Intermittent Generation Comes to Texas: The High Cost of Renewable Energy

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Executive Summary

The power industry is in a fundamental transition, its ultimate shape to be determined by technology, markets, and regulation. The economics is straightforward: intermittent renewable power, primarily wind and solar, is a major disruptive influence on operations and investments, and some of its costs are not being borne by those responsible for causing them. The laws and regulations that affect intermittent power (at both federal and state levels) make it difficult to estimate the costs and benefits of the new sources. The benefits of power produced without fuel are seemingly persuasive, but a growing body of research shows that wind power's advocates in Texas have, at best, overstated their case.

Mix intermittent generation with politics and federal, state, and local renewable subsidies, and you are unlikely to arrive at an economically rational outcome. Wind power is a technology that appears manifestly unsuited for most electricity users due to its randomness and the costs of storage or attempts to back up production. To meet consumers' desires, utilities must offer them both affordability and reliability, which is almost impossible to accomplish if the energy is produced by intrinsically intermittent generators. The fact that air is "free" says nothing about the commercial advantages of wind turbines that do not need purchased fuel. Whatever its engineered ("nameplate") capacity, a generator's economic value depends on the value of its output and not its technology. Wind power is locationally specific, and the capacity of a wind turbine depends in large part on technical factors that may severely limit generation options. A fossil-fuel power plant can be located where its total cost (capital, labor, fuel, transmission) is minimized, but the location of an intermittent power source such as a wind turbine is constrained by wind availability. If windy areas are remote from consumers, as in Texas, reaching a wind generator may require dedicated radial transmission that cannot be used to deliver power from alternative sources; its isolation from most of the energy grid also means that it contributes little to reliability.

Key Points

- Intermittent renewable power, primarily wind and solar, is a major disruptive influence on operations and investments, and some of its costs are not being borne by those responsible for causing them.
- The benefits of power produced without fuel are seemingly persuasive, but a growing body of research shows that wind power's advocates in Texas have at best overstated their case.
- If windy areas are remote from consumers, as in Texas, reaching a wind generator may require dedicated radial transmission that cannot be used to deliver power from alternative sources; its isolation from most of the energy grid also means that it contributes little to reliability.
- Ratemaking practices for transmission that pass costs through to consumers take important intermittency risks away from wind generators and throw them on to non-wind producers and captive ratepayers.

An Overview of Renewables

Intermittency and Degrees of Renewability

"Renewable" is a poor descriptor of wind and solar technologies. All power is, to some extent, renewable. Water behind a hydroelectric dam renews itself with the seasons, and new production methods have made fossil fuels more abundant and less expensive. Wind and solar generators do not burn fuel but nevertheless also have costs. Transmission is a major cost of delivering power to users, and in most regions the wind blows strongest and steadiest late at night when power is least valuable. Most power must be used instantly, and economical storage remains largely on the horizon. Investors weigh the costs of dispatchable fossil-fuel generation against those of intermittent wind and solar power, but the comparisons are often misleading. Claims that, for example, a wind generator can power

"X thousand homes" often disregard the value of reliability (and the fact that residential users in most areas consume no more than 40 percent of all power). Unsteady power is less valuable to most users than reliable ("firm") power, and reducing the difference requires investments in additional generation and transmission, an expense also likely to be borne by ratepayers.

The value of a generator is, in part, determined by its nameplate capacity (maximum output) but also on its productivity and availability. Productivity is the ratio of physical output (MWh) to physical input (e.g., MMBTU of gas burned), sometimes referred to as technical efficiency. A wind turbine's output depends on both its scale and its availability factor, the latter defined as the average percentage of all hours in a year that it is capable of generating. The value of that output is determined by demand and cost. A wind unit that injects power into the grid at peak hours is more valuable than one that operates during hours of low demand because its output displaces higher-cost conventional power. Wind's intermittency, however, means that additional costs of backup generation must be incurred to transform a turbine's output into reliable megawatt-hours, since most consumers place far higher values on dependable (firm) than on interruptible power.

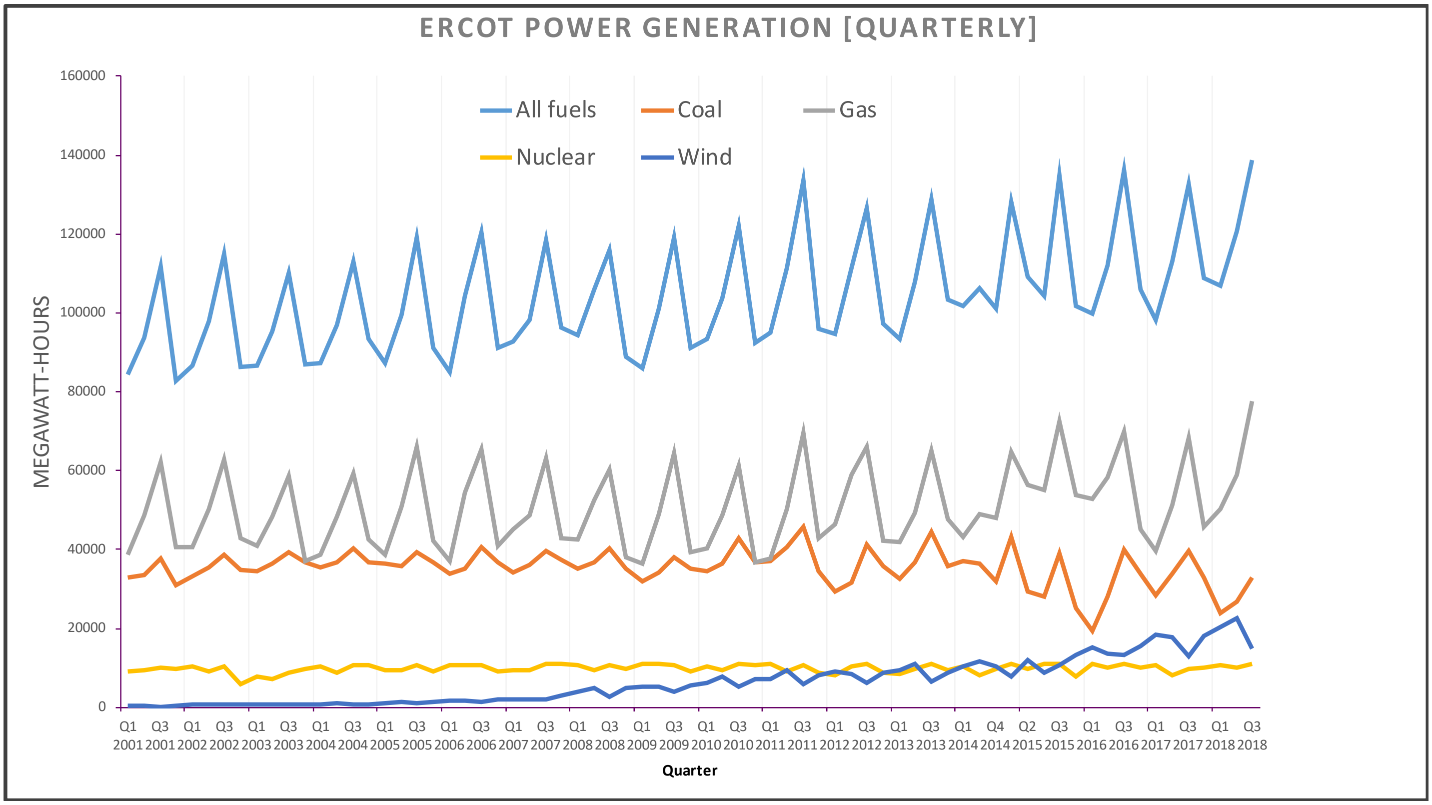
Most of a day's power from a typical inland Texas wind turbine comes at night when demand is low. By contrast, some newer plants in the Panhandle and on the south Texas coast have higher availability factors and produce during hours of higher demand. Their relatively high productivity reflects improvements in turbine technology and the fact that transmission to these areas has been developed only recently. At present, however, 73 percent of wind capacity is in west Texas (Potomac Economics, 83). Its actual output per hour depends on wind speed, which ranges from zero (still air) to limits imposed by design. Wind's low productivity when power is most valuable is not unique to Texas. Looking at ERCOT, the Pennsylvania New Jersey Maryland Interconnection (PJM), and the Mid-Continent Independent System Operator (MISO) in 2012, between 82 percent and 86 percent of wind generation capacity did not operate during their top 10 peak demand days. During peak periods, only 10 percent or less of conventional generation capacity is typically unavailable (Huntowski, 11).

For planning purposes, ERCOT uses capacity values of 14 percent for inland wind generation and 59 percent for coastal, i.e., the equivalent of 100 MW of reliable (firm) capacity requires investment in slightly over 700 MW of inland wind generation (Potomac Economics, 76). This casts a different light on the growth of wind power. Specifically, 3.6 gigawatts (GW), i.e., thousands of megawatts, of generation resources came on line in 2017, 2.2 of which were combined-cycle gas units and 1.1 were wind turbines which had effective peak-serving capacity below 300 MW (Potomac Economics, 77). Gas-fired generation in Texas has an average capacity factor of 88 percent and is, in part, controllable by its owner who can, for example, schedule maintenance for months when power prices are typically low. If all power in ERCOT receives the same market price (a rough approximation) and, on average, gas-fired powerplants just break even, wind turbines will be competitive only if they are very cheap to build and operate. With subsidies such as the federal Production Tax Credit (PTC) described below, wind generators may appear profitable to investors, while their true costs may exceed their benefits. In addition, while ERCOT's short-term wind forecasting ability is improving, it remains impossible for generators to predict future winds during times of peak demand. This additional uncertainty may significantly increase the risk of investing in more reliable generators necessary to serve future peak loads.

Figure 1 shows the growth of power production in Texas from various types of generation. The high blue line shows total power generated in the state quarterly for each year 2002-2017. As in other warm regions, production peaks annually in summer. "All sectors" means the total amount generated in the state by all providers, including utilities, non-utility power producers, governments, etc. Except for a few direct current (DC) ties, Texas imports no power from outside its boundaries. Output from coal-fired generators (brown line) has lower seasonality than that of gas-fired units, which account for the bulk of load-following. Nuclear remains a relatively constant and small component of the total. Also note the decline of coal-fired power beginning around 2012 that has resulted from both environmental restrictions and changes in markets for other fuels.

Wind power in Texas, as elsewhere, has risen with developments in technology and federal energy policy, from a minuscule output in 2002 to 14.8 percent of the state total in 2017. Texas is often noted as a state that has made great efforts in advancing wind power, but the fact is not obvious in a comparison of the data. Between 2009 and 2017 Texas wind power production rose by 234 percent, while the nation's rose by 244 percent. Wind may be growing in a number of other areas, but its scale in Texas is now large enough relative to other states that the policy problems addressed in this paper have arisen. Problems of scale are further complicated by the fact that the ERCOT grid is essentially an island with only the most limited opportunities to move power across its boundaries. Texas thus has

Figure 1



Source: EIA, Electricity Data Browser at EIA.gov

limits on its markets that have not yet arisen in states with fewer boundary constraints but may do so in the future.

Location of Renewable Generation

With the possible exception of the southern Gulf Coast, most Texas wind power is produced in thinly populated areas where demand is low, relative to potential production. If so, such power would normally sell at a discount to power generated and used in a large consuming area. The situation would be even more extreme if either the ties between consumers and the source are weak or if a potential investor in such generation had to search for interested parties to finance a proposed line. However, the Public Utility Commission of Texas (PUCT) sets transmission rates to diffuse the costs of a new line among consumers, who pay the costs of construction and maintenance in their bills. There are two general rationales for doing so: (1) a new line's benefits can improve reliability of deliveries to consumers who are not directly connected to it and (2) increased capacity can reduce average costs of energy over a wider area.

These rationales depend on market conditions at both ends of the line. If it links a consuming area with a distant producing area that is unlikely to grow, justifications for diffuse benefits become shakier. Unlike lines in a network that covers a more densely populated area, the line between the areas is basically point to point. With fewer interconnections, this relatively isolated line confers fewer reliability benefits on more distant consumers. Non-dispatchability of wind turbines adds to the problem if the producing area is dense with intermittent generators. If their outputs are positively correlated rather than varying randomly (e.g., in an area over which weather varies little), the line's value becomes less certain. It either carries very little power or is capacity-constrained and leaves some power unexportable from the area.

A generator located closer to users is more valuable than a distant one, other things being equal. Likewise, one which creates output that varies sporadically with wind strength is less valuable than one that can be controlled to produce an output that matches demand. A conventional generator can be built wherever its fuel can be delivered, but an intermittent one must generally be located close to its wind or solar source. It is thus difficult to rationalize the construction of transmission facilities to reach electrically isolated intermittent generators. They will have little reliability value for the grid and will not facilitate larger markets, and intermittent power entails extra costs of integration with the grid. This reasoning leads to questions about Texas' promotion of intermittent renewables through its Competitive Renewable Energy Zones (CREZ) program.

Response to Isolation and Intermittency: Texas's Competitive Renewable Energy Zones

The market may reject an investment that is not cost-effective for consumers and producers, but political forces may allow uneconomic generation or transmission to be built. Those forces were in evidence during Texas's policymaking on CREZ, initiated in 2005 legislation (according to their backers) as "proactive means" to meet growing energy demand, reduce greenhouse gases, and relieve transmission congestion (ONCOR). Between 2009 and 2013 new transmission between load centers and CREZ regions cost approximately $7 billion. In the process, CREZ would "approximately double" the state's renewable energy goals and build additional transmission to meet demand in then-underserved oil producing areas (ONCOR).

A variety of generators and distributors are owners of CREZ facilities, approved by PUCT as eligible to collect "non-bypassable" charges in their regulated rates. The approval was based on a consultant's estimates that the costs of CREZ would be outweighed by increased employment, hardly necessary in a state with heavy in-migration and low taxes (Perryman). The figures came from a commonly used regional economic model in which the only mathematically possible outcomes are increases in employment and regional incomes (Michaels 2010). The coalition that "supported" the study was a diverse set of at least 40 beneficiary entities, including a substantial contingent of wind power producers the lines would reach (Perryman Group). Missing were business and residential consumer groups, who did not publicly support claims that power delivered by the CREZ lines would be less expensive.

The formation and operation of the CREZ coalition would have probably been predicted by the contemporary economic theory of regulation (Stigler; Peltzman). Its principal beneficiaries are large generators and distributors whose costs of mobilizing for political action (e.g., through trade associations) are relatively low and whose individual (corporate) members have much to gain. Consumer groups are harder to organize because their members' individual stakes are small relative to the aggregate wealth being transferred. CREZ supporters included large construction, utility, and environmental interests covering much of the state. The largest included regulated transmission and distribution utilities such as Oncor and CenterPoint, who (absent extraordinary circumstances) would be guaranteed recovery of their CREZ facility costs (plus a return on capital) by the PUCT. In effect, regulation assembled a community of interests whose impact on consumer utility rates was governed by a non-bypassable charge, with retail electric providers (REPs) serving as collection agencies.

The longer-term effects on competitive markets may be less favorable. The growth of renewable power and its infrastructure have increased non-bypassable charges and possibly reduced the price sensitivity of ratepayers. Between 2003 and 2017 these charges increased by 72.3 percent for a 1,000 KWh residential bill from CenterPoint and 60.2 percent for one from Oncor (38.5 and 26.4 percent after adjustment for inflation) (Texas Coalition on Affordable Power). Texas law treats CREZ charges similarly to taxes, but with the important exception that the PUCT may impose them without specific legislative approval (Klump). Beyond the cost impact, it is possible that increases in consumer bills have decreased public support for competition among REPs because consumer savings on energy costs are falling relative to total bills, and non-bypassable charges have risen.

Wind's Variability and Intermittency

The Paradox of Utility-Scale Wind Generation

If I invest in a generator which sells output into a market at the regional price, both I and other participants, including consumers (but not higher-cost competitors), can gain. If market prices are low and my costs are high enough, I will be better off purchasing power rather than selling it. If prices are high, all else being equal, I will choose to be a seller. The paradox of utility-scale wind generation is that this pro-market argument does not always scale up to ensure that wind power's benefits exceed its costs. A variety of evidence shows that seemingly free wind power can impose substantial costs on competitive generators and their customers without producing commensurate benefits for users. Understanding the paradox requires explanation of how a "lower-cost" generation technology like wind could degrade reliability in the short run and imperil the benefits of competition for consumers in the long run. Here we also discuss the related paradox of negative energy-market prices, where legal and regulatory institutions encourage generators to take losses in order to obtain the profits from injecting intermittent energy into the grid. Although our discussion is restricted to wind, it will become apparent that increases in solar generation can have analogous effects.

The Importance of Prices That Accurately Reflect Scarcity: The PTC and Accelerated Depreciation

Economics tells us that profit-seeking behavior in competitive markets reallocates productive resources to their most valuable uses. A competitive producer with no power to affect market price (a "price-taker") will only produce more output if the revenue it generates covers its incremental ("marginal") cost. Those whose costs are relatively lower will profit, and those with insufficient revenue will take losses and ultimately leave the market. In the language of economics, the end-state is an "equilibrium" price that "clears" the market by equating production to demand. At equilibrium there are no frustrated buyers willing to pay market price who cannot find sellers and no frustrated sellers unable to find purchasers at that price. In the long run, profitable newcomers (if they exist) enter the market and loss-taking incumbents exit. In the still-longer run, more efficient generators will be developed and compete with less efficient older generators. Prices will fall along with the profitability of older ones, some of whom may exit the market. This swap-out that changes the generation mix exemplifies "creative destruction" in a well-functioning market that scraps high-cost plants and replaces them with lower-cost ones.

Our examples thus far have a common characteristic: in all of them, market prices reflected the underlying scarcities of productive resources. But the opposite is also possible. For a simple example, assume generators in a region compete to sell power across its boundaries but outbound transmission capacity is limited. To ensure production of the most valuable power if transmission is scarce, there must be a way for low-cost generators to bid it away from higher-cost ones. Whatever the details, lower-cost producers will win the bidding for the limited transmission, and total exportable power will be produced at the lowest avoidable cost. The net effect will be a transfer of wealth ("rents") from generators and consumers to transmission owners.

Next, introduce the possibility that wind turbines generate power intermittently, and simplify by assuming that the marginal cost of a MWh is zero because no fuel need be burned. Further, assume that federal taxes subsidize each MWh produced by wind generators but are unavailable to other producers. With or without subsidies, wind power producers will be the high bidders for transmission because their marginal costs are zero. If some generators have lower marginal costs than others, we can derive a "supply curve" of power. The market equilibrium price settles at the marginal cost of the highest cost producer who can survive at that price. Producers with lower marginal costs than these will profit and those with higher costs will not operate.

Next, assume that every wind generator gets a $5 subsidy per MWh produced. To get that payment, a producer (whose marginal cost is still assumed to be zero) injects power into the grid and receives the market price for it. Subsidized generators in effect bid to buy the subsidy. A prospective producer will be willing to pay any amount up to $5 to put its power into the grid, i.e., if there are enough subsidized sellers, the market price will be negative. In most markets, producers gain revenue by selling at the market price. Here they profit by paying any price below $5 to the market administrator for the right to use the grid. What happens to the payment is immaterial: what matters is that the payment is in fact made. If unsubsidized generators continue to produce, they will receive the market-clearing price, $5 below what it would have been absent the subsidy program.

Negative Prices

Negative prices in ERCOT appear to be rare but have consequences for future markets. ERCOT-wide negative prices occurred in 131 hours in 2016 and 36 in 2017 (Potomac Economics, 20). Here negative prices are best understood as extreme cases of low prices. The resulting subsidies raise the returns to wind generators relative to other types and incentivize construction of inefficiently large amounts of wind capacity. At the same time, they discourage investment in conventional plants that are necessary for reliable dispatch. Like any such subsidy this one shifts spending to the subsidized goods with costs that exceed their value to buyers. Subsidy recipients become wealthier, but excessive investment in renewables raises rather than lowers total power costs over the area. The federal PTC (discussed below) has indeed increased total wind generation capacity. That change, however, creates significant economic value only if its intermittency is mitigated, which requires that consumers or other generators bear additional costs. A wind generator's revenue is thus an inaccurate overstatement of its true economic value. New wind capacity reduces prices received by both wind and non-wind generators, blunting incentives to build dispatchable power plants that may be of greater value (Potomac Economics, 75). A negative market price is in no sense a sign that wind power is a good bargain. It is instead a signal that generation is in acute surplus as a result of subsidization. This reasoning holds for investments in transmission and reserves that are complements to the wind power.

Subsidies to Wind Power

The on-again, off-again federal PTC pays a wind generator a premium over what would have been the market price of a megawatt hour. As previously noted, an otherwise unsubsidized producer that gives its power away will still earn a profit on each MWh thanks to the PTC and accelerated depreciation. In a competitive energy market, a wind power producer will be able to underbid unsubsidized competitors. If transmission capacity is scarce, subsidized producers will bid negative prices, i.e., offer payments for transmission access, and they will do so as long as their incomes, net of the subsidy, exceed zero. Subsidies to encourage wind capacity reduce generators' cost of acting and investing inefficiently.

As currently set, the PTC yields a wind generator approximately $24 per MWh produced. The first five years of a project's life are further subsidized by accelerated depreciation that, on average, reduces its levelized cost by 10 percent. Taken together the average 2015 subsidies in the PTC (35 percent) and accelerated depreciation (21 percent) raise the value of a 1,000 KW project by 56 percent (Linowes, 6, 14). These figures are necessarily dependent on assumptions about taxes and the value of renewable energy credits, which have fallen to under $1 in Texas as a result of its generation boom. Improved capacity factors and capital cost reductions have raised the value of the PTC subsidy. If the PTC phaseout continues as currently scheduled, by 2019 it will have fallen to 40 percent of its 2016 value. The current Congress has yet to enact a PTC extension, but the record of rebirths tells us that renewal remains a possibility.

All electric grids require reserves, but wind is unique because it necessitates additional backup that would be unnecessary, absent intermittency. Necessary backup varies with generation conditions, load, and other region-specific data, and no quick summaries are available. One representative study estimated the cost of keeping gas-fired plants ready to meet wind fluctuations at $0.017 per KWh, plus $0.006 for otherwise unneeded fuel. The former is approximately the capital cost plus some operating costs, which only exists because wind requires additional reserves (Taylor and Tanton, 5-7). The details of estimating gas-fired capacity value (for actual generation) relative to the cost of maintaining availability are situation-dependent. Most major states impose surcharges on wind power and include them as "uplift" amounts for accommodating intermittency. 2016 uplift costs averaged over ERCOT (including the system administrative fee) accounted for $1.03 per MWh, up from $0.74 per MWh in 2015 (Potomac Economics, iii).

Price Suppression and Network Expansion

Intermittent generation has costs that depend on the resource mix of the grid and also on its scale. A single wind unit in a larger interconnection poses few problems because an outage of a small turbine is a random disturbance that can arise for any type of generator. As wind becomes a larger presence, its impact on reliability grows. There are no available studies that summarize wind's effects on cost for the entire U.S., but a growing number of studies have examined Europe, where many national grids have relatively small footprints. The European data make clear that, beyond country-specific levels of wind capacity, there are thresholds past which additional wind resources raise the total cost of delivered power. Summarizing the growing body of findings, German economist Lion Hirth and his colleagues isolated three basic costs and analyzed their behavior: (1) "profile costs" that reflect ramp rates and intraday patterns of use; (2) "balancing costs" incurred to cope with wind's randomness; and (3) "system costs" of generation and transmission investments needed to facilitate capital adjustments. Each of them carries production and mitigation costs. The threshold depends on the system's resources and load characteristics, and Hirth's averages are, at best, approximations. He finds that, at high penetration rates (approximately 20 percent for wind, 10 percent for solar), "they are the technologies that produce least-value electricity." He goes on to note that "ignoring [technological and market factors] can impart upward bias to estimates of the value of the power [and] the upward bias may be greatest for wind and solar power" (Hirth, 24).

The most important takeaway from Hirth's European research is that "when wind penetration reaches 30-40 percent, system costs appear to be in the range of €25–35/MWh, assuming an average electricity price of €70." In other words, electricity from wind power is worth only "€35–45/MWh under these conditions, i.e., 35-50 percent less than the average electricity price" (Hirth, 32). If wind's levelized cost of energy is €60/MWh, costs associated with its variability are 50 percent of generation costs (Hirth, 21). In general, above some threshold, a high percentage of wind resources will disproportionately increase grid operating costs. These broad conclusions are based on European data, and we have yet to estimate the tipping point at which the net benefits in ERCOT and other U.S. regional transmission authorities (RTOs) would become negative. Measurement in the U.S. is further complicated by PTC and depreciation subsidies that can further induce excessive wind investments. More specifically, ERCOT's position as a (rather large) island in the national network may leave it with fewer export opportunities that lower its potential benefits relative to those encountered in more diffuse European systems. If so, estimates of CREZ's benefits may be biased upward because they do not account for these increased costs of greater dependence on wind.

Summary and Conclusions

For both economic and political reasons, Texas was an early experimenter with wind power and carving out regulatory boundaries, such as renewable portfolio standards. These regulations protected wind generators from competition by requiring REPs to comply with renewable quotas when choosing their supply mixes. Growth continued as wind's apparent success brought forth CREZ legislation that further facilitated access to wind-rich areas by imposing non-bypassable transmission charges. In combination with wind's scale economies, rate designs further redistributed renewable costs and revenues. Rate designs that passed costs through to captive consumers redistributed intermittency risks away from wind generators and toward non-wind producers and captive ratepayers, a practice with few valid efficiency rationales. Wind producers often have dispatch priority in markets administered by regional transmission operators like ERCOT, but even without priority rules, the promise of subsidies incentivizes negative bids.

The PTC, however, is more than a simple wealth transfer from ratepayers to wind entrepreneurs. It changes the relative profitabilities of intermittent and dispatchable generation to favor the former, a situation that can only become more problematic as wind power continues to grow in the nearly isolated ERCOT grid. ERCOT is not alone in facing the price suppressions and distortions due to wind development, but it faces stringent limits because it has very few safety valves in the form of connections with other grids. Things will become more, rather than less, problematic in the long run because wind power that the grid operator must utilize, when offered, reduces the profits of generators that are necessary for meeting loads and discourages future investment in them.

Low average power prices rooted in the growth of wind are economically inefficient if they impose costs on ratepayers and other generators with few countervailing benefits, as is becoming clear from studies of some national grids in Europe. Put more simply, the presence of substantial "must-take" wind generation alongside the PTC can lead to inefficiently low or negative energy prices. Such prices are at variance with rationales for competitive markets, because they give consumers and producers incorrect signals about today's resource scarcities and tomorrow's necessary investments. In a future paper we examine ERCOT's responses to these distortion-laden developments and the ways in which it and other RTOs are adapting to the changed realities that have come with intermittent generation.

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Michaels has participated in electricity restructurings in California, Japan, and New Zealand. He has served as an expert witness in utility merger proceedings before the Federal Energy Regulatory Commission and has testified on the economics of electricity market monitoring. He has also testified before the California Public Utilities Commission, Illinois Commerce Commission, Mississippi Public Service Commission, Vermont Public Service Board, and Washington State Energy Facilities Siting Council, among others. He has testified on four occasions as an invited expert before committees of the U.S. Congress.

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