

# Challenges for wholesale electricity markets with intermittent renewable generation at scale: the US experience

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**Abstract:** The supply of intermittent wind and solar generation with zero marginal operating cost is increasingly rapidly in the US. These changes are creating challenges for wholesale markets in two dimensions. Short-term energy and ancillary services markets, built upon mid-twentieth century models of optimal pricing and investment, which now work reasonably well, must accommodate the supply variability and energy market price impacts associated with intermittent generation at scale. These developments raise more profound questions about whether the current market designs can be adapted to provide good long-term price signals to support investment in an efficient portfolio of generating capacity and storage consistent with public policy goals. The recent experience of the California ISO (CAISO) is used to illustrate the impact of intermittent generation on supply patterns, supply variability, and market-based energy prices. Reforms in capacity markets and scarcity pricing mechanisms are needed if policy-makers seek to adapt the traditional wholesale market designs to accommodate intermittent generation at scale. However, if the rapid growth of integrated resource planning, subsidies for some technologies but not others, mandated long term contracts, and other expansions of state regulation continue, more fundamental changes are likely to be required in the institutions that determine generator and storage entry and exit decisions.

**Keywords:** electricity, renewable energy, intermittency, wholesale electricity markets

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## I. Introduction

This paper examines the current and likely future effects on wholesale electricity markets and the challenges these markets face due to the rapid expansion of intermittent (or variable) renewable energy, primarily wind and solar, with close to zero marginal generating costs. Generation ‘intermittency’ of wind and solar is a consequence of the natural variations in wind speeds and directions and available sunlight at specific locations and at specific times. The increase in wind and solar generation is already having significant effects on wholesale markets in some regions of the US. Solar and wind generation collectively are expected to become major sources for generating electricity (grid-based and distributed on homes and commercial establishments) in many regions of the US by 2050.

Wind and solar will continue to expand rapidly in the US despite the current posture of the Trump administration toward policies to mitigate CO<sub>2</sub> emissions in order to fight climate change. While the Trump administration has rejected concerns about climate change and has sought to curtail federal policies to promote renewable energy and energy efficiency, the majority of US states have adopted policies to facilitate the deployment of more wind and solar to meet their own CO<sub>2</sub> emissions reduction goals.<sup>1</sup> Hawaii and California have goals of 100 per cent carbon-free electricity by 2050 and other states are ramping up their goals for aggressive expansions of wind and solar and adopting policies to turn these goals into reality. Federal tax incentive policies for renewable energy remain in force, though they will phase down or out over the next few years. Moreover, the Federal Energy Regulatory Commission (FERC) continues to issue rules affecting wholesale power transactions and the use of the grid that are friendly to the efficient integration of wind and solar, the increased deployment of storage, and the integration of an active demand side into wholesale markets. Finally, the cost of wind and solar have declined dramatically over the last decade and are increasingly competitive with gas-fuelled alternatives even without special support mechanisms (LBL, 2018a, p. 14).

High penetration of intermittent generation with zero marginal operating costs creates challenges for wholesale market designs. And it is *both* intermittence and zero marginal operating that are important. To oversimplify, wholesale markets as they are now structured in the US perform two related resource allocation functions—short run and long run. First, they provide for the efficient real-time operation of existing generating capacity, clear supply and demand at efficient wholesale prices that represent the marginal cost of supply at any moment, and do so while maintaining the reliability of the system. Second, market prices and price expectations are supposed to provide efficient long-run profit expectations and incentives to support efficient decentralized investments in new generating capacity and efficient retirements of existing generating capacity. Wholesale market designs in the US that have evolved since the late 1990s now do a reasonably good job supporting the first set of short-run resource allocation tasks under most states of nature. However, they have been challenged in providing

<sup>1</sup> Thirty-one states have mandatory renewable energy portfolio standards (REPS). Another eight states have established voluntary targets for increasing the penetration of carbon-free generation. The states without REPS are primarily in the south (National Conference of State Legislatures, <http://www.ncsl.org/energy/renewable-portfolio-standards.aspx>). Other sources have slightly different numbers. See the DSIRE web site operated by the North Carolina Clean Energy Technology Center at <http://www.dsireusa.org/>.

adequate financial incentives to support efficient entry (investment) and exit decisions consistent with reliability criteria established by system operators. That is, the short-run price signals do not lead to long-run price expectations that adequately incentivize efficient investment and retirement decisions. The disconnect emerges primarily as a result of energy and ancillary price formation during tight supply and other stressed conditions. Prices under these conditions do not rise high enough to reflect the scarcity value of the generation due to price caps, limited demand-side participation in the wholesale market, and out-of-market actions by system operators during network security emergencies (Joskow, 2007). This in turn has led to the development of a variety of ‘resource adequacy’, capacity obligation, capacity pricing, and scarcity pricing mechanisms.

The expansion of intermittent generation with zero marginal operating costs creates additional challenges for wholesale markets in both the short-run efficient operating dimension and the efficient investment dimension. Wind and solar benefit from a variety of direct and indirect subsidies and opportunities to compete for long-term contracts. As supplies from these resources expand, spot market prices for energy decline and the net revenues from energy prices provide declining quasi-rents to support unsubsidized investment. While the ‘missing money’ or net revenue adequacy problem is not new, I expect that inadequate entry and exit incentives will turn out to be more severe from the perspective of unsubsidized generation as the supply of favoured intermittent generation grows. These developments are likely to lead to more profound changes in the design of competitive wholesale markets in the US than the current approach of simply tinkering with current market designs. The growing importance of intermittency will require new market products and services to ensure an efficient and reliable system. The impact of the growing importance of this zero marginal cost generation further undermines incentives for decentralized investment in generating capacity that can efficiently provide these services (e.g. fast response turbines and batteries) as spot energy prices decline and imperfections in capacity markets and scarcity pricing mechanisms have a growing impact on investment incentives. We are moving away from a decentralized model based on market incentives to a model where some technologies rely heavily on subsidies, long-term contracts, and other out-of-market revenues to support their capital costs, and others must rely on the market for all of their revenues. This is an unstable and inefficient model. It is a slippery slope where subsidies and special contracts lead to more subsidies and more special contracts guided by centralized resource planning rather than decentralized market incentives.

This paper proceeds as follows. The next section discusses the growth of wind and solar generation in the US and the federal and state policies that have promoted it. The paper then turns to a discussion of the wholesale electricity market designs that have been adopted by RTO/ISOs (regional transmission organizations or independent transmission system operators) and supported by FERC in the US and the performance attributes of these markets. The theoretical bases for these market designs are discussed next, along with some recent theoretical work on how the markets will be affected by the transition to systems dominated by wind and solar. The wholesale market in California managed by the CAISO is currently the most interesting in the US.<sup>2</sup> This

<sup>2</sup> In most cases, when I refer to California, I am referring to the portion of California governed by the CAISO. The CAISO covers about 80 per cent of the wholesale electricity supplied to California citizens. Some public power entities, including the Los Angeles Department of Water and Power which supplies electricity to the City of Los Angeles, have chosen not to be part of the CAISO.

is the case because the penetration of intermittent generation, especially the penetration of solar which is more ‘interesting’ than wind, is far more advanced than in other parts of the US, making it possible to see some of the impacts more clearly in practice. Accordingly, I use the CAISO experience to examine changes in generation supply, spot energy pricing, and entry and exit patterns associated with intermittent generation at scale. We can think about this as a sort of case study.

The final substantive section puts the theoretical and empirical evidence together to highlight challenges to prevailing wholesale market designs and potential responses to these challenges. This discussion focuses heavily on long-term investment incentives, storage, and dynamic retail prices. I conclude with some observations about more fundamental changes taking place in the US in response to growing state intervention in electricity markets through integrated resource planning, renewable portfolio mandates, subsidies, resource adequacy policies, and long-term contracting obligations. Short-run resource allocation through competitive energy and ancillary service markets are adapting to the challenges of intermittent generation at scale. However, the philosophy of free entry and exit driven by market forces rather than regulatory requirements is rapidly being replaced with extensive government intervention affecting the kinds of resources that will enter and exit a market and how they will be compensated. This transition will proceed more efficiently if we recognize that it is coming and adjust the procurement process accordingly.

## II. The growth of intermittent renewable generation in the US

For at least a decade the US has adopted and implemented a variety of policies to encourage investment in wind and solar energy. More recently, federal and state policies have expanded to promote and support the expansion of grid-based and behind-the-meter (BTM) storage as well, as it becomes clear that, due to intermittency, aggressive solar and wind penetration goals cannot be achieved at reasonable cost without storage. (I discuss storage *per se* later in the paper.) At the federal level, there are a variety of tax subsidies for grid-based solar energy, grid-based wind energy, BTM ‘rooftop’ or ‘distributed’ solar photovoltaic (PV), and wind energy facilities.<sup>3</sup> These subsidies and incentives include federal investment tax credits for solar (both grid-based and BTM) and production tax credits for wind.<sup>4</sup> Many states offer additional subsidies. These include specific dollar tax credits or grants, investment tax credits, exemptions from sales taxes, marketable renewable energy certificates, and the implicit subsidies associated with binding renewable energy portfolio mandates which many states have adopted.<sup>5</sup> The investment tax credit subsidies can typically be extended to cover storage if the

<sup>3</sup> Federal tax subsidies are also available for geothermal, biomass, fuel cells, and other technologies. Though these technologies are not intermittent, they are likely to remain a small share of the generation portfolio for the foreseeable future.

<sup>4</sup> The federal tax subsidies for solar and large-scale wind decline over the next few years. For solar the investment tax credit falls from 30 per cent today to 10 per cent in 2022 (zero for residential installations). For wind the production tax credit is scheduled to end after 2022 (<https://www.energy.gov/savings/business-energy-investment-tax-credit-itc>).

<sup>5</sup> For a complete list of state incentive programmes, see <http://www.dsireusa.org/>.

storage is integrated with wind or solar facilities eligible for these credits. The FERC has issued an order requiring RTO/ISOs to develop rules to allow storage to compete with generation on a level playing field and a number of states have extended direct and indirect subsidies to storage to support expansion goals.<sup>6</sup> A growing number of states have paired renewable portfolio mandates with requirements that distribution utilities enter into long-term contracts with solar and wind generators through a competitive procurement process. A similar approach is slowly emerging for grid-based storage. In several states, these explicit and implicit subsidies cover a large fraction of the investment costs in wind and solar facilities.

In addition, 38 states and the District of Columbia have adopted ‘net-metering’ rules for residential and small commercial customers.<sup>7</sup> These rules effectively allow BTM solar facilities to get credit for 100 per cent of the entire retail *revenues* avoided or displaced by their generation rather than their—much lower—actual avoided *costs*.<sup>8</sup> This results from the fact that (a) the bulk of residential and small commercial distribution and transmission costs are recovered through relatively flat per KWh usage charges rather than per customer charges or coincident peak demand charges, (b) generation, distribution, transmission, and other charges are not unbundled in many states, (c) states have not required that dual meters or smart inverters with data collection and retrieval capabilities be installed, so that purchases from the grid and sales to the grid cannot be measured separately, and (d) even in states that have deployed real time meters, real time pricing and settlements have not yet been widely adopted.

Thus if the avoided generation and distribution costs resulting from generation by a rooftop PV facility is, say, 6 cents/KWh (e.g. the wholesale market price for generation plus losses plus avoided distribution costs), while the marginal bundled retail price is 20 cents/kWh, a rooftop PV installation effectively receives 20 cents/kWh that it generates rather than the 6 cent/KWh avoided wholesale market generation and avoided distribution cost. While rooftop PV may indeed avoid some distribution and transmission costs, careful analysis shows that these savings are very small (Cohen and Callaway, 2016; Cohen *et al.*, 2016) and far below the average cost of distribution networks reflect in per KWh retail tariffs. There is also evidence that the wide diffusion of rooftop PV facilities increases local distribution costs rather than decreasing them as investments in remote monitoring and control capabilities, new transformers and capacitors, and other ‘smart grid’ investments are required to manage short-term variations in PV production and reverse flows to maintain distribution network operating criteria and avoid outages and equipment overloads (Wolak, 2018b). It is clear that if there are avoided distribution and transmission costs, the cost saving is much less than the average total cost of distribution and transmission reflected in regulated retail per Kwh rates, so in this sense net metering provides a subsidy.

Not only does net metering provide a large subsidy for BTM PV, but the subsidy from net metering is paid for by shifting regulated distribution and transmission costs from those with rooftop PV systems to those without (Wolak, 2018b). This cost shifting has

<sup>6</sup> FERC Order 841, effective 4 June 2018.

<sup>7</sup> Several states have placed limits of one kind or another on access to net metering compensation.

<sup>8</sup> Having learned its lesson from the Public Utility Regulatory Policies Act (PURPA) experience, the US does not generally rely on feed-in tariffs for grid-based renewables. However, net metering for BTM PV is effectively a high feed-in tariff.

unattractive income distribution consequences. As a consequence, a number of states have capped the availability of net metering, required smart inverters or meters to measure BTM generation, and begun to reform distribution rate designs. Not surprisingly, these changes have been vigorously opposed by environmental groups and BTM PV suppliers and installers.

One of the stated goals of the various subsidy programmes has been to help wind and solar technologies to move down a learning/innovation curve and achieve economies of scale in production and installation so that they would eventually become a competitive carbon-free alternative to fossil-fuel generation. Regardless of what the causal factors may have been, the installed cost of wind and solar PV facilities (grid-based and rooftop PV) have fallen very dramatically over the last several years, making wind and solar competitive with new fossil generating capacity with similar load factors and output profiles at some locations even without subsidies, though these comparisons typically ignore the back-up costs required to respond to intermittency in order to meet demand reliably (Gowrisankaran *et al.*, 2016). For example, the National Renewable Energy Laboratory (NREL, 2017) reports that the prices for utility-scale solar projects have fallen by about two-thirds since 2010 and rooftop PV by over 50 per cent, and these costs continue to fall. See also LBL (2018b, p. 14). Grid-based PV is much less expensive than BTM PV, but the incentives for grid-based PV are much less generous in many states than are the incentives for BTM PV.

Table 1 displays the growth in wind and solar generation in the US between 2010 and 2017. Grid-based solar has grown by a factor of over 40. Rooftop PV has grown by a factor of 10.<sup>9</sup> Grid-based wind has grown by a factor of 2.7. Overall, wind plus solar generation has grown from about 2 per cent of total US generation in 2010 to over 8 per cent of total US generation in 2017, and continues to grow rapidly. During this time period total generation to meet load has been flat. United States Energy Information Administration (EIA) projects in its reference case that by 2050 wind and solar (including behind the meter generation) will account for about 1,200 GWhs of generation on a national basis, or roughly 25 per cent of total US electricity generation (calculated from EIA (2018), various pages).

The national figures mask wide differences between states reflecting state policy choices, the available wind and solar resources which vary widely across a large country like the US, and differences in the wholesale and retail prices of electricity in different regions which affect the ability of wind and solar to compete. In California (CAISO), grid-based solar and wind already account for about 18 per cent of grid-generation and rooftop PV probably accounts for roughly another 5 per cent for a total of 23 per cent from wind and solar in 2017. However, on some days, when demand is relatively low, the wind is blowing, and the sun is shining, grid-based wind and solar account for as much as 60 per cent of total grid-supplied electricity in some day-time hours, while BTM PV further reduces the net demand on the grid at those times. While states such as New Jersey and Massachusetts do not at first blush appear to be natural candidates for solar PV in view of their northern locations, the combination of state subsidies, in addition to federal subsidies, net metering, and high retail rates (backed out by net

<sup>9</sup> Rooftop PV generation is typically not measured directly today. These are estimates developed by the US Energy Information Administration. There is a further discussion of the measurement of BTM PV generation below.



**Table 1:** US solar and wind generation (GWh)

	Grid solar	Rooftop solar	Total solar	Grid wind	Total grid wind plus solar	Total grid generation	Grid generation plus rooftop PV	Wind plus solar, % of total
<b>2010</b>	1,212	2,329	3,541	94,692	98,233	4,125,060	4,127,389	2.4
<b>2011</b>	1,818	3,692	5,510	120,177	125,687	4,100,141	4,103,833	3.1
<b>2012</b>	4,327	5,927	10,254	140,822	151,076	4,047,765	4,053,692	3.7
<b>2013</b>	9,036	8,131	17,167	167,840	185,007	4,065,964	4,074,095	4.5
<b>2014</b>	17,691	11,233	28,924	181,655	210,579	4,093,606	4,104,839	5.1
<b>2015</b>	24,893	14,139	39,032	190,719	229,751	4,077,601	4,091,740	5.6
<b>2016</b>	36,054	18,812	54,866	226,993	281,859	4,076,675	4,095,487	6.9
<b>2017</b>	52,958	24,139	77,097	254,254	331,351	4,014,804	4,038,943	8.2

Source: US Energy Information Agency, Monthly Energy Review, various years (<https://www.eia.gov/totalenergy/data/monthly/>)

metering), now make rooftop PV quite attractive in these states. States such as Iowa, Nebraska, Oklahoma, Kansas, and especially Texas have seen the installation of a lot of wind generators because of strong and steady winds which allow grid-based facilities with 40–50 per cent capacity factors to be built and operated, resulting in what appear to be very competitive prices, taking into account the benefits of federal tax subsidies. California accounts for over 40 per cent of US solar generating capacity and a similar fraction of rooftop PV. In most other states solar generation lags far behind wind generation, but is forecast to grow more rapidly over the next few decades (EIA, 2018, p. 93). Over the last 5 years over half of the utility-scale generating capacity added in the US was wind or solar. As things stand now, it looks as though we will continue to see large differences among the states in the penetration of wind and solar as a result of variations in state policies, economic attractiveness, and endowments of wind and sunshine.

The average capacity or average annual production percentage from intermittent generation also understates the impacts that these resources are already having on wholesale power markets. Especially during times of low demand—at night, during the day if there is a lot of solar on the system, on the weekend, in the spring, etc.—intermittent generation can already account for a large fraction of demand. For example, about 20 per cent of the generating capacity in the Southwest Power Pool (SPP), which stretches from north-western Texas to Montana and has the highest speed winds in the on-shore US, is presently accounted for by wind. However, wind generation exceeded 60 per cent of total load at times during spring 2018. Another 44 GW of wind is in development. Solar accounts for only 1 per cent of SPP's generating capacity at the present time, but 16 GW of solar has applied for grid connections, almost as much as the 18 GW of existing wind capacity.<sup>10</sup> In a few years there will be many hours each year when intermittent generation accounts for a large fraction of the load in several RTO/ISO areas.

<sup>10</sup> Platt's Megawatt Daily, 7 August 2018, by Kate Winston; Mike Ross, 'SPP Overview', 16 August 2017, <https://www.google.com/search?q=SPP+Overview&ie=utf-8&oe=utf-8&client=firefox-b-1>.

### III. Wholesale market design: overview

The wholesale market designs adopted by most RTO/ISOs in the US and supported by the regulator (FERC) are ‘centralized’ wholesale markets built upon a security-constrained bid-based economic dispatch model that uses competitive multi-unit auction mechanisms to choose the least-cost schedule and dispatch of generating plants to supply energy to meet demand, to manage congestion, to provide ancillary network services (frequency regulation, spinning reserves, etc.), and to derive market-clearing prices for these services.<sup>11</sup> These markets are managed ‘centrally’ by the system operator and are built upon day-ahead auction markets that yield hourly day-ahead forward prices and commitments to supply and to purchase services, intra-day adjustment markets, real-time balancing and settlements procedures, and associated prices and dispatch actions. In most US RTO/ISO markets, scheduling of generation and the management of transmission congestion are handled simultaneously via a security-constrained bid-based economic dispatch mechanism that incorporates the attributes of the transmission network and reliability criteria. The security-constrained bid-based dispatch (potentially) yields a very large number of day-ahead, intra-day, and real-time nodal (locational) prices reflecting transmission congestion and reliability constraints. Bilateral physical contracts may also be submitted to system operators, along with adjustment parameters to allow them to be integrated with the primary day-ahead and hourly adjustment markets. Buyers and sellers rely on independent futures markets to hedge financial commitments or to speculate on the future evolution of prices.

Most of these organized markets have also evolved some kind of ‘resource adequacy’ process to deal with the fact that ‘energy only’ markets, especially with price caps (Joskow, 2007; Joskow and Tirole, 2007), do not, in practice, as well as in theory, yield adequate revenues to respond to inefficient exits of existing plants and to attract new plants to meet reliability requirements. PJM, New England, and New York have developed similar organized capacity markets. Generators whose bids clear in the capacity market receive market-based capacity payments in addition to payments for supplying energy and ancillary services at market-based prices. In California, the California Public Utilities Commission (CPUC) has required load serving entities to contract forward for adequate capacity to meet their forecast loads during the next five (peak) summer months, but there is no organized market. The CPUC has recently announced expanding the requirement to up to 5 years, reflecting concerns that too many gas-fuelled generators, needed to respond to intermittency and the large 4-hour ramp required to balance supply and demand as the sun goes down, were retiring (<http://www.cpuc.ca.gov/General.aspx?id=6316>). The Midcontinent ISO (MISO) has short-term resource adequacy requirements that can be supported by owning generation (many of the utilities in the MISO are still vertically integrated) or through bilateral contractual arrangements. Texas (ERCOT) has no resource adequacy requirement or capacity market. However, the price cap in Texas is \$9,000/MWh, far above the price caps typical in other ISOs. The ERCOT market is an ‘energy-only’ market relying on ‘scarcity pricing’ rather than capacity payments to provide the marginal suppliers with quasi-rents (net revenues) that can cover investment costs in the long run (see below).

<sup>11</sup> The Midcontinent ISO (MISO) and SPP market designs have evolved more slowly than those in New England, New York, PJM, California, and Texas. The states in the south and much of the western region have not created this type of organized wholesale market, and utilities remain vertically integrated.



## IV. Wholesale market design in the US: a duality between central planning and wholesale market models

### (i) Theoretical bases for RTO/ISO wholesale market design

It is important to understand the conceptual bases for current US wholesale market designs to better understand the challenges created by the transition to intermittent carbon-free zero short-run marginal cost generation at scale. Perhaps ironically, the conceptual basis for the design of organized wholesale electricity markets in the US during the late 1990s and early 2000s can be traced directly to the mid-twentieth century economic-engineering literature on optimal dispatch of and optimal investment in dispatchable generating facilities and the associated development of marginal cost pricing principles for generation services. These models were developed to apply to pre-structuring vertically integrated electric utility monopolies subject to some kind of regulation, including government ownership (Boiteux (1949 (1960), 1951, 1956); Drèze (1964); and Turvey (1968)). These models of generation dispatch, marginal cost pricing, and investment were eventually integrated with transmission network management and nodal pricing based on the work by Fred Schweppe and colleagues (1988).<sup>12</sup>

These old central planning models embodied the assumptions that electricity demand varies widely from hour to hour, that it is inelastic in the short run, that demand is controlled by consumers and not the system operator, except under shortage conditions when non-price rationing is applied by the system operator, and that the electricity generated to meet variable demand cannot be stored economically. Demand is not rationed by price but is exogenous and intermittent from the perspective of the system operator. The models also reflect the fact that the physics of electric power networks requires that the generation of electricity must exactly match the exogenous (to the system operator) variable and uncertain demand for electricity continuously in real time, or outages and damage to equipment will occur. This characterization of electricity demand and non-storability of generation made it convenient to represent demand over the course of a year with a load duration curve which specifies the number of hours during a year when load (demand) reaches a specific level from lowest duration (peak) to highest duration (base), but is not affected at all by short-run variations in prices. This foundational theoretical work focused heavily on the supply side and the development of short-run and long-run marginal cost principles, but little on the demand side which, due to metering, control, and pricing constraints, was effectively treated as both variable and uncontrolled. This being said, it is not too difficult to extend the classic models of this genre to incorporate price sensitive demand as well (Joskow and Tirole, 2007).

On the generation supply side, the models specify a mix of *dispatchable* generating technologies. The technologies in the feasible set have different ratios of capital and operating (mostly fuel) costs. They are typically characterized as peaking technologies that have relatively low capital costs and relatively high operating costs (e.g. combustion turbines), mid-merit generating technologies with higher capital costs and lower operating costs (e.g. steam turbines fuelled with oil, gas or both), and base load generating technologies (e.g. coal and nuclear) with still higher capital costs and lower

<sup>12</sup> Boiteux (1949 (1960)) also discussed the locational variation in prices due to transmission congestion.

operating costs.<sup>13</sup> The optimal investment problem is then to identify a mix of peaking, mid-merit, and base load capacity that exactly meets the load duration curve at minimum total cost. Once the optimal dispatchable generation mix is defined, a generation dispatch curve representing the short-run marginal operating costs of supplying any specific level of demand can be defined. Generators are dispatched in merit order along this dispatch curve from lowest cost to highest marginal operating cost to meet demand plus operating reserves and ancillary network support services at each point in time. The marginal operating costs of the marginal generator required to balance supply and demand at each point in time also defines the short-run marginal cost of supplying each level of demand. Over time, this classic model was enhanced to include demand uncertainty, demand curtailments (outages), short-run demand response, stored (dispatchable) hydro-electric technology, planning and operating reserves, and network support services such as frequency regulation, and spinning reserves. [Joskow and Tirole \(2007\)](#) contains a more complete development of this classical model that includes price-sensitive and price-insensitive demand, a continuum of generating technologies, and network outages, in a market rather than a planning context.

## **(ii) Energy and ancillary services markets: short-run resource allocation**

The initial design of organized wholesale markets in the US implicitly assumed that instead of ‘central economic dispatch’ by the vertically integrated system operator with a geographic monopoly based on the reported costs of each generator, competitive wholesale markets could be developed which replaced the vertically integrated central planner with competitive bidding by competing generators via appropriately designed auctions to define a least-cost dispatch curve (from lowest to highest marginal price bid to just meet demand at each point in time) for energy supply and ancillary network support services at each point in time (day-ahead and intraday hourly auctions). Generators would make multi-unit offers to supply quantities of generation services from the generators they own, which would include constraints specific to individual generators—e.g. start-up costs and ramping times and constraints. The system operator uses this competitive bid information in a security-constrained bid-based dispatch programme, which includes the transmission network topology and other network operating constraints, to solve for the least-cost day-ahead dispatch to meet forecast hourly demand during each hour and the associated uniform market-clearing prices at each location (locational or nodal pricing). A similar process proceeds for intra-day markets. The market-clearing spot prices are directly analogous to the short-run marginal cost along the dispatch curves in the old centralized economic dispatch models. Basically these competitive market mechanisms were developed to replicate the idealized central economic dispatch process, essentially adopting the view that there is a duality between the competitive market mechanisms and this idealized central economic dispatch process.

<sup>13</sup> Green and Vasilakos (2011) graphically depicts this classical model nicely. [Joskow \(2008\)](#) contains a numerical example of this model enhanced with a ‘technology’ that allows demand to be curtailed based on the ‘value of lost load’.

We should recognize that in both a vertically integrated system and an organized wholesale market of the type that has developed in the US, the system operator always keeps physical control of the system, making dispatch decisions as much as possible by choosing the generators that have offered to supply energy and ancillary services at the lowest prices reflecting their short-run marginal costs (SRMC) consistent with maintaining the reliability requirements of the network. The reliability requirements are in turn typically defined by engineering criteria that have been carried over from the vertically integrated utility regime. System operators have the flexibility to dispatch generators 'out of merit order' if necessary to maintain reliability of the system and a variety of imperfect rules have been specified to compensate generators called out of merit order and those in merit order which, as a result, are not called to supply. If these 'out-of-market' payments become significant they can lead both to short-run operating inefficiencies and distorted investment incentives.

One might ask why bother with the difficult process of creating wholesale electricity markets with these attributes if we are simply reproducing the central planning results for generator scheduling and dispatch? The answer is that the central planning models for vertically integrated utilities are 'idealized' models that do not take into account the incentives faced by the regulated vertically integrated monopoly and how these incentives affect behaviour. It is generally thought that regulated monopolies have poor incentives to control operating and construction costs, to maintain generator availability at optimal levels, to retire generators when the expected present value of their costs exceeded the expected present value of continuing operations, to overinvest in new generating capacity, to fail aggressively to seek out innovations, and other inefficiencies. In short, the real world regulated monopoly does not perform as the idealized model implies. In principle, if competitive market mechanisms are well designed and market power is absent, competing generators should have high powered incentives to control operating costs, construction costs, to maintain availability, to seek out innovations, to invest to enter the market, and to exit the market to cut expected losses. However, if there are imperfections in the market mechanisms and associated rules and market power, the market model will be characterized by imperfect performance as well. The move to liberalizing the electricity sector in this way was effectively a bet that the costs of any residual imperfections in competitive wholesale markets are smaller than the costs of imperfections associated with the behaviour of vertically integrated regulated monopolies.

These organized wholesale markets also produce transparent spot prices for energy and ancillary services. These prices provide signals to generators regarding when and where to offer to supply, as well as price signals to guide entry and exit decisions. Locational prices can also be used to guide transmission investment decisions and adjustments in reliability rules and operating decisions. If these price signals are conveyed in prices charged to consumers that better match variations in marginal cost through variable retail pricing, more efficient consumption behaviour will be induced (more on variable pricing below). While in theory, the central economic dispatch process produces shadow prices that are conceptually similar to spot market prices, these shadow prices are not transparent. This creates challenges for using them to support pricing and investment decisions by regulators.

### (iii) Entry, exit, capacity pricing, and scarcity pricing: long-run resource allocation

Wholesale markets in the US were designed as well to support decentralized free entry (and exit) of generating capacity along with efficient dispatch, efficient pricing, and reliable clearing of supply and demand. In the long run, forward wholesale price and associated profit expectations were expected to determine decentralized decisions by investors to build new generating capacity to enter the market and decisions by existing generators to exit. That is, ‘the market’, rather than integrated resource planning by the vertically integrated utility, interest group interventions, plus regulatory oversight, would determine entry and exit decisions by decentralized owners of generating plants and lead to an efficient portfolio of generating capacity over time. Investors would bear the risks of changes in market conditions, construction cost overruns or construction efficiencies, etc., rather than consumers as was the case when all ‘prudent’ generating costs were passed on to consumers through regulated rates. Decentralized entry of generating capacity based on market price signals, rather than regulated integrated resource planning, reflected one of the hidden goals of restructuring and reliance on competitive wholesale markets: get the interest group politics out of the regulated utility’s entry, exit, and fuel supply decisions. However, this goal assumed implicitly that market mechanisms would also be introduced to deal with the most important externalities through some form of efficient emissions pricing.

In my view, the initial ‘centralized’ wholesale market designs in the US paid too little attention to their investment incentive properties. In this regard, there is one particular attribute of the fully developed Boiteux–Turvey model (see [Joskow and Tirole, 2007](#)) that was not adequately taken into account initially in many wholesale market designs and is a source of an important wholesale market imperfection.<sup>14</sup> This imperfection will become more and more important as intermittent renewable generation with zero marginal operating costs becomes a large portion of generation. Regulators and system operators have been chasing their tails to deal with the resulting imperfections in investment and retirement incentives. Drawing on the Boiteux–Turvey Model (and nicely explained by [Drèze \(1964\)](#)), in order to support an efficient long-run equilibrium, prices must rise *above* the short-run operating cost of the highest marginal operating cost plant on the system when total available generating capacity is a binding constraint on balancing supply and demand. Prices must rise high enough under these contingencies for decentralized investors to expect that the present discounted value of future prices will be high enough to cover the capital costs as well as the operating costs of an investment in generating capacity.<sup>15</sup> In the standard model prices must be high enough to be expected to cover the capital costs of a peaker, the least capital intensive generating technology in the standard model. This in turn produces enough revenue to cover the capital costs of an optimal portfolio of infra-marginal generators as well ([Joskow, 2008](#)).

<sup>14</sup> Another ‘surprise’ was that a voluntary long-term contracting market between generators and load serving entities did not emerge. While voluntary forward markets have emerged, they offer contracts or hedges of relatively short duration (e.g. up to two or three years) and are quite illiquid beyond a year or so. The reasons for this are beyond the scope of this paper, though short-run prices that are too low lead to forward prices that are too low as well.

<sup>15</sup> Obviously, under these conditions these prices should be conveyed to consumers and supply and demand balanced by responses on the demand side. See [Joskow and Tirole \(2007\)](#).

Whether one relies only on short-run marginal cost pricing in the regulated central planning world of Boiteux–Turvey, or instead designs wholesale markets so that prices cannot rise much above the short-run marginal operating cost of the highest operating cost generator at the top of the bid-based dispatch curve (e.g. by imposing price caps), the fact is that these prices cannot support a long-run equilibrium with an optimal configuration of generators. Boiteux (1949, 1956), Drèze (1964), and Joskow (2008) recognize this fact, but it was given inadequate attention initially in wholesale market designs. Market design efforts focused on designing short-run market mechanisms: generation and ancillary services auction design, efficient nodal price formation to reflect network congestion, multi-settlement systems, and other important ‘details’ of market design required to operate the system efficiently and reliably under most contingencies.<sup>16</sup> Little attention was played to the long-run incentives for exit and entry that these market design features produced.

Basically, if the peaking plant that is called last to meet peak demand levels can earn only its marginal operating costs, or prices are capped below the value that reflects consumer valuations of their consumption being rationed to balance supply and demand when demand exceeds generating capacity and threatens system reliability (value of lost load—VOLL), then it cannot recover its investment costs. Indeed, as Joskow (2008) demonstrates with a numerical example, pure short-run marginal cost pricing plus non-price rationing when demand exceeds generating capacity does not allow any generator in the optimal configuration to fully recover its capital costs. This ‘revenue inadequacy’ or ‘missing money’ problem can lead to premature exit of existing generating capacity as well as inadequate investment in new generating capacity.

Most wholesale markets in the US have repeatedly failed this ‘revenue adequacy’ test based on energy market revenues only.<sup>17</sup> A significant shortfall would exist for grid-based wind and solar as well, but for various federal and state direct and indirect subsidies and ‘out-of-market’ payments that they receive.<sup>18</sup> Although the ‘missing money’ problem focuses on new investments in generating capacity, this imperfection in pricing also affects exit decisions. Existing generators incur more than marginal fuel costs. They have employees to pay, property taxes to pay, and other fixed costs associated with keeping a plant open. More importantly, as plants age, there are incremental capital costs that must be incurred to sustain availability and operating efficiency. Thus, even for existing plants, the longer-run avoidable costs are typically significantly higher than their avoidable fuel costs.

There are two more or less equivalent ways to reflect the value of reliability under scarcity conditions and allow generators to monetize the marginal value of more or less generating capacity when generating capacity constraints are binding. Ideally, wholesale markets would include active demand sides that reflect the price sensitivity and willingness to pay of all consumers, especially during contingencies when the system operator confronts operating reserve deficiencies and begins to implement emergency

<sup>16</sup> Let me note that this also has implications for measuring market power. A long-run competitive equilibrium can only be supported by revenues that exceed the revenues produced by short-run marginal cost pricing. Accordingly, a finding that revenues exceed what would result from setting prices exactly equal to short-run marginal operating cost does not necessarily imply that there is a market power problem. As a practical matter, one has to look at ‘uneconomic’ withholding of capacity to identify market power.

<sup>17</sup> See, for example, *Monitoring Analytics* (2018, pp. 309–35).

<sup>18</sup> *Monitoring Analytics* (2018, p. 324).



actions to avoid voltage reductions, rolling blackouts, or a system collapse (Joskow and Tirole, 2007). During such situations wholesale market prices should rise above the marginal operating costs of the last generating unit to be dispatched to reflect the value that consumers place on consuming less electricity or being subjected to involuntary blackouts. We can refer to this as the value of lost load (VOLL). Estimates of the VOLL vary widely, but are typically much higher than the marginal operating cost of the last unit to be dispatched (Schröder and Kuckshinrichs, 2015). And as prices rise, consumers should reduce consumption to bring supply and demand back into balance in the short run with prices rather than non-price rationing.

However, in the RTO/ISO markets in the US, prices generally do not rise to clear the market when generating capacity constraints bind because (a) there is typically a price cap set well below VOLL, reflecting concerns about market power,<sup>19</sup> and (b) there is not a fully representative price-sensitive aggregate demand function to allow prices to rise to reflect the VOLL to individual consumers plus a representation of the external cost that could lead to a network collapse affecting all consumers (Joskow and Tirole, 2007).<sup>20</sup> If such a demand function were properly represented in the wholesale market, prices would continue to rise to ration demand in the face of generating capacity constraints. This is often referred to as ‘scarcity pricing’. These anticipated demand responses and associated market prices would also affect the optimal investment profile, with ‘scarcity pricing’ contingencies factored into the choice of total generating capacity and the quantity of each of the generating technologies that make up the optimal portfolio of generation investments. Unfortunately, consumer demand and valuations of reliability are not and probably cannot be fully represented in wholesale market demand functions today. Perhaps the spread of smart meters and grid monitoring and control technology will ultimately allow better representation of consumer demand and associated demand response, but, as Joskow and Tirole (2007) point out, there are also externality or common goods attributes of reliability that cannot be represented fully in the aggregation of individual consumer demand functions placed on the wholesale market.

Note that scarcity pricing is not a departure from the basic principle of short-run marginal cost pricing. Rather, movements along the appropriate demand curve when capacity constraints are binding reflect consumer valuations of sudden reductions in available generating capacity (reliability) and represent consumers’ short-run marginal *opportunity cost* of having more or less generating capacity. While there may be few hours when capacity constraints are binding, energy prices would likely go to very high levels as demand is price-rationed and yield substantial revenue for all generators which would allow them to recover their capital costs in long-run equilibrium (Joskow, 2008).

<sup>19</sup> US RTO/ISO system operators have proposed and FERC has approved price caps well below VOLL. The justification is to mitigate generator market power as the system approaches capacity constraints. Even with many generation suppliers, as demand approaches capacity constraints, even a small generator can recognize that withholding a little capacity from the market can lead to a large price increase absent a price cap and an active responsive demand side represented in the wholesale market.

<sup>20</sup> Texas (ERCOT) is an exception. It has a \$9,000/MWh price cap. However, it is not at all clear that the mechanism that leads prices to rise to high levels reflects an efficient representation of consumer demand for energy and reliability, since price-sensitive consumer demand is only partially represented in the wholesale market.



An alternative approach to producing the expected net revenues needed to support investment costs has been adopted in the several RTO/ISOs in the US. This approach is referred to as ‘capacity market’ mechanisms. These mechanisms require establishing a minimum generating capacity target to meet reliability constraints and running a forward market that determines ‘capacity prices’ that generators receive if they can commit to being available to supply energy and/or ancillary services under ‘stressed’ system conditions. The creation of capacity markets recognizes that wholesale energy spot prices are capped to mitigate market power, that VOLL is not directly reflected on the demand side in organized wholesale markets, and that RTO/ISOs have retained target reserve margins for reliability from the pre-liberalization era, which determine when system operators begin to take emergency actions to ensure that demand does not exceed capacity constraints, requiring actions such as voltage reductions and rolling blackouts. It recognizes further that some additional competitive market mechanism needs to be adopted that reflects these considerations so that the quasi-rents that would be produced if there were efficient scarcity pricing can be produced through an alternative competitive mechanism.

The design and implementation of this ‘capacity market’ mechanism has involved the creation of aggregate system (and local where there is persistent congestion separating portions of the RTO’s control area) capacity targets, auction markets when generators can submit bids to commit to being available to supply under capacity-constrained conditions, and resulting forward capacity prices (Cramton and Stoft, 2005; Léautier, 2016; Keppler, 2017). This mechanism requires the system operator to define a target aggregate generating capacity to meet specified reliability/reserve requirements for the system, specify a demand curve for capacity anchored at this target, and set up a bid-based ‘capacity market’ to allow existing capacity, potential new capacity, and certain demand curtailment actions, to compete in a forward market that establishes forward prices for capacity for some number of future years (e.g. 3 years in New England), along with performance obligations during time periods when the committed capacity may be called. The structure of these capacity markets varies from ISO to ISO and the market designs have changed over time. Typically, existing and new generation resources (as well as demand-side resources, including energy efficiency, per rules established pursuant to FERC Order 745<sup>21</sup>) compete to be selected to meet an aggregate peak generating capacity target established by the ISO consistent with its reliability/reserve criteria.<sup>22</sup>

While perhaps attractive based on the standard Boiteux–Turvey theory, the capacity market designs and implementation have not been without problems in practice. Getting pay for performance (availability) incentives right has been especially problematic. Capacity market designs have gone through numerous ‘refinements’ over time, including recent actions to create zonal capacity markets reflecting transmission congestion, adjustments in the slope, upper and lower bounds on the system capacity demand curves, treatment of demand-side resources, availability/performance requirements and penalties, treatment of subsidized generation, and other changes.<sup>23</sup> Despite these

<sup>21</sup> I agree with William Hogan (2016) that the payment mechanism for demand-side resources adopted by FERC and approved by the US Supreme Court is deficient and can lead to perverse results.

<sup>22</sup> An excellent description of the capacity market in New England can be found in ISO New England (2018c, Section 6.1.

<sup>23</sup> See, for example, ISO New England (2018c, p. 146).

challenges, capacity markets have now become the favoured approach in the US and now Canada for dealing with incentives to maintain levels of generating capacity that satisfy reliability criteria. PJM, ISO New England, and New York ISO have adopted organized wholesale markets, and Alberta, Ontario, and others are now moving from energy-only markets to energy plus capacity markets, as it is perceived that energy-only markets with price caps do not yield sufficient revenues economically to sustain existing capacity and to attract new generating capacity. California has a resource adequacy mechanism that appears to be evolving into an organized capacity market. We should remember, however, that there is a linkage between properly designed and implemented scarcity pricing mechanisms and properly designed capacity market mechanisms.

Why have I spent so much time on scarcity pricing and capacity pricing problems and the associated efforts to solve the ‘missing money’ problem? As I discuss further below, the rapid growth of intermittent generation means that (putting out-of-market subsidies and payments aside) revenues from capacity prices and/or scarcity prices will have to be a growing source of revenues to support investment and retirement decisions consistent with an efficient long-run equilibrium *if* it is expected that we will rely on decentralized wholesale market price signals to attract an efficient generation portfolio. Very simply, as the penetration of intermittent generation with zero short-run marginal costs grows to become a large fraction of total generation, market-based energy prices during the hours it operates will fall towards zero—perhaps to zero in many hours if very aggressive wind and solar penetration goals are met. The energy market will produce little in the way of net energy and ancillary service market revenues to cover investment costs. If we expect to rely on the standard RTO/ISO decentralized wholesale market model, scarcity pricing and/or capacity pricing will have to be a much more important source of revenues to cover the investment costs of solar, wind, dispatchable generation for ramping and ancillary services, and storage.

#### **(iv) Extending the Boiteux–Turvey model to incorporate intermittent generation**

Recent theoretical literature has extended the traditional Boiteux–Turvey model to incorporate intermittent generation at scale (MacCormack *et al.*, 2010; Green and Vasilakos, 2011; Green and Léautier, 2018; Llobet and Padilla, 2018) with interesting implications. This theoretical work indicates that the changes in the level, hourly distribution, and volatility of wholesale prices has implications for the profitability of incumbent dispatchable generating capacity, for incentives for entry of new generating capacity that is better matched to the attributes of a generating system with a large fraction of intermittent generating capacity (e.g. quick start, flexibility), and for the optimal mix of generating capacity. Let me note that most of this theoretical work takes the penetration of intermittent generation as being exogenous, driven by policy actions, and does not derive the optimal mix of solar, wind, and fossil generation, etc.

This work implies that the attributes of electricity sectors with large-scale deployment of intermittent generation are not favourable to traditional base load generating and mid-merit capacity with high capital costs, high start-up costs, and limited flexibility in dispatch. As intermittent generation expands, existing dispatchable generation becomes increasing unprofitable and eventually retires (Green and Léautier, 2018). There will be

just too many hours with very low or negative prices and too much day-to-day price volatility for these plants to cover their going forward costs, let alone their capital costs. Simple modern combustion turbines—that have relatively low capital costs and the flexibility to supply very short-term frequency control, voltage support, and balancing services, to increase output rapidly enough to meet the variable end of day ramp—are in a much better position to recover both operating and capital costs with relatively low capacity factors, assuming that wholesale prices are set right. The generating units with these flexibility attributes should be the last to find it economical to exit the market and first to enter the market. We turn next to a discussion of whether and how these effects are being realized in California.

## V. Impacts of intermittent renewable energy at scale in the California ISO (CAISO)<sup>24</sup>

Among the wholesale electricity markets in the US, California is the most interesting. This is not because California has a particularly interesting market design—it does not. Rather it is because California is far ahead of the rest of the US in terms of meeting goals for replacing fossil-generating capacity with intermittent wind and solar. While California is not yet close to the longer-term goal of moving to a zero carbon emissions electric power system with much greater reliance on wind and solar, it is far enough down the path to a system dominated by solar (primarily) and wind, that we can begin to observe empirically some of the implications of this transformation. California is particularly interesting because the mix of solar and wind is much more like it is projected to be in the rest of the US in the future, especially as solar generation is expected to grow much more quickly than wind and other renewable generation in the future (EIA, 2018, pp. 93–7). The data available for California are also much richer and more available than the data for other regions. So, California (CAISO) is a worthwhile case study.<sup>25</sup> Let me note, however, that the effects on wholesale markets that we are seeing in California are being seen, to a lesser extent so far, in the other organized RTO/ISO markets in the US. As the other regions catch up with California, in terms of the penetration of intermittent generation, the effects will be similar (LBL, 2018b).<sup>26</sup> Moreover, my reading of wholesale market reform discussions in Europe and the US is that the issues associated with integrating intermittent renewable resources at scale into wholesale electricity markets are very similar.

<sup>24</sup> This section focuses on the effects on wholesale prices, entry, and exit of dispatchable generation. Energy storage and demand-side responses also have the potential to respond efficiently to intermittency. I turn to storage and demand response in the next section.

<sup>25</sup> While this paper was being written, Bushnell and Novan (2018) distributed a working paper that contains a comprehensive analysis of supply and pricing patterns affected by the penetration of wind and grid-based solar in the CAISO. I don't think that there are significant differences in our empirical conclusions.

<sup>26</sup> California does have access to an unusually large amount of conventional hydroelectric capacity which can be used to some extent to manage intermittency.

### (i) Intermittent generation supply and price patterns

The energy supplied by wind and solar generating facilities has a short-run marginal cost of roughly zero once the facility has been constructed (as well as ongoing maintenance costs which are properly treated as fixed costs per year). If they were traditional dispatchable generating facilities, they would be dispatched all of the time except when they experienced forced outages or were off line for maintenance. They would be the ultimate base-load facilities—with even lower short-run marginal generation costs than nuclear, which has a capacity factor of over 90 per cent in the US. However, solar and wind facilities are not dispatchable in the traditional sense. Their production is driven by the availability of wind and sun at their locations. Both wind and solar resources vary significantly from hour to hour, day to day, and season to season, and their supplies are characterized by significant uncertainty. As a result, the production of electricity from solar and wind facilities is highly variable, controlled by natural variations in wind and solar, rather than traditional economic dispatch curves and protocols.

I now turn to exploring the extent of this variability of solar and wind generation observed in the CAISO in more detail. [Figure 1](#) contains a chart that displays the hourly production of grid-based solar energy on a hot summer day in 2018. [Figure 2](#) contains a chart that displays the hourly grid-based solar generation in California on a winter day in 2018 with an overlay of the grid-based solar production on the hot summer day. These days were selected for illustrative purposes only. We can see, not surprisingly, that solar generation only takes place during daytime hours, that solar production in the winter is lower than solar production in the summer as the days are shorter and peak insolation is lower. [Figure 3](#) adds wind generation to [Figure 1](#). This hot summer day was a relatively low wind generation day. [Figure 4](#) adds wind generation to [Figure 2](#). This winter day is

**Figure 1:** CAISO grid-based solar generation (PV + thermal), 18 July 2018

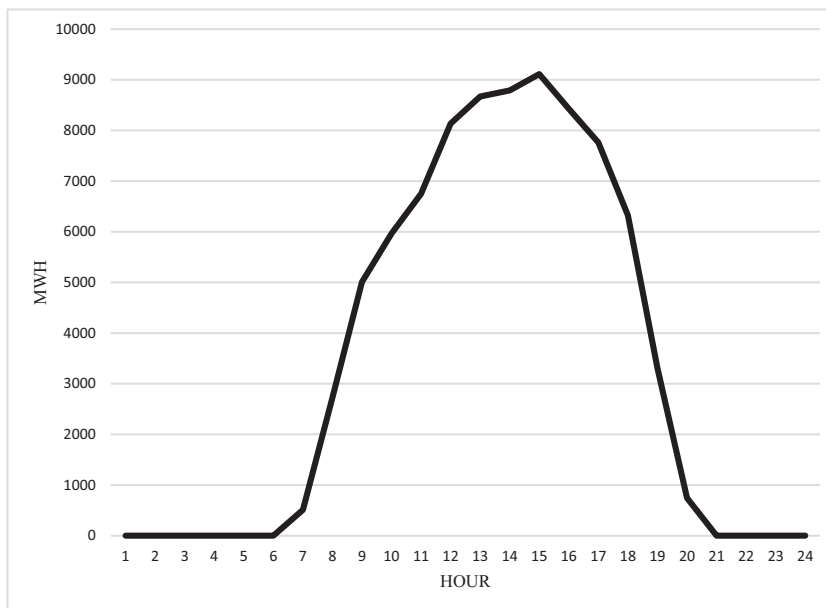


Figure 2: CAISO grid-based solar, 7 February and 18 July 2018

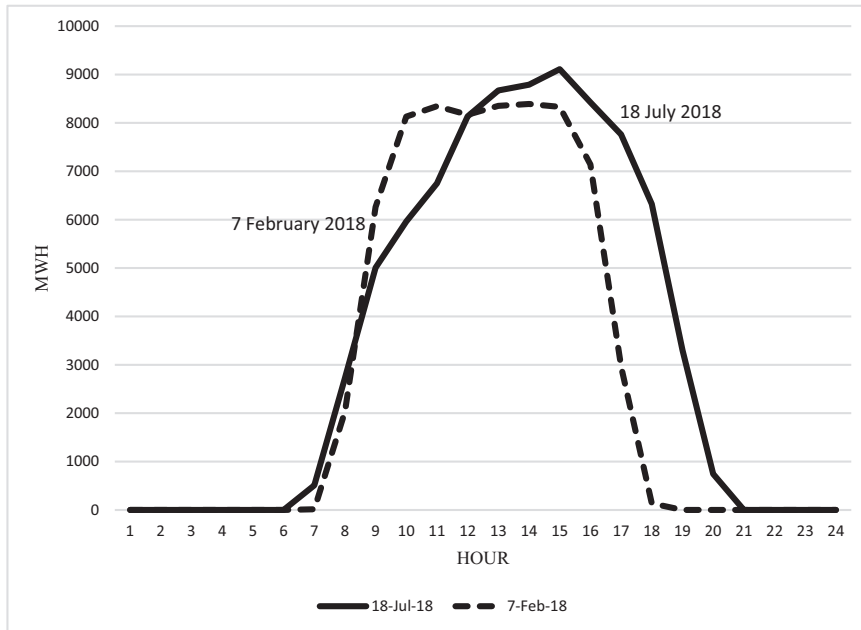
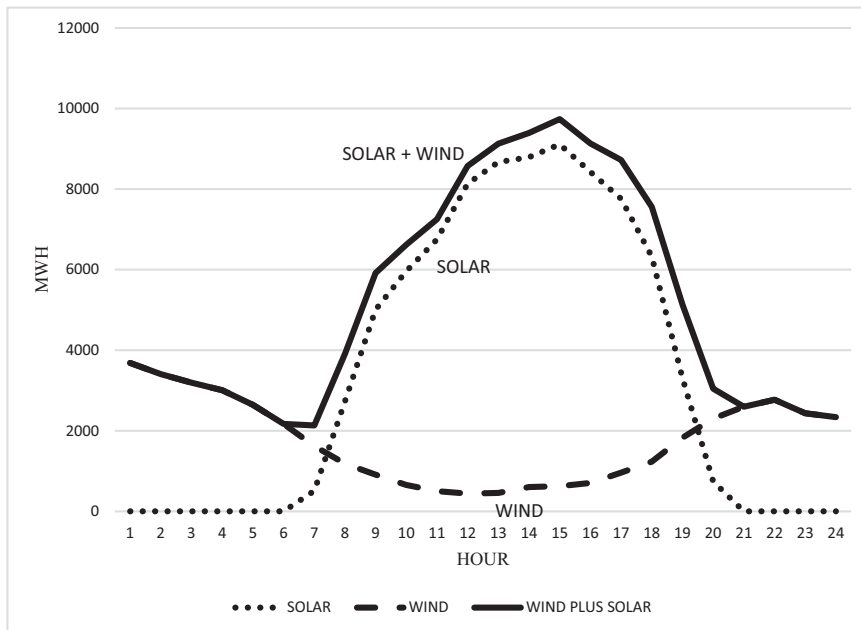
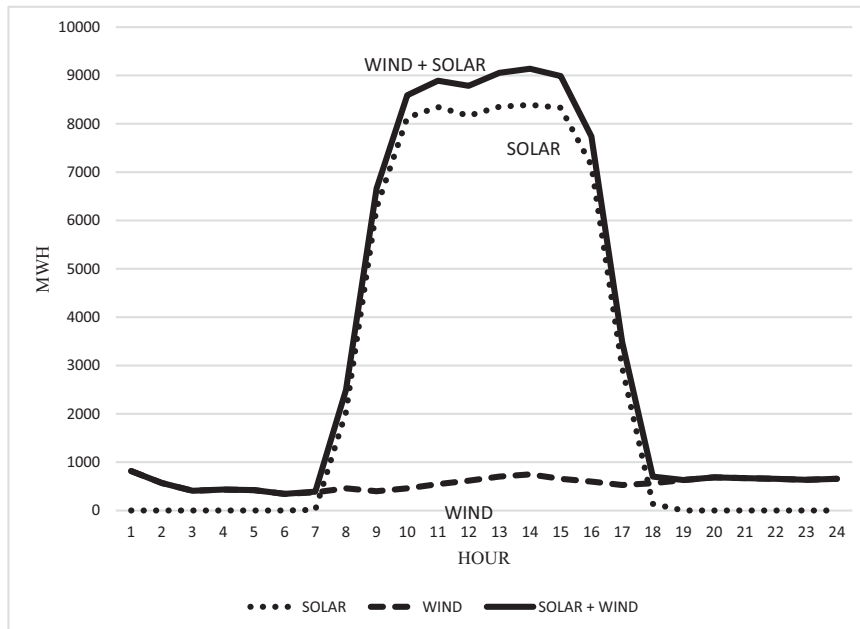


Figure 3: CAISO grid-based solar and wind, 18 July 2018



also a relatively low wind generation day. We can see that on these particular days, aggregate intermittent renewable generation far exceeds wind generation during the day, but wind generation is fairly steady across all hours during the day, with higher production

**Figure 4:** CAISO solar plus wind generation, 7 February 2018

at night than during the day in the summer. However, wind generation varies widely from day to day as we shall see.

Figures 1, 2, 3, and 4 do not include generation from BTM PV facilities (‘rooftop PV’ for short, though these facilities do not have to be located on roofs). Output from rooftop PV is typically not measured directly by and cannot be ‘seen’ by the system operator. There is a measurement and ultimately operational issue here. BTM PV appears in the CAISO data only as a reduction in the demand to be served from the grid that is ‘seen’ by the system operator. This may have been fine when generation from rooftop PV was very small, but it is now significant and expected to grow rapidly. Rooftop PV has similar effects on the system as grid-connected PV. These effects are now buried in what is generally referred to as ‘load’ or ‘demand’ on the grid. However, ‘demand’ measured in this way is more properly characterized as consumption net of BTM generation. In 2017 the CAISO had about 10 GW of utility-scale solar (nearly 12 GW by October 2018) and roughly 6 GW of BTM PV. Utility-scale solar accounted for 11 per cent of total CAISO delivered generation (total generation includes imports) in 2017, but was as high as 20 per cent on some days in the first half of 2018. Rooftop PV has a lower capacity factor than utility-scale PV, so 5 per cent is a reasonable guestimate of the associated generation in 2017, and almost 10 per cent on a recent peak solar day. Accordingly, about a third of the total solar production in California cannot be seen by the system operator.<sup>27</sup>

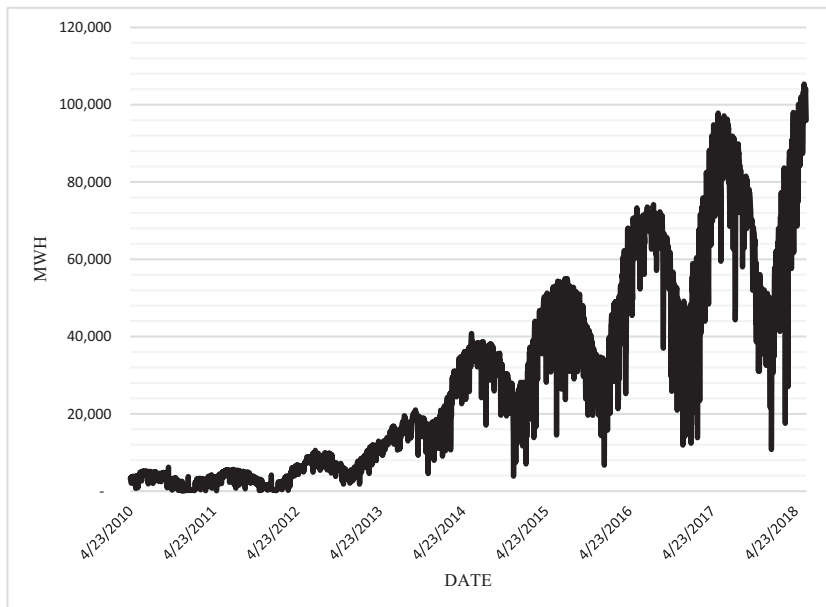
<sup>27</sup> The situation in New England is even more extreme. The ISO presently ‘sees’ only about 100 MW of grid-connected solar. However, there is another 2,300 MW of BTM solar or grid-connected solar that is not monitored by the ISO. See [ISO New England \(2018b\)](#). The New England ISO recognizes that it needs to incorporate into its understanding of the evolution of the wholesale market the production from BTM solar facilities and other unmonitored solar PV generators. It has used direct measurement of generation for



The variation in wind and solar production is not just hourly and seasonal. There is very substantial variation from day to day as well. Figure 5 displays the *daily* production from grid-based solar in the CAISO between 2010 and mid-2018. There is very significant day-to-day variation and seasonal variation observed, as well as a trend reflecting growing grid-based solar generating capacity during this time period. The unobservable generation from rooftop solar should exhibit a similar pattern, but the effects would be buried in the level and volatility of observed demand on the grid seen by the system operator, since, as already noted, BTM PV generation is not measured directly by the CAISO. Figure 6 contains the same data but for the more recent June 2016 to June 2018 period. The daily and seasonal variation can be seen more clearly in this figure. Figure 7 displays the daily wind generation variation for this same time period. The day to day variation for wind generation is even greater than for solar with some seasonal variation between summer (higher) and winter (lower) observed. Even over the course of a week, there is substantial day-to-day variation in generation from wind and solar. Electricity consumption also varies from day to day, hour to hour, and seasonally, though in reasonably predictable patterns.

Let us return to the summer and winter days examined earlier. Figure 8 displays the total demand on grid-based generation and the total demand less wind and grid-based

**Figure 5:** CAISO daily grid solar PV, 2010–18



a *sample* of facilities combined with capacity and locational information from interconnection agreements to develop current estimates of generation for typical days and in its forecasts. Its forecasts indicate that the vast majority of solar capacity for the next 10 years will be BTM or energy-only grid-connected solar that is not monitored directly by the ISO (ISO New England, 2018a). As BTM solar expands, it is likely that direct measurement of production from these facilities and curtailment capabilities will be necessary to manage system operations and price formation efficiently.

Figure 6: CAISO daily grid PV + thermal solar, 10 June 2016 to 10 June 2018

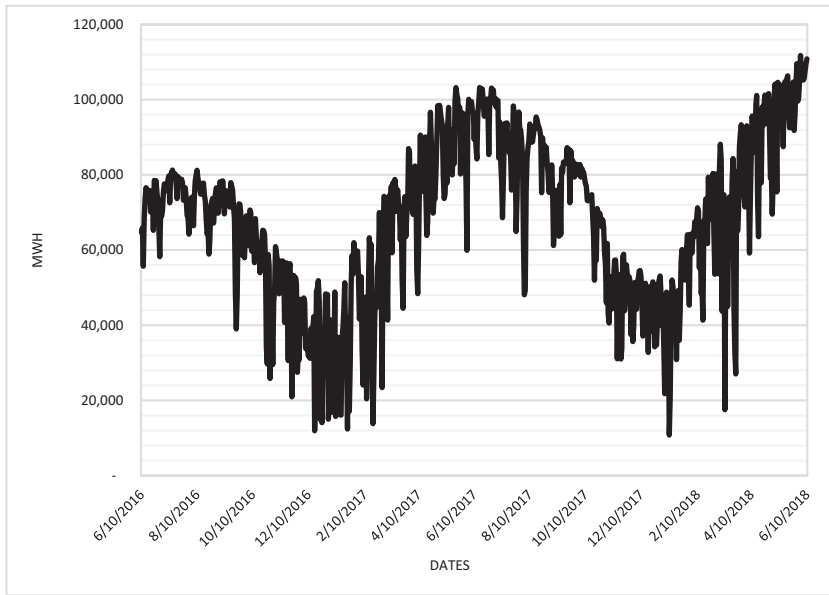
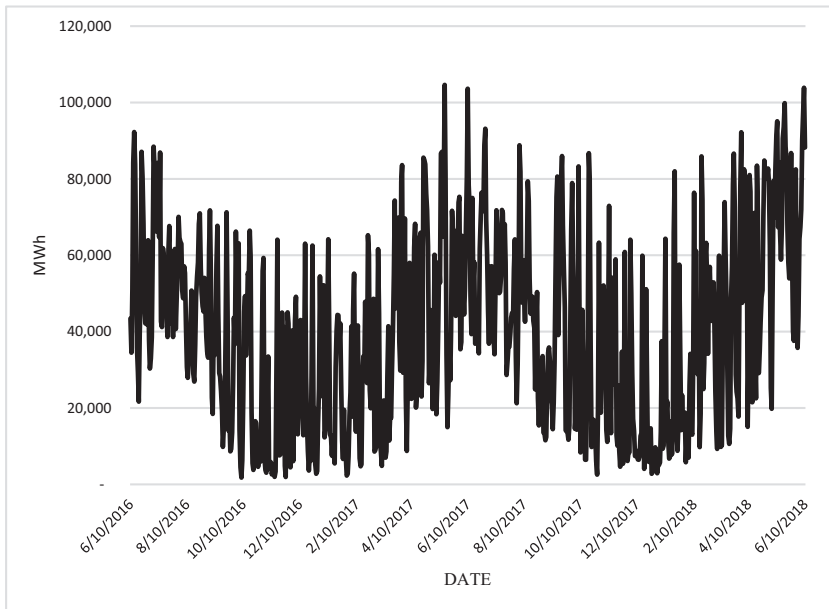
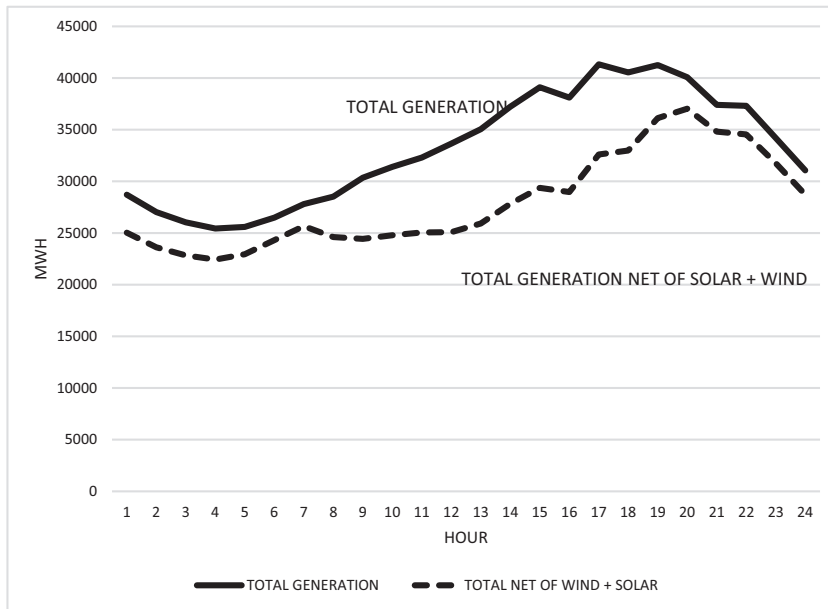


Figure 7: CAISO daily wind generation, 10 June 2016 to 10 June 2018



solar generation, or the net demand on the grid, on the summer day displayed in [Figure 3](#). On the margin, increases and decreases in the net demand are met with dispatchable generation. More importantly, the net demand on the grid is what drives spot energy prices. This is a particularly hot summer day, so that total and net demand on the grid

**Figure 8:** CAISO total and net grid generation, 18 July 2018

is unusually high throughout the day. Nevertheless, we can see that the demand net of solar and wind has a local peak in the morning and is then fairly flat until 2:00 pm. It then increases over the next 8 hours by nearly 15,000 MW before beginning to decline at 8:00 pm. The 15,000 MW increase in net demand on the grid reflects both rising demand during the day and the decline in solar production as the sun goes down later in the day. There is a ramp of nearly 10,000 MW between 4:00 pm and 8:00 pm. The increasing demand on the grid after 2:00 pm is met by dispatchable generation. [Figure 9](#) provides the same information for our winter day. This is a more typical winter day, but with relatively low wind generation. The net demand clearly displays the famous ‘duck curve’ shape associated with systems with high penetrations of solar energy. Here we see both an early morning peak and a (higher) early evening peak. The demand on the grid that needs to be met with dispatchable generation declines significantly between these two local peaks, reflecting the pattern of solar energy generation. There is a 10,500 MW ramp between 4:00 pm and 7:00 pm (3 hours), which must be satisfied with dispatchable generation and storage.<sup>28</sup>

As the shape and volatility of the net demand for dispatchable generation have changed, the hourly and day-to-day patterns of spot energy prices have also changed significantly ([Bushnell and Novan, 2018](#); [LBL, 2018b](#)). Relative spot energy prices during the day have declined and energy prices in the early evening have increased as the hourly net demand on the grid for dispatchable generation has changed. [Figure 10](#) displays the average hourly day-ahead locational marginal spot prices (LMP) observed in the CAISO for 2010, 2015, 2016, and 2017 relative to the mean LMP for

<sup>28</sup> California has stored hydro resources that can be dispatched to help to meet the evening peak. The California Public Utility Commission (CPUC) is now promoting battery storage. Storage is discussed below and when I refer to ‘dispatchable’ generation I recognize that it may include storage depending on the economics and its availability.

Figure 9: CAISO total and net generation, 7 February 2018

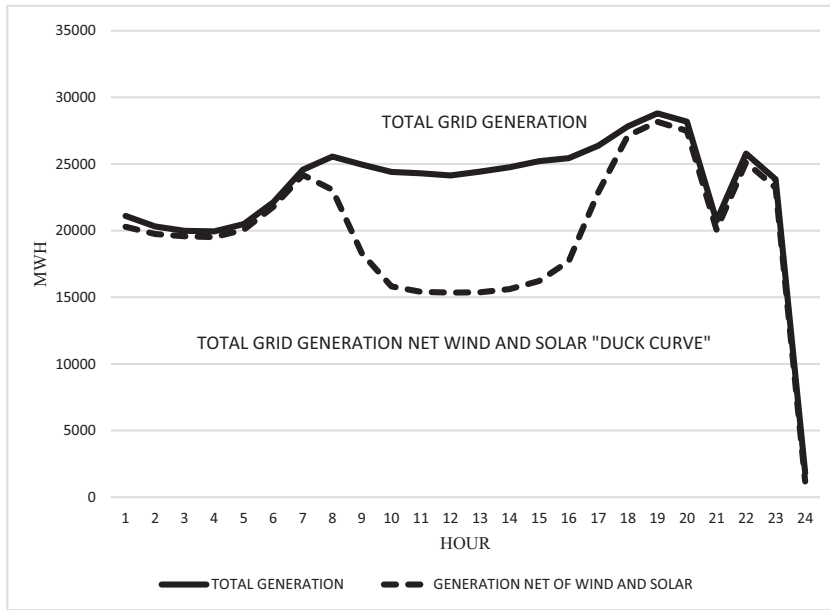
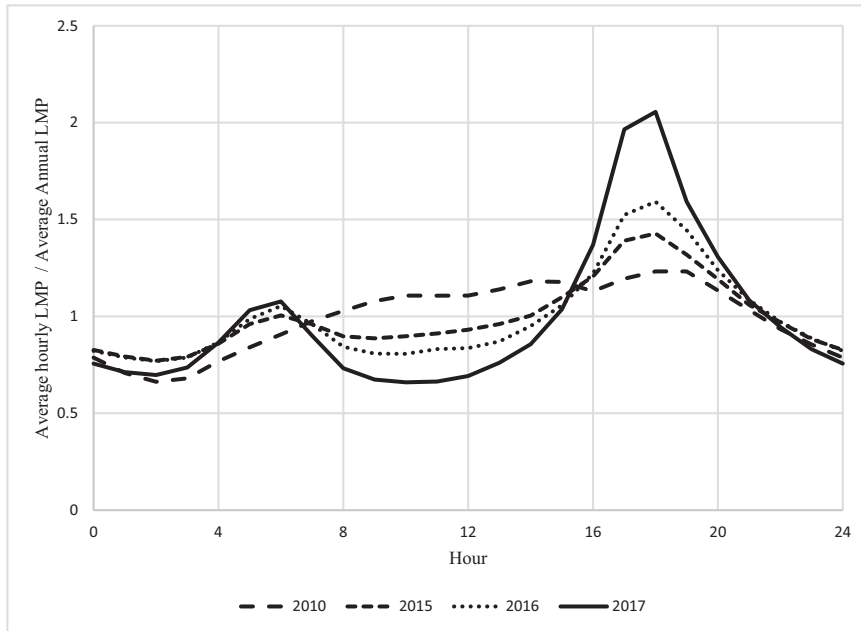


Figure 10: CAISO average hourly LMP/average annual LMP by year



that year.<sup>29</sup> Dividing the average hourly spot price by the mean spot price for all hours that year is a crude way to control for the variations in natural gas prices, which drive spot energy prices during many hours over these 4 years. It is quite evident that as

<sup>29</sup> I have not included the data for 2011, 2012, 2013, and 2014 because including the data for these years makes the chart unreadable. Including these years simply reinforces the story. Prices are adjusted for inflation.

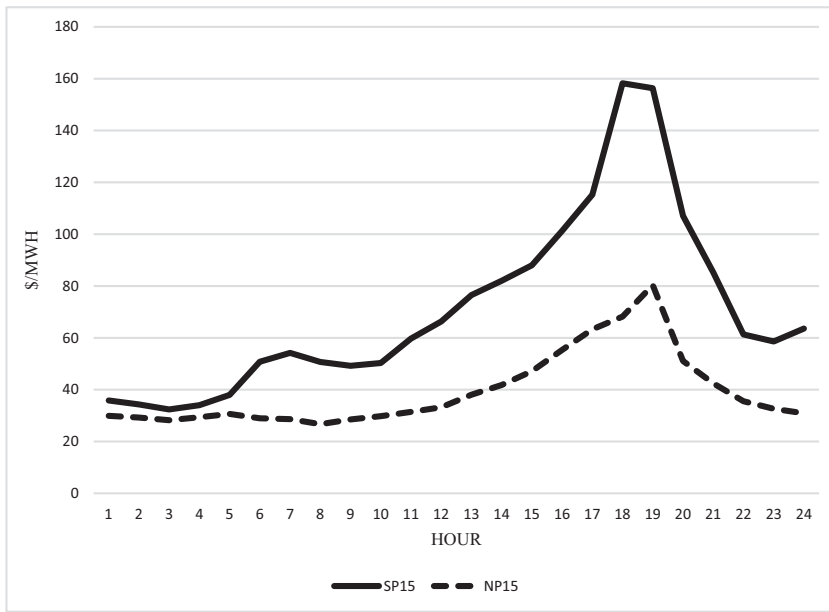
generation from solar and wind have increased over time, the hourly spot price distribution has also changed significantly, though the interesting effects are driven by the increased penetration of solar. As the penetration of solar has increased, prices have declined during the day and increased during the evening ramp as solar generation fades away. In 2010, when there was much less solar and wind generation, spot energy prices were fairly flat between 8:00 am and 8:00 pm. However, in 2017 spot energy prices nearly doubled on average between 3:00 pm and 7:00 pm and increased by a factor of nearly three between noon and 7:00 pm. The data for the years of 2010, 2015, and 2016 demonstrate how this pattern of relative hourly prices has evolved as solar penetration has grown. There is a very clear connection between the growth of solar generation and this distinct change in hourly price patterns.

Due to the day-to-day and seasonal volatility in wind and solar generation, the average hourly energy prices over the course of an ‘average’ day do not tell the full story, however. There is significant day-to-day variability in hourly prices as well. Price volatility has increased and is expected to continue to increase as more intermittent generation is added to the system. Indeed, as intermittent generation has expanded, the number of hours with zero or negative energy prices has grown, especially during mid-day hours on weekends and other low-demand days (CAISO, 2018, p. 73).<sup>30</sup> The volatility of spot prices is expected to continue to increase as intermittent generating capacity expands (LBL, 2018b). This is the case because as the fraction of intermittent generating capacity on the system increases, on average, the swings in aggregate intermittent generation will increase as well in response to variability of sun and wind. To balance supply and demand the system operator moves up and down the bid-based dispatch curve to dispatch more or less dispatchable generation as the swings in intermittent generation grow as a fraction of total generation. Ancillary services prices are also expected to increase as the need for short-term balancing and larger ramps increases (LBL, 2018b).

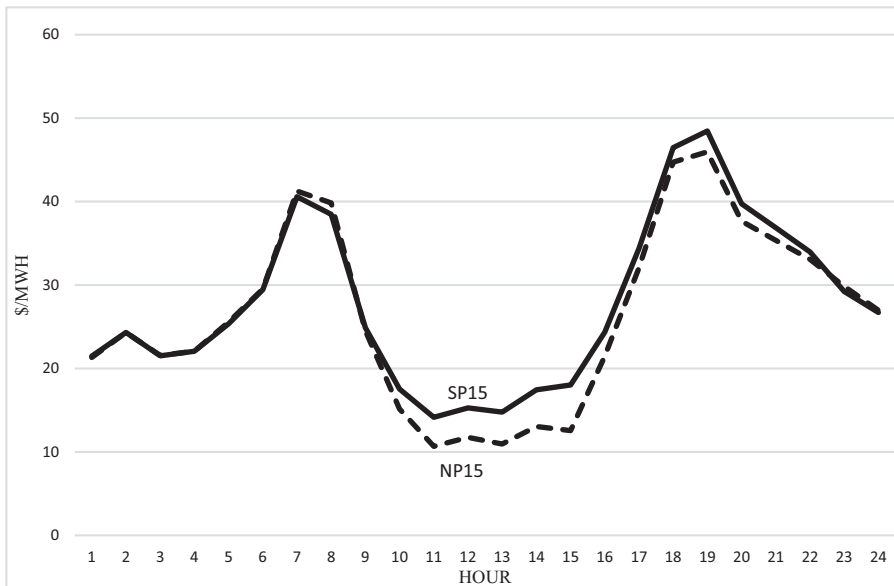
To get a sense for the variation in hourly prices and the pattern of prices on days with different supply and demand attributes, Figures 11 and 12 display hourly day-ahead prices in the southern (SP15) and northern (NP15) zones of the CAISO for the hot summer day (Figure 11) and the typical winter day (Figure 12) discussed earlier. I have added Figure 13, which displays the price data for a late spring Sunday with relatively low demand but relatively high wind and solar generation. Recall that the prices displayed in Figure 11 are for a hot day in July with very high demand, good solar, but low wind production. Note from Figure 11 that there is significant congestion between NP15 and SP15 as the prices are significantly lower in NP15 than in SP15 during the entire day. Focusing on SP15, relatively high marginal cost fossil generation or imports are on the margin as net demand starts to rise after noon. Prices rise fairly rapidly during the afternoon and the rate of increase grows between 6:00 pm and 8:00 pm as the sun goes down. Figure 12 is a more typical winter day with relatively low wind production and fairly robust solar production that tails off starting at about 4:00 pm. There is some

<sup>30</sup> While the hourly distribution of CAISO energy prices has changed and will change considerably as solar and wind expand, the annual average wholesale cost per MWh, including revenues from sales of energy, ancillary services, capacity payments, and other products through the CAISO, normalized for variations in gas prices, was very roughly constant between 2013 and 2018 (CAISO, 2018, p. 69). Bushnell and Novan (2018) provide a more detailed analysis.

**Figure 11:** CAISO day-ahead prices SP15 and NP15, 18 July 2018

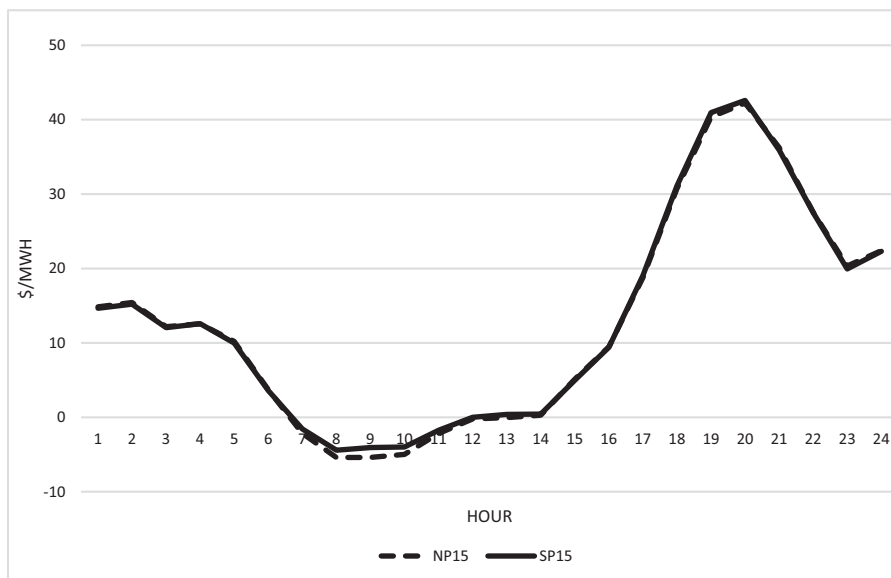


**Figure 12:** CAISO day-ahead prices NP15 and SP15, 7 February 2018



congestion between NP15 and SP15, though prices follow similar hourly patterns. We see that prices fall starting after 8:00 am, following the decline in net demand, as solar production increases. Prices then increase by a factor of 2.5 between 4:00 pm and 8:00 pm, before declining along with demand. Finally, [Figure 13](#) is a late spring Sunday with relatively low demand and high levels of wind and solar generation. There is almost



**Figure 13:** CAISO day-ahead prices, 10 June 2018 (Sunday)

no congestion, so the prices in NG15 and SP15 are close to being equal in all hours. Between 7:00 am and 2:00 pm prices are negative or zero. Prices then rise rapidly after 2:00 pm, though solar generation peaks at 2:00 pm while wind generation increases about 25 per cent between 3:00 pm and 8:00 pm. On all 3 days we observe rapidly rising and relatively high prices late in the day as solar generation fades.

These changing price patterns affect the magnitude of the net revenues that generators can earn in the energy market. As solar generation expands, the net revenues earned during the day decline and the net revenues earned during the evening ramp increase on average. In the long run this must affect the profitability of different generating technologies (entry and exit), including fast start and highly flexible gas turbines and storage supported by revenues earned by price arbitrage (buy low and sell high) that will be required to meet the evening ramp and respond to the wide variations in wind and solar production—hourly, daily, seasonally, etc. When significant quantities of generation are partially supported by out-of-market revenues there is no reason to believe that the energy market will support an efficient equilibrium of subsidized and unsubsidized generating technologies.

## (ii) Effects on exit and entry

Incumbent generators have been adversely affected by low natural gas prices, stagnant demand, and the rapid entry of wind and solar generating capacity. Stagnant demand in turn is partially affected by the growth of BTM PV installations. However, the effects of low natural gas prices *per se* have largely been realized while the effects on wholesale prices from secular expansion of intermittent generation will continue to intensify. On a national basis, a growing fraction of the existing fleet of nuclear plants, large coal

plants, and older gas/oil steam generators already or will soon find continued operations unprofitable and have or will exit the market. In recent years most of generating capacity exiting the CAISO has been older oil/gas steam capacity originally constructed for base load and mid-merit operations, has relatively high heat rates and start-up costs, and can respond relatively slowly to rapid variations in dispatch needs (CAISO, 2018, p. 15). The same is true for New England (ISO New England, 2018c, p. 151). Some older cogenerators and peakers have also retired in California (CPUC, 2018, pp. 44–6). There has been essentially no entry of dispatchable generation into the CAISO and only very small amounts of grid-based storage.

While there has been significant exit of incumbent dispatchable generators and relatively little entry of new dispatchable generating capacity across the country over the last few years, most of the RTO/ISOs in the US have not yet found that the retirements leave them with too little remaining dispatchable generating to manage their systems reliably. However, premature exit and inadequate entry of flexible dispatchable generation in the future is clearly of concern to system operators and regulators and they follow developments on this front closely. Resource adequacy appears to be of growing concern in California (CAISO, 2018, pp. 223–43). The CPUC is considering revising the short-term contracting requirements in its existing out-of-market ‘forward’ (1 year) Resource Adequacy protocols (<http://www.cpuc.ca.gov/RA/>) to require contracts for up to 5 years to ensure that retirements do not threaten reliability.<sup>31</sup> An incumbent generator with a flexible combined cycle gas turbine (CCGT) plant in California recently filed a complaint with FERC requesting that FERC order the CAISO to abandon its current short-term resource adequacy mechanism and adopt a centralized forward capacity mechanism such as those in New England, PJM, and New York.<sup>32</sup> As already noted, both Alberta and Ontario are introducing forward capacity markets and the existing RTO/ISOs are almost constantly redesigning their capacity markets to respond to accommodate intermittent generation, subsidized generation, pay-for performance criteria, and other issues. Incentive issues associated with premature exit and closely related to incentive issues associated with entry of new generating capacity.

Accordingly, there is growing recognition that in the long run an energy-only market with price caps will not yield adequate revenue to deter premature exit of dispatchable generating capacity or attract efficient entry of new dispatchable generating capacity (or substitutes for it, like storage) that are well matched to the operating attributes of a system with intermittent generation at scale. For example, the net revenues a hypothetical new gas turbine and a hypothetical new CCGT built in the CAISO would have earned in 2016 and 2017 do not come close to covering the capital costs (carrying charges) of a new entrant (CAISO, 2018, pp. 58–65). It is also becoming clearer that capacity markets are not producing enough net revenues to deter inefficient exits and attract entry of the kinds of flexible generating capacity and, I suspect, storage, needed to balance supply and demand reliably in a system with intermittent generation at scale. Relying on special ‘reliability must run’ contracts (RMR) for selected generators that the system operator decides to pay is not an attractive long-term solution.

<sup>31</sup> Jeff Stanfield, S&P Global Intelligence, 22 June 2018, 20:53:55 GMT; ‘Arem Suggests 3-Year Forward RA in California’, *Power Markets Today*, 11 July 2018. California does not have an organized and transparent forward capacity market like New England, New York, and PJM.

<sup>32</sup> *Power Markets Today*, 26 June 2018.

We must recognize that new-entrant solar and wind generators today confront a completely different economic regime from new-entrant dispatchable generating capacity almost everywhere. The former currently have available to them federal tax subsidies, state subsidies, renewable energy portfolio mandates, tradable renewable energy credits, and benefit in some cases from mandated long-term contracts between regulated load serving entities and solar and wind generators selected through some type of competitive procurement requirements. On the other hand, existing and new entrant dispatchable generators today must rely on day-ahead, intra-day, and real time energy, ancillary service spot market revenues, plus capacity prices in markets with capacity pricing mechanisms, as counterparties generally will not enter into contracts of more than 2–3 years. Basically, the policy of incentivizing large-scale entry of intermittent solar and wind, without making necessary changes in wholesale market designs to provide better incentives for entry and exit of dispatchable generation (and storage) that is well adapted to the attributes of a system with intermittent generation at scale, has been made relatively easy so far by free riding on the declining existing stock of dispatchable generating capacity. It is not at all clear that with intermittent generation at scale, the ‘standard’ RTO/ISO market design can support a long-run equilibrium with the optimal quantities of intermittent and dispatchable generation.

## VI. Wholesale market design challenges

Let’s contemplate a hypothetical wholesale power market that is 100 per cent solar and wind. The marginal cost of operating solar and wind is zero. Assume that it is an energy-only market (no capacity market) with a price cap set far below the VOLL. When the price cap is hit, demand is subject to non-price rationing at the default price cap which is far below VOLL. There is no fossil generation and no storage. A system with these attributes only has two states of nature (see [MacCormack \*et al.\*, 2010](#)): one state where the price of energy is zero, and the other state where it defaults to the price cap and non-price rationing takes place. This system cannot be a long-run equilibrium unless the capital costs of intermittent generation are subsidized heavily outside the market or there are (too) many hours when the price cap is hit and demand is subject to non-price rationing—more rolling blackouts. This is the case because it is only in this state where the price cap is hit that any quasi rents are generated to cover the capital costs of the intermittent generators which provide 100 per cent of the generation by assumption. Moreover, given the variability in generation from solar and wind, and their very different generation time profiles, well more intermittent generating capacity than 100 per cent of peak demand on the grid would have to be installed to avoid many hours of non-price demand rationing. At the same time, there would be many hours when intermittent generation would have to be constrained off as intermittent supply would exceed demand leading to over-generation. Not a pretty picture.

This thought experiment should suggest a number of things. First, a 100 per cent intermittent generation portfolio (no dispatchable generating capacity) would be very expensive absent inexpensive storage and/or demand-side adjustments that could make up for low intermittent supply levels and/or reduce demand during states of nature

when supplies from intermittent generators are low. Relying on storage and demand-side responses is especially challenging because the impacts of intermittency are not just reflected in intra-day variation in solar and wind generation. Intermittency can lead to low or high production levels for multiple days and there are seasonal effects as well. Second, if we expect to rely on today's organized US wholesale markets to support aggressive de-carbonization goals met with wind and solar, then more effective scarcity pricing and/or capacity pricing mechanisms will be required to provide net revenues to deter inefficient exit and attract efficient entry.

### **(i) Market tools and technologies for adapting to large-scale intermittent generation**

As intermittent generation expands, concerns have been expressed that the almost random variability in output from intermittent generators will threaten the reliability of electric power networks whose physical infrastructure was not designed to respond to large, sudden, and only partially predictable variations in generation. The operational challenges have been recognized for years (MIT Energy Initiative, 2011) and changes in system operating protocols to adapt to intermittent generation at scale have been ongoing.<sup>33</sup> I think that it is fair to say that *if* system operators have the right tools and technologies at their disposal, they can reliably manage physically a system with a high penetration of intermittent generation. These tools involve both a compatible physical infrastructure and market mechanisms needed to support investment to create this infrastructure and to respond to new operating challenges without incurring large additional costs.<sup>34</sup>

### **(ii) Tinkering with the existing wholesale market designs**

An electric power system with large-scale deployment of intermittent generation with the attributes of wind and solar discussed above will need highly flexible generating capacity (and/or storage, demand-side responses—more below) with relatively low capital costs, low start-up costs, and the ability to respond rapidly to dispatch instructions. There are a number of dimensions of flexibility. There is a need for generation that can increase or decrease production very quickly to respond to the very short-term fluctuations in the output of solar and wind facilities both to supply energy to balance variable demand and to stabilize what would otherwise appear as unwanted fluctuations in frequency and voltage. Similarly, there is a need for generation (or storage) that can ramp up quickly to contribute to the large but variable ramp over 3 or 4 hours at the end of the day as the sun goes down and before demand declines later in the evening.<sup>35</sup> Products (and technologies) will be needed that can make up for low production levels

<sup>33</sup> US Energy Information Administration, 2011, <https://www.eia.gov/todayinenergy/detail.php?id=670>; *Scientific American*, 11 March 2015; <https://blogs.scientificamerican.com/plugged-in/renewable-energy-intermittency-explained-challenges-solutions-and-opportunities/>

<sup>34</sup> For a very optimistic view see Wynn (2018).

<sup>35</sup> Evening electricity consumption will eventually get a boost as electric vehicle ownership expands, if the owners choose to charge their vehicles at night.

that last for days, not just respond to intra-day variability, as well as responses to seasonal variability. Dispatchable gas-fuelled generators can provide these products easily if they have the proper incentives. But as we drive the system toward 100 per cent renewables, fossil-fuelled dispatchable generation will be increasingly limited. Wholesale markets will need to adapt by creating new product categories to enable system operators to schedule, dispatch, and pay for generating capacity that meets these response needs efficiently. This likely will require expanding or revamping the current scope of ancillary service products as well. Moreover, flexible generating capacity with relatively low capital costs will be favoured as dispatchable generating capacity may be called for relatively short durations when it can earn market revenues from sales of energy, absent capacity payments.

While this transition takes place it will be desirable to make efficient use of the remaining existing dispatchable generating capacity. Some of this capacity has relatively high start-up costs and will likely require that system operators develop products and payment mechanisms that guarantee that these generators will recover their start-up costs if they must start up early in the day in order to be ready to be dispatched during the evening ramp, or to respond to uncertainty about solar and wind production during the course of a day.

As discussed above, an efficient long-run equilibrium based on sales of energy at market prices cannot be achieved if wholesale markets maintain price caps that are far below VOLL without a complementary capacity adequacy and capacity market system. Capacity markets have been redesigned frequently as their imperfections have been revealed, and efficient scarcity pricing will not be feasible without reforms of retail pricing. While the ongoing refinements to capacity markets have improved their performance, they too have been based on conceptual models for electric power systems which rely primarily on dispatchable generation. But it is not at all clear how a capacity market mechanism can be implemented with intermittent generation at scale. Capacity payments are made based on performance commitments that require generators to be available to supply when the system operator determines they are needed. How would this work for intermittent generators that cannot predict whether and how much capacity will be available at a particular hour on a particular future date? If we want an efficient portfolio of intermittent and dispatchable generation, storage, etc., how do we deal with the subsidies, mandates, and contract procurement preferences given to intermittent renewable generation and storage? Can different capacity prices be paid to different technologies with different subsidy and contracting mechanisms? This would conflict with FERC's historical policy of treating all supply-side and demand-side technologies equally, though allowing for differences in generator characteristics that can be applied to all technologies (e.g. start-up costs, ramp rates, availability at time of peak system need). These issues suggest to me that it will be hard to extend today's forward capacity pricing mechanisms to a world with intermittent generation at scale.

On the other hand, there may be reasons to be more hopeful, that progress can be made with expanding the use of efficient scarcity pricing mechanisms. As I discuss presently, there are very good reasons to fully integrate retail pricing with pricing in wholesale markets, including scarcity price signals conveyed to retail consumers. The spread of smart meters makes some variation of real time retail pricing, including critical peak pricing and related variations on this theme, much more feasible than was once the case. Intermittency and volatile spot prices make variable pricing more desirable than

it is now from an efficiency perspective as well. Integrating retail pricing with wholesale market pricing will then make it easier to represent customer demand and valuations in wholesale markets, a precondition for relying on efficient scarcity pricing to produce the quasi-rent needed to pay for investment costs. This will, of course, lead to perhaps many hours during the year when spot prices are very high and this will not be popular. But then there will also be many hours during the year when spot prices will be very low. Market power issues may also re-emerge as a concern if price caps are removed. Nevertheless, I think that more attention needs to be directed toward developing efficient scarcity pricing mechanisms. I return to variable retail pricing presently.

### (iii) Storage

In most systems with goals of very high penetration of intermittent renewable generation,<sup>36</sup> both grid-based and importantly customer-based storage are now expected to play a significant role (Imelda *et al.*, 2018). This should not be surprising as very high solar and wind penetration goals (e.g. as part of an 80–90 per cent renewables goal) are not consistent with retaining significant dispatchable fossil generation to manage intermittency. With neither dispatchable fossil generation nor storage, it is impossible to balance supply and demand reliably with intermittent generation alone. Given the large fluctuations in day-to-day production from intermittent generation, sequential days of very low or very high production from intermittent generators, and the seasonal variations in production by these generators, longer-term as well as short-term storage options would appear to be targets of opportunity for systems with very high penetrations of intermittent generation.

Many US states and ISO/RTOs have started pilot projects to examine how storage can be integrated effectively into the grid to provide a variety of services. The Department of Energy has also supported storage R&D projects. A few US states have specified mandates and established storage expansion goals (GAO, 2018, pp. 36–40). There are many different storage technologies with different operating attributes, current and expected future costs, and historical operating experience being deployed or in development today.<sup>37</sup> While storage costs have fallen in the last decade (Schmidt *et al.*, 2017), they remain high compared to modern simple-cycle gas turbines providing similar services.<sup>38</sup> However, the combination of significant R&D, manufacturing and installation experience, and mandated long-term contracts with distribution utilities, costs are likely to fall further (McKinsey & Company, 2018).

As of March 2018, the US had about 25 GW of grid-based storage.<sup>39</sup> However, about 95 per cent of the existing storage capacity is conventional hydroelectric pumped storage. The rest is divided between batteries (733 MW), thermal storage (669 MW),

<sup>36</sup> If the goal is 100 per cent renewables, as a practical matter dispatchable storage must play a large role in balancing the system.

<sup>37</sup> <https://www.eia.gov/todayinenergy/detail.php?id=4310>; GAO 2018.

<sup>38</sup> Of course, this comparative cost analysis may not matter if the mandate is for 100 per cent renewables.

<sup>39</sup> <https://www.epa.gov/energy/electricity-storage#storage> The US also has about 80GW of conventional hydroelectric capacity. Most of this capacity is potential energy storage capacity. While there is no expectation that conventional hydroelectric capacity will increase significantly in the future, this capacity can be used differently from the way it has been used in the past and help to manage intermittency.



compressed air (114 MW), and flywheels (58 MW). About 75 per cent of the storage under development is also pumped storage, with batteries accounting for most of the rest (GAO, 2018, p. 10). While a lot of popular discussion has focused on lithium-ion batteries because of their use in electric vehicles, e.g. the Tesla Power-Wall for customer use, and the 100 MW/126MWh Tesla battery installed in South Australia, there are many different types of batteries with different chemistries and operating characteristics that may be promising. Most are experimental at this point and wide-scale deployment faces economic challenges and uncertainties (GAO, 2018, pp. 21–8), though the costs of some battery storage technologies are falling rapidly (McKinsey & Company, 2018). BTM storage, typically integrated with a BTM PV system today, is relatively small, less than 5,000 MW nationally at the end of 2017, but growing rapidly (Smart Electric Power Alliance, 2018a).

Economists tend to think of energy storage as a type of generating plant that buys energy when prices are low and then sells it when prices are high, effectively moving electricity generated in one period to a later period of time. For example, an energy storage device in California could buy power during the day when prices are low (see Figure 10), store the energy, and then sell it during the evening ramp when prices are high. Or in regions where there is a lot of wind generation at night when demand is low and prices are zero or negative, the storage device could buy power at night and sell it during the day to provide energy, ancillary services, and capacity (see Figure 12). This is exactly how conventional pumped storage is often used, though pumped storage use has become more sophisticated with the development of competitive wholesale markets and provides various ancillary services and capacity (Brattle Group, 2018). Depending on the technology, this price arbitrage process can take place several times during a day, release energy for short or long periods of time, or store energy for multiple days and release it gradually when prices are highest. In the ‘energy arbitrage’ scenario, the capital and operating costs of the storage devices are then recovered through the net revenues produced by the low/high price spreads. An efficient scarcity pricing mechanism is also likely to be better matched to storage that earns revenues from price arbitrage opportunities than would be a capacity pricing mechanism. The ultimate questions, though, are whether revenues from price arbitrage can support investment in storage at scale and whether storage is more economical than quick-start flexible combustion turbines that use natural gas.

In practice, energy storage is more complicated than simply taking advantage of price variability and associated price arbitrage and associated time shifting of supply in the energy market. This is the case because storage can provide multiple services (GAO, 2018, pp. 16–21). In addition to responding to opportunities to move energy from one period to another stimulated by price arbitrage opportunities, storage can provide peaking capacity to meet reliability standards, frequency regulation, and other ancillary services, defer transmission and distribution network investments, provide emergency back-up power, and other services. Thus, there are multiple potential revenue streams and it is the sum of these revenue streams that will determine whether or not specific storage devices are profitable. Most of the *ex ante* simulations and historical case studies of pilot projects that have been completed indicate that the net revenues from energy price arbitrage are today a relatively small fraction of the revenues/benefits produced by these projects and that net revenues earned from sales of energy, capacity, and ancillary

services based on price arbitrage opportunities have not been sufficient on their own to attract investment (Pacific Power, 2018; Sidhu *et al.*, 2018).<sup>40</sup>

The hybrid nature of storage services<sup>41</sup> raises questions about the economic and regulatory model that will govern the entry of storage into the system. While there may be traditional market entry of storage based on price arbitrage opportunities alone in the future, reflecting similar economic considerations as the competitive entry of generating capacity (energy sales and capacity prices), transmission and distribution deferral benefits complicate things as transmission and distribution deferral opportunities are typically location specific and, until recently, undertaken by the transmission or distribution grid owner as a regulated investment. FERC Order 1000 has required RTO/ISOs to use a competitive bidding process for certain transmission investments, though the experience is still limited (FERC, 2017).

One approach to recognizing the multiple revenue streams associated with projects that are anticipated to be a mix of traditionally competitive services (energy, capacity, ancillary services) and traditionally regulated grid deferral and other especially distribution grid-based services which are also location specific, is a hybrid model for these projects which mixes ‘competition for the market’ with ‘competition in the market’. Very simply, as a response to the open transmission planning process required by FERC Order 1000, the RTO/ISOs would either identify a transmission network ‘problem’ that needs to be resolved, or identify specific grid enhancement projects, including their views on storage options.<sup>42</sup> The system operator would then conduct an auction for grid investment deferral alternatives (which could be storage, generation, demand-side actions) and choose the least-cost options that can defer the grid investment at a cost lower than the base case grid investment. A winning storage bidder would likely also make sales of energy, capacity, and ancillary services in the wholesale market and would reflect the present value of these revenues in its bid. FERC Order 1000 effectively requires this type of planning and competitive procurement approach for transmission network investments that seek to recover revenues through RTO/ISO regional cost allocation. This approach would also be compatible with the increasing reliance on mandates, long-term contracts, and competitive procurement by load serving entities for wind and solar. One potentially controversial detail will be whether or not the grid owner can participate in the auction for deferral investments in storage.

<sup>40</sup> Of course, energy price arbitrage could generate more revenues to cover capital and operating costs as the stock of intermittent generation expands significantly. Focusing only on solar as an example, as solar capacity grows, wholesale prices during the day will fall. Prices during the early evening ramp should also rise as unprofitable fossil generation exits. How high prices will be allowed to rise will depend on the evolution of capacity markets and scarcity pricing. And the size of the associated price spread is the \$64,000 question regarding the ability of the basic ISO/RTO market design to support efficient investment in storage.

<sup>41</sup> Hybrid in the sense that storage can supply both competitive energy and ancillary market services and regulated distribution and transmission services.

<sup>42</sup> According to FERC staff (2017), RTO/ISOs have adopted too general models to meet Order 1000’s open planning and competitive procurement requirements. One model is called the ‘sponsored model’. Under this model the RTO/ISO’s open planning process results in a set of specific proposed projects. Incumbent and non-incumbent transmission developers then compete to be selected to develop these projects. The second model is called the ‘competitive procurement’ model. Here, the RTO/ISO identifies transmission upgrade ‘needs’. Incumbent and non-incumbent transmission developers then compete to provide solutions to these needs. See FERC (2017).

Federal and state regulators have begun to work diligently to develop market and regulatory protocols to remove market barriers to the entry of storage. In February 2018 FERC issued a final rule (Order 841) requiring RTO/ISOs to develop rules that remove barriers to the economical entry of storage facilities into their markets.<sup>43</sup> There are many questions that need to be addressed, from interconnection rules, to the terms and conditions of participation in energy and ancillary services markets, to the treatment of storage as a capacity resource eligible for capacity payments. State regulators, the Department of Energy, and the RTO/ISOs have also adopted a number of policies, pilot programmes, and mandates to facilitate the entry of more storage capacity (GAO, 2018, pp. 26–33; North Carolina Clean Energy Center, 2018, pp. 11–13). Many of these projects rely on procurement through competitive bidding to win long-term power purchase agreements (PPAs) designed for storage, whose costs are included in regulated transmission and distribution (T&D) rates.<sup>44</sup> Or new storage facilities may be owned by the local T&D utility, included in its rate base and passed on to customers through regulated rates. All things considered, storage represents a promising response to intermittency and its market impacts, but in the end its viability will depend on the cost of storage and the revenues that storage can generate from wholesale markets.

#### (iv) Dynamic pricing and an active demand side

Finally, I want to turn to the demand side. At least in theory, conveying real time wholesale price signals to retail customers would be efficient in the long run (Borenstein, 2005). Despite the spread of smart meters, most residential and commercial customers are still charged for electricity based on per KWh rates that do not vary from one hour to the next. In short, they are disconnected from price variations in the wholesale markets. As a result, retail customers have poor incentives to take efficient demand-side actions reflecting the changing distribution of spot prices and the increased volatility in these prices. Let me offer two prominent examples of the costs of this failure to connect retail prices with wholesale prices. There are significant potential storage opportunities at the (retail) customer level. These include battery storage, storage cooling, and storage water heating (Imelda *et al.*, 2018), in addition to increased opportunities to time shift the use of traditional appliances, especially as smart internet-enabled appliances become more common. With flat KWh retail rates and net metering, there is no incentive to seek out these opportunities, even though the daily pattern of spot wholesale prices and the volatility in these prices (and associated short-run marginal costs) may make such price-responsive actions efficient responses to the effects of intermittent generation on wholesale price levels.

Indeed, the price variations created by intermittent generation at scale significantly increases the welfare gains from dynamic pricing compared to flat per KWh rates. The simulation results report by Imelda *et al.* (2018) for a 100 per cent renewable (mostly

<sup>43</sup> *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators* 18 CFR 35, Federal Register, 83 (44), 6 March 2018, effective 4 June 2018.

<sup>44</sup> For example, on 29 June, 2018 Vistra Energy announced that it had entered into a 20-year contract with PG&E for a 300MW/1,200MWh (4-hour) battery storage project subject to approval of the CPUC. <https://investor.vistraenergy.com/investor-relations/news/press-release-details/2018/Vistra-Energy-to-Develop-300-Megawatt-Battery-Storage-Project-in-California/default.aspx>

intermittent generation) system in Hawaii are instructive. They find that dynamic pricing yields only a modest gain in fossil-fuel dominated power systems—2.4–4.6 per cent of expenditures. However, in a system that is heavily dependent on intermittent renewable generation, the savings from dynamic pricing increase significantly—an 8.5–24.3 per cent welfare gain. This makes intuitive sense. In a system where the short-run marginal cost of generation fluctuates a lot from hour to hour and day to day, the welfare cost of flat per kWh rates is much higher than in a system where the short-run marginal cost of production does not vary very much. This is the case because with flat retail prices the average gap between retail price and marginal generation cost is much larger in a system with widely time-varying short-run marginal costs than in a system where short-run marginal costs do not vary very much. In their analysis, Imelda *et al.* find that the demand-side responses induced by variable prices reflecting intermittency and associated variations in spot prices and short-run marginal costs significantly reduce the costs of meeting a 100 per cent renewables goal. Of course, the benefits depend heavily on the assumptions about consumers' demand elasticities and, more generally, their attention to and responsiveness to variable pricing.

A second example is the positioning of rooftop PV systems. We have seen above (consider the pattern of hourly wholesale prices for 2017 displayed in [Figure 10](#)), that on average the diffusion of grid-based solar reduces net demand on grid-based dispatchable resources during the day when the sun shines, leading to lower spot energy prices during the day. As the day proceeds after peak insolation, the sun moves west and solar production declines until the sun sets and solar production drops to zero. Towards the end of the day, as the sunshine fades, the net demand for dispatchable generation increases sharply and spot prices increase as well. Some utility-scale solar farms install tracking equipment that allows the solar panels to move from east to west during the day to produce more electricity later in the day when prices are high. Extending generation to later in the day thus increases their revenues. However, the equipment that allows large solar farms to move the direction towards which the solar panels point over the course of a day and from season to season is expensive and incurs high maintenance costs. It is too expensive for a typical rooftop PV system, so these systems must be oriented in a fixed direction. Without variable retail pricing that reflects the higher value of energy late in the day as the sun fades, rooftop PV facilities will be positioned to maximize total generation rather than to maximize the social value, potentially more profitable generation, since the benefit to them is driven by a flat per kWh rate rather than the prospect of increasing revenues by producing more later in the day when prices are high. As a result, rooftop PV facilities usually point straight south if the contours of the roof make this possible. However, if the rooftop PV facilities were positioned to point further west, they would produce more later in the day when prices are higher but produce less in total during the day (see [Brown and O'Sullivan \(2018\)](#) for a detailed analysis). With dynamic pricing that reflects wholesale price levels they would have an incentive to reorient their PV facilities further to the west to capture the higher prices, reduce the end-of-day ramp, and lead to lower equilibrium prices as the sun fades.<sup>45</sup>

<sup>45</sup> We don't have to wait for real time pricing to improve incentives to install PV facilities that point further west. The BTM subsidy structure could give higher subsidies for BTM facilities that choose a more efficient orientation. Or a simple time-of-day pricing mechanism that has higher prices during, say, the 3:00 pm to 9:00 pm period would provide better incentives.

I recognize that the responsiveness of retail consumers to variable pricing in particular, and to marginal rather than average prices in general, has been questioned (Ito, 2014). However, I think that the bulk of the evidence drawn from variable pricing experiments, including critical peak pricing and other variations on the real time pricing theme, supports the view that consumers are responsive to price variations (Alcott, 2011; Wolak, 2011, 2018b; Faruqui, 2016; Anderson *et al.*, 2017). Of course the responsiveness observed varies from study to study and may not be as large as is expected. However, this is not surprising. The experiments have different designs, different levels of price variability, different durations, and different promotion and customer education components. On balance, I believe that these experiments underestimate long-run consumer responsiveness. This is the case because (a) consumers will not invest in appliances and equipment that will allow them more easily to respond to dynamic prices if the dynamic pricing mechanism they are given is only temporary, (b) smart appliances, equipment, and control mechanisms are still at an early stage of development and diffusion, (c) energy service companies and equipment suppliers do not have incentives to invest heavily in marketing and promotion if the experiment is temporary, and (d) the experiments do not take advantage of the potential power of retail competition and the demand response services that they can provide. I do not anticipate that consumers will sit around watching their meters and turn their heating, ventilating, and air conditioning (HVAC) equipment on and off in response to dynamic prices. I do expect that, for example, rooftop PV installers will orient facilities to take better advantage of higher evening prices. I also expect that competitive retail suppliers will begin to offer demand management products in response to variable pricing that trade the right to partially control the customer's consumption during high-price hours for a more stable partially hedged retail price structure provided to these customers. The retailer now takes on the bulk of the dynamic price risk in return for rights to partially control its customer's consumption when prices are high. The demand-side bidding programmes that RTO/ISOs now have are compatible with this vision. And some utilities have had air-conditioner and water-heater cycling programmes for many years. The customer agrees to allow the utility to cycle her air conditioner a maximum number of times during scarcity conditions and gets a discount for doing so. These programmes are popular. About 4m customers are enrolled in air conditional switch programmes, 1.2m customers in water heater switch programmes, and nearly 1.4m in thermostat control programmes. These programmes are taking advantage of smart meters and remote control capabilities made possible by internet-enabled thermostats and appliances. Participation in these programmes is growing. Variable pricing will give competitive retail supply companies the incentives to offer services of this type. While much attention has focused on price responsiveness by residential customers, we should not forget that commercial and industrial consumers account for about 65 per cent of consumption. (Smart Electric Power Alliance, 2018b).

It is clear to me that one of the challenges for markets with very high penetration of intermittent generation is to better integrate the demand side with spot wholesale market pricing through the introduction of real time pricing (variable pricing) and related demand control mechanisms.



### **(v) Partial re-integration through government mandates, competitive procurement, and long-term contracts**

Tinkering with existing wholesale market designs in these ways may not, in the end, be a successful programme for efficiently integrating intermittent renewable energy at scale into the system. We need to recognize that the attributes of the electricity market liberalization initiatives that have taken place in the last 25 years or so are being threatened, not by the entry of intermittent generation at scale *per se*, but rather by the public policies that are trying to force systems to have very high penetrations of intermittent renewable energy, whether or not this is economical based on market prices. Subsidies for renewables, renewable energy mandates and portfolio standards, mandates that require retail suppliers to enter into long-term contracts with renewable suppliers through competitive procurement, etc., have replaced the decentralized market incentives for entry and exit upon which the restructuring and wholesale market designs developed over the last 20 years have been based.

Of course, I recognize why policy-makers may turn to generation portfolio standards, subsidies, and long-term contracting obligations. They want to decarbonize the electric power sector as part of a broader programme to mitigate carbon emissions in response to climate change. First best instruments, like emissions pricing, with prices set at appropriate levels, are not available. If they were available, many policy-makers would probably be reluctant to rely on them fully anyway. However, the subsidies, mandates, and selective long-term contracts have consequences, and these consequences need to be recognized and adaptations made to accommodate them.

Is it reasonable to expect that we can rely, on the one hand, on central planning for renewables, and associated mandates, subsidies, and long-term contracting with load-serving entities, and, on the other hand, on enhancements to the existing energy, ancillary services, capacity market, and perhaps expanded scarcity pricing to govern operations, entry, and exit for the ‘residual’ market? Can this bifurcated approach to wholesale markets be successful in retaining and attracting the kind of flexible dispatchable generation and storage needed to manage a system with a high level of intermittent generation efficiently? If the result is that exit of existing dispatchable generation and limited entry of new flexible dispatchable generation and storage with equivalent capabilities leads to operating problems or a large number of hours where non-price (or very high price) rationing is required to maintain reliability, there will be pressure to introduce mandates for the procurement of dispatchable generation and storage as well.

Accordingly, I can see the present system changing in a way that separates investment/procurement of new generation and storage facilities of all kinds and retention of incumbent generators deemed essential to manage intermittency, from the short-term markets that ‘dispatch’ these facilities economically. For example, the regulator might adopt a goal of having a system that is 80 per cent renewable and a ‘residual’ mix of dispatchable generation and storage that planners determine efficiently manages the resulting intermittency. The regulator could then force the regulated T&D owners to obey the policy by ordering regulated retail suppliers and grid owners to enter into long-term contracts to attract new generating and storage facilities to match the 80 per cent renewable goal, as well as the residual dispatchable and storage facilities needed to meet system reliability criteria, by using some type of competitive long-term PPA-based procurement mechanisms. The wholesale market as we now know it would then only be



a short-term energy dispatch and balancing market that would try to produce efficient spot prices but would not be relied upon to provide all of the incentives for investment or retention of dispatchable generating and storage facilities. Any net revenues potential new generators expect to earn in the energy and ancillary services market would be reflected in bids made into the long-term procurement auction. We may be well down the path in this transition to a very different kind of wholesale market structure. In Europe, there appears to be a much clearer recognition that wholesale markets for long-term procurement and short-term operations have become separated, that this needs to be recognized, and that more efficient wholesale market designs for both market segments should be pursued (Grubb and Newbery, 2018; Newbery *et al.*, 2018).

## VII. Conclusions

Policies aimed at rapid de-carbonization of the electricity sector by aggressively expanding the penetration of wind and solar generation have significant implications for the performance of wholesale electricity markets. The combination of intermittency, near zero marginal operating costs, imperfections in capacity and scarcity pricing mechanisms, and the reliance on out-of-market revenues to provide financial support to wind and solar generation, raise important questions about the continued reliance on market incentives to support efficient operations and to provide adequate revenue support to retain existing generators that are needed to balance the system, to attract entry of new flexible generators and storage. I do not believe that ‘fiddling’ with existing market designs will deal adequately with all of these challenges. I do believe that market design reforms can work to align incentives with operating challenges. The development of new products that better reflect operating needs with intermittent generation at scale is an important goal. So too is better linkage of spot prices in the wholesale market with retail prices seen by end-use customers. However, I am not optimistic about the prospects for reforming capacity pricing and scarcity pricing mechanisms with minor modifications to existing mechanisms. The continued reliance on subsidies, resource mandates, mandated long-term contracts, etc. for intermittent generation is simply incompatible with relying on markets for the rest of the supply portfolio. The mandates, subsidies, and contracting obligations will just spread as the market fails to deliver adequate retention and entry of generating capacity and storage needed to manage intermittency. We might as well face this sooner rather than later. This requires developing a separate market for long-term contracts that is compatible with attracting investment consistent with the integrated resource portfolios that are increasingly being defined by government policy-makers rather than market incentives. Once in the market, these resources would operate based on market incentives in reformed hourly and real time energy and ancillary services markets.

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