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Pre-technical conference statement

Reconciling Wholesale Competitive Markets with State Policies: Overview

Well-structured wholesale energy and capacity markets deliver value to consumers when competitive forces drive rival suppliers to efficiently provide reliable electricity whenever consumers want it while taking into account the operational needs and the dynamics of the grid.

Choices have already been made at both the Federal and state level to employ "outside of the market" approaches to achieve policy objectives. These market interventions are causing significant and persistent Eastern electricity market distortions and economic inefficiencies.

Opportunities exist to address market distortions. One approach would be to only employ market-based approaches to achieve policy objectives. Alternatively, available market interventions can augment or replace deficient market-based cash flows. This latter approach directly supports cost-effective investment in flexible cycling dispatch capability, baseload generation production efficiency, generating portfolio diversity, and low CO_2 emission intensity electric generation.

The efficient electricity market outcome provides the benchmark to assess policy distortions

Comparing the expected outcomes from an efficient electricity market to actual energy and capacity market outcomes indicates whether state policies increase or decrease market distortions. However, the benchmark for electricity market assessment is more complex than the simple economics textbook market equilibrium result involving a static long run demand and supply curve intersection that produces a single market-clearing price equal to the long run marginal cost of efficient supply.

The long run electricity market equilibrium involves a demand curve that shifts in the short run due to the underlying recurring annual hourly aggregate consumer load pattern. The implication is that all electric supply resources do not have to run at the same utilization rate through time. Since generating technologies involve a trade-off between upfront capital cost and production efficiency, no single generating technology is the least cost source of electricity supply across all possible annual utilization rates. Therefore, an efficient long run electricity market outcome requires demand and supply interactions to determine ***varying*** price levels throughout the year. This price pattern is the market signal that coordinates investment in a mix of generating technologies with different costs, efficiencies and operating characteristics, that in the aggregate, will produce the lowest average total cost to reliably meet the recurring annual power system net load pattern.[1]

In a well-structured long run electricity market outcome, competition to supply the infrequent, peak segment of aggregate consumer demand drives rival generators to invest in dispatchable "peaker" technology capable of producing the lowest average total costs at low annual utilization rates. In the short run, competition produces efficient utilization by driving the energy market to clear on prices

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[1] Williamson O E, "Peak Load Pricing and Optimal Capacity under Indivisibility Constraints" AER, vol 56 no 4, September 1966, pp 810-827

reflecting incremental variable production costs. However, an inherent generating technology characteristic shaping incremental costs prevents short run marginal costs from rising to equal long run marginal costs when the market is in long run balance with the desired level of reserves for reliability.

The “missing money” in market-based cash flows for new entrants is partially offset when the production efficiency of new peaking technology is greater than existing peaking technologies. In this case, operating new technology whenever the less efficient existing technologies are setting the market-clearing price produces what economists call “infra-marginal rents” that contribute to reducing the market-based new entrant cash flow shortfall. These market-based cash flows lower the investment cost recovery threshold for the least cost peaker from the levelized annual “Gross” Cost Of New Entry (CONE) to “Net” CONE (CONE minus the expected energy market cash flows generated by infra-marginal rents).

A well-structured electricity market requires interventions to close the remaining “missing money” gap for the cost effective peaking technology. Eastern RTO and ISOs employ capacity markets alongside energy markets to produce market-clearing capacity prices capable of covering Net CONE when the electric market demand and supply are in long run balance.

Although we can expect the long run outcome produced by well-functioning electricity capacity and energy markets to generate adequate cash flows to support the most cost effective peaking technologies, we do not expect investment in peaker technologies alone. Competition to supply the varying, non-peak segment of aggregate consumer demand drives rival suppliers to invest in the flexible “cycling” technologies with the lowest average total costs arising from the higher utilization rates making the benefits of greater production efficiency outweigh the higher upfront capital costs. Competition forces suppliers to use the energy market cash flows available from operating these more efficient cycling technologies when the less efficient peaking technologies are setting market-clearing prices to cover the additional upfront investment in cost-effective cycling technology production efficiency.

Although we can expect the long run outcome produced by well-functioning electricity capacity and energy markets to generate adequate cash flows to support flexible generating technologies with varying productive efficiencies, we do not expect investment in peaking and cycling technologies alone. Some segments of consumer demand do not fluctuate through time. For example, in PJM the minimum level of aggregate consumer demand across the year typically accounts for over 60% percent of electric energy output. Competition to supply this segment of aggregate consumer demand drives rival generators to invest in “baseload” technologies capable of producing the lowest average total while running at the highest utilization rates by trading less dispatch flexibility and higher upfront capital costs for more production efficiency, as found for example, with combined heat and power cogeneration technologies. Again, competition forces suppliers to use energy market cash flows available when cycling and peaking technology incremental costs are setting energy market prices to cover the additional upfront investments in cost-effective baseload production efficiency.

Energy market cash flows are also a key market mechanism to coordinate efficient investment in intermittent electric generating technologies. For example, intermittent wind resources provide some capacity market contributions that yield a Net CONE for unsubsidized wind entry (wind CONE minus capacity revenues). Economic entry occurs when the Present Value (PV) of the wind Net CONE cost stream is at or below the PV of the revenues available from selling energy when the wind blows at market-clearing prices reflecting the SRMC of rival dispatchable generators (energy market infra-marginal rents).

Energy market cash flows are also a key market mechanism to coordinate efficient investment in electric storage technologies. Electricity storage has capacity and ancillary service values that yield a Net CONE for storage investment entry. Storage is economic when the PV of the storage Net CONE cost stream is less than or equal to the PV of the difference between the cost of charging and discharging at market prices (an intertemporal difference in energy market infra-marginal rents).

The bottom line is that the level and pattern of annual hourly wholesale electric energy prices and the associated energy market cash flows are keys to producing an efficient market outcome involving a cost minimizing supply portfolio composed of a diverse mix of fuels and technologies reflecting cost effective tradeoffs between upfront capital and electric generation production efficiency, and incorporating adequate investments in operating flexibility.

Market distortions

Federal and state policies currently distort annual hourly wholesale price patterns. In the Eastern electricity markets, the most significant distortions arise from state mandates and subsidies for wind resources already subsidized by Federal Production Tax Credits (PTCs). The PTC shifts as much as 50 percent of wind power supply costs to tax expenditures and away from electricity bills and creates a short run marginal generating opportunity cost of a negative 23 $(2016)/MWh. The size of the PTC pre-tax value made tax equity a primary funding vehicle for wind projects. Although a phase out of the PTC is scheduled for 2019, the PTC is grandfathered for the first 10 years of project operating life and thus, the PTC will impact markets for more than a decade to come.

Current market impacts are significant because Eastern electricity market outcomes would involve little, if any, wind resource investment in the absence of mandates and subsidies. For example, selling wind output during 2015 at PJM market-clearing prices yielded an average wind output weighted price of 34.40 $/MWh. The US Energy Information Administration estimates that unsubsidized levelized cost for wind entry is between 41 and 71 $(2015)/MWh. The 2015 PJM market monitor report indicates PJM wind entry costs are at the high end of the EIA range and also indicates that PJM wind entry is typically uneconomic without subsidies.[2]

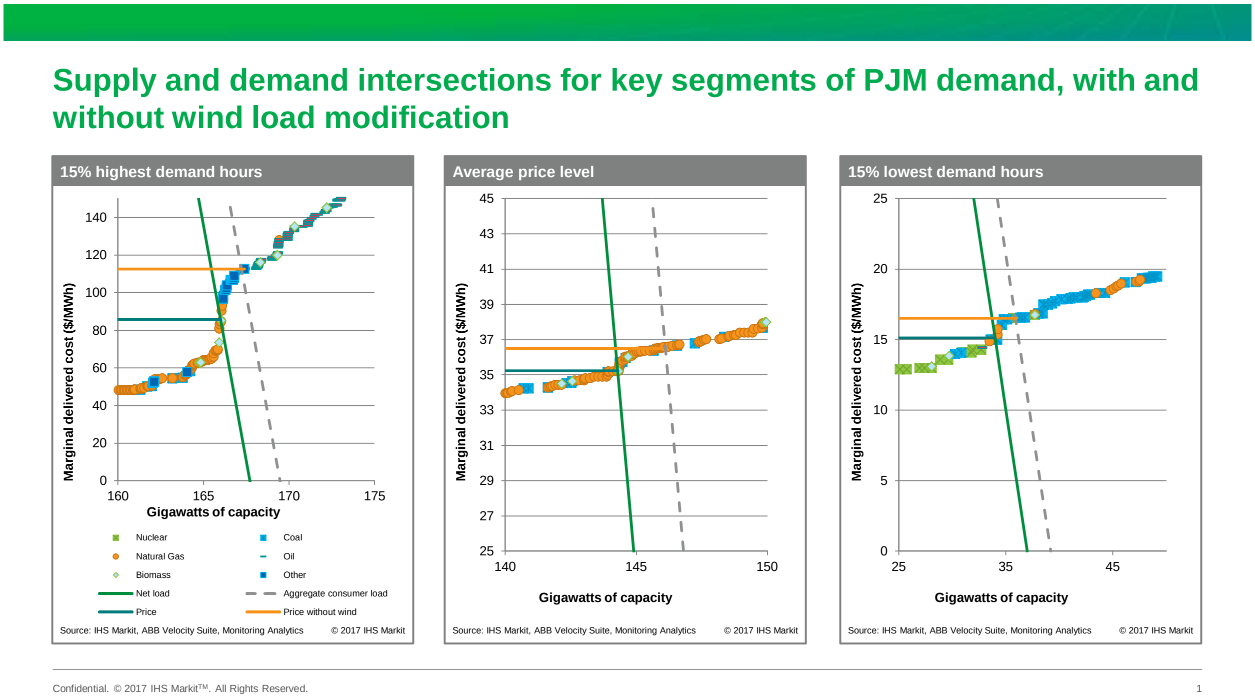
Mandates and subsidies of wind technologies are not a proxy for a CO_2 emission externality charge because these policies are technology specific. An economically efficient CO_2 emission charge would not distort the market because it would neither competitively disadvantage alternative zero CO_2 emission technologies such as nuclear, nor fail to alter the relative costs of generating technologies with different CO_2 emission intensities, such as natural gas versus coal-fired technologies.

Uneconomic wind resource market entry in the Eastern RTO and ISO markets suppresses wholesale energy prices and reduces the energy market cash flows needed to produce an efficient market outcome. This wholesale price suppression can be graphically illustrated with current PJM demand and supply curve interactions.

Figure 1 illustrates the intersection of the 2015 PJM electricity market demand and supply curves during three different demand intervals and with two market demand curves reflecting Net Load (aggregate consumer demand less wind output) and aggregate consumer load. The supply curve is the cumulative, ordered incremental generating costs (including average zonal transmission congestion costs) of the derated non-wind capacity (based on typical forced outage rates) of installed generating resources.

[2] "2015 State of the Market Report for PJM." Volume II, Section 7 (Net Revenue). Monitoring Analytics, 2016.

Figure 1



Wind output suppressed prices by around 24 percent during the 15 percent of maximum 2015 net load hours when rival peaking technologies are setting the price. Wind output suppressed prices by around 4 percent during the 15 percent of hours around average net load and by around 9 percent during the minimum net load interval.

Wind output reduced 2015 PJM energy market cash flows. On the revenue side, wind output suppressed prices. On the cost side, compensating for the impact of wind on the sequential hourly net load pattern caused net load following generators to increase output ramping and starts and stops, causing less production efficiency and higher O&M costs.

Uneconomic wind output during the peak net load interval reduces peaker technology cash flows thereby increasing the peaker Net CONE. A short run market distortion arises because wind entry adds subsidized capacity and suppresses the capacity market price. However a well-functioning capacity market provides a mechanism to mitigate this distortion because capacity markets should produce an offsetting increase in the market-clearing price of capacity to cover the higher Net Cone when the market achieves demand and supply balance in the long run, all else equal.

Capacity market adjustments do not offset the suppression of cash flows supporting investment in cycling and baseload technology production efficiency. Cash flow suppression is magnified for the most efficient generating production technologies when wind output variation is so great that in some hours the security constrained dispatch produces “overgeneration” conditions when the sum of wind output, inflexible generation, out-of-merit order dispatch (network security constraint-driven dispatch), and minimum operating spinning reserves required to back up intermittent resources exceed net load. Under these conditions, cost minimization requires reducing supply or increasing net load from the least cost options. However, wind–on-wind competition to avoid curtailment reflects the opportunity cost of losing the volume based subsidy. Consequently, overgeneration produces inefficient curtailment outcomes. An indicator of these market distortions are negative market-clearing prices during low net load intervals. For example, PJM experienced 25 hours of off-peak period negative prices in 2015.

Uneconomic wind generated cash flow reductions trigger underinvestment in cycling and baseload technology production efficiency as well as uneconomic retirements. In the short run, market distortions reducing cycling investment cause a loss of supply portfolio operating flexibility until the capacity market price adjustments trigger entry of flexible, but less efficient peaking technologies in the longer term. This shift generates higher overall average cost of electricity production and higher production cost variability. In addition, CO_2 emissions will increase when the replacement power resources for uneconomic retirements are intermittent renewables integrated by natural gas-fired technologies with relatively higher combined CO_2 emissions per KWh. For example, the uneconomic closure of the Vermont Yankee nuclear power plant caused ISO New England electricity market CO_2 emissions to increase by 7 percent from 2014 to 2015. A similar impact will occur when the Pilgrim nuclear power plant prematurely closes.

In summary, out-of-market interventions cause predictable distortions and consequences, including:

1. Reduced market-based cash flows for non-peaking generating resources, causing lower investment in electric generating production efficiency.
2. Uneconomic displacement of lower cost energy production causing a shift toward a less cost-effective fuel and technology mix and resulting in higher overall average electricity supply costs.
3. Less supply diversity causing more generation production cost and availability risk.
4. Premature retirements of low CO_2 emitting resources, causing replacement with higher CO_2 emitting resources that subvert market intervention policy goals.

Options to reconcile market outcomes and out-of-market interventions

The market impacts of state mandates for subsidized renewable resources are significant and increasing. New York recently upped its market interventions to require 50 percent renewable generation share by 2030. Other Eastern states are debating regulations that would mandate 100 percent renewable power supply within the next several decades. The full impacts of these interventions are yet to come, but the potential market distortions are large enough to eventually force the determination that such market interventions produce unjust and unreasonable market distortions. In contrast, the default approach is to wait for market distortions to undermine support for electricity markets and shift the industry structure toward a greater reliance on state regulatory processes.

The most straightforward approach is to replace subsidies and mandates for renewable resources with an appropriate charge on CO_2 emissions. However, as long as distorting out-of-market interventions remain in place, the available remedy is to provide sufficient payments to augment or replace suppressed market-based cash flows to prevent the premature retirement of generating resources with going-forward costs below replacement costs, as well as support cost-effective investments in flexible cycling dispatch capability, baseload generation production efficiency, generating portfolio diversity, and low CO_2 emission intensity electric generation. Such interventions are not “bailouts” at odds with the creative destruction of the marketplace because distorted market prices are not producing a market test for economic efficiency.