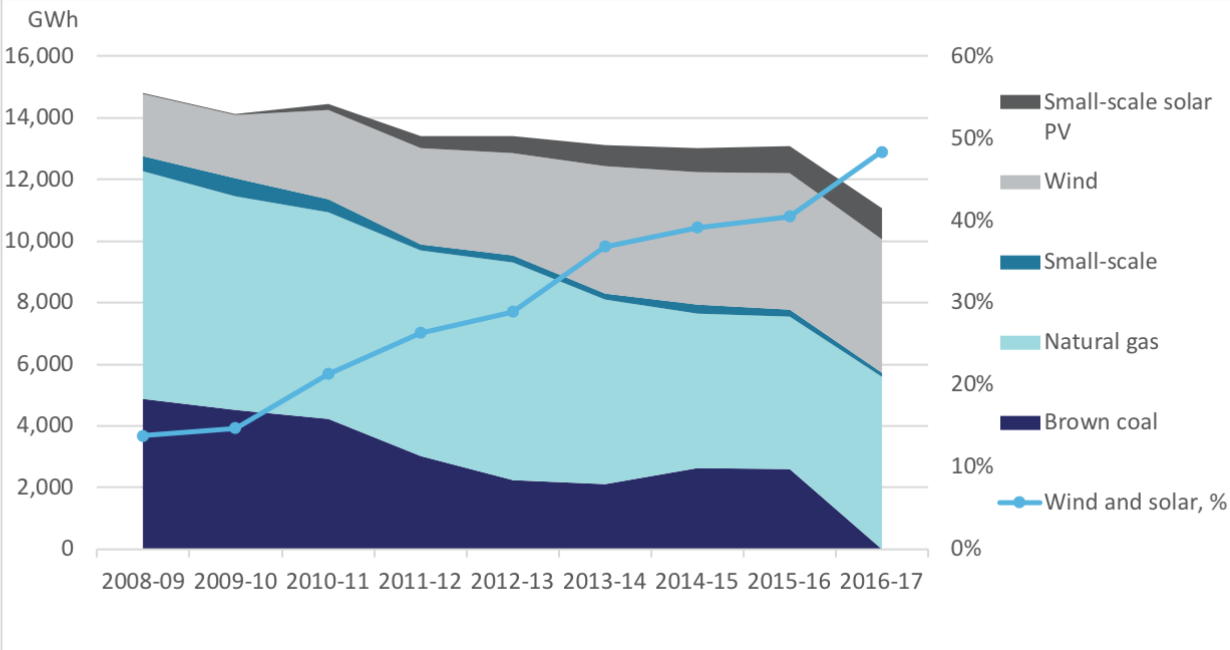
[53] EA Energy Analyses (2014): READY project: Summary of main findings with a focus on market aspects and local grid constraints, Copenhagen, 10.12.2014.

[54] Ea Energy Analyses (2015): p. 3.

[55] Page 3 http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2017/South-Australian-Electricity-Report-2017.pdf

last year. South Australia has a target for 50% of its electricity to come from renewable sources by 2020, and a 2050 target of net zero emissions.[56] Gas generation still marginally dominates, with a 50.5% power market share.

Figure 6: Electricity Generation by Source (GWh) & Wind & Solar Market Share (%)



Source: Australian Department of the Environment and Energy, 2017 [57]

Drivers of Renewables Growth

The high market share of wind and solar in South Australia can be attributed to a federal government-inspired renewable energy target. In addition, the state is blessed with ample wind resources, being on the edge of the Great Australian Bight. Developers flocked to the state to take advantage of subsidies and fill a market that was undersupplied. There was a rising business case for new generation, particularly following the closure of the Playford B coal-fired power plant in 2012 and the Northern Power coal-fired power plant in May 2016. Wholesale power prices in South Australia were the highest in Australia in 2016-17, having risen by 76% over the year.[58] Meanwhile, rooftop solar remains very popular with consumers and, with high electricity prices throughout Australia, has short pay-back periods. The integration of rooftop solar with behind-the-meter storage applications accelerated rapidly over 2017 as consumer offerings multiplied and prices fell.

[56] https://statedevelopment.sa.gov.au/upload/energy/facts/Renewable%20and%20future%20electricity%20generation_DSD_11216.pdf

[57] https://www.energy.gov.au/publications/australian-energy-update-2017

[58] Page 3 http://www.aemo.com.au//media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2017/South-Australian-Electricity-Report-2017.pdf

Indicators of Integration Challenges

Recent Wind Curtailment

Following the blackouts experienced in South Australia in 2016, and the problems restarting the grid, the Australian Energy Market Operator (AEMO) introduced new rules for wind farms in South Australia. The new rules, released in December 2016, restrict wind generation according to the number of gas units operating. For example, up to 1,200 MW of wind is allowed without restriction if three gas units are operating, and beyond 1,200 MW if four are on-line.[59] The restrictions have led to new curtailment, which in one eight-week period to mid-September 2017 amounted to an estimated 65,746 MWh, or 6.5% of wind generation.[60] Curtailment has the effect of pushing up wholesale prices, as these are set by gas generators. Augmentation of the interconnector to Victoria, a new 100 MW battery and a new gas-fired power plant at Barker Inlet should alleviate the need for curtailment.

Market Concentration and Manipulation

The wholesale market for electricity in South Australia is highly concentrated, according to a report by the Melbourne Energy Institute.[61] This has led to gaming of the market and monopoly profits, it concluded. "Concerns about the exercise of market power in South Australia have been evident in relatively low levels of liquidity in its market, and there is demonstrable evidence for the extraction of monopoly rents by some generators, arguably through physical and economic withholding of capacity," the report said.[62] Market illiquidity may undermine the integration of variable renewables by raising the cost of flexible back-up.

Gas Shortages in Australia?

One of the extraordinary features of the Australian electricity market has been the scarcity of domestic gas available for domestic electricity generation. While the east coast of Australia has become a major global gas exporter, domestic power generating assets have struggled to secure gas at a reasonable price, with a trebling of the wholesale gas price, despite a trebling of domestic gas production in the last decade. In early 2017, three gas-fired power plants, Pelican Point (SA), Stanwell (QLD) and Tamar (TAS), were mothballed because they could make more money selling their gas supply contracts into the domestic market than by generating electricity. In March 2017, under intense political pressure, power plants secured new gas supply, albeit at high prices.[63] Given that gas-fired power is one of the most flexible generation options, such problems may raise the cost of integrating renewables.

[59] http://reneweconomy.com.au/wind-output-curtailed-again-in-south-australia-65992/
[60] http://www.wattclarity.com.au/2017/09/how-much-wind-powered-electricity-production-has-been-curtailed-in-sa-since-these-new-constraints-were-invoked/
[61] https://d3n8a8pro7vhmx.cloudfront.net/auscon/pages/1246/attachments/original/1470896648/SA_PRICES_FINAL.pdf
[62] Page 4 https://d3n8a8pro7vhmx.cloudfront.net/auscon/pages/1246/attachments/original/1470896648/SA_PRICES_FINAL.pdf
[63] http://www.afr.com/business/energy/electricity/origin-energy-to-provide-gas-to-pelican-point-plant-in-sa-20170328-gv8nau

Factors That Have Favored Integration

Boosting Grid Resilience: Lessons From a Blackout

On September 28, 2016, some 850,000 customers in South Australia lost their electricity supply because of cascading events that stemmed from extreme weather.[64] Two tornadoes damaged transmission lines, causing voltage levels to dip six times over a two-minute period. Some 456 MW of wind generation tripped off-line due to a protection setting to disconnect output if voltage dipped a certain number of times. This loss of wind power caused a very rapid and significant increase in power imports through an interstate interconnector, which tripped off-line as a result, isolating the South Australia grid. The resulting supply-demand imbalance led to a collapse in grid frequency. The collapse was too rapid to allow automatic load shedding, leading to a general blackout. Following are some lessons from the blackout, related to increasing the grid integration of variable renewables.

Improve Performance of Variable Renewables During Major Events

AEMO's report on the incident found that wind generation itself was not a contributory factor, rather the protection setting for the wind farm was the issue. Following the blackout, changes to wind turbine control settings have removed the risk of a recurrence. "Changes made to turbine control settings shortly after the event have removed the risk of recurrence given the same number of disturbances," AEMO said in its report on the incident.

New Frequency Control Services by Renewables

The main cause of the blackout was the speed of the frequency change following the tripping of the interconnector. AEMO concluded that non-synchronous generators, including variable renewables, would have to be used for frequency control increasingly in the future. "Additional means of procuring these services must be considered, from non-synchronous generators, where it is technically feasible." One way to allow wind turbines, for example, to provide frequency control and other grid balancing services is to install active power control (APC). APC allows wind turbines to modulate their output, on instruction from the network operator, for example by altering the pitch of the turbine blades.

Another way to increase the flexibility of entire wind farms is to run them alongside battery storage. South Australia now appears to be a world leader in major grid-scale and residential battery deployments, with at least five completed or announced installations at the time of writing. Regarding completed projects, the 315 MW Hornsdale wind farm in late 2017 installed a 100 MW lithium-ion battery – at the time the world's biggest – to provide frequency control, as well as other grid balancing services.[65] Regarding present installations, a 30MW/8MWh battery is being installed next to the Wattle Point wind farm on the Yorke Peninsula in South Australia. And regarding confirmed plans, Singapore's Nexif Energy plans a 125 MW Lincoln

[64] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf

[65] https://hornsdalepowerreserve.com.au/overview/

Gap wind farm and 10 MW battery project at Port Augusta. In February 2018, South Australian Premier Jay Weatherill announced a plan to build the world's largest virtual power plant in suburban Adelaide, giving 50,000 households free solar panels and Tesla storage batteries.[66] And finally, also in February, plans were announced for a 44MW solar farm to be accompanied by a 21MW/26MWh battery storage system, in the state's mid-north.[67]

New Flexibility

Following the political backlash that occurred after the statewide blackout, plus the closure of the Hazelwood coal power plant in neighboring Victoria, the government devised an energy plan that included plans for new sources of flexibility.[68] These include:

- Some 1,000 MW of contracted demand management.[69]
- The return of 833 MW of existing market generation capacity from gas-powered generators.
- Support for the A$650 million, 150 MW/1,100 MWh Aurora concentrated solar thermal plant at Port Augusta, to be completed by 2020,[70] which will have between eight and 10 hours of storage capacity, at a levelized cost of electricity of A$75-85/MWh (US$60-68/MWh), half the modelled costs presented just two years previously.[71]
- The acquisition of temporary diesel generators to supply 276 MW of capacity at a cost of A$339 million. These generators will be converted into a gas-fired power station in two years.[72]

Rising Interconnection

South Australia has grid interconnections with the national market through the Heywood line to the state of Victoria. A project to increase the capacity of the Heywood Interconnector, from 460 MW to 650 MW in both directions, is nearing completion (as of November 2017). While this is a positive development, with the closure of the 1,600 MW Hazelwood coal-fired power station in the Latrobe Valley in April 2017, Victoria will not have as much spare capacity as in years past.[73]

Electranet, South Australia's transmission provider, is investigating building another interconnector to eastern Australia to facilitate better "integration of more renewables in the region and improve system security".[74] One of the possible routes is to NSW to diversify sources of supply and demand.

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66 http://www.afr.com/business/energy/jay-weatherill-elon-musk-to-build-worlds-biggest-virtual-power-plant-20180204-h0tcbh
67 http://reneweconomy.com.au/south-australia-unveils-another-big-battery-this-time-with-solar-16727/
68 http://ourenergyplan.sa.gov.au/sites/default/files/public/basic_page_attachments/4/24/441088034/our-energy-plan-sa-web.pdf
69 https://www.aemo.com.au/Media-Centre/AEMO-releases-summer-readiness-report-for-2017-18
70 http://www.solarreserve.com/en/global-projects/csp/aurora
71 http://www.abc.net.au/news/2017-08-14/solar-thermal-power-plant-announcement-for-port-augusta/8804628
72 http://www.afr.com/business/banking-and-finance/diesel-generators-cost-339m-in-sa-power-fix-20171220-h08axd
73 http://www.abc.net.au/news/2017-03-30/hazelwood-power-plant-shutdown-explained/8379756
74 Page 5 http://www.aemo.com.au//media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2017/South-Australian-Electricity-Report-2017.pdf

Uruguay

Uruguay has a long history of very high market share for renewable electricity. Combined wind and hydropower are presently above an annual average of 90%. Historically, the country exploited its rich hydropower resources. Today, it is one of the world's fastest-growing wind markets.

Uruguay's recent success in integrating wind power can be attributed to two overarching factors:

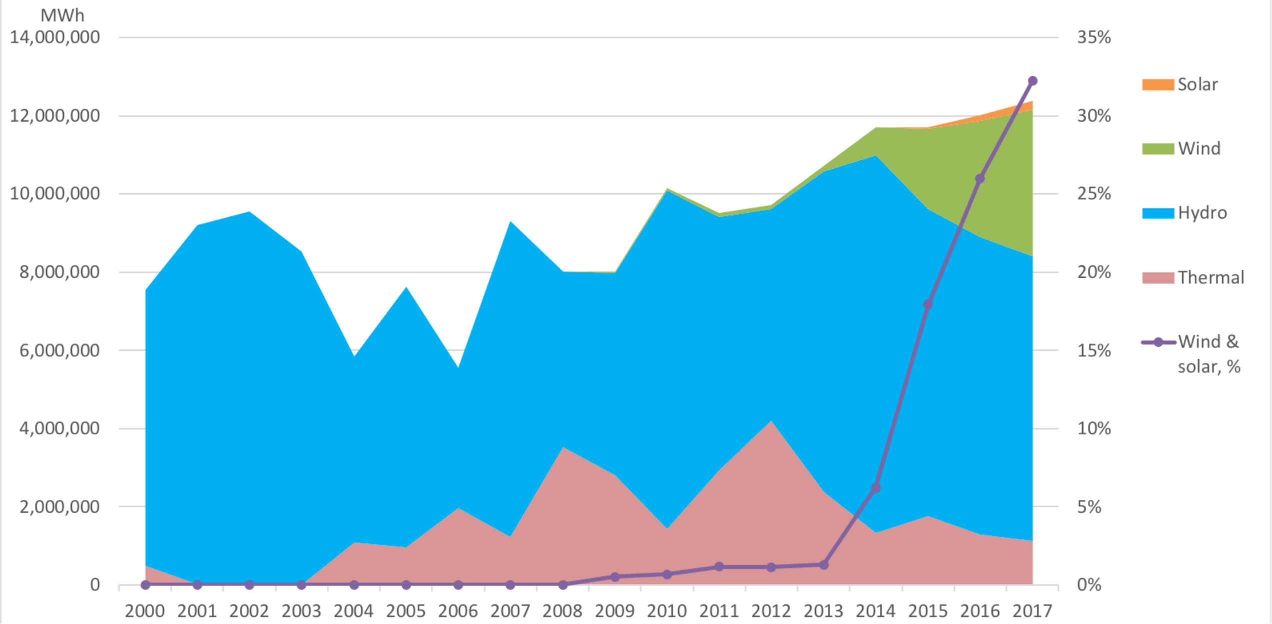
1. Forward planning, including installation targets, within a highly regulated electricity system that has provided investment clarity. An important goal was to reduce dependency on energy imports, including oil for thermal generation, and of electricity from Brazil and Argentina. This goal has been already achieved, with wind power turning the country into a net electricity exporter.
2. Excellent, flexible balancing resources that can offset the variability of wind power. Uruguay has both massive hydropower resources, which can cover shortfalls in wind, plus cross-border interconnections to two much bigger neighbors, Argentina and Brazil, which can be used to export wind power surpluses.

Market Share of Renewables

Phenomenal Growth

Combined wind and solar power market share has increased at a phenomenal rate in Uruguay, to an average 32.2% in 2017, from just 1.3% in 2013 (see Figure 7 below). Wind and solar hit a record monthly market share of 42% in December 2017. Growth in wind and solar has pushed out thermal (oil-fired) generation. Wind, hydro and solar power combined accounted for 90.4% of generation in 2017, compared with just 56.9% in 2012.

Figure 7: Electricity Generation by Source (MWh) & Wind & Solar Market Share (%)

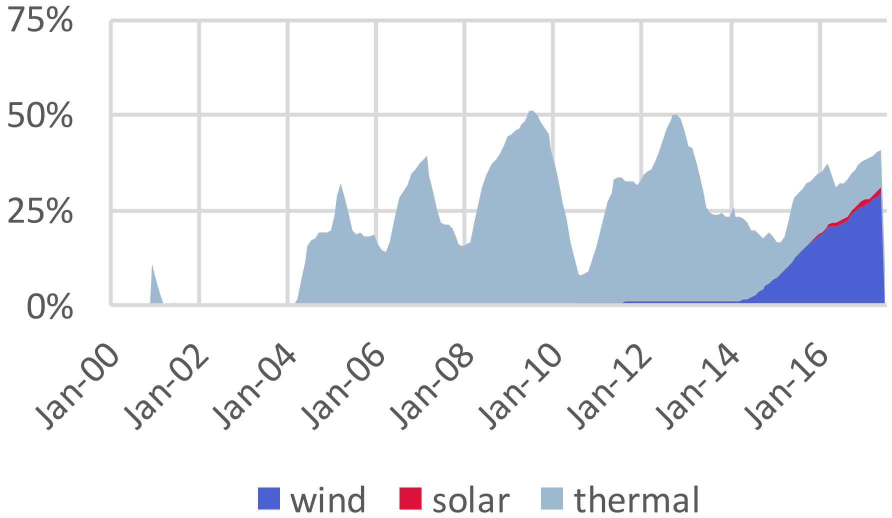


Source: MIEM [75]

2014 was the crucial year for Uruguay's installed wind generation. In terms of installed MW, 2014 recorded an eight-fold jump over 2013. The consequences of such a dramatic increase in filling demand can be seen in Figure 8 below. Before 2014, Uruguay relied on expensive (and polluting) imported oil-fired generation to top up hydro generation. Today, wind generation keeps thermal generation at a minimum. Importantly, additional wind generation also allows hydro reservoirs to be kept fuller, with an eye to providing quick, back-up power.

[75] http://www.dne.gub.uy/web/guest/publicaciones-y-estadisticas

Figure 8: Wind and Solar Vs. Thermal Generation (% of demand)

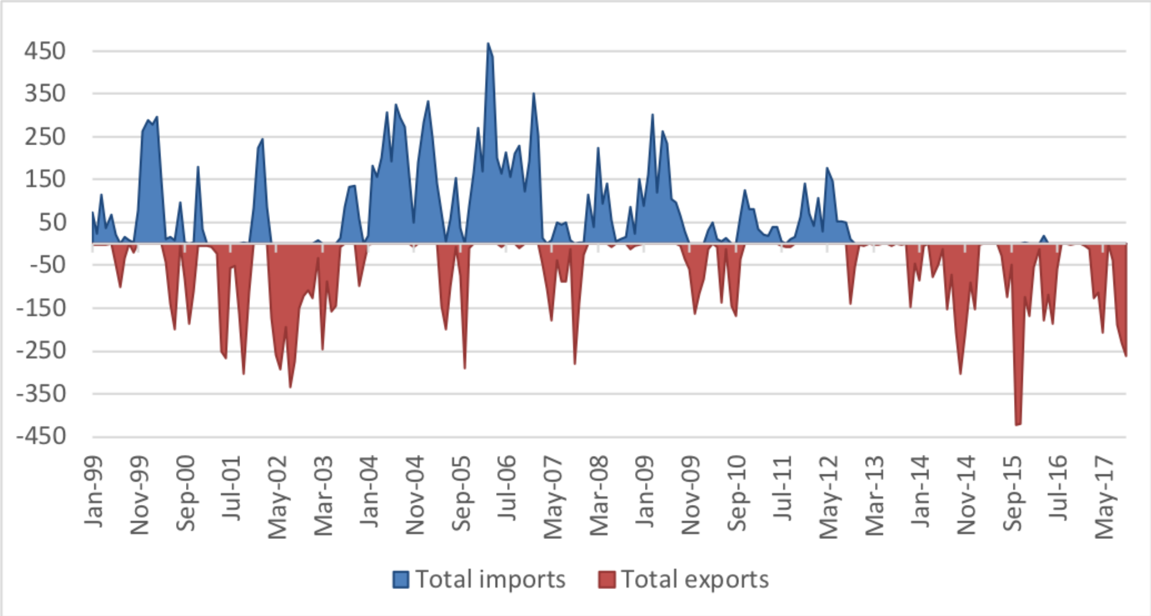


Source: Own elaboration on MIEM data. Note: for clarity of depiction, a 12-month moving average is shown for all series in the chart. Each year hydro fills the rest of the power needed (up to 100%)

Now an Energy Exporter

Uruguay has now turned into an energy exporter, as shown in Figure 9 below. The difference in import-export trends starting in 2014 is quite evident, as wind generation grew. Uruguay appears well ahead of achieving its goals of greater energy independence (by reducing imports of oil for thermal generation, and of electricity), and less vulnerability to dry hydro years.

Figure 9: Monthly Imports and Exports to Brazil and Argentina (GWh)



Source: MIEM [76]

The Uruguay Power Market

The Uruguayan electricity market comprises a vertically integrated, state-owned company, Administración Nacional de Usinas y Transmisiones Electricas (UTE), which owns about half of Uruguay's generating assets outright. UTE also owns and is the sole operator of transmission and distribution; it is required to provide third parties open access in return for a toll on transmission services. UTE also is the only authorized buyer in the wholesale electricity market. To counterbalance the presence of a single buyer, rules allow for the presence on the supply side of independent power producers (IPPs). UTE is free to enter into public–private agreements and contracts with IPPs, for example by tendering for 20-year power purchase agreements with renewables developers, with the goal to meet Uruguay's national 2005-2030 plan as efficiently as possible. This public–private model has been successful to date.

The power market in Uruguay is an energy-only market with physical (spot market) and financial (forward market) contracts, where UTE operates as the only vertically integrated public utility. The spot market is managed by ADME (the electric market operator), but UTE is the de facto principal figure. Independent companies can decide to sell electricity at an administered market price on a day-ahead basis, or according to long-term PPAs with UTE.

In 2016, there were a total of 45 producers authorized to operate in the wholesale market in addition to UTE. According to ADME, IPPs were responsible for approximately 30% of all volumes, while UTE provided the rest. Excluding the UTE share, wholesale market volumes were subdivided into spot (4% of total exchanges) and forward markets (96%). Forward market volumes have grown by nearly 500% since 2013 – reflecting the increase in wind power generation from private producers under PPAs – while the spot market retains coverage of very low levels of total exchanges.

[76] http://www.dne.gub.uy/-/series-estadisticas-de-energia-electrica-

Indicators of Integration Challenges

Power Outages

As noted in Figure 4 above, Uruguay is by far the worst performer among our case studies for power outages, as measured on the World Bank's SAIDI score, which measures the annual average duration of power outages per consumer, in hours, in each country's largest business city, in this case Montevideo. Uruguay's score of 5.6 hours compares with less than 30 minutes for our four other case study countries (the World Bank does not supply SAIDI scores for regions). We can speculate that Uruguay's score may reflect its lower per capita income, or perhaps a failure to contract sufficient back-up capacity. Other countries with comparable income have similar scores, such as Romania (3.4 hours), Croatia (5.9 hours), Argentina (4 hours) and Iran (5.7 hours).

Factors That Have Favored Integration

Forward Planning

Critically, from the perspective of lessons for other countries, Uruguay's renewable energy growth has been minutely planned, reflecting a highly regulated electricity sector. Uruguay in 2008 adopted a national energy policy running through 2030 that set specific renewable goals for the short, medium and long term (2015, 2020 and 2030). The government committed to meet 15% of electricity demand from non-hydro renewable sources by 2015. The 2030 plan aimed to achieve diversification of Uruguay's energy matrix, mainly by promoting the use of indigenous renewables. An important goal was to reduce dependency on energy imports, including oil for thermal generation, and of electricity from Brazil and Argentina. Another goal was to prepare against dry hydropower years.

The legal support for renewables was provided by Decree 354 on the Promotion of Renewable Energies, approved in 2010 by the Ministry of Energy, Mining and Industry (MIEM). In practice, the government acted to pick winners by establishing aggressive PPAs and tax exemptions (20-100% of income tax, depending on the project) to foster wind and solar generation. By 2012, Uruguay had announced a plan to bring 1,000 MW of wind capacity onto the grid by 2016, compared with peak demand of less than 2,000 MW. UTE contracted to buy the future production coming from the wind farms. To achieve stable demand and prices, private companies were allowed to participate in auctions for wind offtake contracts of up to 20 years, which also allowed them to sell surplus power in the spot market. UTE has conducted several auctions for both wind and solar power.

TSO Preparedness

In planning for the expected inflow of wind power, UTE invested in automated generation control (AGC) components to manage short-term intermittency and balancing needs. And in 2011, UTE signed an agreement with the University of the Republic to implement a wind prediction system at hourly resolution.

A New Complementary Market Develops

Importantly, and by design, the new wind resources have freed hydro from having to generate, allowing for reservoirs to be kept comfortably full and ready to generate. This is one of the keys to Uruguay's success: hydro and wind generation profiles complement each other in meeting demand, yielding new benefits in terms of system stability and lower costs, as well as boosting export revenues and delivering on legal commitments such as the Paris Climate Agreement.

Germany

Germany's original Grid Feed-In Law (Stromeinspeisungsgesetz – StromEinspG) contributed to massive growth in wind generation beginning in the early 1990s. The law, which took effect January 1, 1991, has been used as a model for many later feed-in tariff laws around the world. In 2000, the Stromeinspeisegesetz was replaced by the Renewable Energy Sources Act (EEG 2000).[77] Remuneration under the EEG 2000 was differentiated between technologies, with feed-in tariffs for PV systems increased to further promote solar power, incentivizing similar growth in solar generation.[78]

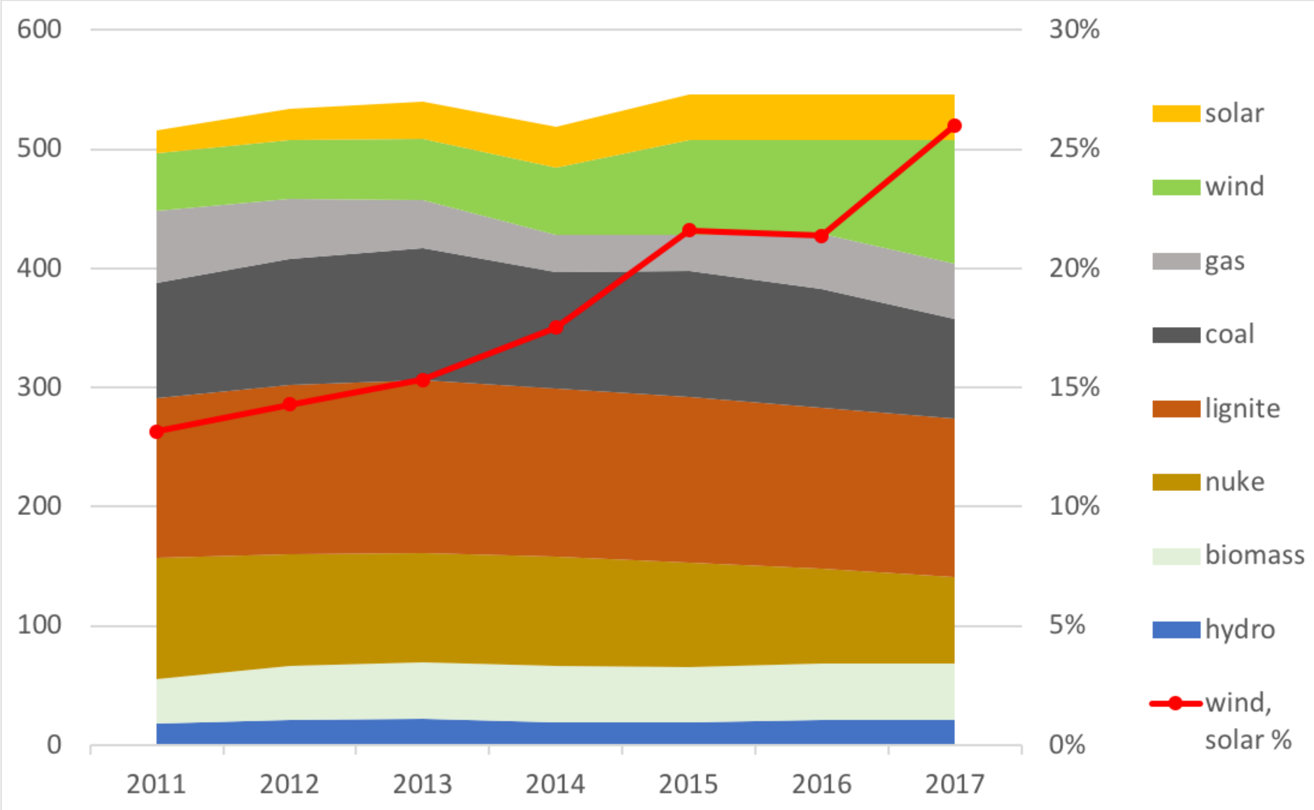
Amendment of the EEG in 2004 improved the legal status of operators of renewable power plants regarding network access. Further revisions entered into force under the EEG 2012, especially intended to encourage direct marketing of renewables in wholesale power markets, allowing generators to claim a market premium (Marktprämie), in addition to the revenue obtained by the sale of the electricity, with the goal of encouraging generators to respond to price signals and thus to contribute to supply security. The most recent substantial reform under EEG 2014 further developed the Energiewende (energy turnaround) concept and focused on compliance with EU state aid rules.

Market Share of Renewables

Wind and solar generation combined accounted for about 26% of net electricity generation in Germany in 2017, strongly up from the year before because of a surge in wind generation (see Figure 10).

[77] https://www.clearingstelle-eeg.de/files/private/active/0/5-EEG_2000_BGBl-I-305.pdf
[78] German Ministry for Economy and Environment (2017): Das Erneuerbare-Energien-Gesetz; online: https://www.erneuerbare-energien.de/EE/Redaktion/DE/Dossier/eeg.html

Figure 10: Electricity Generation by Source (GWh) & Wind & Solar Market Share (%)



Source: Fraunhofer Institute [79]

Indicators of Integration Challenges

Wind Curtailment Costs

The current imbalance between renewable generation supply and power demand is highlighted by wind curtailment. According to German market design rules, the grid operator must compensate wind farms for their renewable generation if grid integration is not possible.

Curtailment is especially high in the northern German state of Schleswig-Holstein, where wind generation is in coastal regions and curtailment is required to maintain grid stability, partly because of grid congestion between the north and south of Germany.[80]

At the national level, wind generation accounts for the vast majority of curtailment, at 4.5% of all wind generation in 2016, followed by solar, at 0.5% of all solar generation (see Figure 11 below).[81] Curtailment varies from year to year, according to total generation (which has generally been rising for wind and solar), as well as developments in transmission capacity.

[79] https://www.energy-charts.de/energy.htm

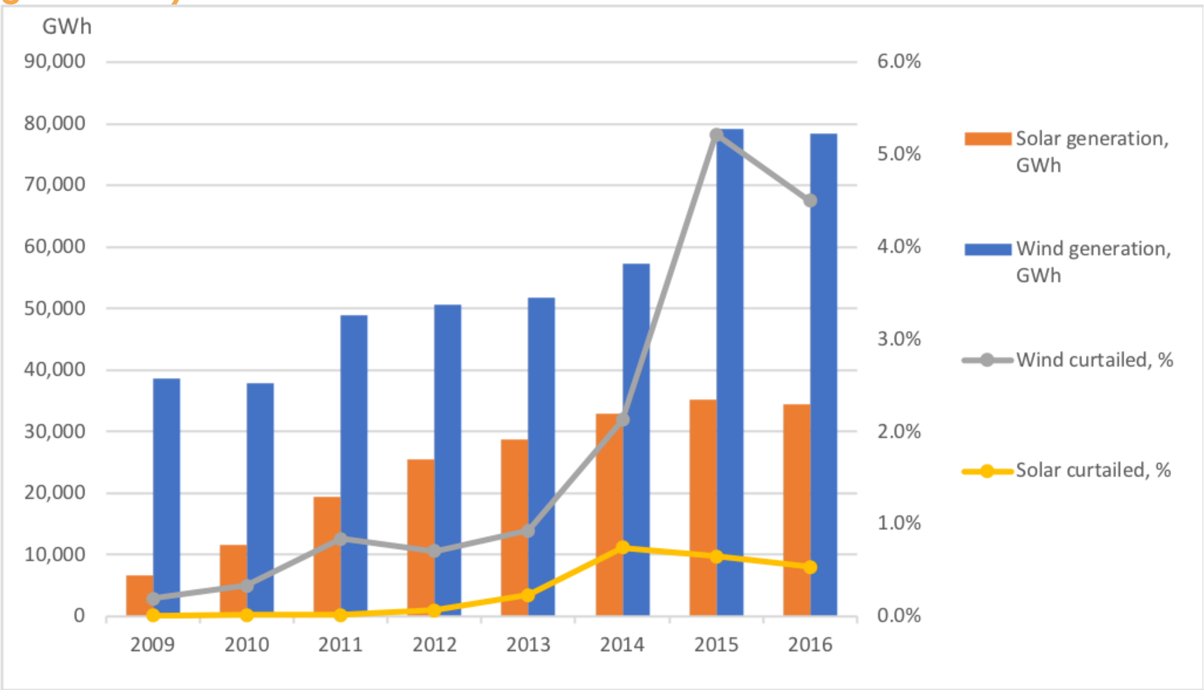
[80] Ministerium für Energiewende, Landwirtschaft und ländliche Räume (2016): Abregelung von Strom aus Erneuerbaren Energien und daraus resultierende Entschädigungsansprüche in den Jahren 2010 bis 2015, Kiel, 2. August 2016, p. 8; online: https://www.schleswig-holstein.de/DE/Schwerpunkte/Energiewende/Strom/pdf/abregelungStrom.pdf

[81] https://www.bundesnetzagentur.de/EN/Areas/Energy/Companies/RenewableEnergy/Facts_Figures_EEG/FactsFiguresEEG_node.html

For example, the dip in wind curtailment in 2016 was likely a result both of a dip in onshore wind generation compared with the previous year, and the opening of new north-south Germany transmission capacity, called Thüringer Strombrücke (Thuringia power bridge).

The total cost of curtailment across all generation technologies more than doubled in 2016, compared with the previous year, to €643 million, including €467 million for wind power.

Figure 11: Wind & Solar Generation (GWh) and Curtailment (as a percentage of generation)



Re-Dispatch

As explained in the Denmark section, excess generation on one side of a congestion point in the grid may require the network operator to request power plants on the other side to increase output, to serve customers locally.

The electricity market regulator, the Federal Grid Agency (BNetzA), adds up such so-called re-dispatch hours for all four German TSOs. In 2016, these TSOs required re-dispatch of some 11,475 GWh of power, at a cost of €219 million. While this was down from re-dispatch volumes of 15,436 GWh (€412 million) the year before, re-dispatch is still strongly up over the past five years.[82] Re-dispatch volumes rose nearly 30-fold from 2011-2016, and costs rose five-fold. Re-dispatch volumes rose again in the first quarter of 2017, up 40% compared with the same period the year before, the latest data show. The German regulator does not indicate which sources are responsible for the rise in re-dispatch.

[82] Bundesnetzagentur (2017): Quartalsbericht zu Netz- und Sicherheitsmassnahmen – Viertes Quartal und Gesamtjahr 2016, Bonn, 29. Mai 2017, p. 6. https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Allgemeines/Bundesnetzagentur/Publikationen/Berichte/2017/Quartalsbericht_Q4_Gesamt_2016.pdf

Poor Grid Planning: Transmission Upgrade Delays

One of the main reasons for wind power curtailment is inadequate transmission capacity. BNetzA conducts annual transmission planning analyses incorporating regional renewable development forecasts for the next 10 years. These analyses identified regional imbalances of generation and demand, particularly regarding the difficulty in transmitting wind generation from the north to demand centers in the south. As a result, the agency is planning three additional north-south transmission lines. Commissioning of the three lines is expected to reduce curtailment costs.[83] However, there is significant public resistance to building these power lines. A German government overview in 2015 showed that halfway toward a 2020 deadline for grid expansion, under a law adopted in 2009, only a quarter of the work had been completed.[84] Costs have risen to €34 billion, and the completion date has slipped to 2025.[85]

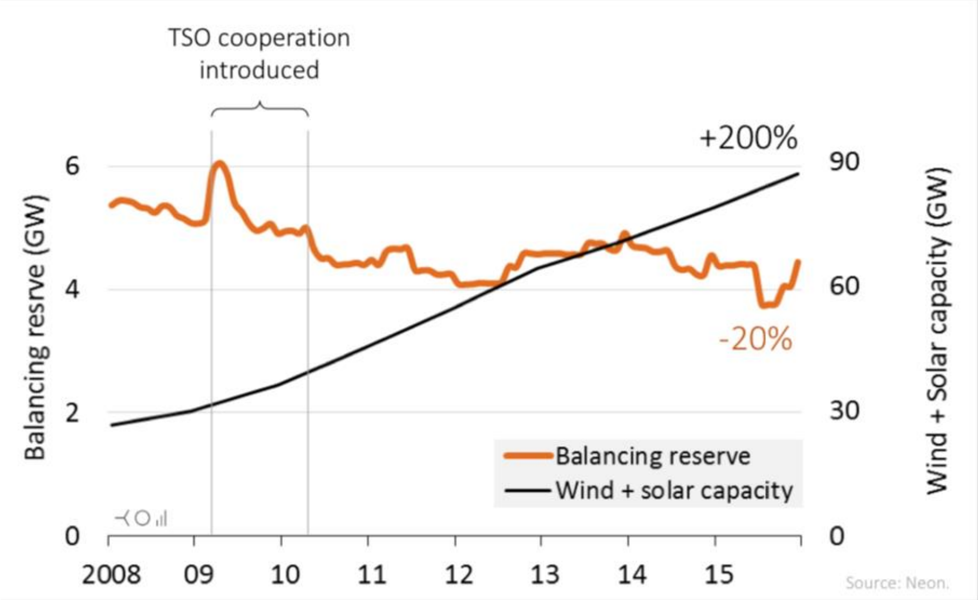
Indicators That Germany's Grid is Coping

We noted above that Germany has very low power outages, at an average 0.21 hours per customer per year from 2013-2015, putting the country in seventh place worldwide according to a World Bank analysis.

Another indicator of grid stability is Germany's use of options put in place to deal with critical situations. One example is the use of a power plant reserve, tendered for by TSOs, to call upon as needed in the balancing market. The reserve comprises power plants contracted on a weekly or daily basis, under pre-arranged terms, such as ramp rate and duration. Given that wind and solar forecasting is imperfect, growth in renewables might be expected to lead to supply-demand imbalances, which required greater use of such reserves. However, research shows the opposite: while the installed capacity of wind and solar power trebled from 2008-2015, use of secondary and tertiary balancing reserves fell 20% (see Figure 12 below).[86] One explanation for this is greater cooperation between Germany's four TSOs since 2009. This cooperation has allowed individual TSOs to expand their balancing area to the whole of Germany, now a single balancing area, giving them a much wider array of generating resources to call upon to match demand, before having to call up reserve capacity. Other explanations include optimization of renewables and other resources, through measures such as: wider TSO cooperation across central Europe; improved forecasting of demand and variable renewables supply; improved intraday market liquidity; and reduction of settlement periods to 15 minutes.

[83] Ministerium für Energiewende, Landwirtschaft und ländliche Räume (2016): p. 8.
[84] http://dip.bundestag.de/btd/18/062/1806270.pdf
[85] Unpublished report: HSBC, 2017. *Renewables and the Grid*.
[86] https://neon-energie.de/Hirth-Ziegenhagen-2015-Balancing-Power-Variable-Renewables-Links.pdf

Figure 12: Use of Balancing Reserves Vs Growth in Wind and Solar Capacity



Factors That Have Favored Integration

Grid Measures

Investment in the Grid

A prerequisite for the relatively smooth integration of the increasing amounts of electricity from renewable sources is Germany's grid strength, referring to the number and capacity of distribution and transmission lines compared with actual electricity generation and demand. However, even with its strong, overbuilt grids, Germany needs to strengthen some transmission lines to accommodate higher renewable penetration, in particular by adding new north-south transmission capacity.

TSO Cooperation

Operators of national, high voltage transmission systems across Europe hold system security conferences every morning, and as required on an ad-hoc basis. These TSO conferences use improved forecast models to calculate system reliability against so-called "N-1" contingency events, or the resilience to an unplanned power plant outage. These models now explicitly incorporate the effect of renewables and use improved day-ahead weather forecasting.

DSO Measures

The main challenge facing operators of local, low-voltage networks, called distribution system operators (DSOs), is the high share of solar generation, which has resulted in two-way electricity flows on the distribution grid, which were previously non-existent. Two-way flows occur when solar generation at a local node exceeds power demand. Grid upgrades, such as the installation of substations, transformers and new power lines, have helped manage these flows.

Grid Codes: Changes to the Cut-Off Frequency of Solar Inverters

A central task of German DSOs and TSOs is to maintain the grid frequency at 50 hertz, to safeguard system equipment, including household appliances. Solar PV inverters feed solar power into the local distribution grid, after transforming the generated power from DC to AC. These inverters are equipped to respond to grid frequency and were previously all programmed to cut off solar output if the grid frequency exceeded 50.2 Hz. However, with the growing share of solar PV, this meant that if the grid frequency indeed exceeded 50.2 Hz, all solar power could be disconnected at once, threatening system stability.[87] As a result, inverters were redesigned to allow variation in the cut-off frequency across individual units.

Management of Cross-Border Congestion

Germany's borders have seen a rise in grid congestion, as electricity trade has exceeded transmission capacity. Underlying causes for this congestion include: market liberalization; a more trade-oriented outlook among some European countries, which has seen them replace domestic generation with cross-border imports; and growth in variable wind energy, which has caused congestion at bottlenecks when peak flows are fed into the grid. Since electricity cannot flow through bottlenecks within market areas and price zones (e.g. between north and south Germany), it follows instead the path of least resistance, and often through the power grids of neighboring countries. As a result, there has been a sharp increase in the difference between commercially contracted and physical flows of electricity across Germany's borders.[88, 89, 90] For example, while commercial power trading between Germany and Poland barely exists, excess wind power from the north and east of Germany routinely flows via Poland, in route to southern Germany and Austria. These so-called loop-flows have led to TSO-triggered technical and commercial actions. Phase shifters were installed for transmission connections with Poland to limit power flows into the country to resolve a network stability issue.[91] In addition, the Agency for the Cooperation of Energy Regulators (ACER) decided to separate the single price zone of Germany and Austria and introduce congestion management at the German-Austrian border, as a means of reducing power flows from Germany to Austria via Poland.[92]

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[87] Martinot, E. (2015).

[88] Göss, Simon (2017): Dreaming of the copper plate: How physics and power trading diverge, EnergyBrain Blog, 26 January 2017.

[89] Online: https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/DatenaustauschUndMonitoring/Monitoring/Monitoringbericht2016.pdf

[90] Online: https://transparency.entsoe.eu/transmission-domain/physicalFlow/show

[91] Martinot, E. (2015).

[92] Göss, Simon (2017).

Power Market Measures

Introduction of Negative Spot Market Electricity Prices

The leading European Spot Power Exchange (EPEXSPOT)[93] introduced negative spot electricity prices in 2007 and 2008, in the German intraday market and German-Austrian day-ahead market respectively, to incentivize generators to reduce production in times of renewable electricity over-supply. Negative pricing was subsequently introduced in more of Germany's neighbors, in the French price zone in 2010, and in the Austrian and Swiss intraday markets in 2012 and 2013.[94] Negative pricing affects other neighboring countries, such as the Netherlands, because generators from conventional sources like coal and gas will seek higher market prices in other countries. In this way, the combination of negative pricing and high renewable generation penetration in Germany has reduced electricity wholesale market prices across central-western Europe.[95]

Direct Marketing of Renewables in Wholesale Power Markets

As described above, the 2000 Renewable Energy Act has been amended various times. One of the most important amendments was the introduction in 2012 of incentives for the direct sale of electricity from renewable generation into the wholesale spot market. The aim of the amendment was to make renewable electricity production more responsive to price signals, and thus to respond both to shortages and excess generation, thereby boosting system stability.

Prior to the amendment, renewable generators were paid a fixed feed-in tariff, per unit of power production. Now, they are paid the difference between the average monthly price for electricity on the spot market, and the guaranteed feed-in tariff, through a so-called market premium (Marktprämie). Thus, renewable energy producers do not experience any financial loss when selling electricity directly through the spot market, but rather can make extra profit by marketing at times of peak demand, when the price is above the monthly average. Further, the operators of flexible renewable generation (such as biomass) have the chance to take advantage of additional bonuses: the management premium (Managementprämie) and the flexibility premium (Flexibilitätsprämie) reward operators able to forecast their electricity production and adjust output quickly in response to real-time demand. Additionally, operators of biogas plants can participate in the market for operating reserves, exempt from prohibition on multiple sales (Doppelvermarktungsverbot) under the Renewable Energy Act.[96] According to the Renewable Energy Law of 2017, the flexibility premium only applies to new biogas generation. The amount of the flexibility premium is €130 per additionally installed kilowatt per year for 10 years. The support will end when 1,350 MW of additional capacity has been added.

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93 www.epexspot.com

94 EPEX Spot (2016): Negative Prices – Q&A, online: https://www.epexspot.com/en/company-info/basics_of_the_power_market/negative_prices

95 Martinot, E. (2015).

96 Graf, Jakob (2012): Through the Marktprämienmodell towards a necessary Flexible Electricity Production from Biogas in Germany?, Master Thesis, University of Aalborg, 2012, pp. 2; online: http://projekter.aau.dk/projekter/files/63567164/Master_Thesis_Final.pdf

Increasing Flexibility of Conventional Generation

Combined cycle gas turbines (CCGT) are among the most flexible conventional technologies available. On the down side for Germany's system flexibility, investment in new CCGTs in the 2000s has been stranded by high natural gas prices compared with coal. As a result, some gas plants are seeing service levels of only hundreds of hours per year, and many new plants have been retired prematurely. On the upside, most hard coal power plants in Germany were either originally designed, or have been subsequently modified, for flexible output. They can now ramp on an hourly basis to much less than full output, and cycle on and off daily. They also have developed better software to ramp their plants faster and developed operational practices that reduce the stress on equipment from ramping and cycling. Lignite coal power plants in Germany are less flexible but also have been modified in recent years to allow ramping down to 40% of their maximum output, compared to only 60% previously. As a result, while coal plants are not selling as much power into day-ahead wholesale markets, due to the priority delivery of renewables in those markets, they have adapted to participate more in balancing the variability of wind and solar power.

Changes in Intraday Markets

TSOs use intraday and balancing markets to balance supply and demand within their grid on a short-term and real-time basis, respectively. As renewable penetration has grown in Germany, these markets have been modified to provide greater flexibility and respond better to the variability of renewables. In 2011, the German regulatory authority designated that the intraday market should help handle imbalances created by wind forecast errors, and so reduced the time interval of these market auctions to 15 minutes from 1 hour, to handle faster system ramping on the conventional generator side. EPEX Spot conducts a daily intraday auction, at 15:00, for trade in increments of 0.1 MW for the 96 quarter-hour intervals on the following day. Continuous trading is offered from 16:00 for all 15-minute periods on the following day.

Changes in Markets for Ancillary Services

Until recently, grid operators ran auctions for ancillary services to maintain grid stability on a weekly or bi-weekly basis. However, renewables and some demand response options struggle to bid on that basis, due to forecast uncertainties.[97] As a result, in mid-2017, the German regulator announced it would roll out daily tenders, to make it easier for wind and solar generators to submit bids based on forecasted power output.[98] There are other ways to increase the participation of demand-side response and renewables in such markets. First, price signals could better reward flexibility, compared with selection at present based on capacity and operating costs. Second, the current system requires reserve power to be activated for a duration of four hours for minute reserves and 12 hours for secondary reserves. However, the service is normally only required for much shorter periods. Markets in Austria, Belgium, the Nordic countries and the U.K. have lowered the required activation period, to allow demand-side resources and renewables to compete.[99]

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[97] Jahn, Andreas (2014): Demand Response - US experiences, German challenges and market barriers, Berlin, 2014; online: https://so-ups.ru/fileadmin/files/company/markets/dr/germany/dr_germ_us_expir.pdf

[98] Unpublished report: HSBC, 2017. *Renewables and the Grid*.

[99] Stede, Jan (2016).

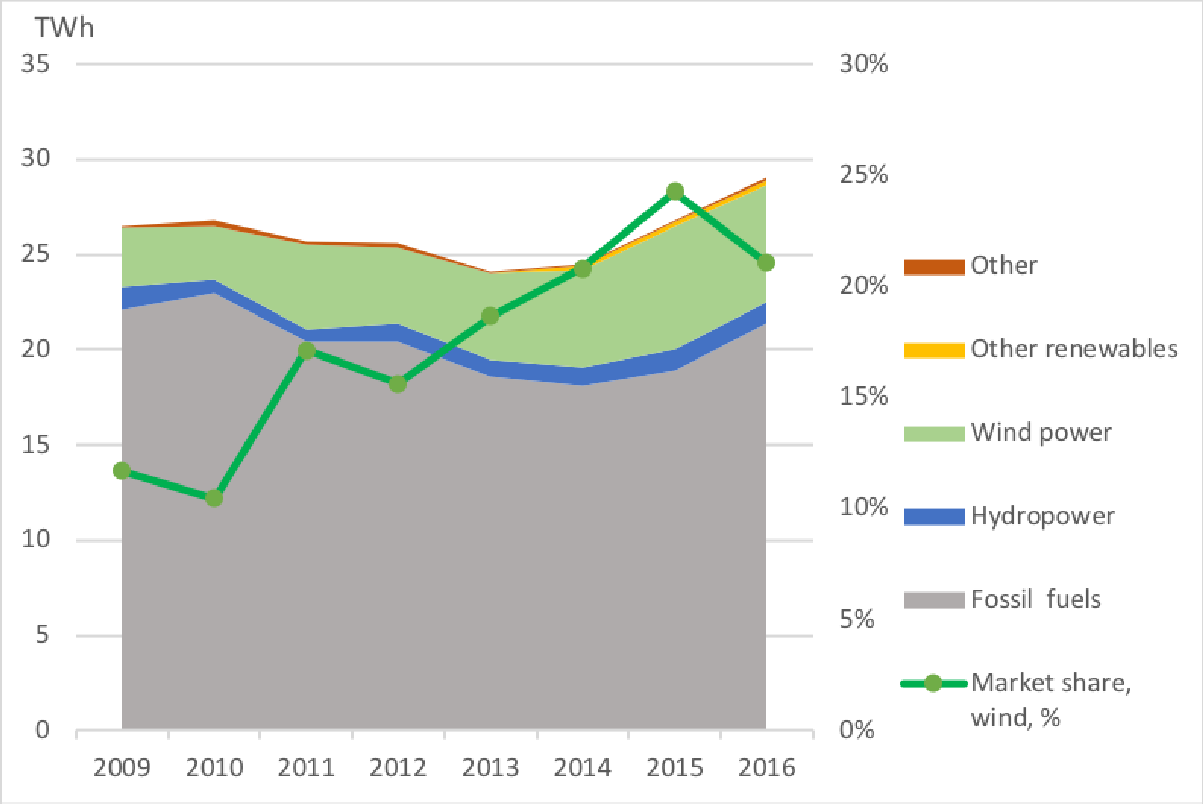
Ireland

Market Share of Renewables

Wind provided 21% of net electricity generation in Ireland in 2016 (see Figure 13), from an installed wind capacity of 2,800 MW.[100, 101] The latest data available at the time of writing, from the European Network of Transmission System Operators for Electricity (ENTSOE), shows that Ireland grew its market share for wind power in 2017, to 24.6% of net generation.[102]

It is estimated that installed capacity will have to rise to between 3,900 and 4,300 MW by 2020 to meet the current target to source 40% of electricity from renewable generation. Renewables have achieved a large share of instantaneous generation. In January 2015, for example, Ireland experienced maximum instantaneous wind penetration of 66.2%.[103]

Figure 13: Electricity Generation by Source (TWh) and Market Share of Wind (%)



Source: ENTSOE

[100] i.e. the Irish Republic
[101] ENTSOE annual statistical reviews
[102] https://www.entsoe.eu/data/statistics/Pages/monthly_domestic_values.aspx
[103] Almenta, M.M., et al., *An analysis of wind curtailment and constraint at a nodal level.* IEEE Transactions on Sustainable Energy, 2017. **8**(2): p. 488-495.

Successive support schemes have driven the growth of renewable electricity in Ireland. From 1995 to 2005, the main scheme was the alternative energy requirement (AER), which awarded PPAs for up to 15 years by means of first-price, sealed-bid competitive auctions.[104] The AER scheme resulted in a high proportion of unrealized projects. It is believed that the first-price bidding process incentivized strategic bidding, whereby winning bids were unsustainably low to obtain funding and/or in anticipation of unrealized future cost reductions.[105] Further problems were experienced with regard to poor spatial planning, access to planning permission and access to financing due to the novelty of the technology (and/or unsustainable rates of return due to strategic bidding).[106] The renewable energy feed-in tariff (REFIT) scheme replaced the AER process in May 2006. REFIT provided a guaranteed price floor for each unit of electricity generated by renewable sources over a 15-year period.

Beginning in January 2017, EU rules required that all new support for mature renewable energy technologies take place via competitive tender. Ireland is in the process of switching to such competitive support, which should mitigate risk to all by providing a price guarantee at a level that facilitates deployment, but at a more reasonable cost to consumers.

Indicators of Integration Challenges

Difficulties Meeting Ambitious Growth Targets

There was marked improvement in the rate of renewable deployment in Ireland in 2016. Still, the deployment rate will need to be greater than that of the 2007-2015 period to meet the country's 2020 targets. Several factors have contributed to delaying deployment.

First, project connections were historically processed only every few years, in batches of new generation known as gates. Large volumes of new wind capacity were difficult to process in this way. This system has evolved into a more continuous approach of smaller batches.[107]

Second, planning permission has been difficult. Ireland's most productive locations coincide with areas of natural beauty and/or rural settlement.[108] This has led to public opposition. Several factors may have exacerbated opposition. Community engagement has not been a legal requirement for seeking planning permission, and while many developers now carry out engagement activities voluntarily, a lack of engagement may have contributed to previous opposition. This is in contrast to many other European countries where community

104 References:
Huber, C., et al., *Economic modelling of price support mechanisms for renewable energy: Case study on Ireland.* Energy Policy, 2007. **35**(2): p. 1172-1185.
Farrell, N., *Wind Energy in Ireland*, in *Rural Economic Development in Ireland*, C. O'Donoghue, Editor. 2013, Teagasc: Oak Park.
Sustainable Energy Ireland, *Renewable Energy in Ireland: Trends and Issues 1990-2002*. 2004, SEI: Dublin.

105 Wiser, R., *The U.K. NFFO and Ireland AER Competitive Bidding Schemes.* Berkeley Lab and Clean Energy Group Case Studies of State Support for Renewable Energy, 2002.

106 McLean, A., McGovern, P., Donnelly, K., *ELG Ireland Renewables Article.* International Energy Law and Taxation Review, 2007. **10**.

107 https://www.cru.ie/wp-content/uploads/2016/07/CER16075-Response-from-Irish-Wind-Energy-Association-to-CER15284.pdf; https://www.cru.ie/wp-content/uploads/2017/04/CRU17309-ECP-1-Proposed-Decision-FINAL.pdf

108 González, A., G. Daly, and J. Gleeson, *Congested spaces, contested scales–A review of spatial planning for wind energy in Ireland.* Landscape and Urban Planning, 2016. **145**: p. 12-20.

engagement is often a legal requirement or community participation is more the norm.[109] To overcome opposition going forward, a community engagement code of practice has been advocated by the Department of Communications, Climate Action and the Environment.[110] Industry representatives have stated that community consultations of up to two years' duration are now being carried out voluntarily to avoid lengthier delays due to planning appeals. [111]

Third, a focus on wind over solar power has slowed progress to the 2020 goal, given that solar power is so much faster to install. Greater solar deployment likely would help Ireland speed its decarbonization efforts, and thereby avoid penalties for non-compliance with EU targets. A few factors have limited solar deployment. There has historically been no obligation for suppliers to pay customers for electricity supplied via domestic solar.[112] And Ireland has had no solar support mechanism for large-scale generation. This may change. Ireland's energy minister has announced that a solar support for microgeneration will become available in 2018[113]. At a larger scale, there is a debate as to whether the transition to competitive tendering for renewables should be done on technologically neutral grounds. Solar proponents argue that there is scope for limited solar deployment, at higher cost than wind, because this would enable the country to avoid EU penalties.[114]

Wind Power Curtailment

Figure 14 below shows that there has been considerable annual variability in the degree with which wind generation has been curtailed in Ireland. This variability is influenced by many factors, including the weather, wind capacity, demand and the generation portfolio. In 2016, for example, total curtailment fell, partly because of rising demand and a less windy year. In general, an increase in wind penetration is likely to increase total curtailment; as such added measures will be required to ensure curtailment is limited to a reasonable level in the future. Eirgrid and SONI assume curtailment levels of at least 5% for future studies, whilst McGarrigle et al. find that various measures would be needed to accommodate 75% renewables at any one time (i.e. increasing the system non-synchronous penetration limit from 60% to 75%). The latter authors estimated that even with such measures, wind curtailment would rise to 7% in a 2020 system with 37% wind.[115] That is a relatively high degree of curtailment by global benchmarks, and underscores how additional measures will be of fundamental importance to ensure curtailment is minimized on the Irish system going forward.

109 Brennan, N., T.M. Van Rensburg, and C. Morris, *Public acceptance of large-scale wind energy generation for export from Ireland to the UK: evidence from Ireland.* Journal of Environmental Planning and Management, 2017: p. 1-26

110 https://www.dccae.gov.ie/documents/Code%20of%20Practice%20community%20engagment.pdf

111 https://fora.ie/wind-farms-planning-delays-ireland-3500789-Jul2017/

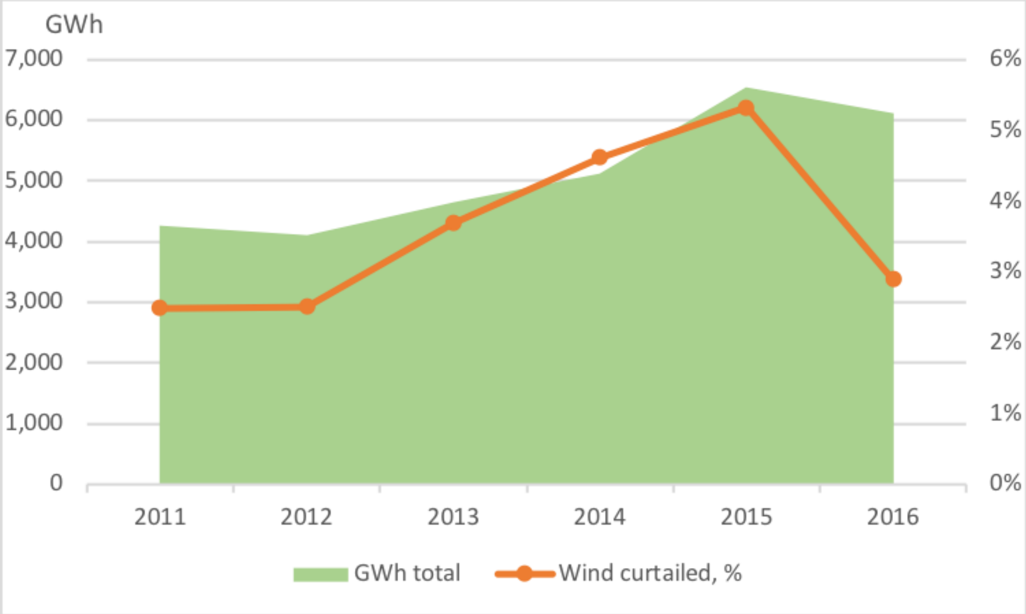
112 https://www.seai.ie/resources/publications/FAQs_on_Solar_PV.pdf

113 https://www.solarpowerportal.co.uk/news/ireland_to_pilot_microgeneration_support_for_solar_homes

114 http://irishsolarenergy.org/news-docs/ISEA%20ECP1_151217_clean.pdf; http://irishsolarenergy.org/news-docs/ISEA-Submission-to-NMP.pdf

115 Mc Garrigle, E.V., J. Deane, and P.G. Leahy, *How much wind energy will be curtailed on the 2020 Irish power system?* Renewable Energy, 2013. **55**: p. 544-553.

Figure 14: Wind Power Generation (GWh) and Curtailment (% of wind generated)



Source: Eirgrid[116]

Factors That Have Favored Integration

Several measures have been put in place to manage curtailment in Ireland. These include: increased interconnection, interconnector counter-trading and direct control of wind generation.

Interconnection

Ireland illustrates the importance of being interconnected to neighboring power grids and using this capacity as efficiently as possible. As a relatively small island grid, use of interconnection with Britain via sub-sea cables is critical for managing variability in Ireland's wind generation. For example, exports via interconnector reduced curtailment by up to an estimated 50% in 2013.[117] Ireland at present has limited cross-border interconnection equivalent to just 7% of its total installed generation, which is below the EU target for all member states of 10% by 2020.

To manage excess Irish wind power, it is important that interconnector flows are in the right direction, i.e. exporting to Britain. While this may seem straightforward, studies of the Irish market have shown that transmission flows often occur in the direction opposite to that expected.[118] The reason, according to researchers, likely can be tied to the nature of the Irish electricity market, which encompasses Ireland and Northern Ireland and does not have either forward or derivative components. As such, suppliers are exposed to potential price spikes and may use interconnection to hedge this exposure, importing from Britain at a

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[116] http://www.eirgrid.ie/site-files/library/EirGrid/Annual-Renewable-Constraint-and-Curtailment-Report-2016-v1.0.pdf

[117] Eirgrid and SONI, *Annual Renewable Energy Constraint and Curtailment Report 2014.* 2014.

[118] McInerney, C. and D. Bunn, *Valuation anomalies for interconnector transmission rights.* Energy Policy, 2013. **55**: p. 565-578.

known price, rather than taking the uncertain prices available in the Irish market, where definitive pricing is only available after trading has concluded.

To counter such inefficient use of Ireland's interconnection, the system operator will on occasion participate in interconnector countertrading to help reduce curtailment on the system and prevent incorrect interconnector flows. Following gate closure, the system operator may seek to initiate changes to the interconnector flows. Throughout 2016, countertrading arrangements were regularly used to alleviate curtailment of priority dispatch generation. This countertrading is predominately carried out using the services of a third-party trading partner.[119]

Going forward, Ireland's electricity market is moving toward what is called an integrated single electricity market (I-SEM), which will include forward markets, ex ante markets and other hedging products. This should facilitate more efficient electricity trading, particularly regarding the use of Ireland's limited interconnection capacity, by reducing its use in hedging activity. In turn, this should help reduce curtailment. The I-SEM also will introduce a balancing and an intraday market. This will provide important price signals to potential investors in flexible generation, demand-side response and storage, aiding the development of a flexible grid to better respond to increased renewables penetration.

Systems Under Development

The Irish government has carried out various studies to examine the technical feasibility and cost of achieving various renewable energy penetration scenarios. These studies have established that system security, in particular frequency stability, could be maintained even when variable generation accounted for 50 percent of total system generation. Raising the level of so-called system non-synchronous penetration to 75% was also found to be possible, provided certain grid codes were enhanced, including: generator performance monitoring, resolving high rate of change of frequency (RoCoF) protection, and other measures. To facilitate 75% SNSP, upgrades are being made by the TSOs both in Ireland and Northern Ireland.[120] Examples of these upgrades include a ramping tool, a voltage trajectory tool, an enhanced performance monitoring system, and the development of a long-term operational policy for large-scale demand side management market share.[121]

[119] Eirgrid plc, *Annual Renewable Energy Constraint and Curtailment Report 2016.* 2017.
[120] Flynn, D., M. Power, and M. O'Malley, *Renewables Integration, Flexibility Measures and Operational Tools for the Ireland and N. Ireland Power System.* 2016
[121] Eirgrid plc, *The DS3 Programme Delivering a Secure, Sustainable Electricity System.* 2016.

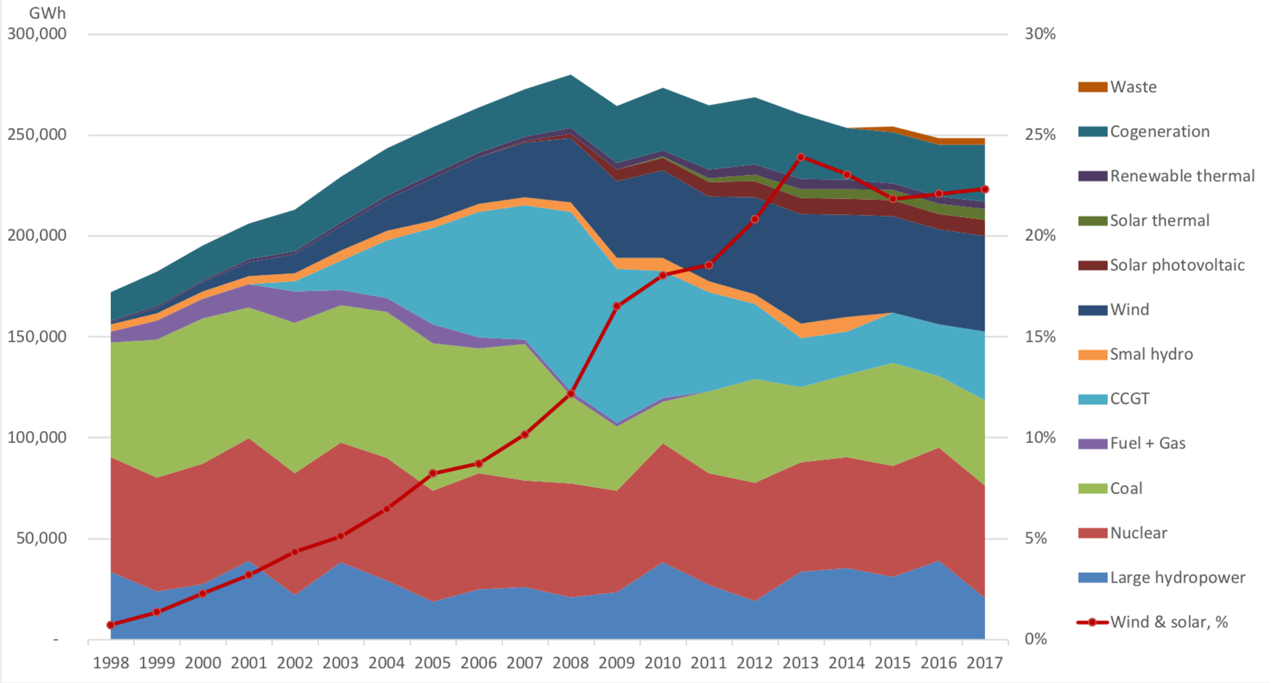
Spain

Market Share of Renewables

Wind and Solar Power Climb, Then Plateau

The market share of wind and solar PV power has doubled in the past decade, to more than 20% of generation in peninsular Spain, excluding the country's offshore islands (see Figure 15 below). Growth has plateaued at around this level since 2013, when the annual average market share peaked at nearly 24%. The latest data from the grid operator, Red Eléctrica de España (REE), shows that the market share of wind and solar PV (not including solar thermal power) in 2017 reached 22.3% of total generation.

Figure 15 Electricity Generation by Source (GWh) and Wind and Solar Market Share (%)



Source: Red Eléctrica de España [122]

Renewable Energy Support

In the decade preceding the global financial crisis, renewables generation support in Spain was excessively generous to developers, a policy that was at least partly responsible for creating a multi-billion-euro obligation to electricity suppliers called the tariff deficit. This deficit arose from the fact that regulated retail power prices or tariffs were much lower than

[122] http://www.ree.es/en/statistical-data-of-spanish-electrical-system/statistical-series/national-statistical-series

system costs for electricity generation and distribution. As a result, suppliers were unable to recover their costs, leading to the deficit.

High system costs were partly due to the premium paid to generators of wind and solar power when these technologies were still in development and relatively expensive. The deficit was also partly a result of low retail prices in the wake of the financial crisis, which saw economic activity and hence electricity demand enter a decade-long period of decline. Since 2012, regulatory and legislative changes have eliminated renewables support, stalling growth. Going forward, the Spanish government has decided to use competitive auctions to contract future renewables capacity, in line with new EU-wide state aid rules. This policy began in 2016. In 2017, such auctions resulted in more than 8 GW of new renewables capacity at globally competitive prices (3,9 GW solar and 4,1 GW wind). All plants will be added to the power system by 2020.

Policy and Power Market Background

Spain's present electricity system stems from its 1997 Electricity Act (Law 24/2013), which liberalized the country's power market. The Iberian Electricity Market (MIBEL) covers both Spain and Portugal, and comprises forward markets managed by OMIP (the Portuguese market operator), and daily and intraday markets managed by OMIE (the Spanish market operator). The market also includes forward markets, ancillary services and a balancing market. The role of REE, the system operator, is to ensure the continuity and security of electricity supply, and to coordinate generation and transmission. REE uses demand and supply forecasts provided by the market operators to balance these in real time.

Most power is traded in wholesale markets, with spot markets accounting for 73.6% of energy exchanged in 2016, with the rest traded through bilateral contracts. The operation of the wholesale market at any moment is determined by a combination of available generation, import capacity, grid operation, demand elasticity and the capacity reserve margin. Electricity traded through daily and intraday markets is paid based on marginal pricing, according to supply and demand. Electricity traded through bilateral contracts or the physical or term market is paid based on the price of the firm's contracted operations in those markets.[123]

In the day-ahead market, electricity producers and resellers submit offers for each hour of the following day, in a process that ends at noon. Sale and purchase offers are matched, starting with the cheapest, until demand is met, thus fixing the price for all power traded in that hour. Bilateral contracts from outside the market are incorporated into the system via a process that analyzes grid operation for each hour of the following day.

Intraday markets allow buyers and sellers to adjust their contract commitments up to four hours prior to real time through six daily auctions. REE incorporates these intraday sessions into its final schedule. Changes required to meet demand in near real time involve primary reserve for small tweaks in frequency (mandatory, non-remunerated), and secondary and tertiary regulation (voluntary, remunerated), for bigger changes in capacity. The Deviation Management Market (voluntary, remunerated) allows reconciliations and resolution of generation and consumption deviations above 300 MWh, following the closure of intraday market sessions.

123 http://thelawreviews.co.uk/edition/the-energy-regulation-and-markets-review-edition-6/1144552/spain

The result of this entire process is the Operational Schedule Program (known as the "P48"). The P48 is published 15 minutes before the hour-long period to which it applies. Based on this final forecast, REE issues instructions to generators to increase or reduce production (through primary reserve or real-time regulation) to balance the system at any moment.

Indicators of Integration Challenges

The Spanish grid faces several challenges related to efficiently and reliably integrating renewable power. On the supply side, these challenges include low interconnection with neighboring countries and low load factors for combined cycle generators, which are an ideal source of flexibility to balance variable renewables. On the demand side, challenges include wide variation in daily consumption between peak and off-peak hours, and a declining overall demand profile. Meanwhile, power market design also could be improved to better integrate variable renewables.

Poor Interconnection

The transmission network is an important tool to integrate wind and solar power, both to smooth variability in supply and to access back-up resources. However, Spain's peninsular location, with only its mountainous Pyrenees connection to France, has resulted in low cross-border grid connections. Spain's interconnection capacity to France is equivalent to just 6% of its installed generating capacity, well below a 10% target set by the European Union for 2020. In 2013, a project was announced for a Spain-France submarine interconnection through the Bay of Biscay to lift the electricity exchange capacity by 80% to 5,000 MW with a commissioning target in 2024-2025.[124]

Low Capacity Factor of Combined Cycle Gas Turbines

Combined cycle gas turbine (CCGT) power plants are more flexible than nuclear and coal power, and therefore more suited to a grid with growing renewables penetration. However, Spain's CCGT fleet has become a victim of the country's capacity glut and declining demand. They produced less than one fifth of their potential maximum generation for the last five consecutive years. Because of lower fuel costs, coal generating units are dispatched more often, even though CCGTs are more flexible. At present, Spain supports flexible back-up of wind and solar through capacity payments for gas, coal, hydro and nuclear. However, we note that these capacity payments may be excessive or even unnecessary and counter-productive, given Spain's massive over-capacity at present.

Variability in Wind and Solar Supply

In Spain, wide variability in wind power generation may lead to a challenging mismatch with demand. In 2016, for example, wind power ranged from a maximum of 52% of total daily generation to a minimum of 3%, in February and October, respectively. Spanish demand also for the first time switched to summer peaking last year. The highest daily peak, of 40,489 MW, was still well below the highest recorded summer peak (of 41,318 MW in July 2010), however.

[124] http://www.ree.es/en/activities/unique-projects/submarine-interconnection-with-france

A permanent switch to summer peaking would see a seasonal mismatch with wind, which tends to be lower in summer months. That could be problematic, given the importance of wind generation in Spain. However, summer peaking would clearly suit solar generation.

Power Market Design

Transparent, functioning intraday and balancing markets are vital to integrate wind and solar power, by providing the clear forward and real-time prices needed to allocate variable and conventional generation efficiently, according to availability. In intraday markets, we note that Spain has a coherent – although not perfect – design. Production choices can be submitted in block- or multi-part bids, as well as in successive auctions, which allows more optimal dispatch by back-up generators. In balancing markets, a higher price is charged for market participants that are short of power in real time than is offered to market participants that are long. While the aim is to create incentives for market participants to provide accurate schedules, it may make more sense from the point of view of rewarding flexibility to have a single price, given that flexibility to decrease generation, when wind and solar are available, is as important as increasing generation when they are unavailable. At present, balancing markets are one-hour long. This contrasts with 30 minutes in the United Kingdom, 15 minutes in Germany, and five minutes in Texas. A shorter scheduling period in Spain would be a step forward, particularly as it would help reduce renewable generation forecasting errors. It should be noted that market-design rules can make the operation of a power system more or less efficient but cannot make up for significant structural deviations in factors such as the available generation mix, import capacity, grid operation, demand elasticity and the reserve margin.[125]

Indicators That Spain's Grid is Coping

Power outages in Spain, as measured by the World Bank's SAIDI score, are low and in line with peer countries by income. Spain's average SAIDI score (of average annual power outages per customer in Madrid) was 0.37 hours from 2013-2015, putting the country in the top quartile of performers globally.

In another indicator that the system is coping, system costs for managing system imbalances/deviations have fallen in the past three years, after peaking in 2014. These costs are incurred when the grid operator must pay generators to increase or reduce generation, to cover a shortfall or surplus of supply. The total cost of all so-called system service adjustments fell to €2.36 per MWh of electricity supplied in 2017, from €3.76/MWh in 2010, according to REE.[126]

[125] http://thelawreviews.co.uk/edition/the-energy-regulation-and-markets-review-edition-6/1144552/spain
[126] http://www.ree.es/en/statistical-data-of-spanish-electrical-system/statistical-series/national-statistical-series

Factors That Have Favored Integration

Flexible Back-Up

Research shows that annual wind power curtailment is strongly related to excess wind energy production, as well as with periods of low power demand.[127] To reduce wind power curtailment, and so increase the cost-effectiveness of renewables integration, some level of grid system flexibility is vital. Spain has significant flexibility in electricity supply, including hydropower, pumped hydro power (PHP) energy storage, and CCGTs. Spain is also a world leader in solar thermal power (or concentrated solar power, CSP), which provides dispatchable electricity and accounted for 2.2% of total generation in peninsular Spain in 2017. However, the country also has low interconnection capacity.

Over-Capacity

In theory, over-capacity should favor integration of variable renewables, by providing back-up generation when wind and solar power are unavailable. Certainly, Spain does have over-capacity at present. In general, grid operators target a surplus of generating capacity over peak electricity demand of around 15%. In Spain, this capacity margin is presently around 30%. However, as we noted above, Spain's over-capacity has in fact undermined the country's most flexible generation, its CCGTs. As a result, the country's over-capacity has proved something of a double-edged sword concerning the issue of integrating the country's renewables.

Investment in the Grid

REE, the Spanish grid operator, is investing in expanding the network, and so progressively reducing the amount of unserved energy in the system. According to REE, the total length of high-voltage transmission lines in Spain has increased by 13% since 2010, to 40,767 kilometers. The volume of unserved energy has fallen by 96% since 2010 (a poor year, admittedly).[128]

Growing Participation of Renewables in Liquid Power Markets

Spain has functioning day-ahead, intraday and balancing markets that ensure demand and supply are balanced transparently. We identify two features of Spain's intraday markets that favor balancing renewables. First, the intraday markets allow buyers and sellers to adjust their contract commitments up to four hours prior to real time, through six daily auctions. These auctions provide six options every day to update generation assets, according to information on outages and renewable and demand forecasts (Rodilla and Battelle, 2015). Neuhoff et al. argue that these auctions, and their uniform price and standardized trading times, are especially beneficial to small players without sophisticated trading departments operating 24/7. In other words, they bring more resources to the table for balancing renewables.

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[127] Martin Martinez et al (2015).
[128] http://www.ree.es/en/statistical-data-of-spanish-electrical-system/statistical-series/national-statistical-series

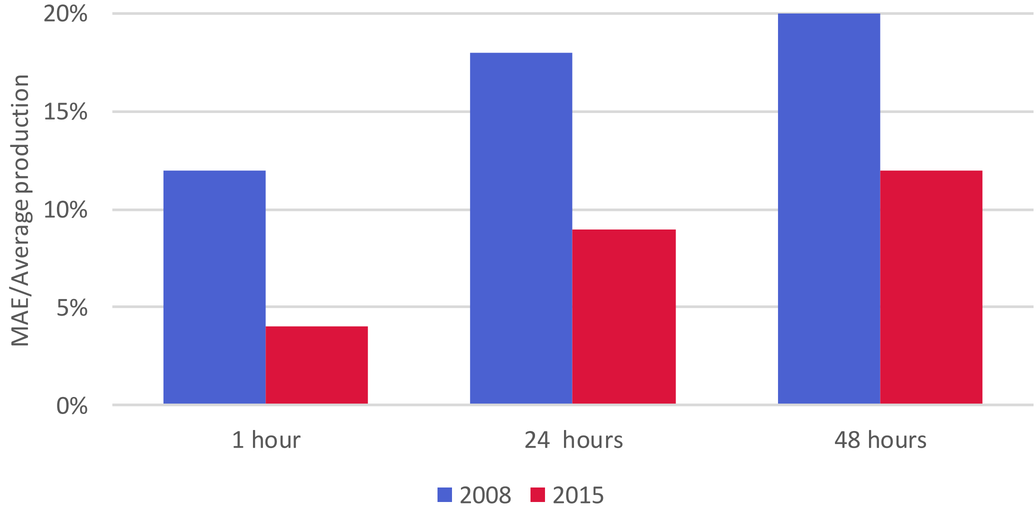
Because auctions typically allow for a longer calculation time, compared with continuous trading, they ensure more accurate execution, considering technical and economic factors. The result is improved liquidity, as compared with central and western European power markets, which are based on continuous intraday trading (Hagemann and Weber, 2015). Second, the auctions allow so-called multi-part bidding, where the bidder includes information on multiple parameters, including start-up cost, minimum load requirement and ramping rate. In this way, the auction can reward the most flexible generation best suited to balancing fast-changing variable wind power (Reguant, 2014).

In addition, since February 2016 renewable energy operators have been allowed to sell balancing services in addition to trading power in the intraday auctions. Encouraging renewables to participate in grid balancing in this way takes some of the strain off the rest of the electricity system.

Better Wind Forecasting

The integration of wind resources has been further aided by improvements in forecasting, as seen in Figure 16 below. The national forecasting system, Sipreolico, provides hourly wind production forecasts for up to 10 days ahead. According to REE, between 2008 and 2015 the percent mean absolute error (MAE) has halved at the 24-hour prediction horizon, falling from 18% to 9%. An equivalent system, called Sipresolar, uses neural networks to improve forecasts for solar energy production, providing two sets of forecasts: one for PV and one for concentrated solar power.

Figure 16: Wind Forecast Improvements in Spain



Source: REE [129]

[129] http://www.ieawindforecasting.dk/-/media/Sites/IEA_task_36/BCN-2016/IEAWindTask36-ExpGapsForecastingWorkshop_Barcelona_Rodriguez_2016.ashx

Texas

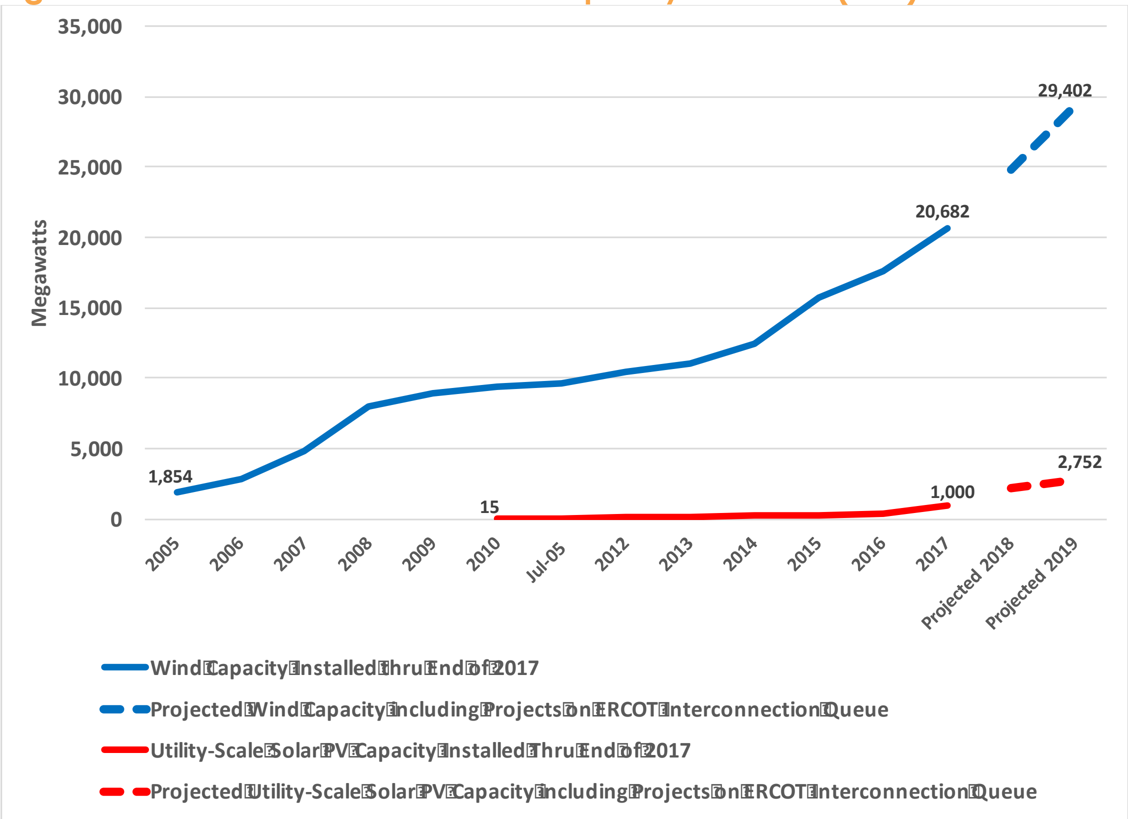
Market Share of Renewables

ERCOT, the Electric Reliability Council of Texas, was created in 1999 as part of the restructuring of the Texas electric market. ERCOT serves 90 percent of the electric load in Texas through an energy-only wholesale electricity market; there is no capacity market.

The Texas legislature also established a renewable portfolio standard in 1999 (updated in 2005) that mandated that 5,000 MW of new renewable capacity be installed by 2015, with a goal of 10,000 MW by 2025.[130] The state has blown past these goals, as nearly 12,000 MW of wind capacity had been installed by 2015, and more than 20,000 MW of wind and 1,000 MW of utility-scale solar capacity had been installed by 2017.

Growth of variable renewables in Texas has been driven by plentiful wind and solar resources, and the presence of landowners keen to maximize the value of their land, just as they have hosted oil derricks and related facilities for several generations. In addition, because wind and solar projects don't produce air and water emissions, they don't have to go through an extended environmental permitting process. This has accelerated licensing and construction.

Figure 17: Installed Wind and Solar Capacity in ERCOT (MW)

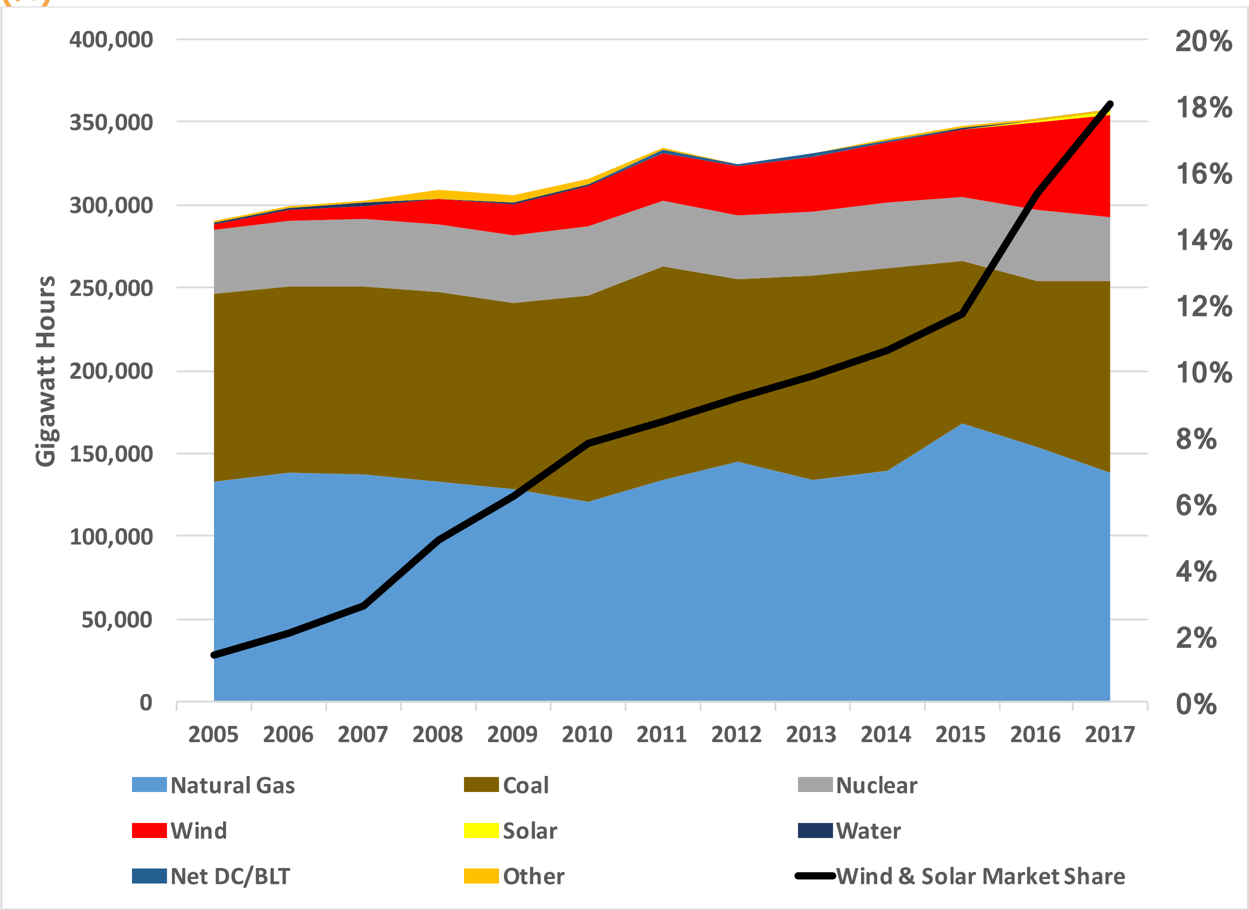


Source: ERCOT

130 https://energy.gov/savings/renewable-generation-requirement.

The growth in installed capacity has led to increased generation from wind and solar PV facilities and a dramatically higher market share for these renewable sources. Thus, wind and solar PV's market share has grown from a mere 1.2% in 2005, past 10% in 2014 and reached 18% in 2017. It is important to note that the market share of wind and solar PV resources would be even higher if it included distributed rooftop solar facilities.

Figure 18: Electricity Generation by Source (GWh) and Wind and Solar Market Share (%)



Source: ERCOT

ERCOT achieved record wind generation of 17,376 MW, at 3:34 P.M. on January 11, 2018. It saw record wind penetration of 54.22% of load at 4 A.M. October 27, 2017. Given the additional wind capacity on the way, these records are certain to be broken in the future.

It seems certain that much more wind and solar are coming. ERCOT's December 2017 Generator Interconnection Status Report (GIS) shows another 8.72 GW of wind and 1.25 GW of solar in the queue for addition to the grid by the end of 2019. The GIS report also shows that a total of 30 GW of new wind and 24 GW of new solar projects are under study by ERCOT. What must be considered a tsunami of new renewable resources is going to hit Texas in coming years. Meanwhile ERCOT's December 2016 Long-Term System Assessment projected that total solar additions by 2031 would range between a low of 14,500 MW and a high of 28,100 MW.[131]

Indicators of Integration Challenges

The main challenge to the integration of renewable resources in Texas has been, and continues to be, that those areas with the highest potential for wind and solar are in the west and northwest regions of the state, far from load centers where the power is needed.

Regarding the location of wind resources, the Panhandle in northwestern Texas is a prime location for wind generation development, due to favorable wind conditions.[132] Extensive transmission planning was historically successful in providing a route to market for this wind generation, as described below. In recent years, however, there has been a significant increase in the amount of new wind capacity in the Panhandle, both operating and future plants committed for construction. Congestion has increased dramatically and is expected to continue to rise. Two transmission improvements were under way at the end of 2017. However, these projects were not expected to eliminate the congestion in the area.[133] Additional lines and upgrades will be needed.[134]

Additional transmission also will be needed to bring to market all the solar PV capacity that is poised to be added in ERCOT. Unfortunately, the CREZ transmission improvements do not extend into the best solar resources in far southwest Texas.[135] For example, of the 24,700 MW of solar generation projects under study by ERCOT as of November 2017, almost 10,000 MW were in the far western part of Texas. Transmission line upgrades also will be required because the addition of solar generation in the western part of Texas coupled with the expected retirement of significant coal and natural gas-fired generation in the eastern part of the state could result in substantial increases in west-to-east power flows on the transmission system.[136]

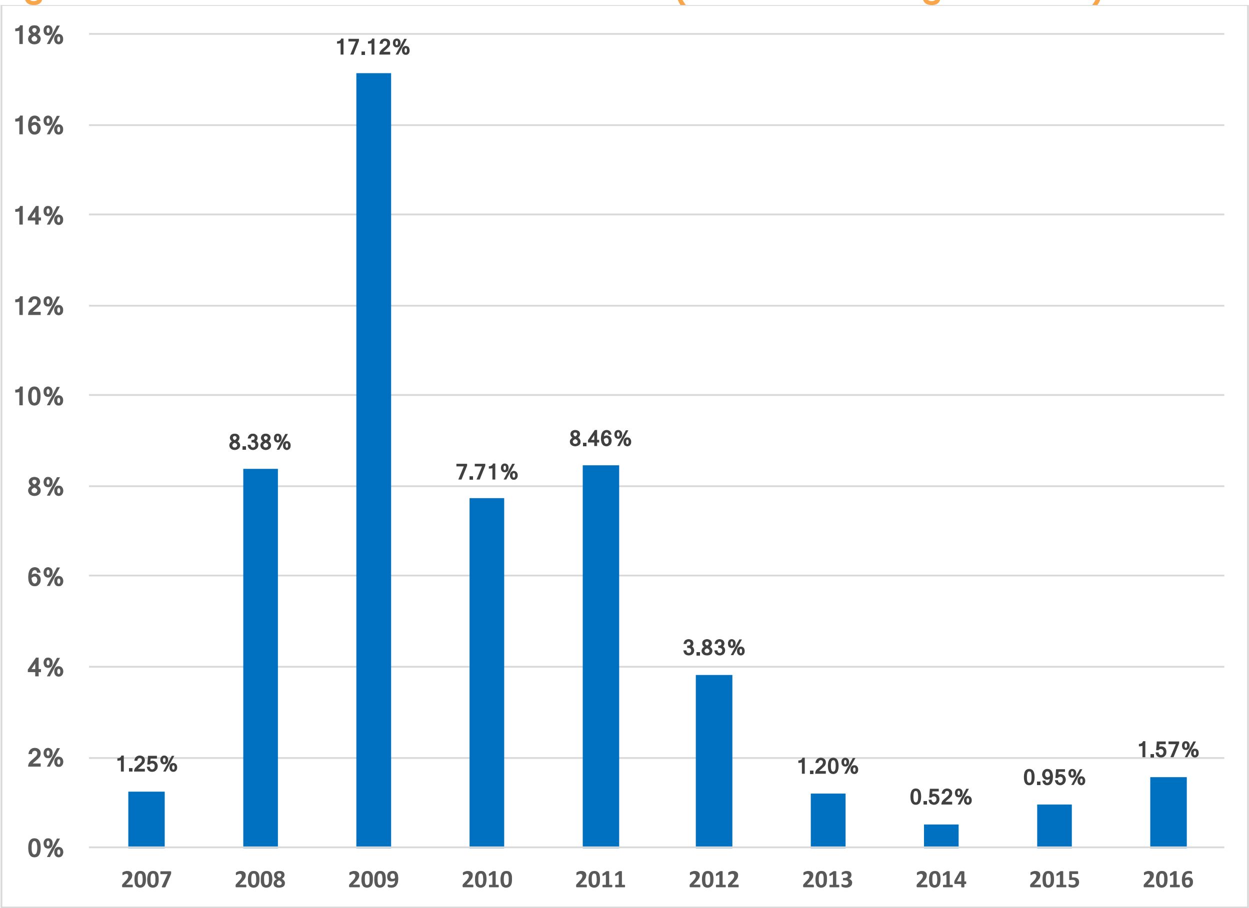
Indicators That Texas' Grid is Coping

There are two main indicators that the grid is coping with all the new wind and solar PV capacity presented in Figure 17 above. First, there has been no degradation in system reliability, even in 2017 when Hurricane Harvey hit the state or, more recently, in the cold weather of January 2018.

Second, wind curtailments declined dramatically once the new CREZ transmission lines were completed in early 2014.

[131] http://www.ercot.com/content/wcm/lists/89476/2016_Long_Term_System_Assessment_for_the_ERCOT_Region.pdf
[132] *Report on Existing and Potential Electric System Constraints and Needs*, ERCOT, December 2017. Available at http://www.ercot.com/content/wcm/lists/114740/2017_Constraints_and_Needs_Report.pdf.
[133] Id.
[134] *ERCOT Transmission Planning Assessments*, December 2017. Available at http://www.ercot.com/content/wcm/lists/114740/OnePager-Constraints_and_Needs_December_2017_FINAL.pdf.
[135] *Integrating New Technologies in ERCOT: Successes and* Challenges, Presentation of Warren Lasher, Senior Director, System Planning, at IEEFA Energy Finance 2017, March 14, 2017.
[136] *2016 Long-Term System Assessment for the ERCOT Region*, December 2016. Available at http://www.ercot.com/content/wcm/lists/89476/2016_Long_Term_System_Assessment_for_the_ERCOT_Region.pdf

Figure 19: Annual ERCOT Wind Curtailments (% of total wind generation)



Source: ERCOT

(Note: The rise in curtailments in 2008 was due to a lag in the completion of new transmission lines following the construction of new wind capacity. This situation changed once the CREZ lines were in service.)

Factors That Have Favored Integration

Transmission Planning

The challenge of integrating resources located far from load centers has been addressed through extensive transmission planning. In 2005, in response to interest from wind developers in the vast wind-rich areas in western Texas, the state legislature created Competitive Renewable Energy Zones (CREZ) and directed the state's public utility commission (PUCT) and ERCOT to determine, first, which parts of the state are optimal for renewable power generation, and second, to build transmission lines to those areas. Ultimately 3,600 miles of CREZ transmission lines were built, at a cost of $6.8 billion. The last CREZ transmission line came online in early 2014. As illustrated above, wind curtailments declined sharply after the CREZ transmission lines were built. CREZ lines are open access. If a generator clears the energy market, meaning if the system operator accepts their offer to generate power, they have access to transmission for the period in which they have cleared.

Additional transmission upgrades have been authorized as the amount of wind connected to the grid has grown. The CREZ plan was to build 345-kV transmission lines and upgrades to add 18,500 MW of new wind to the system, but it is now reaching that limit. As a result, congestion is rising, as not all the wind-generated power can reach the loads where it is needed. This problem is expected to grow in coming years as more wind and solar capacity is added.

Transmission planning in ERCOT went beyond recognizing the need for long-distance, high-voltage transmission lines. Analyses evaluated how many megawatts of new renewables (initially wind) would come online and where and when. There was no siting process to slow the design and construction of the new CREZ transmission lines. While this accelerated their completion, it also led to the defacement of many pristine areas that might have been avoided through more prudent evaluation of environmental impacts.

Finally, ERCOT is in some ways an island – with limited interconnections to neighboring balancing areas. While we have stressed generally in this report the advantages of interconnection, for balancing variable renewables, from a study/modelling perspective, ERCOT administrators note that having little interconnection can allow a better idea of how modelled changes will work if/when put into practice.

Load Matching

Load matching refers to the degree to which the availability of wind and/ or solar power matches demand. The closer they are matched, the less likely system operators will have to shift demand or supply, for example using battery storage or demand response.

Texas has two main categories of wind. Onshore coastal wind is located in southeast Texas along the Gulf Coast. Texas' non-coastal wind resources are in the western part of the state. Coastal wind is far more likely to generate a substantial amount of power during peak periods in the middle of the day. Non-coastal wind generally produces the most power during the night-time hours, when loads are low.

ERCOT reports average capacity factor during the top 20 peak demand hours annually. Capacity factor refers to actual generation as a percentage of the theoretical maximum. The ERCOT data show coastal wind capacity factors during these peak hours has on average been more than four times greater than non-coastal wind over the last eight years during these peak hours. The average capacity factor of coastal wind was 59%, compared with 14% for the non-coastal resources.

Similarly, the generation from solar PV power in Texas corresponds with peak demand in the middle of the day. ERCOT data show that solar PV has an average capacity factor of more than 75%, during the 20 highest load peak hours.

However, ERCOT does face a potential duck curve, with oversupply of generation leading to negative prices and/or curtailments of renewable resources in the midday if, as expected, huge amounts of solar come on-line. This is an issue that ERCOT will have to address, just as CAISO is addressing the issue of oversupply due to new utility-scale solar resources during daytime hours in California. The problem for ERCOT is that, unlike CAISO, it is essentially an island with few interconnections to neighboring balancing areas. Consequently, unlike CAISO, ERCOT will have very limited opportunities to create an energy imbalance market that will allow it to export excess renewables generation to other markets.

Market Design

There are various market design features that have favored grid integration of renewables in Texas.

1. Open access to the transmission system: once a generator has received approval from ERCOT, and successfully bids into the energy market, it has access to the transmission system. This contrasts with a situation where incumbent utilities have rights to transmission, and renewables get the leftovers. The underlying plan of ERCOT was not for wind to take over. The plan was to reduce the cost of power for ratepayers by allowing new technologies to have equal access and to give every technology the right to compete.
2. All resources, including wind, participate in the ERCOT day-ahead and real-time markets. All parties are responsible for ramping and dispatch capability. The fleet (fossil and renewable) is relied on to address variability in loads and resources.
3. ERCOT requires wind generators to provide inertial response, which helps keep the system stable in the initial moments after a disturbance.[137]
4. The real-time balancing market has been shortened to five minutes from the previous 15-minute intervals. Market rules also were modified to allow updates to generation schedules (gate closure) until 10 minutes or less before the dispatch period, which greatly minimizes forecast errors.[138]
5. ERCOT's dispatch software includes an automatic process of ex-ante mitigation of market power.[139] A special scarcity pricing mechanism is deployed that allows energy prices to rise to a very high level in case of a shortage of short-run capacity in meeting the demand for electricity and operating reserves.
6. Wind and solar resources may submit negative bids to address periods of oversupply and to reduce the need for manual curtailments. Generation oversupply already has contributed to instances of system-wide negative pricing in the middle of the night and the potential for oversupply in the middle of the day (the duck curve) grows as more solar PV resources are added.
7. ERCOT relies on state-of-the-art wind forecasts. In addition, ERCOT posts day-ahead and intraday forecast system conditions that can be used in unit commitment and dispatch.[140]
8. Reductions in output (downward dispatch) for wind and solar resources in ERCOT most often occur automatically as part of normal outputs from ERCOT's security-constrained economic dispatch machine. However, ERCOT may issue verbal dispatch instructions to specific resources in special circumstances, in which case the resources may be given special compensation based on the settlement prices in effect during the time of the instruction.[141]

[137] https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf (page 85)

[138] *Wind and Solar Energy Curtailment: Experience and Practices in the United States*, March 2014, at page 9. Available at https://www.nrel.gov/docs/fy14osti/60983.pdf.

[139] page 22 http://iea-retd.org/wp-content/uploads/2016/09/RES-E-MARKETS-presentation-1.pdf

[140] *Wind and Solar Energy Curtailment: Experience and Practices in the United States*, March 2014, at page 9. Available at https://www.nrel.gov/docs/fy14osti/60983.pdf.

[141] *Wind and Solar Energy Curtailment: Experience and Practices in the United States*, March 2014, at page 9. Available at https://www.nrel.gov/docs/fy14osti/60983.pdf.

9. ERCOT obtains half of its spinning reserves from demand response (DR) and is considering a DR-based fast frequency response service that is position between inertia and governor response.[142]

California

Market Share of Renewables

The California independent system operator (CAISO) was established in 1998 as part of the state's electricity market restructuring. It now includes 80% of the state's electric load.

Penetration of renewables in CAISO has skyrocketed in recent years in response to renewable portfolio standards (RPS) adopted by the California state legislature beginning in 2002. The RPS has grown from requiring that 20% of retail sales be served by renewable energy resources by 2010 to the current requirement, adopted in 2015, that 33% of sales be from renewables by 2020 and that 50% come from renewables by 2030.[143] Even more aggressive RPS goals have been considered by the legislature. For example, Senate Bill 100 (SB100) would increase the renewable power mandate to 60% (from 50%) by 2030 and 100% by 2045, including hydropower. SB100 failed to pass the state legislature last September but may be considered again in 2018.

The RPS has led to a tremendous growth in installed solar PV capacity delivered by CAISO, growing to more than 11,000 MW as of early 2018.[144] An average of 2,000 MW were installed annually in each of the last three years.[145] Some 1,100 MW of new solar PV resources were added in just the last 3-4 months of 2017.[146] Even more solar PV capacity is under construction as the state moves to meet the 2020 and 2030 RPS goals. The present 11,000 MW of installed solar PV capacity only reflects the utility-scale resources that are delivered by CAISO. There is another 5,000 to 6,000 MW of distributed rooftop solar capacity that is not included in this total.

The growth in solar generation shown in Figure 20 has meant that the percent of system energy provided by renewable solar PV and wind resources directly-connected to CAISO tripled from 2012 to 2016. The market share of solar PV increased some eight-fold in just those four years.

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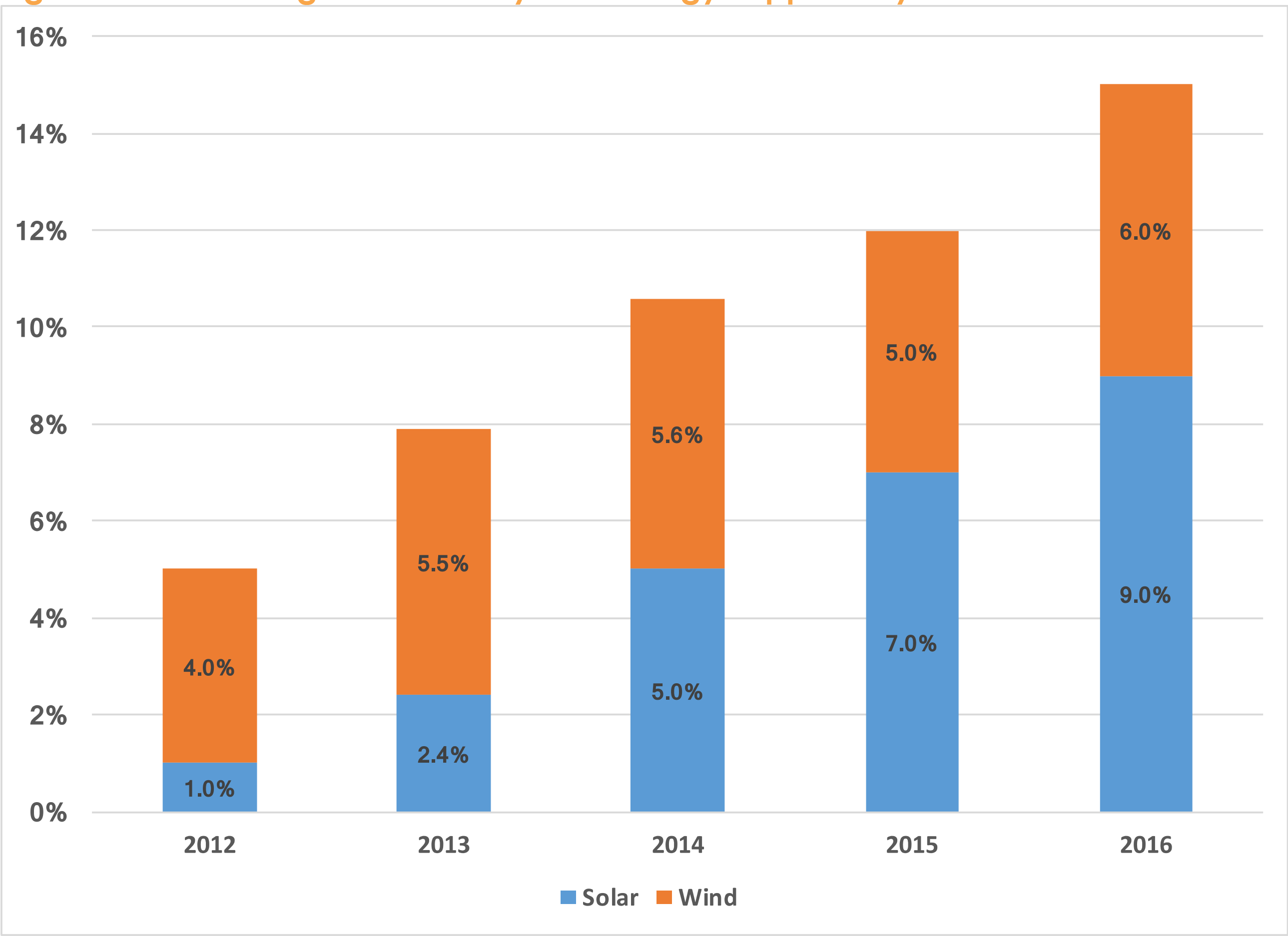
[142] http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Concept%20Paper.pdf (page 15)
[143] California Senate Bill 350, signed in October 2015.
[144] http://www.caiso.com/Documents/December2017MonthlyStats.pdf.
[145] https://www.caiso.com/Documents/CurtailmentFastFacts.pdf.
[146] Comparison of installed capacity in CAISO's September 2017 and December 2017 Monthly Stats. See http://www.caiso.com/Documents/September2017MonthlyStats.pdf and http://www.caiso.com/Documents/December2017MonthlyStats.pdf.

Figure 20: Percentage of CAISO System Energy Supplied by Wind and Solar



The record peak for solar was 9,914 MW at 12:13 p.m. on June 17, 2017, breaking the record of 9,892 MW set just a month earlier.[147] This record likely will be topped on many occasions in 2018 and later years. The record peak for wind was 4,985 MW at 5:56 p.m. on May 16, 2017. Renewables set the current record of serving 67.2% of CAISO system demand on May 13, 2017 at 2:55 pm,[148] with solar and wind alone accounting for 58.7% of system demand at that time.[149]

Indicators of Integration Challenges

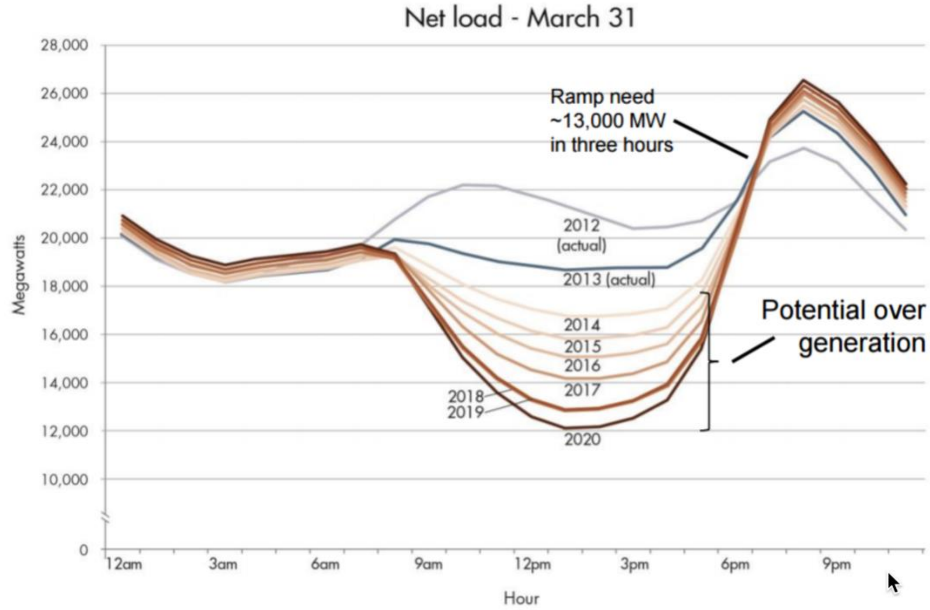
Oversupply and the Duck Curve

Oversupply of electricity generation has emerged in CAISO because of excess renewable energy compared with customer demand. Such oversupply is happening throughout the year, with its daily form taking the shape of the now-famous duck curve.

[147] http://www.caiso.com/Documents/December2017MonthlyStats.pdf.
[148] Id.
[149] Id.

As can be seen in Figure 21 below, soon after the sun rises, the net load (referring to demand minus wind and solar generation) begins to decline steeply as solar resources generate more power.

Figure 21: The Duck Curve on a Typical Day



Net load falls further through the morning hours as more energy from renewable solar resources comes onto the grid, leading to oversupply during the middle of the day, when solar generation is the highest (as shown by the duck's belly in the graphic above). To cope, system operators increasingly have resorted to curtailing solar resources during these periods.

CAISO describes the problem of midday solar oversupply as follows:

> "More like the canary in the mine: it is showing us that as each year goes by, the risk rises that midday over-generation will occur, which undermines grid reliability as well as driving up costs."[150]

The continual solar additions also are making the morning down ramp and evening up ramp for conventional generation steeper, adding to CAISO's operational concerns by increasing the need for fast-ramping capacity. These issues are exacerbated on the weekends when system loads are lower. The duck curve, which used to be mostly a spring issue when demand was generally low and hydro generation was at its peak, is also now occurring throughout the year.

According to CAISO, average hourly prices in both the day-ahead and real-time markets now reflect the load pattern of the duck curve throughout the year. The highest prices are during the morning and evening ramping hours and some of the lowest prices are experienced during the midday hours when solar output is highest.[151]

[150] http://publications.caiso.com/StateOfTheGrid2014/RenewablesIntegration.htm
[151] CAISO 2016 Annual Market Issues and Performance Report, at page 1.
http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf

Renewable Generation Curtailment

Currently, CAISO says its most effective tool for managing oversupply is to curtail renewable resources. Curtailment refers to the scaling back of generation when there is insufficient demand to consume total production. It is calculated by subtracting the energy that was produced from the amount of electricity forecasted to be generated.

Renewable generation is curtailed in two ways: either via economic curtailment, which is an automatic process performed by CAISO's dispatch model, or manually when the ISO orders generators to reduce their output. Regarding economic curtailment, the energy market generally selects the lowest cost power resources. Renewable resources can bid into the market in a way to reduce production when prices begin to fall. This is a normal and healthy market outcome. Self-scheduled curtailment is triggered and prioritized using operational and tariff considerations. Such economic curtailments and self-scheduled cuts are considered market-based, because the ISO's market optimization software automatically adjusts supply with demand. However, if market-based solutions fail to clear the surplus of electricity, the last resort is for the ISO to manually intervene. When ISO operators intervene in this fashion (which is also known as exceptional dispatch), they can direct specific renewable plants to reduce output to prevent or relieve conditions threatening grid reliability. An exceptional dispatch order is considered manual curtailment, because the ISO operators intervene.

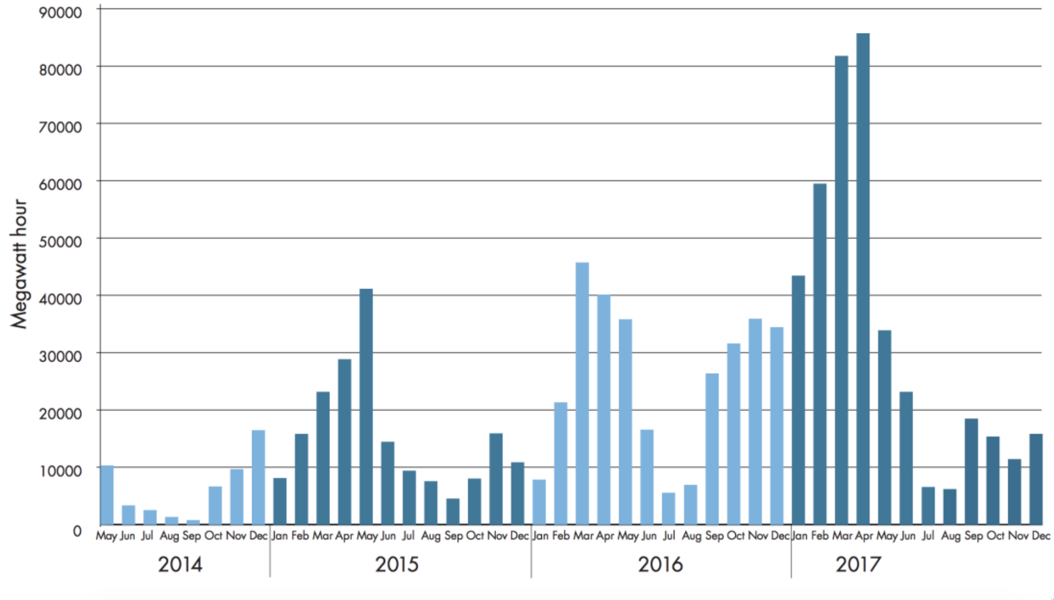
In one sense, curtailment may be considered a positive tool, since it addresses excess electricity supply.[152] However, curtailing renewables results in lost opportunities for clean resources to generate all the carbon-free power that otherwise could be produced. Curtailment also fails to ensure that the lowest cost resources are called upon to serve Californians.[153] Better solutions are needed to address oversupply.

Curtailment of wind and solar generation is still relatively low on a percentage basis: 1.2% of wind and solar generation in 2015, 1.6% in 2016, and about 3% in the first quarter of 2017. Although, as CAISO notes, during certain times of the year, it's not unusual to curtail 20 to 30% of solar capacity. On March 11, 2017, for example, solar curtailment exceeded 30% for an hour.[154]

While curtailments are small percentage-wise, they are important and are going to rise as additional solar PV resources are added in the CAISO footprint to achieve its 50% renewable target.

[152] https://www.caiso.com/Documents/CurtailmentFastFacts.pdf
[153] Id.
[154] Id.

Figure 22: Monthly CAISO Renewable Curtailments (2014-2017)



Indicators That California's Grid is Coping

There are several indicators that the CAISO grid is coping with the increasing share of renewable resources as it moves toward the RPS goal of 50% by 2030:

- Weather-related events, T&D equipment failures, and accidents are the main factors behind major system outages—not growing utility-scale and distributed solar PV resources.[155]
- Generation outages, both forced (unscheduled events such as when there is a plant failure) and scheduled (for maintenance, for example) have fallen recently. In 2012 annual generator outages (in MW) totalled 13,500 MW (of which 4,600 MW were forced); in 2016 the total had dropped to 11,000 MW (3,000 MW forced).[156]
- CAISO has cited increased solar generation as one of the main factors behind lower wholesale power prices, alongside other significant factors such as natural gas prices and hydroelectric generation. For example, CAISO's 2016 Annual Report noted: "Market prices were kept low and highly competitive by improved hydroelectric conditions, moderate load and the addition of about 2,300 MW of summer capacity-consisting mostly of solar generation."[157]
- As noted earlier, total wind and solar curtailments have remained low, at 1.6% or lower in 2015 and 2016.

[155] See http://www.cpuc.ca.gov/2016_aers/.
[156] CAISO Annual Reports on Market Issues and Performance, available at http://www.caiso.com/market/Pages/MarketMonitoring/MarketIssuesPerfomanceReports/Default.aspx.
[157] http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf, at page 1.

Factors That Have Favored Integration

California already has introduced several important measures to minimize oversupply and renewable energy curtailments. In addition, it is now taking new steps to move toward the mandated goal of providing 33% of system energy from renewable resources by 2020 and 50% by 2030.

Allowing Negative Prices

During times of oversupply, wholesale energy market prices can be very low and even go negative at which time generators must pay utilities to take the energy from their fossil or renewable facilities.[158] Negative pricing is a market-based strategy used to address over-generation. A negative price for power sends a signal to generators to curtail their output or pay to generate during periods when the system does not need power. Negative prices dissuade generators from bidding in too much power when the system cannot handle it and improve the economic viability for deployment of storage technologies.

For some resources it is too expensive to shut down, so they continue generating even when they must pay to do so.[159] This is true for wind and solar resources that can profit even with negative pricing due to federal tax credits.

There were low system loads and oversupply due to very high hydroelectric and solar generation during the first quarter of 2017. According to CAISO's Department of Market Monitoring (DMM), this led to consistently negative prices in the day-ahead market during the key midday hours (10-17) and also caused frequent negative prices in the real-time markets during those same hours.[160]

Prior to this quarter, negative prices had occurred in the day-ahead market during only a few hours since the market was created in 2009.[161] In the first quarter of 2017, day-ahead negative prices as low as -$15/MWh occurred in more than 10% of all hours between 10 a.m. and 5 p.m., according to CAISO.[162] As a result, average prices in the day-ahead market in the first quarter of 2017 were far lower than the prices during the same period in 2016, despite a significant increase in the price of natural gas.[163]

At the same time, the day-ahead prices during the morning and evening ramping hours were up to $10 per MWh higher than during the same period in 2016. This reflected the significantly higher gas prices, as well as the steeper upward ramp of net load on the CAISO system during the late afternoon hours.[164]

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158 http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

159 Utility Dive, May 11, 2017, *A rainy winter and growing solar have CAISO prices going negative and renewable energy going to waste—what should policymakers do?*

160 http://www.caiso.com/Documents/AgendaandPresentation-DMMFirstQuarterMarketIssuesandPerformanceReport-Jul312017.pdf

161 http://www.caiso.com/Documents/Department_MarketMonitoringUpdate-Memo-May2017.pdf

162 Id.

163 Id.

164 For example, during the first quarter of 2017, the average monthly maximum 3-hour ramp grew nearly 25%-from about 10,130 MW in 2016 to 12,500 MW in 2017. This was because the system net loads were lower due to the increased renewables generation.

Increased Energy Storage

Pursuant to California Assembly Bill 2514, the CPUC in 2013 created a program under which the state's three investor-owned utilities (IOUs) must procure 1.3 GW of energy storage by 2020. Assembly Bill 2868, further requires each of the three IOUs to deploy an additional 166 MW of behind-the-meter and/or distributed tied storage.[165]

Greater Regional Coordination to Expand CAISO's Footprint

CAISO and PacifiCorp launched the western Energy Imbalance Market (EIM) in November 2014. The EIM extends the real-time balancing features of CAISO's market to areas outside the grid operator's footprint. There are currently six members in the EIM spread across eight western U.S. states, with another five members expected to join by 2020. According to CAISO, increased transfers between balancing areas in the EIM in 2016 helped increase the efficiency of generation dispatch across all the balance areas, reduce the need to curtail renewable generation in the ISO and lower the frequency and magnitude of negative prices. The capability to export renewable generation out of CAISO through the EIM reduced curtailments by 502,357 MWh from Q1 2015 through Q3 2017.[166]

Regional coordination clearly does have the potential to produce substantial benefits and to enhance the broader penetration of renewable resources. However, some environmental groups also are concerned about the potential for leakage under the EIM, and under a proposal for a regional ISO. The concern is that while regional coordination might mean additional renewable resources would flow to California to meet its RPS goals, the exports to California could also be replaced by additional generation from fossil-fired units in the exporting states. This could be a spur to the continued operation of some coal and natural gas-fired plants. Although CAISO data suggest that the direct import of fossil-fired generation into California through the EIM has been reduced using a GHG adder, the potential for leakage remains.[167]

Steps to Boost System Flexibility

Regulatory frameworks overseen by the California Public Utilities Commission (CPUC) are in place to ensure system reliability with increased amounts of renewable solar and wind. A resource adequacy requirement ensures that electric utilities have sufficient capacity to meet system demands. This includes enough flexible capacity to follow the power system ramping up or down, depending on load and variable generation.

CAISO also has introduced market reforms to incentivize flexibility. These have included measures to boost flexible ramping capacity and a demand response auction mechanism.[168]

Over time, it is likely that renewables themselves will provide the required flexibility, for example through technical changes that encourage wind and solar to respond to changes in grid frequency. In 2016, CAISO, the U.S. National Renewable Energy Laboratory and First

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165 https://www.utilitydive.com/news/an-inside-look-at-using-energy-storage-to-integrate-renewable-resources/505054/.
166 http://www.caiso.com/Documents/December2017MonthlyStats.pdf.
167 http://www.caiso.com/Documents/MarketPerformanceReportforNovember2017.pdf, at pages 51 and 52.
168 http://www.energy-transitions.org/sites/default/files/Low-cost-low-carbon-power-systems.pdf

Solar analyzed the performance of a 300 MW solar PV plant in three areas: frequency control, voltage control, and ramping capacity. They demonstrated that renewable energy plants can provide electric reliability services similar, or in some cases superior to, conventional power plants, according to CAISO.

As the ISO's senior advisor for renewable energy integration explained:

> "These findings mean renewable energy in the ISO footprint and beyond could be integrated into power grids at a much higher level and faster pace than once believed, giving a glimpse at the future green and sustainable electric networks… With these results, the electric industry can expect one day to realize ambitious goals of using primarily renewable resources to power our economy."[169]

In addition, CAISO adopted grid operational improvements in May 2014 that shortened the time frame between creating a renewable generation forecast and actual generation. As CAISO has explained, this has provided a more accurate forecast of the renewable energy expected, so other resources can be dispatched to meet demand.[170]

Enhanced Demand Response and Energy Efficiency

Demand-side initiatives can reduce consumer demand at times when supply is low. For example, time-of-use tariffs can encourage customers to align their electricity use with peak solar power generation, during the day, and to avoid use where possible during the morning and evening ramping periods.

Long-Term Planning

CAISO and the CPUC provide clear guidance as to the goals for the integration of renewables, including participation by a range of stakeholders. Under a long-term procurement planning (LTPP) process, the CPUC reviews utility plans to ensure that enough capacity, including flexible capacity, will be built. A key aspect of the CPUC review is to evaluate whether the LTPP plans include enough flexibility to accommodate projected levels of renewables while ensuring adequate levels of system reliability.

Similarly, the CPUC reviews utility plans to upgrade their distribution systems to integrate increasing amounts of cost-effective distributed generation, including how to manage new developments such as demand response, storage, smart inverters, two-way power flows, and microgrids. The integration of increasing amounts of renewable generation has been facilitated by the existence of an extensive transmission grid in California, including system upgrades, the addition of new lines and links to neighboring balancing areas.

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[169] http://www.caiso.com/Documents/TestsShowRenewablePlantsCanBalanceLow-CarbonGrid.pdf and https://www.caiso.com/Documents/UsingRenewablesToOperateLow-CarbonGrid.pdf

[170] http://www.caiso.com/Documents/ManagingAnEvolvingGrid-FastFact.pdf.

Tamil Nadu

Market Share of Renewables

Wind and solar accounted for 14.3% of Tamil Nadu's total electricity generation in 2016/17 (13.9 TWh out of the 97 TWh total).

The state leads India in variable renewables market share. Tamil Nadu also leads India in installed renewable energy capacity. Of the total 30 GW of installed capacity across the state as of March 2017, variable wind and solar power accounted for 9.6 GW or 32% of the total. Firm hydroelectricity added another 2.2 GW or 7%, nuclear 8% and biomass and run of river 3%. As such, zero emissions capacity represents a leading 50% of Tamil Nadu's total. With much of Tamil Nadu's renewable energy coming from end-of-life wind farms installed 15-25 years ago, average utilization rates are a low 18%, making the contribution of variable renewables to total generation even more impressive.

Tamil Nadu was the host of the largest single-site utility-scale solar project operational in the world at the end of 2016. Built by Adani Green Power in just 18 months, this facility has a total capacity of 648 MW. We note that during 2017 China commissioned an 800 MW solar project, taking the title of largest solar farm, and into 2018 there are several single-site projects under construction in various countries across the globe exceeding 1 GW, demonstrating the ever-larger scale of renewable deployments. At Bhadla in Rajasthan, India has a 2.2 GW solar facility under construction, with almost half of this already commissioned.

Regarding growth going forward, we note that Tamil Nadu is set to announce a 1 GW offshore wind tender in 2018 (for commissioning in 2024/25), which will provide further system diversification in the medium term.[171]

Figure 23: Tamil Nadu Electric Capacity and Generation (by source, 2016-2017)

Source	Capacity			Generation	
	GW	% of Total	Utilisation, %	TWh	% of Total
Wind & solar	9.6	32%	18	13.9	14.3%
Biomass & run of river	1.0	3%	n/a	1.3	1.3%
Hydro	2.2	7%	12	2.4	2.5%
Nuclear	2.4	8%	57	9.7	10.0%
Coal	13.4	45%	62	66.6	68.7%
Gas	1.0	3%	25	2.2	2.3%
Diesel	0.4	1%	25	0.9	0.9%
TOTAL	**30.0**	**100%**		**97.0**	**100.0%**

Source: Central Electricity Authority, IEEFA Calculations

[171] For more information on Tamil Nadu's electricity sector transformation, please refer IEEFA's February 2018 report.

Drivers of Renewables Growth

Integrated Grid

The move by India to develop a fully integrated national grid over the last decade has played a key role in facilitating the expansion of variable renewable investments, as has the central government's policy to waive interstate grid transmission costs for any renewable energy project commissioned by 2019.

Pumped Hydro Storage Plans

Going forward, deployment of pumped hydro storage will lead to even more variable renewables capacity in the medium term. Tamil Nadu has India's largest pumped hydro storage project under way (500 MW at Kundah). With renewable energy deployments across Tamil Nadu likely to grow by 10-20% annually over the coming decade, the Kundah storage facility will provide much-needed extra capacity to manage peak demand requirements.

Factors That Have Favored Integration

Diversified Flexibility

As of March 2017, the state had 1 GW of biomass and run-of-river small-scale hydro, 2.2 GW of conventional hydroelectricity, and 1 GW of gas fired power capacity operational (plus another 1 GW of gas under construction). These resources provide system flexibility to deal with peaking demand and variable generation. In addition, Tamil Nadu has one third of India's nuclear fleet (by capacity) and 13.4 GW of pithead lignite and imported coal-fired capacity, providing a well-diversified electricity system.

A National Grid with International Connections

India has progressively moved toward a single national electricity grid over the last decade. While there are still four regional grid structures (down from seven a decade ago), interstate connectivity has progressively developed. This reflects the disparate position of natural resources, with lignite predominately in the south, the best solar resource in the deserts of Rajasthan in the northwest, the main thermal coal deposits in the center-east, onshore and offshore wind in the south, plus hydroelectricity primarily emanating from the seasonal flows of the Himalayas in the north and northeast. With grid investment across India running at US$20 billion annually over the last decade and clear central government regulatory support, India's transmission sector has proven a strong point in the electricity sector. In contrast, local grid distribution is plagued by financial and operational legacy issues that are proving very difficult to overcome.

Beyond its national market of 1.3 billion people, India has progressively expanded its international grid connectivity as a strategy to manage and balance regional peak electricity demands. Grid connectivity with Bangladesh (having just doubled to an installed capacity of 600 MW in 2016, projects are under way for a fivefold expansion by 2025), Bhutan and Nepal adds almost 200 million people to the reach of India's grid, while a subsea cable connection to Sri Lanka is also under consideration.

Interstate Green Power Corridor

The development of India's interstate green power corridor is a major new government of India energy policy initiative that is motivating the rapid deployment of renewable energy infrastructure in Tamil Nadu, with more than 2,000 MW currently under construction. In January 2018, Union Coal Minister Piyush Goyal told the Lok Sabha (India's lower House of Parliament) that work on a US$2 billion upgrade of this Green Power corridor should be operational by May 2019. Since many states are falling short of meeting their renewable power obligation targets, Tamil Nadu's surplus renewable power generation and strong wind and solar resource base is likely to be much in demand in the national market. In December 2017, the central government extended its waiver of interstate transmission system charges and losses for the first 25 years of operation for all new renewable energy projects commissioned by March 2019.[172]

India's National Renewables Ambition

An electricity sector transformation is under way across India. The 10-year national electricity plan released in 2016 envisages 275 GW of variable renewable energy capacity in place by 2026/27, 43% of India's total forecasted capacity of 640 GW. This is a fivefold expansion in absolute terms from the 57 GW of variable renewables operational in 2016/17 (18% of capacity). India's energy minister R.K. Singh in February 2018 suggested that this plan is looking conservative, with intentions for India to tender 30-40 GW annually of wind and solar in the next two years.[173]

Delivery on this plan would result in an unprecedentedly rapid shift away from coal-fired power, which would drop from 59% of capacity in 2016/17 to just 39% by 2026/27, at the same time as total capacity installed across India doubles. While such a shift would have enormous positive spin-offs in terms of reducing global carbon emissions growth and starting to address spiralling pollution pressures within India, the primary driver is economic. Renewable energy sources are now the low-cost source of new electricity capacity in India. Recent reverse auction results have seen both wind and solar power tenders as low as US$38/MWh (with zero inflation indexation for the full 25-year life of the PPA). This is a staggering 20-30% lower than that of existing domestic thermal power plants across India. Imported coal-fired power and liquefied natural gas power plants have overnight become stranded assets, requiring tariffs double that of new renewable energy.

172 https://mercomindia.com/cerc-waives-ists-for-solar-projects/

173 https://energy.economictimes.indiatimes.com/news/power/indian-economy-to-grow-at-8-5-per-cent-in-2018-19-power-minister/62740037

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Important Information

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Report Title – Georgia, bold – 11pt. font or smaller to fit on one line 23
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