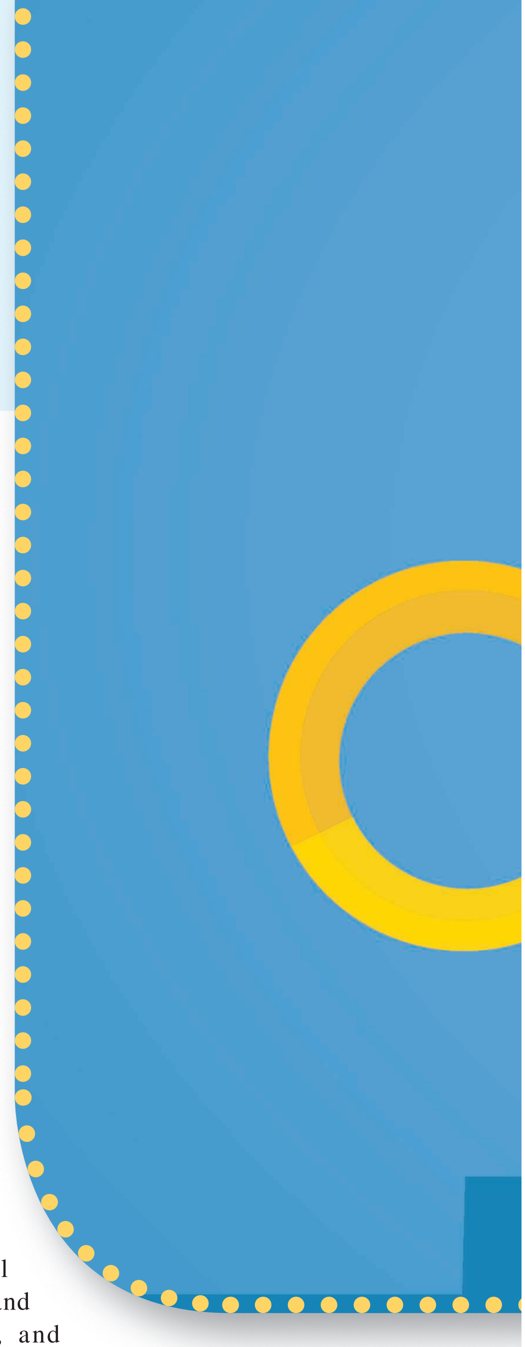
Secrets of Successful Integration



Operating Experience With High Levels of Variable, Inverter-Based Generation

THE UTILITY INDUSTRY IS EVOLVING QUICKLY IN response to mounting public pressure for cleaner electricity and overall cleaner energy. An increasing number of countries such as Denmark, states such as Hawai‘i and California, and utilities such as American Electric Power and Xcel Energy have goals of 100% renewables or 100% carbon-free emissions. Renewable technologies include wind, solar, geothermal, biomass, hydroelectric, and others; carbon-free technologies typically include renewables, carbon capture and storage, and nuclear.

Wind and solar photovoltaics (PVs) dominate renewable energy additions worldwide and represented 84% of all new renewable capacity installed in 2018. Wind power and PVs can create two key challenges for utilities. First, they are variable energy resources (VERs), which can make system balancing more challenging. Many mitigation options are available to manage moderate levels of VERs, including improved forecasting, more interconnections with other regions to smooth wind/solar/demand profiles, faster dispatch intervals, more flexible capability and operation of the overall generator mix, demand response measures, and energy storage. Very high VER levels may require flexibility from other energy sectors, such as transportation or heating, as is detailed in the article, “Flexibility From Energy Systems Integration,” in this issue.

Second, wind technology, PVs, and battery energy storage are inverter-based resources (IBRs). Even a moderate level of wind and PV power generation on an annual basis can lead to high instantaneous penetrations, which can be challenging in many ways. Decreasing system inertia, lower short circuit strength, fault behavior from inverters, and other factors are sources of concern as synchronous machines continue to be displaced by IBRs. A grid based on nonsynchronous control paradigms requires new technologies and is discussed in this issue’s article on grid-forming converters. We refer to wind and PV power generation as VERs when discussing the variable aspect of these resources and as IBRs when discussing the nonsynchronous nature of these resources.

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Figure 1 examines system portfolios across several regions and compares the capacities of nonvariable generation (fossil fuel, nuclear, and others) with VERs. The capacities of interconnections and energy storage are shown, two common options for mitigating variability. Power systems are traditionally overbuilt to accommodate more-than-expected peak demand to account for unexpected outages and variability in weather. Because of the variable nature of the resources, systems with high VER penetrations are likely to have much more generation capacity than peak demand. Figure 1 shows that even those utilities serving areas with very high VER capacities, such as Energinet, South Australia, and the Kauai Island Utility Cooperative (KIUC) in Hawai‘i, continue to have significant nonvariable generation capacity.

Some regions are experiencing very high instantaneous penetrations of VERs (Figure 2). As compared with other areas, those served by Energinet and South Australia have

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slightly higher annual average VER levels (the orange marker in the figure), but their instantaneous VER levels are considerably higher. The length of the blue bars shows that system operators must manage a range of operating conditions: from zero VER output to VER output exceeding regional demand.

Figure 2 also shows the percentage of VER energy curtailment in 2018. In this article, *curtailment* is a broad term for reducing VER output below its potential production; it may be enacted for various reasons, including transmission congestion, provision of down-regulation reserves, and system balancing during oversupply periods. The island system of EirGrid limits instantaneous IBR penetration because of grid stability issues. In Denmark, wind turbines contribute to market-based down-regulation on equal terms with other generators. The island system KIUC uses various means to enhance flexibility, including energy-shifting battery storage, to hold down curtailment.

Here we share system operators' secrets for successful renewable integration. Some regions have unique techniques for addressing the balancing challenge, such as using curtailed wind to provide a fast, accurate regulation service. Others have developed mitigation options for high IBR penetrations, such as running a gas turbine as a synchronous condenser. They all share a practical approach rooted in innovative uses of existing infrastructure; a willingness to develop new market services, incentives, or contractual arrangements; the application of detailed studies and good planning; and a readiness to adopt new practices.

Storage and Synchronous Condenser Capability in Kauai

KIUC is the only electric service provider on the island of Kauai in Hawai'i. Unlike the other regions mentioned in this article, Kauai has no interconnection with its neighbors, so balancing supply and demand is extremely challenging. KIUC has long been a leader in solar integration, with

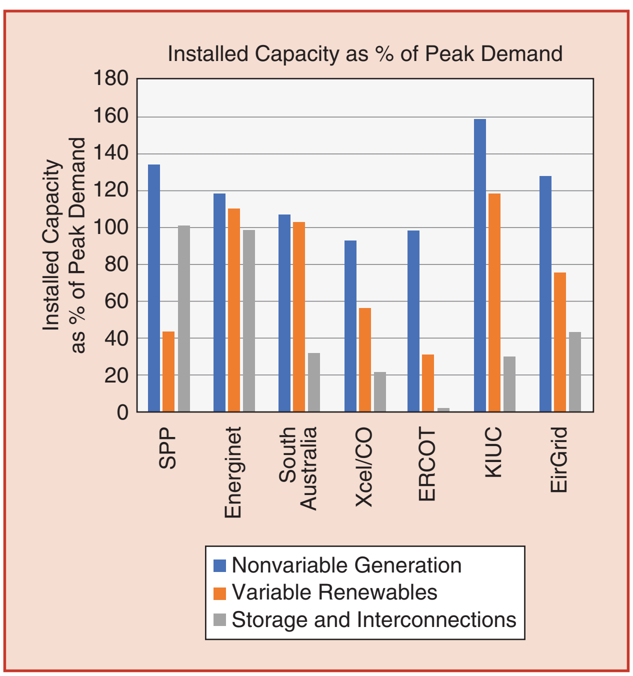

figure 1. The (blue) installed capacity of nonvariable generation, (orange) VERs, and (gray) storage and interconnections as a percentage of peak demand on each system. This includes distributed VERs. SPP: Southwest Power Pool; ERCOT: Electric Reliability Council of Texas.

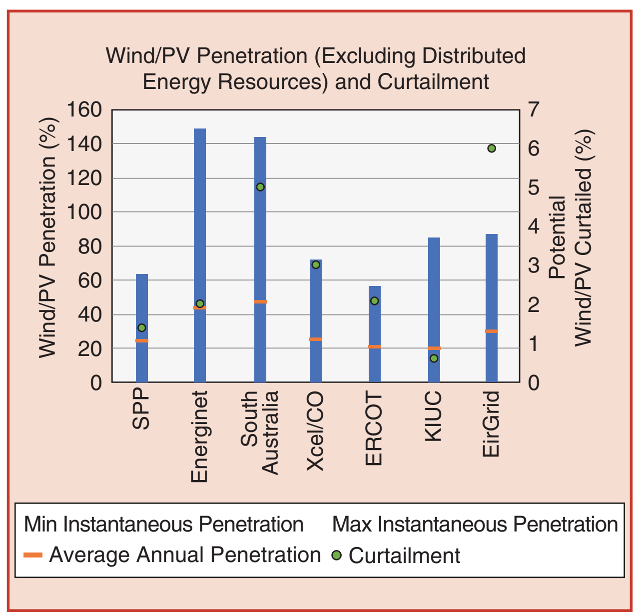

figure 2. The (blue bars) minimum (min) to maximum (max) instantaneous VER penetration as a percentage of demand and (orange marker) the average annual VER penetration. Min values are at or close to zero. This represents transmission-connected VERs, not distributed VERs, which would further increase penetration levels. Green dots depict the percentage of potential VER annual output that is curtailed.

> Curtailment may be enacted for various reasons, including transmission congestion, provision of down-regulation reserves, and system balancing during oversupply periods.

96 MW (nameplate) of PVs at the end of 2018. This is significant for an island with a midday demand of 55–65 MW. How did KIUC transform a resource mix that was 92% oil based in 2010 into today's system?

As PV capacity increased, KIUC reduced minimum generation levels on its thermal generators from 50 to 25% and then later to 10%. This provided more flexibility for integrating midday PV output and enhanced the ability of thermal generator spinning reserves to manage the effects of sudden cloud cover and the late afternoon ramp toward the evening peak demand. However, continued PV growth exhausted this flexibility, and KIUC realized that storage or load-shifting would be needed to accommodate future VER installations. This led to the first PV storage power purchase agreement between KIUC and SolarCity (now Tesla) for a combined 13-MW PV and 13-MW/52-MWh battery, which was commissioned in May 2017.

KIUC's daily peak demand occurs about one hour after sunset. To balance the high solar penetration levels, KIUC uses thermal generators, dedicated battery energy storage systems, PV storage plants, and control algorithms developed in-house. KIUC typically holds contingency reserves equivalent to 50% of the real-time output from PV plants not backed by storage. Online fossil generation is increasingly being replaced by battery storage for the provision of spinning reserves. KIUC has ample quick-start units. However, if they are not already online, they cannot start fast enough to respond to cloud events. A typical midday dispatch for very sunny days in 2018 was 7 MW hydroelectric, 7 MW biomass, 1 MW oil, and the rest (40–50 MW) from PVs, including the PV storage plant. The results speak for themselves. In 2018, 27% of KIUC's annual energy demand was served by utility-scale and distributed PVs, with curtailment of potential PV production lower than 0.6%. On average, in 2018, PVs served 54% of demand at noon, but on an instantaneous basis, KIUC has reached as high as 85% PV penetration.

A second PV storage plant, 20 MW PVs with a 20-MW/100-MWh battery system, was completed in December 2018. Annual energy demand served by PVs is expected to jump to 38% for 2019 due to this new plant. That will increase further with a 14-MW PV 70-MWh storage plant scheduled for commissioning at the end of 2019.

Commercial operation of the second PV storage plant has enabled KIUC to run at 100% renewable energy penetration at times. For example, on 24 February 2019, KIUC ran the grid for 25 min using 100% renewables with zero fossil-fuel consumption (Figure 3). The mix for that period was 80% PV (some of which was backed with storage), 10% hydroelectric, and 10% biomass. The key to this achievement is the ability of KIUC to operate its Kapaia GE LM2500 unit as a synchronous condenser. Operating the gas turbine in synchronous-condenser mode maintains significant inertia, voltage support, and fault current contributions that ensure system security. KIUC is now working to extend these 100% renewables periods to 2–4 h, which will be enabled by the third PV storage plant.

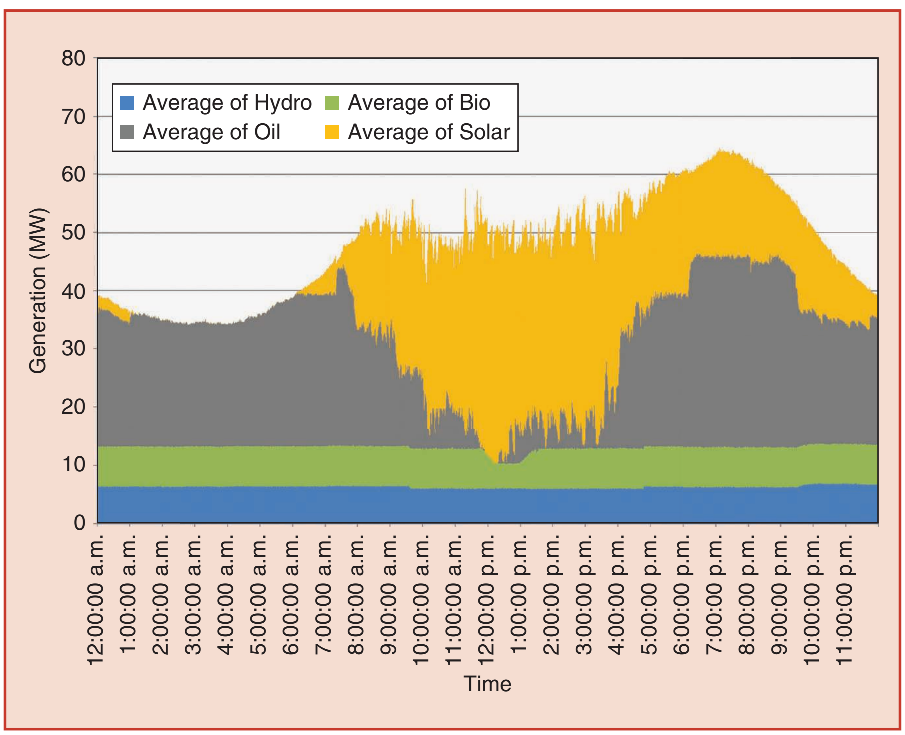

figure 3. The dispatch of the KIUC system on 24 February 2019 with 100% renewables operation. Yellow: PV (Solar); gray: oil; green: biomass (Bio); blue: hydroelectric.

Managing Forecast Errors at SPP

SPP is a regional transmission organization (RTO) that manages the high-voltage transmission system over approximately 546,000 square mi of service territory in 14 states from Louisiana and Texas to North Dakota. SPP staff constantly monitors the operation of the grid and coordinates corrective actions that keep the system in a secure state. SPP has a day-ahead market. Its integrated marketplace uses state-of-the-art optimization software to minimize the cost of committing and dispatching more than 700 resources to serve the region's demand.

The SPP region includes some of the best wind resources in the United States. SPP's wind development grew from 3.4 GW of wind capacity in 2009 to 20.5 GW in 2019. The footprint has seen as much as 16.4 GW of concurrent wind generation. Wind power has served up to 63.4% of demand.

One of the biggest challenges of this high wind penetration is forecasting over the operational horizon and across one of North America's largest RTOs (in terms of land area). Wind forecasting in this region is highly subject to error, partially due to forecast uncertainty stemming from low-pressure systems coming from the Rocky Mountains, which create instability in weather systems in SPP's footprint. Actual wind output can be as little as 40% of day-ahead forecasts. This means that up to 7 GW of wind output may not be available as anticipated. Figure 4 illustrates the forecast and actual wind curves on a day with such an error.

Managing forecast deviations of this magnitude in real time is challenging. SPP has deployed many programs and techniques to do so, including the establishment of the Uncertainty Response Team (URT). The URT was formed in 2018 to focus on mitigating the impact of forecasting errors on day-to-day operations. Specifically, the URT ensures that adequate capacity will be available to balance highly variable wind output. The team analyzes past experience to better assess present system conditions and plan for the near future and employs statistical analysis, using historical data and errors, to increase the robustness and accuracy of system forecasts. The URT identifies days during which wind forecast errors are likely to be high, so SPP can mitigate the risk. This approach has been highly successful.

One innovative practice is site-specific wind forecasting. Individual wind turbine outputs are forecasted at some sites to understand the effects of wind direction and wake effects on aggregate power production. This also enables a higher-resolution analysis of the propagation of wind cutout events.

Continuous improvement is vital. Many other developments have been instituted to more effectively harness wind energy. These include the following:

- ✔ enhancing automatic generation control (AGC) to simultaneously dispatch VERs and provide regulation from them
- ✔ investigating new market products to account for the effect of forecast uncertainty and ramp in both dispatch and pricing
- ✔ enhancing system visibility through more granular wind forecasting and new solar and icing forecasts
- ✔ adding more granular VER forecasting requirements to increase forecasting accuracy
- ✔ using a high-resolution weather model to predict site-specific forecasts
- ✔ implementing real-time voltage and transient stability studies
- ✔ adding wind forecast confidence bands as inputs to market studies
- ✔ enabling policy changes necessary for increasing VER levels
- ✔ carrying out designs and policies to incorporate electric storage resources into the market
- ✔ deploying and using phasor measurement units to identify grid impacts that may affect reliability.

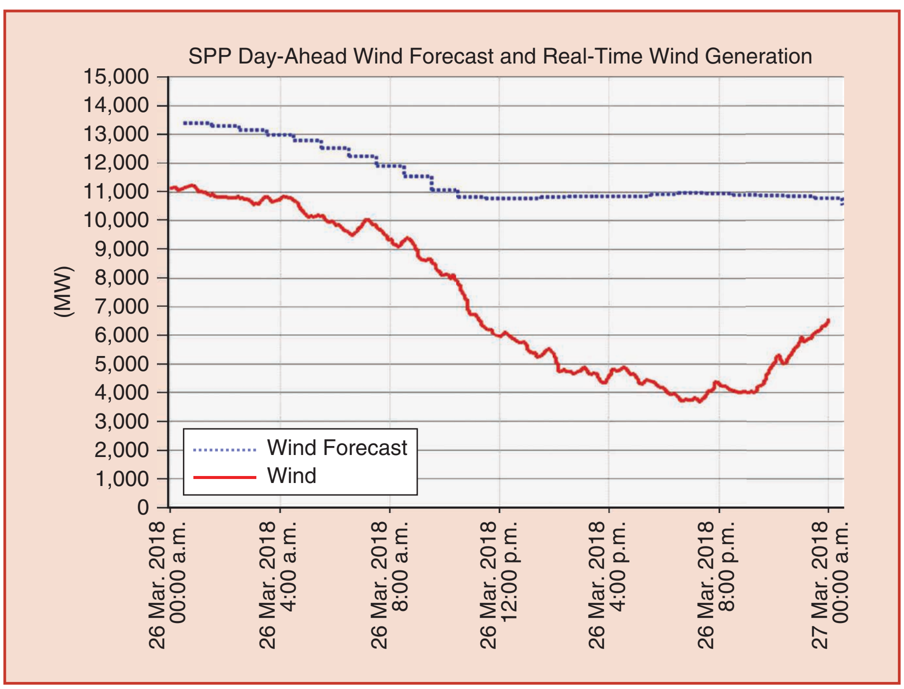

figure 4. The SPP wind forecast error on 26 March 2018.

Energy-Sector Coupling at Energinet

In 2018, renewable energy sources satisfied more than 60% of Denmark's electric demand. The country's goal is to achieve 100%

renewable electricity by 2030 and 100% renewable energy by 2050. Over three decades ago, Denmark depended on large coal plants. Government plans and policies drove the development of distributed combined heat and power and onshore wind power, followed by offshore wind power and, later, PVs. In 2018, 43.5% of its annual energy demand was served by VERs (40.7% from wind and 2.8% from PVs), 23.5% from fossil fuels, 17.8% from biomass and waste, and 15.3% from imports.

Denmark has undertaken a market-based approach to balancing high levels of VERs. The Danish RTO Energinet administers day-ahead and intraday markets. It also oversees a regulating market to manage real-time imbalances. The vast majority of electricity is traded in the day-ahead market, with the regulating market accounting for less than 0.5% of demand. This indicates a very dynamic day-ahead market, where price variations create incentives resulting in substantial flexibility from generation and interconnections. As a result, the regulating market has little imbalance to handle. Demand-side flexibility is still very limited, with the main exception being electric boilers in district heating systems that provide regulation. The sizable interconnector capacity with neighboring countries (approximately the same as installed VER capacity) and the scheduling of these interconnectors through the day-ahead market provide significant flexibility. The recent expansion of the intraday market to include cross-border trade has enabled Denmark to extract further flexibility from interconnectors. The price responsiveness of thermal power plants has increased considerably in recent years. This, combined with the addition of synchronous condensers, allows the Danish power system to decommit large thermal power plants over extended periods.

An hour ahead of operation, the intraday market closes, and Energinet prepares for the physical balancing of the system. System balancing is proactive: operational planning tools continuously update schedules and forecasts. Based on these predicted imbalances, operators activate manual reserves in the Nordic regulating market for the following hour. This minimizes the amount of automatic reserves that manage the remaining imbalance and enables the use of the least-expensive resources for regulation and reduces reliability risks to the system.

By 2020, VERs will supply more than 50% of Denmark's electric energy demand. The country's transition from 0 to 50% of VERs was mainly achieved by horizontal integration, where the electricity sector was well integrated through an international wholesale market, a strong transmission grid, and a flexible generation system. These measures will not suffice for the next phases when Energinet envisions a more decentralized digital grid. The focus will shift toward vertical integration, where retail markets and other energy sectors will be integrated to unleash a huge potential for flexibility. Figure 5 illustrates how horizontal integration has enabled VERs to achieve 50% of Denmark's power generation. However, the sources of flexibility that have enabled this will soon be exhausted. The role of the traditional system operator is changing, and they will be part of a green transition driven by the market and consumers.

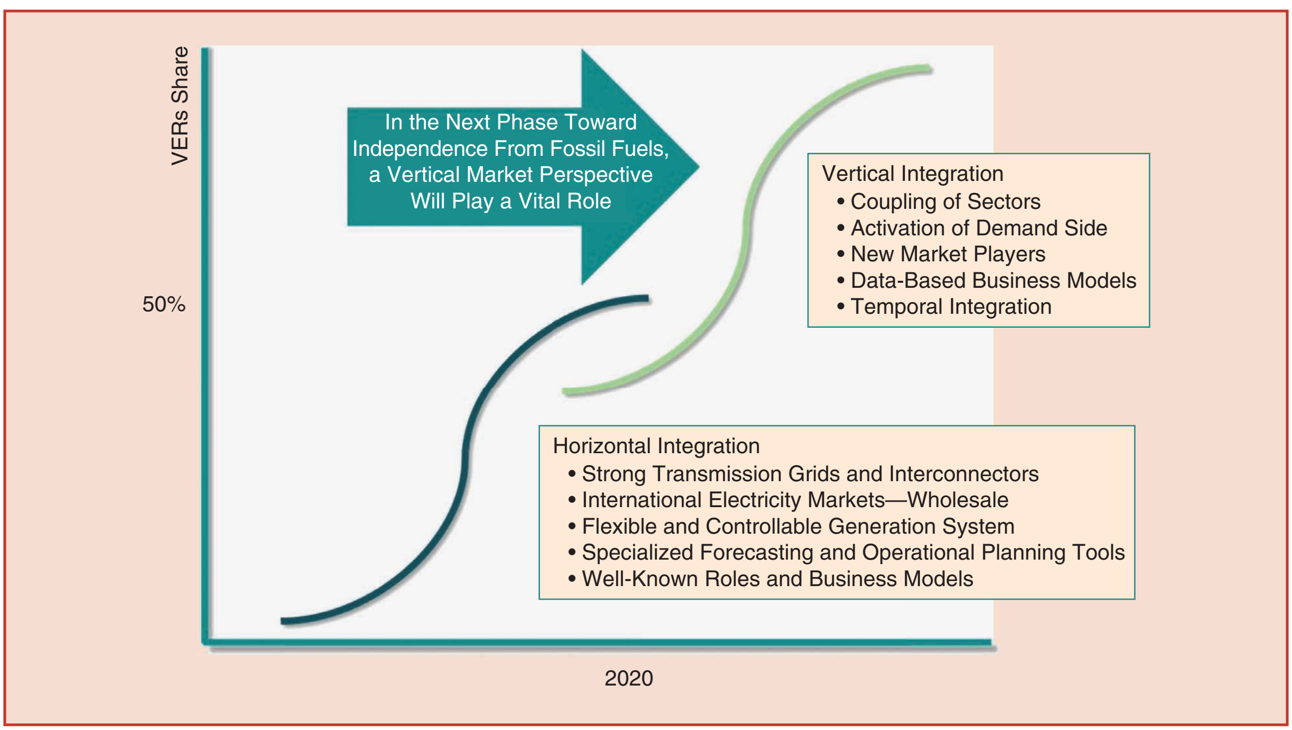

figure 5. "S" curve growth of VER percent penetration. Denmark's transition from 0 to 50% VERs relied heavily on horizontal integration. The further transition toward 100% renewable energy will require vertical integration.

> In response to customer demands for cleaner energy, Xcel Energy has made a commitment to reduce carbon emissions by 80% compared to 2005 levels across all of its service territories by 2030.

New technology, digitization, and data-driven business models will unlock new sources for flexibility. An important role for the system operator is to create a digital framework, promote the free exchange of data, remove obstacles for new technologies, and digitize market processes. This is expected to bring substantial gains by increasing the use of the transmission system while maintaining system security. Sector coupling between electricity and heating, transportation, and the gas systems will allow for efficient energy storage and system balancing.

Wind Plants Provide Reserves at Xcel Energy

Xcel Energy has improved reliability and reduced costs to customers while steadily integrating ever-higher penetrations of renewable generation on its 7-GW Colorado system. In 2010, Xcel's Energy Management System enacted state-of-the-art practices that enabled 4-s AGC at wind facilities in Colorado.

In 2009, when VERs reached a penetration level of approximately 10% of annual energy consumption, Xcel Energy found it could not accommodate additional VERs without regular curtailment. At any moment, a system has some amount of maximum VER headroom, which can be defined by the total demand (plus net interchange) minus the dispatch set points of the units that must be online to provide reliability services (typically minimum generation level plus downward reserve requirements). When potential VER output exceeded the maximum VER headroom, system dispatchers had to manually curtail wind plants to balance the system. Having wind generators provide real-time balancing services reduced the amount of wind-generation curtailments and fossil-fuel costs by allowing fossil-fueled units to be dispatched at minimum generation. A few days of testing resulted in such a large reduction in wind-generation curtailment that AGC control of wind became the preferred curtailment mode. The AGC also improved reliability by enabling fast-acting wind generation to meet the balancing authority area's regulation needs.

Xcel Energy also found that a relatively low level of renewable generation curtailment was a cost-effective integration tool. For example, during the last three years, VERs satisfied approximately one-quarter of Xcel's Colorado energy demand, while only about 3% of the potential VER output was curtailed. In other words, the company's Colorado system has been able to accept 97% of all renewable generation at a 25% penetration level. This is an important observation for other grids, as it is often more economical to curtail some energy rather than design a system with large amounts of storage, for example, to reduce all curtailment.

The increasing magnitude of VER variability has challenged the system's ability to economically dispatch its generation portfolio while maintaining system reliability. Xcel Energy carries extra regulation to address the increase in short-term variability. In addition, Xcel holds a 30-min flex reserve, which is sufficient to cover the largest potential renewable generation ramps as a function of real-time VER output. Appropriate volumes of regulation and the 30-min flex reserve are determined by studying historic VER variability and projecting the additional variability of future VER plants. The company has also determined the volume of curtailed VER generation that can dependably provide up-regulation and 10-min spinning reserves. This enables the use of curtailed VER generation to provide some of the spinning reserve requirements. In this way, some reliability concerns associated with the inherent variability of very high VER penetrations are addressed by the VERs providing essential reliability services. If curtailment is necessary to preserve reliability, it should be used for productive purposes, such as contributing to reserves and controlling ramp rates.

In response to customer demands for cleaner energy, Xcel Energy has made a commitment to reduce carbon emissions by 80% compared to 2005 levels across all of its service territories by 2030, and it aspires to serve customers with 100% carbon-free electric generation by 2050. Increasing VER penetration is clearly one of the ways that the organization plans to achieve these goals. Increasing levels of curtailment will naturally occur as more VER capacity is built, and Xcel Energy has realized that curtailed VERs are valuable resources for minimizing operating costs and improving system reliability.

Dynamic Reserve Requirements at ERCOT

The RTO for most of Texas, ERCOT, is an islanded grid with limited dc ties to Mexico and the Eastern Interconnection. ERCOT has 22 GW of installed wind nameplate capacity and approximately 1,700 MW of utility-scale PV capacity. The interconnection queue indicates that VERs, especially PVs, will grow quickly. This has led ERCOT to continuously revise its generation interconnection requirements, improve forecasting performance, update IBR impact studies, and fine-tune study methods for determining ancillary service requirements.

The key to the reliable and efficient integration of IBRs lies in adopting best grid operation practices: having the appropriate grid codes avoids costly reliability problems in real time, accurate forecasting allows the grid operator to efficiently schedule other resources, and ancillary services can mitigate risks associated with forecast errors. This enables IBRs to provide many of the services usually provided by synchronous generators.

ERCOT currently has four types of ancillary services: regulation service up (reg-up), regulation service down (reg-down), responsive reserve service (RRS), and nonspin reserve service (NSRS). Prior to the huge growth in IBRs, ERCOT procured mostly a fixed level of RRS and NSRS throughout the year. This static approach is no longer appropriate with ERCOT's high IBR penetration levels.

Regulation provides 4-s system balancing so that ERCOT can maintain grid frequency, per North America Electric Reliability Standard BAL-001, which uses the Control Performance Standard 1 (CPS1) metric. Prior to 2010, ERCOT had a zonal market with a 15-min dispatch. In 2009, ERCOT procured an average of 825 MW of reg-up and 851 MW of reg-down. In 2010, ERCOT switched to a nodal market with a 5-min security-constrained economic dispatch (SCED). Contrary to the conventional wisdom that VERs increase regulation requirements, ERCOT today maintains one of the best CPS1 scores in North America while reducing regulation procurements year over year (Figure 6). This has been achieved through 5-min dispatch, refining its SCED algorithm, load frequency control tuning, requiring VERs to follow ERCOT base points under some system conditions, and a primary frequency response (PFR) grid code requirement.

RRS is procured by ERCOT primarily to arrest frequency declines below 59.40 Hz for the loss of 2,750 MW of generation. Increased VER levels displace synchronous generators and the inertia they provide. For an island grid, inertia largely determines the rate of change of frequency (ROCOF) following generator-loss events. If inertia falls below 100 GW/s, the loss of 2,750 MW would result in the frequency dropping so quickly that underfrequency load-shedding would occur before the fastest reserve could respond (0.5 s is the response time of demand response triggered by underfrequency relays).

RRS in ERCOT primarily comes from generators providing PFR and load resources with underfrequency relays. In 2015, ERCOT started factoring anticipated system inertia into RRS procurements. The peak RRS requirements generally coincide with the low-demand, high-wind early morning hours (1–4 a.m.).

The 30-min NSRS provides reserves to address load or VER forecast errors. Today, NSRS is procured for underforecast errors of load and overforecast errors of VERs. When the net load is likely to be ramping up, ERCOT procures NSRS sufficient to cover the 95th percentile of the net forecast errors. When the net load is not likely to ramp up, ERCOT procures NSRS that may only be sufficient to cover the 70th percentile of the net forecast errors.

ERCOT identifies hourly ancillary service requirements for the upcoming year during the fall of the previous year, and historical data play a significant role in determining these requirements. Since ancillary service quantities are determined months in advance, cutting-edge tools help control-room operators identify real-time shortages in RRS or NSRS. ERCOT's ancillary service products, designed more than two decades ago, were recently revised to include contingency reserve service as a new product and fast frequency response as a subset of the existing RRS.

New System Services in EirGrid

Similar to ERCOT, Ireland's grid is also islanded with limited dc interconnection to Great Britain. In 2008, EirGrid, the transmission system operator for Ireland and Northern Ireland, pioneered the analysis of the impact of high penetrations of IBRs on transient stability. The system operator faced several daunting challenges to reaching 75% system nonsynchronous penetration (SNSP differs from the IBR metric in that net imports are added to the IBR generation and net exports are added to the demand) and 1-Hz/s ROCOF. These included

- ✔ managing system stability
- ✔ controlling system voltage (when more than 25% of the total transmission-based synchronous generator reactive power sources would be displaced)
- ✔ protecting the system from overfrequency events (loss of export under high wind conditions)
- ✔ managing the uncertainty of a weather-dependent system.

Today, EirGrid operates the grid up to 65% SNSP with a 0.5-Hz/s ROCOF limit. In November and December 2018, wind power provided more than 43% of the total energy consumed. Over the entire year, wind served more than 30% of demand. An additional 1,000 MW of wind power is expected to be connected in the next 12 months. To successfully integrate this wind power, the company plans to operate the system up to a 75% SNSP ratio and up to 1-Hz/s ROCOF by 2020.

At these high IBR penetration levels, the system stability issues largely arise due to low synchronizing torque. This might be partially mitigated by grid-forming inverters. However, currently the grid code does not require grid-forming inverters, and an understanding of how this new technology would perform and interact with the rest of the system is still being developed. To date, EirGrid has fundamentally revamped its system services to provide incentives for introducing technologies that provide synchronous-like torque and strong reactive power support when wind output is high. With these new system services, there is likely to be sufficient capability in the existing portfolio to reach the 2020 targets efficiently and effectively.

Ancillary services had previously been a very small market (€50 million per year or 2% of generator revenues). The revamped market guarantees incentives are in place for at least six years, as opposed to one year previously, and has a value of up to €235 million per year (in 2018, it was €180

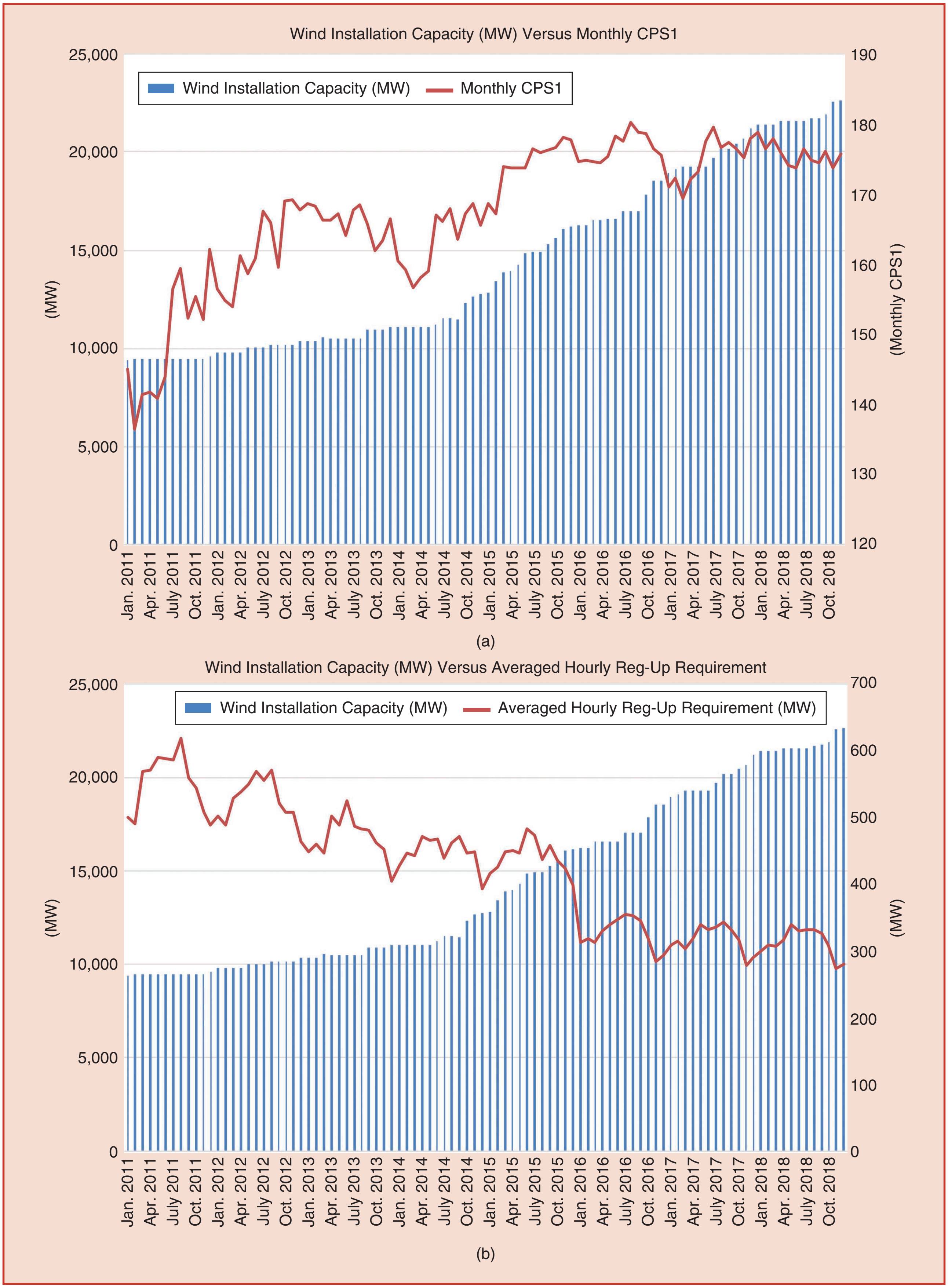

figure 6. (a) CPS1 versus wind-installed capacity and (b) reg-up requirement versus wind-installed capacity.

million). This allows owners who provide these services to recover capital investment in upgrades. Incentives are split across products and earnings are higher when the system operates above 55% SNSP because it is at high IBR penetrations when EirGrid most needs these products.

The Synchronous Inertial Response (SIR) product is one of seven new products implemented last year, in addition to the seven existing ancillary services. SIR is the ratio of the kinetic energy divided by the minimum generation of the plant. EirGrid created a product that paid generators if they were dispatched and had an SIR of 45, with higher payments at high IBR penetrations. In addition to SIR, the reduced minimum generation level allows for the plant to provide higher ramping and reactive power services. As a result, five large plants have now lowered their minimum generation, which they were previously unable to do, by a total of 350 MW. Also in 2018, 39 wind plants and 21 demand-side management units were contracted to provide system services, including more than 99 MW of fast frequency response and 111 MW of primary operating reserves.

System strength, protection, and frequency regulation were also explored for 2020 and were not an issue in the short term. However, EirGrid initiated an exploration of the 2030 system where it will be operating close to 100% SNSP. It is expected that grid-forming capability from IBRs will be considered in this study.

Modeling and Synchronous Generation Management in South Australia

The state of South Australia sits at one end of the eastern Australian interconnection, also known as the National Electricity Market (NEM). While not an islanded system, only one double-circuit ac interconnection spans the 580 mi between synchronous generation centers in South Australia and the next NEM region. In 2018, South Australian wind output exceeded regional demand approximately 5% of the time, and instantaneous output peaked at 144% of regional demand. Additionally, more than 30% of households in South Australia have distributed PV (DPV) systems.

The operator of the NEM, the Australian Electricity Market Operator (AEMO), has the challenge of operating a system that can transition in 12 h from one with only synchronous generators online to one in which IBR output significantly exceeds regional demand. Under these conditions, dynamic performance is dominated by the response of IBRs. To operate stably, current IBR technology requires a level of grid strength provided by synchronous machines. AEMO faces challenges similar to those of ERCOT and EirGrid. AEMO must now explicitly ensure that sufficient synchronous generators remain online at all times within South Australia, specifically to ensure adequate postfault recovery, during the periods of highest IBR penetration.

The NEM design does not feature centralized real-time commitment or a binding precommitment of generating units. Out-of-merit dispatch is, therefore, used to ensure sufficient synchronous generation commitment. Much of the synchronous generation in South Australia is relatively inflexible, with start times of several hours or more and high minimum generation levels in some cases. None of the large synchronous generators is capable of operating in synchronous condenser mode.

Assessing the performance of the South Australian power system requires accurately modeling the behavior and interaction of multiple, widely dispersed IBRs, under low grid strength conditions, in a system where they may be the dominant generation technology. Traditional dynamic modeling tools are inadequate. So AEMO developed a large electromagnetic transient model of the entire South Australian region, which includes all synchronous generation, grid-connected IBRs, the transmission network, and important network and generation protection systems.

These studies have identified 1) the need for a minimum of four-to-five synchronous machines (approximately 150–200 MVA each) to remain online in South Australia at all times and 2) the maximum wind output under low inertia conditions. These limits resulted in curtailment of approximately 4% of wind generation in the fourth quarter of 2018.

While the ac interconnection to the rest of the NEM is vital for short-term balancing and economic interchange, it does not provide sufficient grid strength for reliable post-fault recovery of IBRs in South Australia. So this function must be provided locally. New rules introduced in 2018 require maintaining both minimum fault levels at selected transmission nodes and minimum regional levels of inertia under certain operating conditions. These rules support contracting arrangements with synchronous generators or the potential construction of synchronous condensers where this makes economic sense. The regional transmission owner is currently tendering for synchronous condensers, partly to reduce out-of-merit dispatch driven by reliability concerns.

South Australia also has high levels of DPVs, which continues to grow rapidly. At times, 50% of regional demand is served by distributed energy resources (DERs), and this is forecast to reach 100% by 2027 (Figure 7). DERs add another layer of complexity to the variability and IBR issues. High DER penetrations require DER control and communication infrastructure, strong ride-through capabilities, grid support requirements, and suitable DER dynamic simulation models (see the article "Ensuring Bulk Power System Reliability" in this issue).

A Way Forward

The case studies in this article show how the technical barriers of renewable integration are being overcome and redefined across the industry. While each system is unique, their planners and operators have innovated to increase system flexibility, which is essential for large-scale renewable integration. Flexibility has been

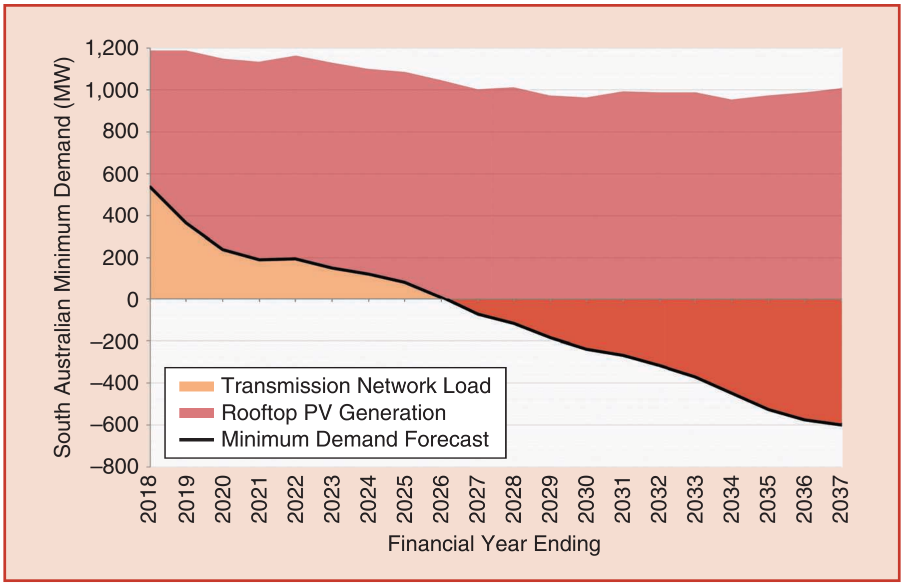

figure 7. The (black line) minimum network demand in South Australia occurs at midday due to high PV penetration. As rooftop PV generation increases, the load on the transmission network decreases. A negative minimum demand necessitates exports, spillage, or both.

enhanced through more advanced capabilities of wind and PV resources, improvements in technologies related to storage and synchronous condensers, more flexible loads, modifications to the thermal fleet, new ancillary services, proactive market designs, tailored policies, and more educated consumers.

The lessons learned demonstrate that technical challenges are not barriers. In fact, the island and low inertia grids discussed, such as those in Ireland, Kauai, Texas, and South Australia, represent some of the most complex power system engineering required for renewable integration. Proven technical and economic solutions, such as those presented here, have enabled VER penetrations to exceed 100% on an hourly basis and to reach 40–50% on an annual basis.

What does the future hold for wind and solar integration? As renewable resources become the primary electricity source, the integration challenges and their mitigations will become more complex. The transition to the renewable future will require new business models, rate structures, market designs, and policies and even more innovation.

For Further Reading

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