Electric Capacity Market Performance with Generation Investment and Renewables

by

Cynthia Bothwell, Ph.D. student
Department of Geography and Environmental Engineering
The Johns Hopkins University
Baltimore, Maryland, USA, 21218
e-mail: cbothwe1@jhu.edu

Benjamin F. Hobbs, Schad Professor of Environmental Management
Director, Environment, Energy, Sustainability & Health Institute
The Johns Hopkins University
Chair, CAISO Market Surveillance Committee
e-mail: hobbs@jhu.edu

Abstract

Competitive markets have become more common for wholesale electricity transactions. Initially markets developed to improve efficiencies in the operational dispatch of electric energy. However, as systems mature and additional capacity is required to meet load growth as well as energy policy objectives, market failures may imply that energy-only markets are insufficient to motivate necessary investments in new capacity. Various countries and market operators have implemented investment incentives, such as capacity markets, that may address specific resource adequacy issues that their particular system has experienced. However, many of these mechanisms have required significant revisions to address unanticipated issues. Additional work is necessary to identify market designs that motivate optimal amounts and types of capacity investments while responding to policies mandating expansion of renewable energy and upgrades of existing facilities to meet clean energy standards.

Several jurisdictions are reviewing capacity mechanisms to identify efficient methods to motivate investment in appropriate future generation technologies. This paper explores the ability of different capacity mechanisms, including those now implemented or under review by several countries and regions, to motivate efficient investment in different generation resources, both new and refurbished. A single year capacity expansion model is use determine a theoretically optimal system based on cost minimization. Then the model calculates energy spot market and capacity mechanism settlements, allowing us to assess whether different market designs support the optimal generation mix, or if instead too much or too little incentive is provided for various capacity types. Interactions with renewable incentives are also examined.
Key findings from the analysis show that:

- The amount of existing low running cost baseload generation can represent a larger market distortion relative to optimal mixes than the introduction of renewables.
- Market distortions from inefficient capacity mechanisms are highly sensitive to natural gas prices, which may lead policy makers to choosing different approaches to incent capacity expansion given the circumstances of a specific region.
- By maintaining system adequacy via installed reserves that may exceed a customer’s willingness to pay for reliability, scarcity energy pricing based on the perceived willingness to pay will not be high enough or frequent enough to motivate sufficient new gas-fired generation, even though this type of investment minimizes total system cost in an optimally developed system. Therefore, additional capacity mechanisms are necessary for optimal development or traditional thinking about what constitutes an adequate reserve margin needs to be reconsidered.

1 Introduction

Decisions to invest in generation capacity are premised on some expectation of returns equal to or higher than what could otherwise be earned in other markets. Electric generators face uncertainties for both inputs and outputs. Historically there has been considerable fuel price variability, particularly for natural gas. Financial instruments exist to increase stability of fuel payments, but this comes at a price. On the output side, generators are uncertain of the demand and price for electricity, and how much the generator will be producing. Additionally, uncertainties exist in environmental and energy policy and market rules affecting the industry. Individually and in combination, these uncertainties increase risk to investment and may influence a potential investor to seek returns higher than for less risky investments. Where utility generation investment is subject to rate-of-return regulation, investors have less risk, meaning that customers have a primary role in mitigating market risk; however, electricity markets do not provide this certainty and in fact additional uncertainty has been added with electricity sales prices fluctuating at least hourly and in some cases more frequently. More detailed descriptions of investment risk is provided by (Botterud, et al., 2008) (Ehrenmann, et al., 2011) and (Gross, et al., 2010).

For some time, the “missing money” problem (lack of sufficient revenues in energy only markets to motivate investment) has been researched and recommendations have been made towards mitigation. As examples, some have suggested improvements in energy only markets (Roques, 2008), and (Muratore, 2011) while others have suggested capacity mechanisms (Finon, et al., 2008), (Doorman, et al., 2008), (Hasani, et al., 2011), (Hobbs, et al., 2001) and (Assili, et al., 2008), and some have advocated for both (Stoft, 2002), (Joskow, 2008) and (Gurkan, et al., 2013).

Although generation markets may shift risk away from consumers in the short-term, in the long-term it is likely that a risk premium will be added to the commodity pricing back to consumers. Whether possible efficiencies in investment and operations spurred by competition will more than compensate consumers for that risk premium remains an open and important question. General investment theory suggests that with greater uncertainty unless large profits are expected (meaning consumers are now paying more), waiting to investment (allowing for more information and less uncertainty) can be the most profitable course of action. Yet in the electricity industry, there is an expectation that reliability standards will be
maintained, and national standards are set to enable this and minimize neighboring interconnected systems from becoming a burden on one another. The market challenge is to facilitate investment in an uncertain marketplace by implementing the market designs that maximize efficiency and motivate investment while maintaining the prescribed level of system adequacy. Industrialized nations have prioritized reliable electric systems (FERC Commission Staff, 2013), and are loath to subject the system to forecasted cycles of over and under supply as investigated by (Arango, et al., 2011). Additionally, in many jurisdictions, policy directs capacity decisions not only to maintain adequacy but also to reduce carbon emissions (Keay-Bright, 2013).

Most of the analytical work to date has not considered market complications arising from the integration of intermittent renewable generation into energy and capacity markets. Additionally, a great deal of work has focused on correcting the “missing money” problem for investors with less emphasis on the companion impacts to consumers. Through a set of modeled scenarios, this paper looks at several market designs and measures the impacts to both generation investors and electricity consumers for several market designs, and assesses whether those designs support appropriate optimal investment by allowing investors to recover their cost. Both a summer peaking, low load factor and a winter peaking, high load factor system are modeled based on historical hourly data for a single year. Impacts of alternative natural gas price scenarios are also explored.

The paper is organized as follows. Section 2 outlines the theoretical background of economic investment in the electricity industry. Section 3 provides some additional background on capacity market failures and the potential of intermittent renewable resources to complicate market designs. Section 4 details the models we use and the market mechanisms we consider in this study. Section 5 steps through the results of the models considering a variety of alternative assumptions, including different levels of renewable penetration and subsidy levels. Finally, section 6 gives concluding remarks and suggests topics for future work.

2 Theory of Capacity Compensation in Electricity Markets

In theory, an electricity market should optimize the amount and type of generation investment if energy is paid the marginal bid (generator variable cost for rational bidders) for each hour (with a premium during times of scarcity representing the willingness of consumers to pay). In the absence of appropriate scarcity pricing, additional payments to make up for the “missing money” would be made to capacity.

Let us assume that we have two generators A and B and that generator A has low fixed costs (FC) and high variable costs (VC) while generator B has high fixed costs and low variable costs. Simplifying operations, B is always dispatched first due to its low operating costs so it has a higher capacity factor (cf), and A is dispatched only when load exceeds the capacity of B. To start with the simplest possible model, to determine the optimal capacity of each generator (A and B) an optimization problem can be written as:

Minimize Total Annual Cost: \( FC_A * A + FC_B * B + [VC_A * A * cf_A + VC_B * B * cf_B] * 8760 \)  

With the optimization being subject to the usual constraints of load matching each hour and the capacity factors being calculated as the total load served by a generator divided by the maximum load that the generator could have served if it were running during all time periods at full capacity (for example:
maximum load that A could have serve being A*8760 in this simple annual model). “cf” is the capacity factor of the generating unit, and A and B are the capacities of the two generators, respectively. “FC” is the $/MW/yr annualized fixed capital cost and “VC” is the variable operating cost in $/MWh. For a more detailed discussion of generation mix optimization see (Hobbs, 1995).

Consistent with microeconomic theory, if there are no scale economies or diseconomies (as assumed by the linearity of (1), then at the optimal investment point Total Costs (TC) = Total Revenue (TR) and the TC_A = TR_A and TC_B = TR_B. The system is at equilibrium within the market; however, this is only in theory. There are many complicating factors, some of which will be discussed within this paper, as to why cost does not necessarily equal revenue in markets. Primarily these factors fall into the general categories that lead to market failure – externalities, whether positive or negative, not being internalized; impairment or immobility of product inputs – such as fixed renewable portfolio (RPS) standards, adequacy requirements or mandates to retire certain technologies; and lack of perfect market information such as knowledge of load and fuel prices. Another reason why revenue does not equal cost is that a system may be out of equilibrium, being planned or built under one set of fuel prices or load shapes, and then being subjected to changed prices and loads, so that the mix is no longer optimal. Of course, given the twists and turns of energy markets, and the long lead times for generator construction, the industry may often be far from equilibrium.

### 3 Capacity Market Failures

In theory, electricity markets provide incentives for development of new resources since all providers are paid the marginal cost of electricity and not their actual operating costs. When generator revenues are higher than costs, motivation is provided for new investment in efficient generation resources. But electricity must be provided on demand – it cannot be stored. Investment in generation is primarily irreversible, meaning once constructed it is not easily sold and moved to another location, thus dramatically reducing its salvage value. Legal requirements that prevent shortages (by mandating construction of extra capacity) may also prevent generator revenues from escalating to the necessary levels for market entry. Therefore, incentives for investment in electric generation need to be higher than for investment in something that could otherwise be sold in a robust market.

There are numerous examples of recent capacity market failures. This paper does not intend to provide an exhaustive list, but rather describes a select few as motivation to continue exploration in this area. Two areas of capacity market failure briefly explored in the paper include insufficient generation development and development of generation technologies that do not support system goals, which may be operational or environmental. ERCOT, Electric Reliability Council of Texas, is an example of a forecast for insufficient generation development, while Germany provides an example that also shows development in less flexible, higher emitting generation and retirements of more flexible clean technology during a time at which the

![Figure 1: Comparison of ERCOT Market Prices and Generator](image)
system needs greater flexibility to responding to increasing intermittent renewable penetrations and the country has set aggressive clean energy goals.

ERCOT is an energy based market that includes scarcity pricing caps. Texas has been ahead of most the United States in the development of wind energy. According to AWEA, in conjunction with state policies 15.6 GW of wind capacity has been installed with another 6.8 MW under construction. Wind generation provided 9% of the state’s energy requirements in 2014. As system reserve margins began to fall, ERCOT recognized a market failure with respect to investment in new generation. This prompted a resource adequacy investigation (The Brattle Group, 2012). Brattle found that scarcity pricing was too low and too infrequent to support reserve margins. 2012 scarcity hours were 1.5 hours while 2013 scarcity hours were 0.2. (The Brattle Group, 2012). In 2014, the day ahead market price maximum was only $1,330 which was considerable lower than the scarcity price cap. Figure 1 shows 2014 ERCOT day ahead market prices along with generation costs curves at varying capacity factors. The generator cost curves, showing the minimum amount needed to be considered profitable, never cross the average price curve – indicating that new generation of these types could not be profitable in this market. Similar results are detailed in the Brattle report for 2012 and 2013 (The Brattle Group, 2012).

In Germany, the top market price was only $130.27 in 2013. Figure 2 compares market prices in Germany during 2013 with new technology costs curves. Although specific conditions may vary, Figure 2 again shows the average prices stay below new generation costs and even just comparing fuel costs for a combined cycle generator, market prices stay below cost most of the year.

Linklaters provides a detailed study of markets and mechanisms in Europe including market failures (Coibion, et al., 2014). Market conditions similar to those shown in Figure 2 are in part behind what they call Europe’s return to coal. With prices low market prices it has been more cost effective to refurbish old coal-fired generators than continue to operate cleaner natural gas generators. According to Germany’s Federal Ministry for Economic Affairs and Energy, in 2013, 25.3% of Germany’s energy was supplied by renewable energy sources. (Federal Ministry for Economic Affairs and Energy, 2015) This increased to 27.8% in 2014, of which 52.4% was wind generation and 35.2% was solar generation – both intermittent sources with low to no variable costs.

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1 Developed from ERCOT 2014 market data (ERCOT, 2015)
2 Developed from EIA generation cost and heatrate data (U.S. Energy Information Administration, 2015), (EIA, 2015)
3 Developed from entso 2013 market data (entso, 2015)
Both examples have a significant amount of intermittent renewable generation. Once wind and solar resources have been constructed, they become first dispatch units due to their very low operating costs relative to other resource types that incur additional costs for fuel. Additionally, many locations provide incentives for renewable generators. Production tax credits are obtained if the unit produces electricity and have created the potential for negative electricity market bid prices. Subsidies received complicate market providing additional sources of revenues outside the market.

4 Comparing Alternative Market Designs for Two Case Study Systems

Using optimization techniques and energy and capacity market clearing models, we analyze two alternative regional power systems based on actual normalized historical load, wind and solar data. The data is highly disaggregate (8760 hours), thus capturing a range of renewable states and load conditions. There are however, a number of simplifications. One is that generation capacity investment is treated as a continuous variable, not discrete blocks. Another is an omission of transmission; although transmission access is important in actual power systems, it was not considered in this high-level attempt to explore generation costs and market prices. Finally, we also do not include non-convex unit commitment constraints, such as start-up costs and minimum run levels. Elsewhere, we have defined optimal generation mixes in the presence of unit commitment limitations, but have not considered their performance under alternative market designs (De Jonghe, et al., 2012).

The first system modeled is winter-peak with a moderately high load factor, typical of European systems. The normalized load data is scaled to a system with a peak of 100,000 MW while maintaining a 70.8% system load factor. Normalized data for wind in this system is scaled according to the scenario to maintain that year’s 39.4% capacity factor while solar was scaled to maintain that year’s 21.5% capacity factor.

The second system we model is summer-peak with a significantly lower load factor typical of U.S. systems with high air conditioning load. The normalized load data for this system is scaled to a system with a peak of 100,000 while maintaining a 55.8% load factor. The two systems require the same amount of capacity; however, have different energy requirements. Normalized data for wind in the second system was scaled to maintain the 43.8% capacity factor while solar was used from the first system due to lack of data availability. It is noted however that the solar resource across the two regions is similar. Due to the nature of results from this study, the solar approximation was adequate, however, should be more precisely modeled to include any load and solar correlations of an actual region should specific regional analysis be considered.

New generation technologies were modeled using the most recent U.S. Energy Information Administration (EIA) cost information (U.S. Energy Information Administration, 2015) and best-in-class resources for peaking, intermediate and baseload operation. (See Appendix, Figure 16 and Figure 17 for the screening curves used to assess best-in class.) Renewable technologies are modeled with and without subsidies to show impact of supports. The subsidy for wind was modeled at the US Production Tax Credit (PTC) level of $23/MWh (U.S. Department of Energy, 2015) which when included in the

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5 Based on European load, wind and solar data from Dr. Martin Greiner (Greiner, 2014)
6 Based on ERCOT load and wind data for year 2011. (ERCOT, 2015)
optimization model is a negative variable cost. The subsidy for solar was examined at both 30% and 10% Investment Tax Credit (ITC) (U.S. Department of Energy, 2015) levels which when included lowers the solar fixed cost. The modeled subsidy rates may be higher or lower than other specific countries and lower than available within particular states in the U.S. The models aggregate coal, natural gas combined cycle, natural gas combustion turbine, wind and solar generation into technology clusters, not as individual generating units, with continuous capacity (as opposed to discrete blocks) available. Models including coal in the portfolio were modelled at a maximum of 45% of the overall peak system load with a maximum 85% capacity factor (this is higher than the U.S. (World Bank, 2015) or Europe (eurostat, 2015) overall but may be lower than specific regions). Coal generation was depreciated such that capital requirements were 25% of new coal construction costs. This represents significantly depreciated existing baseload generation facilities in mature electric infrastructure constructed when prices were lower, such as that existing in the U.S. or Europe. Existing nuclear facilities in these regions are also significantly depreciated and may exhibit similar fixed costs and lower operating costs than the modeled coal. Given this, later conclusions drawn from analysis of baseload coal would be similar for nuclear generation and may to some extent be also applied to vintage combined cycle generation. High level ramping constraints were placed on each dispatchable coal and combined cycle technology clusters to allow consideration of capacity markets that differentiate between flexible and inflexible capacity (such as in California) based on system needs for flexibility due to variability in load and intermittent generation; however, at this point starts are not tracked. Natural gas prices were modelled at the current lower prices reflected in the United States natural gas market and the current higher prices of the European gas market, an approximate two times multiplier.

Table 1 provides the detailed generation cost assumptions used in modeling.

<table>
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<th>Tech</th>
<th>Low Gas $/MW/yr</th>
<th>High Gas $/MW/yr</th>
<th>Subsidy $/MW/yr</th>
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<td>Solar PV</td>
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<td>-</td>
</tr>
<tr>
<td>Solar PV - 30%</td>
<td>$193,289</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 1: Model Cost Assumptions for Generation Technologies

The capacity amounts and annual hourly dispatch of each generation technology have been optimized to minimize total cost while meeting load requirements, within the constraint of the maximum capacity level of coal and at the specified reserve margin.

Minimize: \[ FC_{solar} + FC_{wind} + FC_{CC} + FC_{coal} + VC_{CT} + VC_{CC} + VC_{coal} - Subsidy_{wind} \] (2)

A reserve margin was set at 15% of the total system demand to provide consistency across model results. This is a value comparable to many systems, within a couple of percentage points. As an example, a recent study conducted by the Brattle group suggests that the reserve margin for ERCOT should be 15.25% based on a one day in ten year criteria. (The Brattle Group, 2012) Reserve margins can be calculated many ways and variable resource capacity can also have varying meanings. In this analysis, the author chose to model variable generation as a generator and not as a negative load, yet used the shift in load as the basis for defining capacity contribution. First of all, reserve margin is calculated on the basis of the peak annual load. Coal and natural gas generator capacities are defined as their nameplate

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7 Data from EIA (U.S. Energy Information Administration, 2015)
capacity values. Wind and solar resource capacity contributions are defined as the difference between the peak load and the net peak load after the variable resource is subtracted (which may occur at a different hour). This method captures the amount that the peak load was shifted in the particular year analyzed. Since renewable capacity is not necessarily additive, when both solar and wind are included in a portfolio solar capacity is calculated first using a net load minus solar peak and then wind capacity is calculated as the additional peak net load reduction due to the wind addition.

For cases in which wind and solar technologies would not be competitive in the optimal generation mix, varying amounts representing Renewable Portfolio Standard (RPS) compliance have been added to the model and the dispatch of the remaining generation technologies have been re-optimized with the mandatory renewable sources.

Capacity mechanisms can take many forms and are generally categorized by whether or not they are centralized and all-inclusive, and whether they are based on a price or volume metric. Decentralized mechanisms place obligations on market participants while centralized mechanism place obligations on an overall larger system of multiple participants. A mechanism is all-inclusive if it applies to all market participants and is targeted if it applies to a particular market segment exclusively – examples include renewables, reserves or flexible resources. Another form of targeted mechanism is a tender or uplift payment that provides certain capacity providers the necessary money to cover investment beyond what the energy market is providing. A mechanism is considered volume-based if a particular amount is predetermined (say MWs of capacity needed) while a price based mechanism sets a buying price and will take all providers (any amount of MWs) at the set price. There are various other variants (e.g., operating reserve demand curves, particular methods to calculate capacity credits) that are considered. This paper focuses on several volume-based capacity mechanisms where the volume is set by attainment of a system adequacy criteria, such as a given system reserve margin or loss-of-load probability. The mechanisms analyzed include targeted and market based mechanisms that are centralized or decentralized.

Specifically the mechanisms studied include:

1. Energy only markets: In this market, generation is paid when it supplies energy to the market. The market price for all generators in a given time period is the marginal price to supply the next MWh. In determining generation price bids, the models used included generators bidding their operating costs (which were determined using the latest EIA estimates (U.S. Energy Information Administration, 2015)) including both fuel costs and operations and maintenance costs.
2. Energy markets that include scarcity pricing: These models are similar to the models for energy only markets, however, it includes higher costs than operating costs for scarcity hours. A review of Texas data showed that scarcity occurred very infrequently (1.51 hours in 2012 and 0.22 hours in 2013 at rates of $3000/MWh and $4500/MWh (Potomac Economics, 2014)) the rates have gradually increased to $9000/MWh in 2015. A review of rates in Germany, where energy shortfalls have occurred, show that spot electricity prices only reached €130.27/MWh (roughly $169 US at the time) in 2013 and prices were only over €100/MWh for 17 hours that year. (entso, 2015) For the purpose of this study a generous scarcity price of $9000 was applied for two hours in a year and applied to dispatchable generation. Assuming that part of the reason for the scarcity pricing was the unavailability of renewable generation sources, renewable sources did not receive scarcity pricing. Even though some U.S. locations have gone to this level of scarcity
pricing, the price level is considered generous since lower cost backup generation substitutions may be available to customers and if more accurate pricing signals were eventually passed down to consumers, some amount of curtailment or substitution may be expected, lowering scarcity pricing.

3. Energy market with capacity market for dispatchable capacity. This combined the energy only market described above with a second market for capacity. The models assume all dispatchable capacity is paid at the rate of a new natural gas combustion turbine, since this is the least cost best in class technology for new generation (see Table 1) (U.S. Energy Information Administration, 2015).

4. Energy market with capacity market for all capacity. This design combines the previously described energy only market with a payment to all generation sources that provide capacity to meet or offset the system peak. Many variations exist for counting capacity contributions of intermittent renewable resources. For this paper, a middle of the road approach was taken in which the capacity contribution was determined for the renewable sources by calculating the difference between the system peak demand and the system peak net demand (load less renewable generation) even if these two during different time periods. This measures the change to generation requirements as a result of renewables and preserves any correlation that might exist between load and wind or solar resource. This is the same way that capacity was determined for purposes of meeting an overall designed system reserve margin.

5 Results of Two System Study

This section provides the results of analysis conducted of the two systems comparing cost of the optimal portfolio mix from a least cost perspective to the different market rules detailed in the previous section. First the systems were modeled without renewables. Then select results with renewables added for RPS compliance are considered. Finally, an optimal renewable portfolio is determined. Additionally, an investigation is done looking at market rules considering variations in wind characteristics. The concluding section summarized the results of the analysis.

5.1 System without renewable generation

The first optimization model looks at market mechanisms before renewable generation is added. This will later help to isolate what impact are the result of intermittent renewable generation and what impacts are pre-existing. Even without the addition of subsidized intermittent renewable generation, electricity markets do not provide enough monetary incentives for natural gas development. Error! Reference source not found. and Error! Reference source not found. show that from a total cost perspective, existing partially depreciated baseload plants such as coal (but this would certainly apply to nuclear and some other depreciated plant as well) have the advantage of low remaining capital costs and low operating costs, unless there is significant improvement costs necessitated (for example from environmental regulations or relicensing). As long as the older baseload plants continue to operate properly and require standard type maintenance, their expected income from an energy market exceeds their costs in high or low gas cost gas markets and in varying seasonal load factor systems. These results indicate that electricity markets do not adequately capture investment differences across time, especially when construction prices increase. Transitioning from a cost recover model to a competitive market
paying marginal cost may remove investment risk from consumers but also results in price increases commensurate with the increased revenues provided to generators, specifically existing units with low variable cost. Technological innovation in the industry has heretofore not introduced more economically efficient technologies that can compete with vintage depreciated technologies.

These models show that energy only electricity markets, even those incorporating scarcity pricing do not provide enough economic incentive for the development of new natural gas resources. As previously mentioned, the inclusion of a customary reserve margin most often forces additional capacity beyond the economic equilibrium level which results in associated costs increases without supporting revenues. This is in part because reliability standards prevent scarcity pricing from occurring frequently enough to cover the costs of new investment. Market designs used in Europe where capacity held for reserves and compensated separately could improve incentives as long as scarcity pricing was invoked every time that reserves are used. However, this only exacerbates the chronological market problem of low variable cost vintage resources collecting rents and raising overall costs to consumers over those paid under cost recovery regulation.

The winter peaking system with high natural gas prices in Figure 3 generally provides for market payments in excess of system costs even when considering capital and fixed costs, however, this is not extended to each resource type equivalently. In fact, existing baseload generation facilities with low operating costs will receive revenues in excess of costs while newer natural gas facilities will receive revenues that are less than costs. So even though a least cost system analysis results in one type of optimal system, the market does not provide the incentive for the development of that type of system. The market does provide incentive for the refurbishment of older semiretired baseload facilities that may have higher emissions rates, as currently being seen in Germany (Coibion, et al., 2014) and the UK (National Grid, 2014). Adding scarcity energy payments does not result in a sufficient amount of additional revenues since scarcity situations are not frequent enough nor of sufficient duration. A capacity payment can be provided to all or portions of the system capacity to make whole the natural gas generators, but this moves the overall system cost farther from the optimal cost recovery equilibrium.
The summer peaking system with low natural gas prices in Figure 4 has similar issues. It is noted that a greater amount of combustion turbine technology is optimal in the cost mix, which is expected for a system with a lower load factor and when natural gas prices are lower. Overall energy market revenues are close to the total cost optimal system, potentially slightly under – leading to a premature initial conclusion that markets result in lower costs to consumers. However, like the winter peaking systems discussed above, existing baseload with low operating costs receive energy payments in excess of their energy, capital and fixed costs on an annual basis whereas energy revenues to new natural gas facilities are insufficient to motivate investment. Including scarcity energy payments does not remedy the deficit. If new capacity is not required for system adequacy, lower costs can might be achieved (depending how the existing capacity is receiving its revenues); however, if new investment is required the energy market incentives are not sufficient. Again, adding capacity payments to all or some of the generation types may motivate natural gas investment; however, it does so by increasing consumer costs above the optimal level.

5.2 Adding 20% subsidized wind generation

Next, the market interactions were explored when a 20% energy based RPS is mandated. First it is determined that both portfolios would rely upon wind as the least cost means to achieve the renewable standard. Wind generation is modeled including the PTC subsidy. At the 20% energy level, wind is never curtailed and never on the margin (never sets a subsidized negative market price).

Results of the 20% subsidized wind models are shown in Figure 5 and Figure 6. In both systems, wind receives economic rents with and without capacity payments, indicating that the systems are not optimal with respect to the amount of wind added and that in fact more wind can be added for an efficient system with subsidies. This may not always be possible due to other considerations such as siting and permitting (externalities that might not have direct costs that can be included) and transmission access (a cost that could be added). The added wind displaces all fossil generation types; however, the greatest reduction in both systems is in combined cycle, both in terms of installed capacity and also in unit capacity factor. Installed combustion turbine capacity increases in the optimal mix; however, its capacity factor also...
declines. The increase in wind erodes the economic rents received by existing baseload coal. In both systems, a capacity payment is necessary to restore profitability to new gas-fired generation technologies.

5.3 Adding 40% subsidized wind generation

When the RPS mandate is pushed to 40% of system energy, subsidized wind is occasionally on the margin creating some hours of negative market prices. There are also required wind curtailments when wind generation exceeds load. The summer peaking system is close to optimum for each technology type when including capacity payments.

Results of the 40% subsidized wind models are shown in Figure 7 and Figure 8. The wind continues to receive economic rents in the winter case even without the additional subsidy payment, continuing to suggest that the optimal amount of wind has not yet been reached. In the summer system case, this is not true. Wind revenues are not sufficient without the subsidy. A capacity payment for wind also does not cover costs using the described methodology. With both a subsidy and a capacity payment, more wind can be added for an efficient system. Combined cycle capacity and energy continues to be displaced by wind whereas combustion turbine capacity and energy increase with declining capacity factor. The increase in wind erodes the economic rents received by existing baseload coal, in fact in the summer case almost to the point of coal retirements without scarcity pricing or capacity payments in place. In both systems, a capacity payment continues to be necessary to restore profitability to new gas-fired generation technologies.

5.4 Adding 40% unsubsidized wind generation

As shown on Figure 9 and Figure 10, there are only subtle market differences at the 40% wind energy penetration level when renewable subsidies are removed arising from the few hours of negative pricing when wind is on the margin. Lower penetrations of wind would result in no market changes. Wind collects economic rents when gas prices are high but is unprofitable when gas prices are low. (This may not be the case for a system that has a higher blend of existing gas-fired baseload and less coal and
nuclear. The summer peaking system is close to optimal overall with a capacity payment in place; however, coal receives economic rents from wind.

5.5 Adding 10% unsubsidized solar generation

Solar generation is currently not cost effective at either gas price and raises cost to the generation portfolio, as shown on Figures 11 and 12, whether through subsidies or RPS requirements or both. Potentially if the right combination of best solar sites, summer peaking load profile and high natural gas prices existed on a regional basis, some amount of solar may contribute to an economically optimal portfolio. Brief sensitivities were conducted using the overall study data. Continued price declines show promise for solar technologies in the future.

The models combine two factors – load shape and gas price. Despite higher system prices in the evening hours when solar is unavailable, the winter peaking system provides better compensation to solar facilities than the summer peaking system due to higher natural gas prices.

In the winter peaking, high gas system solar generation raises the portfolio costs slightly. The offset to the high gas price is almost enough to pay for the high fix capital costs of the solar technology.
Comparing Figure 3 and Figure 11 it is shown that most offsets come out of what would have been generated using combined cycle technology – the cleanest of the fossil fuel technologies. In fact, not only does solar development result in serving energy that would have otherwise been served via natural gas combined cycle, but solar development leads to reduced capacity development in combined cycle and increased development in natural gas combustion turbines. As with the above analysis, existing baseload generation collects economics rents, and natural gas technologies require capacity payments in order to be profitable and for investment to be motivated; however, such capacity payments further contribute to escalated consumer costs. Although the solar technology has a minimal increase to portfolio costs over the optimal investment mix, it is not provided with enough revenues to be profitable. Solar provides very little if any capacity in a winter peaking system, due to peaks occurring after sundown. Therefore, adding a capacity payment based on the actual peak net load differential bring little additional revenue.

By contrast, a bit more solar capacity is available at the time of a summer system peak; however, it is smaller than might initially be expected. A few contributors to a somewhat small peak capacity value are: fixed solar panels and those with limited tracking that are typically installed to maximize energy production throughout the year and not production at time of peak; summer peaking systems have highest loads in the late afternoon (not at solar daily peak), closely followed by early evening when solar output has substantially diminished; and July and August peaks demands can be very similar with some years the highest loads occurring in August, yet solar capacity at the hour of peak is lower in August than in July. Using a capacity mechanism that closely matches the product delivered can result in low capacity payments even for the summer peaking system and can also vary from year to year. Like the winter peaking system, solar generation displaces both capacity and energy from natural gas combined cycle.

### 5.6 Optimal gas and wind generation mix, with fixed existing coal

In determining the optimal mix for each of the two systems, the existing coal constraints were maintained and renewable subsidies were removed. The winter peaking, high natural gas price case was optimal with the inclusion of 48% wind energy. Additional amounts of wind would be optimal with reduced amounts of existing baseload. At this high penetration of wind, 0.2% of the total annual wind is curtailed with curtailments taking place during 111 hours (which means that the energy clearing price was set to zero for those hours). It was assumed that curtailed wind was not paid, which prompts a policy discussion.

![Annual Generation Costs and Market Revenues: Winter Peaking System with Existing Coal, High Gas](image)

**Figure 13: Winter system with optimal generation, 48% wind**
regarding how wind curtailments should be handled between wind providers. Which facilities should be curtailed assuming that no transmission constraints exist? Should the market reward facilities closer to load or that would improve system efficiencies such as reduced system losses? Should the reduced energy revenues be spread on a proportional basis across all potential wind providers impacting each provider equally? Again, the market mechanisms should consider these types of issues when moving towards an optimal generation portfolio.

The optimal system shows an interesting effect with regard to existing units, their ability to collect economic rents in an optimal system. This is due to the constraint of only having a limited amount of these older units which in the case of this model would have sought more to be optimal pushing back the amount of optimal wind. The rents provide the aging resources with incentive to refurbish and continue operation even without capacity payments.

Similar results can be seen in the optimal portfolios as already discussed. Existing baseload generation continues to collect economic rents in all market designs examined. Interestingly, wind generation becomes unprofitable in the energy based market designs with high gas, which is a new finding. This is primarily due to the approach used in counting it’s capacity towards the reserve margin which means it needs both energy and capacity revenues to be profitable. In small part losses are due to uncompensated curtailments which reduce the overall portfolio costs, but also reduce the wind generators revenues.

5.7 Renewable impacts in a combined system

To explore impacts of differing renewable resources in the market, the two studied systems were combined into one centrally dispatched system with two separate wind resources. Although each individual system had a peak of 100,000 MW, combining the two non-coincident systems resulted combined coincident peak of 173,935 MW with a load factor of 72.8%. The optimization spread wind equally between systems on an energy basis. The optimum level was 28% wind, or 14% served from
each wind resource; however the costs were different since Wind Resource 1 has a capacity factor of 43.8% while Wind Resource 2 has a capacity factor of 39.4% and is thus more costly with more capacity installed to achieve equivalent amount of energy. At the optimal system level, there were no wind curtailments.

Figure 15 shows that even though the system is optimized, one wind resource could collect economic rents while the other is unprofitable in energy only markets. In this simple model the lower capacity factor wind resource is not profitable while the higher capacity factor wind resource collected economic rents. In the wind industry, costs have declined and capacity factors have increased due to technological innovation, learning curves, and manufacturing efficiencies. So what might have been optimal when it was constructed may in the end become unprofitable creating additional market risks. This suggests that when determining policies, it should be considered that new resources could render existing resources unprofitable. Within a market, the renewable generators could be made whole by additional payments, but then decisions need to be made regarding the rules of such payments. Another question is whether intermittent resources should be paid based on their marginal benefit according to vintage or whether all producers should receive the same payment. Each new market rule creates complexity and uncertainty for investment and the potential for increased costs to consumers.

5.8 Capacity Obligation to Load Serving Entities

Many markets assign the obligation to provide capacity to the load serving entities. The existing generation resources are dispatched in an efficient manner, but when combined with separate capacity cost, there is overall increased cost to consumers based on marginal cost energy pricing that was in some part designed to provide some compensation for investment costs. Consumers may pay for capacity twice. Although this is safe for investors, who primarily enter into long-term capacity agreements with the load serving entities, and it is reliable since the capacity is guaranteed at least in accordance with the rules used to define adequacy and assign obligations, it can lack overall efficiency when coupled with marginal cost pricing. In the theoretical construct, efficiency is achieved when fully regulated or fully deregulated.

5.9 Summary of Results

Based upon the above described analyses, the following is summarizes the results and implications for implementation of capacity mechanisms to facilitate optimal generation investment.

Scarcity Pricing Insufficient to Meet Reliability Targets: If the reliability target is a fixed 15% reserve margin, then energy-only markets provide insufficient incentive for the development of new natural gas
generation to meet reliability targets, in part because scarcity-based prices are neither high enough nor frequent enough to incent construction. At a minimum, if a system reliability corresponding to a 15% reserve margin is desired, either targeted capacity payments to new natural gas generators or payments to all capacity are necessary to cover the missing money not provided in the energy market. This could also be interpreted as suggesting that 15% reserve margins are not justified economically by the value they provide to consumers, but this assumes that costs of outages to consumers are efficiently translated into price signals in the market, which is not the case in today’s distribution markets.

**Solar Needs Subsidies:** In general, under our assumptions, solar development without subsidies is not optimal with either high or low natural gas prices. Some high solar insolation sites in locations with high natural gas prices and lack of lower cost baseload coal and nuclear facilities might be approaching prices that will include solar in optimal portfolios without subsidies, but these locations are not common. The high solar penetration occurring in some markets is due to explicit subsidies, or implicit subsidies in the form of net metering against high (non-marginal cost based) retail rates that are much greater than marginal generation costs. It should be noted that the analysis of this report was initially conducted using EIA generation cost assumptions from 2014. However, analyses based on the 2015 EIA values turn out to be more favorable for solar technologies, as costs have fallen. Additional new information on all assumptions should be periodically reviewed.

**Wind Development Depends on Fuel Prices:** Optimal wind development increases as natural gas prices increase. The low gas prices currently in the U.S. do not support the level of optimal wind development that is mandated by various state RPS requirements therefore some form of additional support is necessary. With high gas prices, wind producers are still profitable receiving energy-only payments for what they produce even though it is sometimes necessary to curtail wind without payment when wind production exceeds load. Optimal wind development increases as low cost baseload facilities decrease. As aging generation infrastructure is retired, additional wind resources will be profitable.

**Wind May Receive Economic Rents:** If siting or other restrictions limit wind development to below the amount needed to minimize system costs, economic rents may be earned in energy-only markets. This occurs even if price caps or missing scarcity pricing mechanisms suppress energy prices. Mixes that are farther from the optimum yield greater rents for wind. Additionally, an economically optimal system may incentivize additional high capacity factor wind development as technology costs fall or efficiency improves, while at the same time pre-existing lower capacity factor wind farms may no longer cover initial investment costs due to overall lower energy market payments created by the additional wind.

On the other hand, if gas prices are low, then augmenting the energy market by adding a market-based capacity payment to renewables for the amount contributed at system peak still does not provide enough economic incentive for investment to achieve the most ambitious state Renewable Portfolio Standards in the U.S. (e.g., California’s 33%). Renewable generation that is required to meet portfolio standards when natural gas prices are low, in general, needs to receive additional forms of payment (tax credits, renewable energy credit revenues) to support the social policy.

**Baseload Capacity Lacks Incentives for Modernization when Gas Prices are Low and Renewable Investment is Higher than the Least Cost Level:** Existing baseload assets that are already significantly depreciated and that have low fuel costs, such as coal and nuclear, earn rents in an energy-only market
with no renewables, especially when gas prices are high. But the rents shrink as the amount of renewable generation increases and substitute fossil fuel prices decrease, thus providing less incentive for modernization. As policy-driven subsidies cause renewable penetration to increase beyond the cost minimizing level, capacity payments may be necessary to provide efficient incentives for baseload upgrades.

6 Conclusions and Future Research

Because market failures in the electricity sector remain uncorrected, there is interest in finding better market mechanisms to support efficient and least-cost capacity investment in generation resources. By simulating optimal investment mixes and returns to investors, our models enabled us to explore the overall profitability of generation technologies given different scenarios.

The analysis shows that markets have different results depending on the existing resource mix, load shapes, and fuel prices. As different regions have a wide range of preferences regarding generation technologies, market rules should be designed both to accommodate those preferences as efficiently as possible. For example, in Germany there is a preference for clean energy sources, excluding nuclear. Our simulation of an energy-only market in Germany, where gas prices are high, shows that it promotes wind development while also promoting coal refurbishment. Meanwhile natural gas, which could provide cleaner energy and more flexible operations, is unprofitable in our simulations. Adding capacity payments to all technologies can move natural gas technologies to profitability, but will also increase economic rents already enjoyed by coal, while raising consumer costs. Policymakers and market operators must work together to develop a path towards regional objectives.

The analysis raises several additional questions for future exploration.

- **Detailed system operations**: The simplified model did not take into consideration detailed operating conditions of the system – starts and stops, minimum generation levels, minimum run times, detailed ramp rates, and operating reserves. Nor did it consider the full range of market remunerations available through ancillary services – all of which factor into investment profitability.
- **Renewable capacity methodology**: There are many methods in use for counting reserves and renewable capacity. Results are likely to be sensitive to varying methods.
- **Extended time period**: The analysis was only conducted for one year on each system. It would be interesting to determine how the optimum mix and market revenues change in a system over a longer period of time.
- **Solar Development**: With solar resources close to profitability, finding more precise circumstances under which they would be competitive without subsidy is of interest.
- **Market simulations**: Here we considered whether the optimal generation investment mix would be supported by alternative energy and capacity markets. An important next step is to simulate what development would occur under each alternative design, and assess the resulting inefficiency, if any, in generation investment (as in our simpler previous analysis, Hobbs et al. 2001). The results of our study above show that investments in some optimal generation types would not be profitable in the given year and would likely not occur, but the next question is how
several shortages of capacity would have to be before prices were sufficient to motivate investment.

- **Cross border issues:** Regions with capacity mechanism that do not compensate all resources for the services that they provide may see investment shift to regions with more favorable energy and capacity markets.

**Acknowledgement**

This work was in part supported by NSF grants OISE 1243482 (WINDINSPIRE) and ECCS 1230788.

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Appendix

Figure 16: Technology Screening Curve with Low Gas

Figure 17: Technology Screening Curve with High Gas