

September 27, 2010 (Revised February 9, 2011)
DISCUSSION DRAFT

COMPARING THE COSTS OF INTERMITTENT AND DISPATCHABLE ELECTRICITY GENERATING TECHNOLOGIES

Paul L. Joskow
Alfred P. Sloan Foundation and MIT¹

ABSTRACT

Economic evaluations of alternative electric generating technologies typically rely on comparisons between their expected life-cycle production costs per unit of electricity supplied. The standard life-cycle cost metric utilized is the “levelized cost” per MWh supplied. This paper demonstrates that this metric is inappropriate for comparing intermittent generating technologies like wind and solar with dispatchable generating technologies like nuclear, gas combined cycle, and coal. Levelized cost comparisons are a misleading metric for comparing intermittent and dispatchable generating technologies because they fail to take into account differences in the production profiles of intermittent and dispatchable generating technologies and the associated large variations in the market value of the electricity they supply. Levelized cost comparisons overvalue intermittent generating technologies compared to dispatchable base load generating technologies. These comparisons also typically overvalue wind generating technologies compared to solar generating technologies. Integrating differences in production profiles, the associated variations in the market value of the electricity at the times it is supplied, and the expected life-cycle costs associated with different generating technologies is necessary to provide meaningful economic comparisons between them. This market-based framework also has implications for the appropriate design of procurement auctions created to implement renewable energy procurement mandates, the efficient structure of production tax credits for renewable energy, incentives for and the evaluation of electricity storage technologies and the evaluation of the additional costs of integrating intermittent generation into electric power networks.

JEL: L51, L94

¹ I am grateful to John Parsons, Denny Ellerman, Bill Hogan, Frank Wolak, and Catherine Wolfram for comments on earlier drafts of this paper. The views expressed here are my own and do not represent the views of the Alfred P. Sloan Foundation, MIT, or any other organization with which I am affiliated- <http://econ-www.mit.edu/files/5860>.

September 23, 2010 (Revised February 9, 2011)
DISCUSSION DRAFT

COMPARING THE COSTS OF INTERMITTENT AND DISPATCHABLE ELECTRICITY GENERATING TECHNOLOGIES

Paul L. Joskow
Alfred P. Sloan Foundation and MIT²

INTRODUCTION AND SUMMARY

This paper makes a very simple point regarding the proper methods for comparing the economic value of intermittent generating technologies (e.g. wind and solar) with the economic value of traditional dispatchable generating technologies (e.g. CCGT, coal, nuclear). I show that the prevailing approach that relies on comparisons of the “levelized cost” per MWh supplied by different generating technologies, or any other measure of total life-cycle production costs per MWh supplied, is seriously flawed. It is flawed because it effectively treats all MWhs supplied as a homogeneous product governed by the law of one price. Specifically, traditional levelized cost comparisons fail to take account of the fact that the value (wholesale market price) of electricity supplied varies widely over the course of a typical year. The difference between the high and the low hourly prices over the course of a typical year, including capacity payments for generating capacity available to supply power during critical peak hours, can be up to four orders of magnitude (Joskow 2008). It is important to take wholesale market price variations into account because the hourly output profiles, and the associated market value of electricity supplied, of intermittent generating technologies and competing dispatchable generating technologies can be very different. Moreover, different intermittent generating technologies (e.g.

² I am grateful to John Parsons and Denny Ellerman for comments on an earlier draft of this paper. The views expressed here are my own and do not represent the views of the Alfred P. Sloan Foundation, MIT, or any other organization with which I am affiliated.

wind vs. solar) also can have very different hourly production and market value profiles, and indeed, specific intermittent generating units using the same technology (e.g. wind) may have very different production profiles depending on where they are located.³ Wholesale electricity prices reach extremely high levels for a relatively small number of hours each year (see Figure 1) and generating units that are not able to supply electricity to balance supply and demand at those times are (or should be) at an economic disadvantage. These high-priced hours account for a large fraction of the quasi-rents that allow investors in generating capacity to recover their investment costs (Joskow 2008) and failing properly to account for output and prices during these critical hours will lead to incorrect economic evaluations of different generating technologies.

In a nutshell, electricity that can be supplied by a wind generator at a levelized cost of 6¢/KWh is not “cheap” if the output is available primarily at night when the market value of electricity is only 2.5¢/KWh. Similarly, a combustion turbine with a low expected capacity factor and a levelized cost of 25¢/KWh is not necessarily “expensive” if it can be called on reliably to supply electricity during all hours when the market price is greater than 25¢/KWh.

I use a simple set of numerical examples that are representative of actual variations in production and market value profiles to show that intermittent and dispatchable generating technologies with identical levelized total costs per MWh supplied can have very different economic values due to differences in the economic value of the electricity they produce. I will also argue that the failure of life-cycle cost comparisons between intermittent and dispatchable generating technologies to yield meaningful comparisons of economic value does not plague comparisons between different dispatchable “base load” generating technologies for which

³ We observe such a large variation in wholesale electricity prices because the demand for electricity varies widely over the hours of the year, electricity cannot be stored economically for most uses, and electricity demand and supply must be balanced continuously to maintain the reliability of the network.

levelized cost comparisons were originally developed and applied. This is the case because the economic value of the output produced by different dispatchable base load generating technologies is likely to be the same because their output profiles are likely to be the same. The extension and use of levelized cost comparisons to intermittent generation has been a mistake and tends implicitly to overvalue intermittent generating technologies compared to dispatchable alternatives.⁴ This problem is easily remedied by integrating generation output profiles for each technology with the associated expected market value of the output that will be supplied by each technology along with their respective lifecycle productions costs.

Most of the current work on intermittent generating technologies, especially wind, has focused on the short-term network operating challenges and associated costs created by rapid swings in output, wide variations in output from one day to the next, and the difficulties of controlling output consistent with balancing supply and demand efficiently and meeting network reliability criteria, in the context of expected large scale entry of wind and/or solar generating capacity. That work assumes that large amounts of intermittent generating capacity will seek to be interconnected to transmission (or distribution) networks due to public policies aimed at promoting the rapid increase of intermittent renewable electricity supplies. It then examines the operational challenges and some of the additional costs that adding large quantities of intermittent renewable generation to the network entails. This work is reasonably well advanced. Though more needs to be done, the methods for evaluating these costs have matured and it seems

⁴ Exactly the same mistake is associated with “stacking” of levelized cost calculations from lowest to highest to create “supply curves” for reducing CO₂ emissions by increasing the penetration low-carbon electricity generation technologies, including nuclear and carbon capture and sequestration, along with end-use electricity efficiency improvements.

to be fairly clear that while these short run network integration costs can be significant, they are typically a relatively small fraction of the total cost of intermittent generation.⁵

This paper does not seek to extend the existing work on short-run network integration costs but focuses instead on a more basic set of questions. How do we properly measure the economic value of additional investments in intermittent generating technologies compared to dispatchable generating technologies before taking account of short run and long run network integration costs?⁶ Among other things, appropriate methods to answer this question are necessary: (a) to properly evaluate the costs and benefits of subsidies and mandates aimed at promoting certain intermittent generating technologies and (b) since the promotion of intermittent renewable technologies is often motivated by a desire to reduce CO₂ emissions, to properly measure the costs per ton of CO₂ avoided by policies that favor intermittent generating technologies like wind and solar. Applying more accurate evaluation frameworks makes it possible transparently to compare the cost of reducing CO₂ emissions using renewable energy subsidies and mandates with the cost of reducing CO₂ emissions in other ways (e.g. promoting energy efficiency, investments in nuclear power). Though it is not the focus of this paper, the proposed “market valuation” enhancement to levelized cost comparisons that I will propose also provides a consistent framework for evaluating the short run and long run technical and economic issues associated with integrating large amounts of intermittent generating technology into electric power networks as well since the resolution of these issues must take into account the output profiles of intermittent generating technologies as well. Finally, I do not opine here

⁵ On the order of \$5/MWh (USDOE, page 47), though these calculations typically ignore costs associated with assumed new investments in transmission capacity and price increases necessary to maintain the profitability of existing conventional generating capacity and investments in new generating capacity required to balance supply and demand reliably (e.g. New England Wind Integration Study (2010)).

⁶ Obviously, the long run goal is to account consistently for all of the costs associated with investing in and operating intermittent generation.

on whether the policies for promoting renewable generating technologies are good or bad, but focus on the improving the methods for evaluating their costs and benefits.

BACKGROUND

The federal government and many states have adopted policies to promote the development of various renewable energy technologies for generating electricity. These policies include tax subsidies, direct subsidies, loan guarantees, marketable renewable energy credits, renewable energy purchase mandates imposed on distribution utilities, and long-term contracting requirements for renewable electricity suppliers that are not applicable to non-renewable generation sources.⁷ The primary renewable generating technologies of interest to utilities to meet regulatory obligations and to respond to political pressure are wind-turbine generation and various solar electric generating technologies and I will focus on those technologies here.⁸ The primary motivation for these policies is to facilitate the development of no or low carbon electricity generation technologies in addition to or in lieu of placing a price on CO₂ emissions and/or, as now seems most likely, administrative regulation of CO₂ emissions by the Environmental Protection Agency (EPA).

There has been a great deal of discussion and analysis of the technical challenges that must be confronted effectively to integrate large quantities of intermittent renewable energy

⁷ The primary federal incentive has been a 10-year 2.1 cent/kWh production tax credit (adjusted annually by the rate of inflation) for each kWh of electricity supplied by a qualifying renewable energy plant. (For wind generators that went into service in 2009 and 2010 an alternative subsidy framework was available and it was recently extended.) About 30 states have adopted “renewable energy portfolio standards” that require electric distribution utilities to purchase specified fractions of the generation they require to serve retail consumers (e.g. 20%) by a certain date, regardless of the associated prices they must pay. If the mandates are binding they must have the effect of increasing the price utilities would otherwise pay for wholesale electricity supplies. The differences between the market price and the higher price paid for renewable electricity generation passed through to retail consumers either in regulated bundled retail prices or in regulated distribution charges in states that have adopted competitive retail models. Individual states have adopted a number of other financial incentives to encourage use of renewable electricity sources either by utilities or by end-use consumers.

⁸ Other technologies that may satisfy renewable electricity criteria include geothermal, small-scale hydro, biomass, methane from waste dumps, tidal power, etc.

technologies --- wind and solar in particular --- into electric power networks (e.g. USDOE (pp. 62-67), NERC, ERCOT, NYISO, Mount et. al.). In a number of cases the technical analyses have been accompanied by estimates of the additional costs of integrating large quantities of one or more intermittent generating technologies into electric power networks consistent with meeting reliability criteria (e.g. USDOE (pp. 62-67), ERCOT, NYISO).⁹ The technical challenges, and the associated costs, arise because of the production characteristics of wind, solar, and some other renewable generating technologies (Mount et. al.). Most conventional (fossil fueled and nuclear) generating technologies are “dispatchable.” This means that they can be controlled by the system operator and can be turned on and off based primarily on their economic attractiveness at every point in time both to supply energy and to supply network reliability services (e.g. frequency regulation, spinning reserves). Conventional dispatchable generators are typically scheduled by the system operator to meet demand by dispatching the generators with the lowest marginal generation cost first and then moving up the “dispatch curve,” calling on generators with higher marginal costs until demand for energy is satisfied in real time. To keep things simple, and ignoring market power considerations, conventional generators are typically dispatched when the wholesale market price for power exceeds their short-run marginal cost of generation. The dispatchability of conventional generators also allows them to be scheduled well in advance of real time and are available to be called quickly and reliably by system operators to supply network reliability services such as frequency regulation, spinning reserves, and other backup-reserves. These choices reflect both economic considerations (e.g. generators providing spinning reserves will typically have higher marginal

⁹ The studies are of varying quality and comprehensiveness and the estimated integration costs for wind vary by roughly a factor of 5. However, the short run integration costs are typically less than \$10/MWh, though the costs of additional transmission capacity, and price increases needed to maintain the profitability of existing conventional generation and investment in new conventional generation needed to balance supply and demand consistent with reliability criteria are typically excluded from the analysis.

generation costs than those dispatched to supply energy) and physical characteristics (e.g. ramp rates and location).

Wind, solar and other renewable generating technologies supply electricity “intermittently” and are not economically dispatchable in the traditional sense.¹⁰ Electricity produced by these technologies is driven by wind speed, wind direction, cloud cover, haze, and other weather characteristics. As a result, they cannot be controlled or economically dispatched by system operators based on traditional economic criteria. The output of intermittent generating units can vary widely from day to day, hour to hour or minute to minute, depending on the technology and variations in attributes of the renewable resource that drives the generation of electricity at a point in time at a particular location. Rather than controlling how much and when an intermittent generator is dispatched, system operators must respond to what comes at them by calling on generators that are dispatchable to maintain network frequency and other grid reliability parameters.¹¹ NERC and a number of system operators have studied the technical issues associated with integrating large amounts of wind and solar capacity into an electric power network. The most important technical issues and some associated analysis of the costs of maintaining network reliability standards with large quantities of renewable energy capacity connected to the grid are summarized very clearly in recent studies and reports (e.g. NERC, USDOE, ERCOT and NYISO, Mount et. al.).

These studies take as given that there will be a large increase in the quantity of intermittent renewable energy that will be supplied in the years to come and proceed to analyze the implications for network operating protocols and the associated costs of balancing supply and

¹⁰ Within limits their output can be physically adjusted to reflect network constraints subject to wind and solar conditions.

¹¹ System operators may order intermittent generators to reduce output due to transmission constraints or other network reliability constraints.

demand in real time in order to meet network reliability criteria. These studies do not address the more basic question of whether the diffusion of these intermittent renewable technologies is economical compared to conventional dispatchable alternatives, or if they are not, exactly how costly they are compared to conventional dispatchable alternatives?¹²

Proponents of renewable electricity generation often argue that one or another renewable technology is now or soon will be “competitive” or “grid competitive” with conventional generating technologies (or that they would be competitive if we took the value of CO₂ reductions into account). Of course if these technologies were really less costly than conventional alternatives then there would be no need for subsidies and mandates. Recently announced contract prices for off-shore wind generation in New England of 18.7 cents/KWh (escalating at 3.5% per year) suggest that wind energy at these locations is roughly three times the wholesale market price for electricity at these locations in 2009.^{13,14} This price is not close to being competitive with conventional dispatchable generation, even ignoring the costs of intermittency discussed below and the costs of network integration discussed elsewhere, and is a costly way to reduce CO₂ emissions. If wind is displacing generation from a CCGT plant in New England the implied cost per ton of CO₂ displaced is on the order of \$300 at these contract

¹² These network integration costs are, of course, one component of the total costs of intermittent generation. I focus on other aspects of the economics of intermittent generation here.

¹³ The original contract price for energy supply by Cape Wind was over 20¢/Kwh with a 3.5%/year escalation and a 15-year contract, but after negative public reaction it was negotiated down to 18.7¢/Kwh with the same 3.5% per year escalation over 15 years. SNL Energy *Electric Utility Report*, August 16, 2010, page 46, page 22 and November 29, 2010, pp.24-25. These reported prices are much higher than the average prices paid for wind generation reported elsewhere in the U.S. See USDOE, page 41.

¹⁴ The “all in” average wholesale market price in New England was about 8 cents /KWh in 2007, 10 cents/KWh in 2008, and 6 cents/KWh in 2009. This includes capacity payments and ancillary service charges. *2009 Annual Markets Report*, ISO New England, May 18, 2010, page 22. http://www.iso-ne.com/markets/mktmonmit/rpts/other/amr09_final_051810.pdf

prices,^{15,16} ignoring the additional costs of integrating wind into the New England network and the costs of non-dispatchability discussed here.

On the other hand, the Energy Information Administration (EIA, p. 67) recently forecast that the “levelized cost” of wind generation would be lower than the “levelized cost” of coal and nuclear by 2020 and lower than the “levelized cost” of natural gas combined cycle, nuclear and coal by 2035.¹⁷ The *Wall Street Journal* also recently reported results (attributed to Goldman Sachs) for levelized cost estimates for a wider range of electricity generating technologies. See Figure 8. Based on the levelized cost values reported there, wind appears to be very competitive with most conventional alternatives, but solar has significantly higher levelized costs (Demming).¹⁸ Similar “levelized cost” calculations appear elsewhere in the literature for wind, various solar technologies and other renewable electricity technologies (e.g. Cory and Schwabe, SunPower).

The “levelized cost” of a supplying electricity using a particular generating technology is a measure of the real total (capital plus operating cost) life-cycle costs per MWh supplied using that generating technology. It is evident from the literature comparing the economics of intermittent generation with conventional dispatchable generation that the “levelized cost” per

¹⁵ Studies of the integration of large scale wind generation in Texas and New York indicate that wind generation will largely displace natural gas fueled generation rather than coal fueled generation. (See ERCOT and NYISO) The CO₂ mitigation benefits are also surprisingly small in New York. Going from 1250 Mw to 8000 Mw by 2018 results in a reduction of only 8.5% in CO₂ emissions in the electricity sector compared to the low-wind entry case. In New York, the electricity sector accounts for about 25% of total state CO₂ emissions, so the net effect of increasing wind generation by a factor of 7 is a 2% reduction in state CO₂ emissions from what they would otherwise be. See NYISO.

¹⁶ Based on Joskow and Parsons (2009), Table 1 and Table 2.

¹⁷ It is not clear from the discussion in the EIA report whether the numbers for wind include the production tax credit and other subsidies.

¹⁸ One of the comparison technologies is natural gas peaking turbines. As will discuss presently, comparisons between an intermittent technology and a dispatchable technology that is built specifically to be utilized to meet very high peak period demand during a small number of hours in the year is not typically a meaningful comparison since intermittent generation cannot be relied upon to be available to be dispatched to meet high peak period demand during the same critical demand hours. It is of course theoretically possible that variations in wind and insolation will track peak demand and prices closely. One of the examples below to constructed to have this property.

MWh supplied of alternatives is the most widely used comparative metric. The National Renewable Energy Laboratory (NREL) conveniently provides a simple on-line program that allows one to calculate the levelized cost of any electricity generating technology using whatever set of assumptions one chooses about capital costs, operating costs, fuel costs, capacity factors, etc., so that their respective levelized costs can be compared.¹⁹ Moreover, competitive procurement programs run by utilities to meet renewable electricity purchase mandates sometimes implicitly make choices based on what is effectively a portfolio of projects that are offered at the “least cost” per MWh supplied over the life of the purchased power contract --- effectively choosing projects with the lowest levelized cost per MWh supplied without taking into account variations in the market value of the electricity supplied.

As already noted, the primary reasons why these levelized cost comparisons between intermittent and dispatchable generating technologies and the associated claims about their being “grid competitive” are not meaningful and lead to erroneous conclusions are (a) the value or wholesale price of electricity varies widely throughout the day, month and year --- by four orders of magnitude if capacity prices are factored in and (b) intermittent generating technologies have very different production profiles from the production profiles of conventional dispatchable generating technologies. A dispatchable generator with very low marginal generation costs (e.g. nuclear) will supply energy during all hours when it is available. If a wind generator were dispatchable it would run all of the time when it is not out for maintenance since its marginal generation cost is almost zero.²⁰ But since its output depends on the speed and direction of the wind, its production is limited both as to time and quantity despite the fact that its marginal generating costs are effectively zero. As a result, the market value of the electricity supplied by

¹⁹ http://www.nrel.gov/analysis/tech_loec.html (accessed on September 6, 2010)

²⁰ Transmission and other network constraints may lead to curtailments of the most economical dispatchable generating units as well as intermittent generating units.

intermittent generating technologies can vary widely depending upon when the electricity is produced and the production profiles of intermittent generating technologies do not follow standard economic dispatch patterns.

As I will show presently, an intermittent generating technology and a dispatchable generating technology may have the same levelized cost while simultaneously having very different net economic values and profitability (absent subsidies, purchase mandates, contracts that do not differentiate the prices paid by the time the electricity is supplied, etc.). Accordingly, choosing between offers to supply wind or solar energy by choosing the suppliers with the lowest levelized cost/MWh bids is likely to fail to lead to the selection of the highest value generation supply offers and increase the burden placed on consumers who are forced to pay for the above market costs of the associated power supply contracts. Such a bidding framework is also likely to distort the kinds of projects that developers of intermittent technologies seek to bring forward. In particular, other things equal, it will undervalue solar (electricity produced during the day when prices are relatively high) and overvalue wind (whose production is more heavily weighted to off-peak periods in many locations when prices are low).

TRADITIONAL “LEVELIZED COST” COMPARISONS

For decades electric utilities have evaluated the economic choice between alternative generating technologies by comparing their expected “levelized cost” per MWh to be supplied over the life of each of the alternative generating technologies under consideration. As I will discuss in more detail presently, the “levelized cost” is essentially the expected real total cost (capital plus operating costs) per MWh produced over the generating unit’s expected life. The generating technology with the lowest expected levelized cost per unit of electricity supplied was

then supposed to be chosen as the technology in which the utility would invest to meet a specified expected incremental demand for electricity.

The use of levelized cost comparisons emerged during the period when electric generating plants were subject to cost-of-service regulation. Its development and use reflected a need for a fairly simple “rule of thumb” metric acceptable to regulators that would allow regulated firms to make and defend choices between long-lived generating technologies with different construction costs, different life-cycle expected operating and maintenance costs and different expected utilization patterns. Regulators also specified accounting rules that defined how capital costs and operating costs of generating plants subject to cost of service regulation would be recovered from consumers over time (Joskow 2007). Evaluations of the costs of alternative generating technologies had to reflect the way in which the regulatory process would transform the capital and operating costs into regulated consumer prices. In the case of capital costs, these accounting rules defined depreciations rates, the computation of the rate base upon which a return on investment would be calculated, the utility’s cost of capital, the treatment of income taxes, etc. By applying these accounting rules to assumptions about construction and financing costs, an expected stream of future “revenue requirements” associated with the return of and on the investment in a generating unit could be calculated. Expected future operating and maintenance costs would then be added to the stream of future capital charges and the total life-cycle “revenue requirements” associated with the plant calculated.

Since alternative technologies had different expected construction, life-cycle operating costs and utilization (capacity) factors, their respective time streams of future revenue requirements differed as well. Accordingly, these streams of future capital and operating costs were discounted back to the present time to give the present discounted value of future (nominal)

revenue requirements or regulated cash flows. To account for inflation, assumptions about general inflation that had (implicitly) been built into this calculation were “unbundled” and a constant real annual levelized cost yielding the same present value would be calculated for each technology in order to compare them on a common basis. This real levelized annual capital and operating cost number would then be divided by the expected annual output of the generating plant over its expected life and a real levelized cost per MWh expected to be supplied for each technology derived. The technology with the lowest expected levelized cost per unit of output to meet a specified increment in demand was then to be the investment choice made by the regulated firm.

An example of this approach can be found in Joskow and Parsons (2009).²¹ They compare the real levelized cost per MWh for three base load generating technologies: nuclear, pulverized coal and natural gas combined cycle. Base load technologies are dispatched during a large fraction of the hours of the year, and are scheduled to be “off line” for maintenance during off-peak hours since they have low marginal generating costs and can be dispatched economically during a large fraction of the hours of the year. Joskow and Parsons (and MIT 2003) report these calculations with different assumptions about future fuel prices and prices for CO₂ emissions. The life-cycle costs of alternative generating technologies under different assumptions about key operating cost variables can then be compared using a simple comparative “levelized cost per MWh” metric.

It should be recognized immediately that this is not the way that unregulated firms selling their output at market prices make investment choices. They do not calculate levelized costs and choose the technology with the lowest number. To oversimplify, market-based investment decisions start with assumptions about future output prices, output quantities and associated

²¹ Updating portions of MIT (2003).

operating costs, taxes, etc., from which a stream of expected future net cash flows is derived. This stream of future net cash flows is then discounted back to the present using a discount rate that reflects the firm's cost of capital or hurdle rate. If the present discounted value of future net cash flows exceeds the expected cost of the investment then the investment would be economically attractive. If the present value of future cash flows is less than the cost of the investment then it is economically unattractive. I will refer to this as a market-based evaluation mechanism.

Historically, the traditional market-based approach could not be applied in the regulated electric power industry because there was no well developed wholesale power market yielding wholesale market prices that could profitably support investments in new merchant generating capacity.²² Indeed, just the opposite was the case. Investment costs, fuel costs and other operating costs determined the prices consumers paid through the cost of service regulatory process. Accordingly, "cost-based" investment evaluation protocols were a necessary feature of the regulatory process governing geographic electricity monopolies.

Of course, the world has now changed. There are now active wholesale markets in which a large number of merchant generators which must rely on market transactions, rather than cost of service regulation, to provide compensation for all of their costs participate. The wholesale market prices produced in these markets can, in principle, be used to evaluate investment alternatives. Moreover, there are a few important hidden assumptions that lie behind the use of traditional levelized cost calculations to make comparisons between alternative conventional dispatchable generating technologies. Of particular importance is the implicit assumption that the

²² Of course there have been wholesale power markets operating in the U.S. for several decades. However, these markets were primarily markets for "economy energy" traded between existing generating units with different marginal generating costs. These markets were essentially "excess energy" markets that could not provide revenues adequate to support the costs of investing in new generating capacity. Instead these costs were recovered through the regulatory process.

generating plants being compared are all dispatchable and can be controlled by the system operator based on economic and reliability criteria. Another related implicit assumption is that the production profiles --- the hours of the year that the generating plant will be available --- are very similar across the technologies. For example “base load” investment candidates are typically compared with other “base load” candidates and not with peaking or intermediate load technologies. If the production profiles are the same then the value of the electricity supplied will be the same and the technology with the lowest levelized cost will also have the highest net value and would be the most profitable choice in a market context.

SIMPLE ILLUSTRATIVE EXAMPLES

Let us use an extremely simple characterization of an electric power system to illustrate why comparing levelized costs for dispatchable and intermittent technologies like wind and solar provides little if any insight into their comparative economic values. There are two demand periods: peak and off-peak. The peak period is 3000 hours per year and the off-peak period is 5760 hours per year. The level of off-peak demand is 50% of the level of peak demand. Demand is perfectly price inelastic and there is a large existing generating capacity portfolio that is almost perfectly adequate to meet demand and associated RTO/ISO/NERC reliability criteria. There is a competitive wholesale market with peak period prices of \$90/MWh and off-peak prices of \$40/MWh. I focus on a very small incremental investments (e.g. 1 MW) so we can safely hold market prices constant. There are two technologies available for incremental investment. Their attributes are depicted in Table 1 and Table 2 along with the (assumed) associated real levelized cost per MWh for each technology. The attributes have been chosen so

that the levelized costs of the intermittent and the dispatchable generating technology are virtually identical (the levelized cost of the intermittent generating technology is slightly lower).

The dispatchable technology has an annualized real capital cost (real rental cost) of \$300,000/MW/Year and real marginal operating costs of \$20/MWh (think nuclear). Since market prices exceed the dispatchable generator's marginal operating cost it will be dispatched whenever it is available. I assume that the plant must be out of service 10% of the year for maintenance and refueling and that these outage hours are concentrated during the off-peak period. Accordingly, the dispatchable generating plant runs for 7884 (capacity factor of 90% = $7884/8760$) hours during the year and runs during all 3000 peak hours. The levelized cost is calculated as the annualized fixed cost of 1 MW of capacity divided by the number of MWh supplied (7884MWh/MW of capacity) plus the operating cost per MWh to yield a \$58.1/MWh real levelized cost.

The intermittent technology has an annualized capital cost (rental cost) of \$150,000/MW/Year and a \$0/MWh marginal operating cost (think wind). The output of the plant varies with the exogenous variation in the resource that drives the generator; speed and direction of the wind, insolation, tidal movements, etc., depending on the technology. That is, the power is supplied when the wind blows or the sun shines so to speak, not based on the value of the electricity produced at different hours during the year. The average annual capacity factor is assumed to be 30%.²³

²³ Let me note a few things about the 30% capacity factor assumption. A 30% capacity factor does not mean that in the real world generator runs at full capacity 30% of the time and produce nothing 70% of the time. The capacity factor is simply the actual generation divided by the maximum generation that would be supplied if the plant ran at full capacity during the entire year. For example, a wind turbine typically has a lower bound wind speed where it does not run at all (e.g. 8 miles/hour) and an upper bound wind speed (e.g. 50 miles/hour) where it must be turned off to avoid damage (e.g. from a hurricane). There is a range of wind speeds where the turbine will run at full capacity. Below this "sweet spot," output varies with the third power of the wind velocity. That is, if wind speed doubles output will increase by a factor of eight. During these hours the wind turbine is running at less than full capacity. The 30% capacity factor is a reasonable assumption for the average wind turbine in operation in the U.S.

The levelized costs for these two technologies are approximately the same. So, if we were to look only at the levelized cost calculations, the two technologies would appear to be “competitive.” Indeed, the intermittent technology appears to be slightly more “competitive” than the dispatchable technology from this perspective. Note that the capacity factors of the dispatchable and intermittent technologies are quite different and the capacity factors have been incorporated directly into the calculation of the levelized costs. While the intermittent technology has a much lower capacity factor, the capital cost per unit of capacity is lower than the capital cost per MW/Year for the dispatchable technology and the operating costs of the intermittent technology are assumed to be zero.²⁴

Let’s return to the numerical examples. As already noted, once a dispatchable generating plant with the attributes assumed here is completed, it will be economical for the dispatchable technology to produce electricity during all hours of the year when it is available since its marginal operating cost per unit of output is lower than the wholesale market price in all hours of the year. Accordingly, it will be dispatched in all hours when it is available. Outages (e.g. for maintenance) do limit production to 7844 hours in this example, and I have assumed for simplicity that the outages are all taken during off-peak hours. These assumptions will be maintained in all three examples. The upper panels of tables 3A, 3B and 3C display the

(USDOE) and may be a little generous (Boccard). Of course capacity factors for wind generation vary widely from location to location and from year to year at a specific location because of differences in the attributes of the wind. A typical photovoltaic facility has a much lower capacity factor (e.g. 15-20%) than a typical wind turbine and a much higher levelized cost. However, since the sun shines during the day and electricity prices are higher during the day than at night, the value of the electricity produced by the solar technology may be higher than the value of the electricity produced by the wind technology.

²⁴ Boccard finds that actual realized capacity factors fall short of forecast capacity factors for wind generators. There are many arguments about the right capacity factors to use to calculate levelized costs, with proponents of each technology trying to drive down the claimed estimated levelized cost by assuming higher capacity factors than are likely to be achieved in reality for political and public perception purposes. That is, the political/public relations game has been to assume that capacity factors are high in order to drive down the advertised levelized cost of a particular technology so that the technology appears to be more competitive than it actually is likely to be (this observation applies to both renewable and conventional generating technologies). Adopting better methods for comparing the economics of different generating technologies can help to improve the level of discourse about them.

revenues, costs and profitability of an incremental 1 MW investment in the dispatchable technology. The dispatchable technology earns enough revenue to cover all of its costs plus a small additional profit.

The intermittent technology, despite the fact that the marginal cost of generation is zero, cannot be dispatched based on traditional economic dispatch criteria and runs, in the case of wind, based on exogenous variations in wind speed and direction. Let us assume in Case 1 (Table 3A) that it is windy at night (off-peak) but that the wind is too calm during the day (peak) to drive the turbine. The intermittent generator then produces electricity only during off-peak periods and only for 2628 of the 5760 hours as limited by the wind resource that drives the turbine. This is an extreme assumption, but for a two period model it is not wildly inconsistent with the performance of wind generation in California (see Figure 2 and Figure 3).²⁵ The revenues, costs and profitability of 1 MW of “off-peak” wind generation is given in the second panel of Table 3A. The wind generating technology with these attributes does not cover its costs and exhibits a large negative profit. Thus, despite having the same levelized cost as the dispatchable generating technology, the economic value of the electricity supplied by 1 MW of these two technologies is quite different. The value of the electricity supplied by a unit of dispatchable generating technology is over 4 times higher than that for the intermittent generation technology. This is reflected as well in the profitability of the two generating

²⁵ While the situation in California is extreme, wind generation is negatively correlated with peak demand in many other areas of North America including Texas, New York, and Ontario. In New York, capacity factors are much higher during winter months than during the peak summer months. The capacity factor for wind generated in New York during the peak summer hours of 2PM to 6PM was 22.9% in 2007, 16.7% in 2008, and 14.1% in 2009 (NYISO, page 95).

technologies. A wind generator with these attributes would surely require a large subsidy or selected in response to a renewable electricity purchase mandate since it is uneconomical.²⁶

Let us look at a second example with a different set of assumptions. See Table 3B. The intermittent generator is now assumed to run for 500 hours during the peak period (a 17% capacity factor during peak hours) and for 2128 hours during the off-peak period (a 37% capacity factor during off-peak hours).²⁷ The attributes of the dispatchable technology are assumed to be the same, and the value of the electricity produced and the associated total costs are the same as in the first example as well. The second panel of Table 3B displays the revenues, costs and profitability for the intermittent technology. Shifting about 20% of the output of the intermittent generator to the peak period increases revenues, but not by enough to cover the intermittent generator's total costs and investment in the intermittent technology (absent subsidies) still yields a negative profit

Again the intermittent technology produces electricity with a lower value than the dispatchable technology and the revenue that would be earned if it sold its output at market prices does not cover its costs. One MW of the intermittent technology has a much lower social value than does one MW of the dispatchable technology despite the fact that their levelized costs are almost identical. The reason is that the intermittent technology produces a larger fraction of its (limited) output during low electricity price hours.

For the third example we will make an extreme assumption about the output profile of the intermittent technology. See Table 3C. Let's assume that the intermittent technology fortuitously produces all of its electricity during the peak period. This would be more plausible for a solar

²⁶ Placing a price on CO₂ might change this conclusion but this could only be determined by adding assumptions about emissions and CO₂ prices. If the dispatchable technology is nuclear then CO₂ pricing would actually make the dispatchable technology more attractive since it would displace more existing fossil generation per MW of capacity.

²⁷ This is roughly equal to the peak period capacity factors for wind generators in New York State (NYISO, page 95).

technology than for wind, though solar technologies still do exhibit intermittency and peak prices may be realized after the sun has begun to fade.²⁸ Solar thermal plants have much more attractive production profiles (Figure 4 --- parabolic trough technology) since the sun shines during the day when demand is high, though cloud cover can both reduce the level of peak output during the day and make it more volatile (Figure 5). Similarly for photovoltaic technology output varies with insolation (Figure 6 and Figure 7). So, solar technology may have a higher levelized cost than wind technology, but it may produce much more valuable electricity. Levelized cost calculations hide this important factor.

The intermittent technology now is assumed to have a peak period capacity factor of 88%, limited only by the availability of the wind or insolation to drive the turbine.²⁹ The dispatchable generator will operate as before and produce electricity with the same dispatch characteristics, output profile, market value and cost. The revenues, costs, and profitability of the intermittent generator are displayed in the second panel of Table 3C. In this case, if the electricity it produces were sold at market prices the intermittent generating technology would cover its costs and earn a substantial profit. Indeed, it would be substantially more profitable than the dispatchable technology characterized so far. It would also be profitable for the intermittent technology to enter the market without subsidies.

The key message from these examples is that when the electricity is produced by an intermittent generating technology, the level of output and the value of the electricity at the times when the output is produced are key variables that should be taken into account in comparing intermittent technologies with dispatchable technologies and intermittent technologies with each

²⁸ This is the reason that short-term storage can be especially valuable for solar energy technologies.

²⁹ In this particular extreme case it may make more sense to compare the intermittent technology to a dispatchable peaking turbine which only runs during peak hours and has a much lower capital cost than does a dispatchable base load generating plant.

other. Since wholesale electricity prices also vary by location, the location of the output and associated locational prices should also be taken into account, as would be the case for dispatchable generating technologies as well.

AN ALTERNATIVE COMPARATIVE FRAMEWORK

It should be clear that using traditional levelized cost calculations to compare dispatchable and intermittent generating technologies or to compare different intermittent technologies is a meaningless exercise and can lead to inaccurate valuations of alternative generating technologies. While levelized cost calculations may be a simple way accurately to compare different dispatchable base load generating technologies with different capital and operating cost attributes (Joskow and Parsons (2009)), it is not a useful way to compare generating technologies with very different production profiles and associated differences in the market value of the electricity they produce. When these kinds of comparisons are at issue, as they now frequently are given the public policy and regulatory pressures to increase investment in renewable energy technologies with intermittent output characteristics, a different set of methods is required to better understand what the true costs are for different generation technologies.

A good starting point would be to evaluate all generating technologies, both intermittent and dispatchable, based on the expected market value of the electricity that they will supply, their total life-cycle costs and their associated expected profitability, rather than focusing only on the levelized cost per unit of output. Such an analysis would reflect the actual expected production profiles of dispatchable and intermittent technologies, the value of electricity supplied at different times, and other costs of intermittency associated with reliable network integration.

That is, abandon levelized cost comparisons and adopt more standard economic evaluation methods for new generating capacity. This kind of analysis can be performed with and without direct subsidies, mandates, renewable credits, etc., so that the true costs of alternative technologies can be identified, the costs of the direct and indirect subsidies can be made transparent, and the cost per unit of CO₂ displaced by different technologies can be easily measured. Of course, there is considerable uncertainty about future electricity prices and we should be skeptical about comparative technology evaluations being based on administrative regulatory estimates of future prices. However, merchant investors in new generating capacity must make estimates of future electricity prices when they evaluate investment opportunities. And we can use properly designed competitive procurement processes to decentralize wholesale market price estimates to investors while accommodating subsidies for renewable generating technologies, as discussed further below.

Many system operators are already using a market-value based framework to identify technical issues with large scale deployment of intermittent generation and to measure the short-run costs networks are likely to incur to respond to intermittency in order to maintain reliability criteria (e.g. ERCOT). This conceptual framework can also be used properly to measure the total costs of the renewable electricity promotion policies that have been adopted by state and federal governments and in this way increase the transparency of these costs to the public. It also provides a useful conceptual framework for quantifying the value of adding storage capabilities to intermittent technologies and for designing competitive procurement programs for renewable energy that properly take account of differences in production profiles and the associated value of the electricity produced from plants at locations with different wind and solar resources.

Finally, this approach will increase transparency about the costs of alternative generating technologies, the costs of subsidies provided to certain technologies, other costs of intermittency, and the environmental benefits of promoting technologies with subsidies, credits, and mandates that would not otherwise be economical choices. The increased transparency will improve public policy decisions and illuminate inaccuracies about costs and competitiveness advanced by interest groups promoting particular generation technologies to feather their own nests.

APPLICATIONS

This type of market based or electric power “systems” approach can help to illuminate other issues associated with the introduction of large amounts of intermittent generating capacity into electric power systems.

a. Renewable Electricity Procurement: Many states with renewable electricity mandates require distribution utilities to run competitive solicitations to ensure that they meet their renewable energy procurement obligation with the “least costly” renewable technologies. The previous discussion should make it clear that the wrong way to organize a procurement auction for intermittent generating capacity would be to select the suppliers that offer the lowest price per MWh supplied without regard to the hours when the electricity is expected to be supplied and the associated market prices for this electricity. As before, the net economic value of competing projects with the same costs can vary widely depending on their production profiles and the value of the electricity that they supply when the wind blows or the sun shines. Paying less for a project that only supplies off peak power could be a very inefficient choice if a more costly alternative with a more economically attractive output profile is available.

There is a relatively simple conceptual way to change the structure of procurement auctions for intermittent generation to remedy this problem. Rather than running an auction to supply renewable energy per se, the auction should be based on the subsidy that will be paid to qualified renewable generators to supply energy at the times the developers expect to supply output to the market and to be paid the associated market prices. Suppliers interested in participating in the auction would bid the subsidy that they are willing to accept for a specified level of output if they are chosen to receive a contract through the auction. The subsidies per MWh supplied bid into the auction by different projects are ordered from lowest to highest. The procurement auction then selects the projects with the lowest subsidy bids that in the aggregate meet the procurement quantity target. The subsidy bid by the marginal bidder that just misses being selected then determines the subsidy per MWh supplied that each of the winning bidders will receive. The renewable generators are then free to make their own commercial arrangements to sell the power they produce itself and will reflect the revenue they expect to receive from sales of their output into the market in their bids.³⁰ The generators that can supply power when it is most valuable will then require a smaller subsidy than those who will supply power when it is less valuable, other things equal. A procurement system that separates the commercial arrangements for supplying the power from the contractual arrangements to provide subsidies for what the renewable generators actually produce will lead to more efficient choices of suppliers than a naïve “least cost” auction that ignores differences in production profiles and the wide differences in the value of electricity at different times. Procurement mandates that incorporate properly designed tradeable renewable energy credits (or, even better, CO₂ “displacement” credits) can be adapted to achieve this result.

³⁰ Of course, whether and how they will do so depends on many other attributes of a renewable energy procurement auction.

b. Storage: If we compare Table 3A with Table 3C we see immediately that storage capacity would be very valuable in locations where the renewable resource has the attribute that it drives the generator mostly off-peak. At the extreme, if storage could shift all of the generation from an intermittent generator from the off-peak period to the peak period, the value of the electricity supplied would increase by a factor of four in the example. However, if procurement programs do not properly take into account the value of electricity produced at different times, renewable generators will have no incentive to add storage capacity to their projects.

c. Consistency with Analyses of Grid Integration Issues: The approach taken here is completely consistent with ongoing analyses of operational issues associated with large scale integration of intermittent technologies into electric power networks, the associated incremental costs, and implications for pricing network reliability services (e.g. frequency regulation and spinning reserves), redispatch costs, output constraints resulting from transmission constraints (including those placed on wind), and capacity values (e.g. based on the expected capacity factor during the few highest peak hours of the year rather than nominal capacity or average capacity factors). The analyses of these issues requires a systems approach that carefully takes into account output profiles, required response speeds to match supply and demand in real time, accuracy of day-ahead forecasting of output, etc. The analyses of these issues performed by ERCOT is an excellent example of how this kind of study can be done. The tools used by ERCOT to examine these operational issues can easily be applied as well to evaluate the more basic questions about the economics of investing in alternative generating technologies discussed here.

d. Production Tax Credits: Qualifying renewable generating units now receive a production tax credit of 2.1 cents/KWh (indexed to inflation) from the federal government.³¹ This tax credit is earned regardless of the time the electricity is actually produced or its economic value. This is an inefficient way to subsidize renewable energy because it does not provide incentives for intermittent generators to choose locations, schedule maintenance, etc. in a way that maximizes the value of the electricity produced. A tax credit that is high for supplies provided during peak hours and low for supplies provided during off-peak hours would provide better incentives and increase the net economic value of renewable energy investments.

e. Other Incentive Issues: It is clear from the comprehensive studies examining economic and reliability issues resulting from large scale expansion of intermittent generation (e.g. NYISO, ERCOT, NERC) that its reliable integration into electric power networks will increase costs related to frequency regulation, spinning reserves, transmission congestion and investment, redispatch, and backup capacity costs. The magnitude of these costs will no doubt continue to be debated. However, it is essential that these additional costs get factored into prices charged to intermittent generators for grid reliability services, redispatch and backup capacity to provide appropriate incentives for more efficient investment in intermittent technologies. Our ability to use proper prices incentives to efficiently guide investment decision, including the location, type, and capacity of intermittent generation entering the market is unfortunately limited by quantitative mandates to purchase minimum quantities of intermittent generation regardless of their economic merits. Relying instead on pricing CO₂ emissions combined with proper pricing of grid services and backup capacity (through proper capacity payment mechanisms) would yield superior economic and environmental outcomes.

³¹ A temporary alternative to this subsidy structure is currently available.

TABLE 1
HYPOTHETICAL LEVELIZED COSTS COMPARISON

	<u>Base Load</u>	<u>Intermittent</u>
Construction + Fixed O&M Cost (levelized/MW/year)	\$300,000/MW/Year	\$150,000/MW/Year
Operating Cost (levelized/MWh)	20.0¢/KWh	0¢/KWh
Capacity Factor	90%	30%
MWh/MW/year	7884	2628
Levelized cost/MWh	\$58.1/MWh	\$57.1/MWh

TABLE 2
HYPOPTHETICAL PEAK AND OFF-PEAK ATTRIBUTES

Peak period:

Hours:	3000
Price (levelized):	\$90/MWh

Off-peak period:

Hours:	5760
Price (levelized):	\$40/MWh

TABLE 3A**HYPOTHETICAL VALUATIONS OF INTERMITTENT AND DISPATCHABLE
GENERATION WITH THE SAME LEVELIZED COST**CASE 1

Dispatchable MWh supply:

Peak:	3000 MWh
Off-peak:	4884 MWh
Revenues:	\$465,360/MW/year
Costs:	\$457,680/MW/year
Profit:	\$7,680/MW/year

Intermittent MWh supply:

Peak:	0 MWh
Off-peak:	2628 MWh
Revenues:	\$105,120/MW/year
Costs:	\$150,000/MW/year
Profit:	-\$44,880

TABLE 3B**HYPOTHETICAL VALUATIONS OF INTERMITTENT AND DISPATCHABLE
GENERATION WITH THE SAME LEVELIZED COST**CASE 2

Dispatchable MWh supply:

Peak:	3000 MWh
Off-peak:	4884 MWh
Revenues:	\$465,360/MW/year
Costs:	\$457,680/MW/year
Profit:	\$7,680/MW/year

Intermittent MWh supply:

Peak:	500 MWh
Off-peak:	2128 MWh
Revenues:	\$130,120/MW/year
Costs:	\$150,000/MW/year
Profit:	-\$19,880/MW/year

TABLE 3C**HYPOTHETICAL VALUATIONS OF INTERMITTENT AND DISPATCHABLE
GENERATION WITH THE SAME LEVELIZED COST**CASE 3

Dispatchable MWh supply:

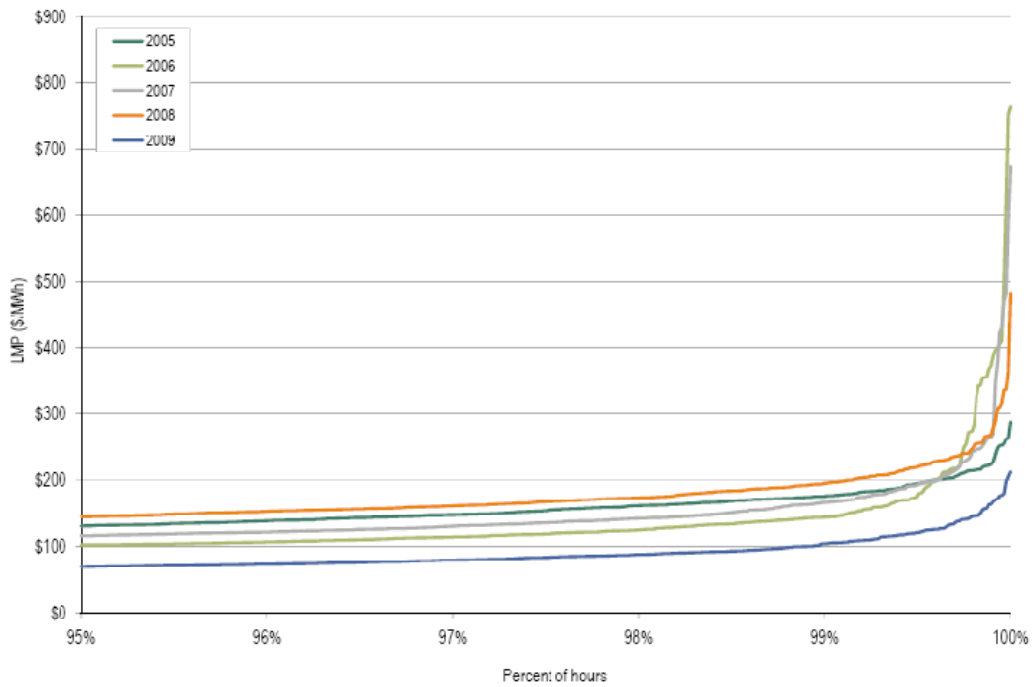
Peak:	3000 MWh
Off-peak:	4884 MWh
Revenues:	\$465,360/MW/year
Costs:	\$457,680/MW/year
Profit:	\$7,680/MW/year

Intermittent MWh supply:

Peak:	2628 MWh
Off-peak:	0 MWh
Revenues:	\$236,520/MW/year
Costs:	\$150,000/MW/year
Profit:	\$ 86,520/MW/year

FIGURE 1

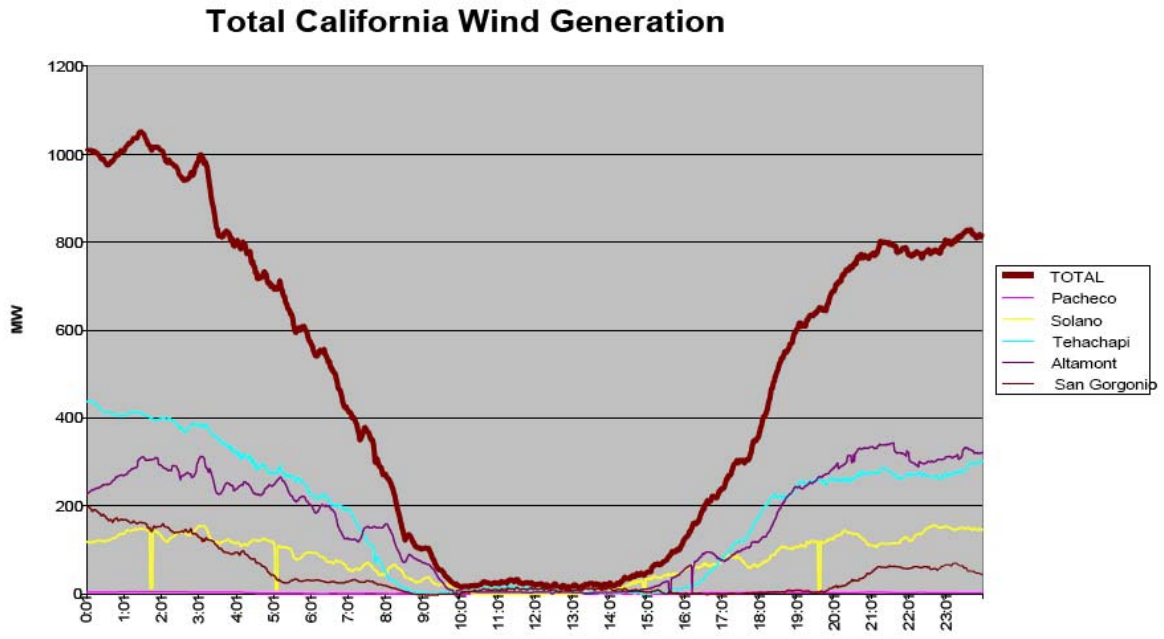
Top 5% of Real Time Energy (only) Prices in the PJM RTO³²



State of the Market Report for PJM 2009, Monitoring Analytics, LLC (Independent Market Monitor for PJM), Volume 2, page 64, March 11, 2016

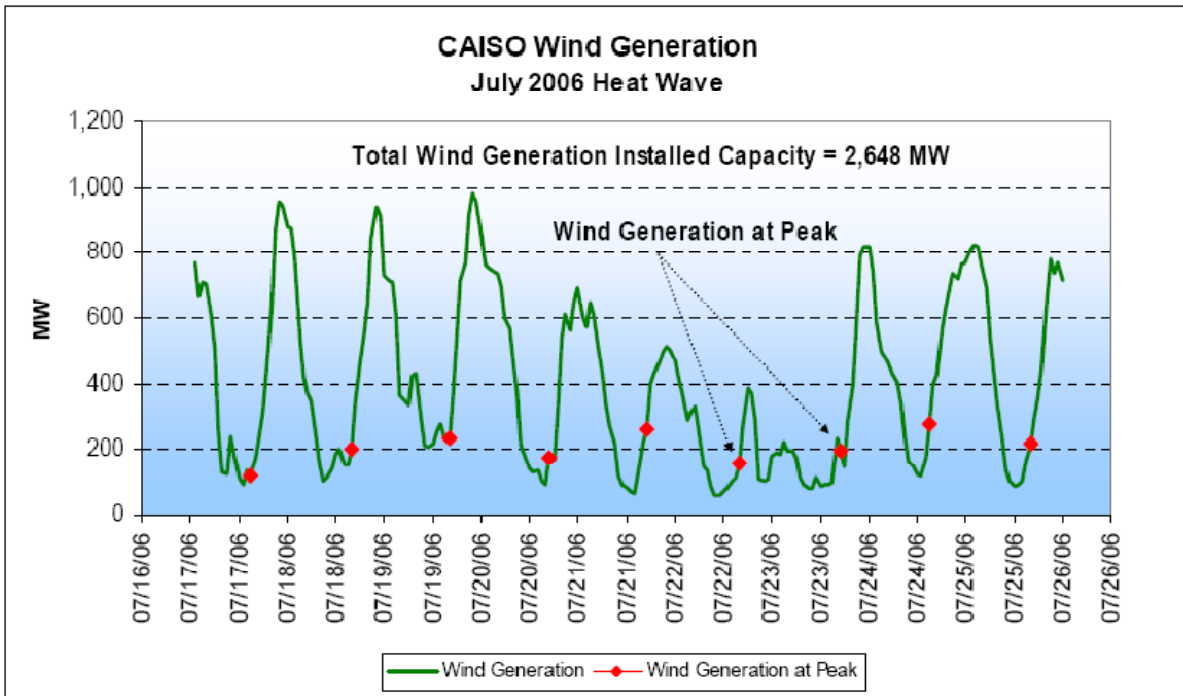
³² Note that this excludes capacity payments and payments for ancillary services.

FIGURE 2



Source: NERC (2009), p.16

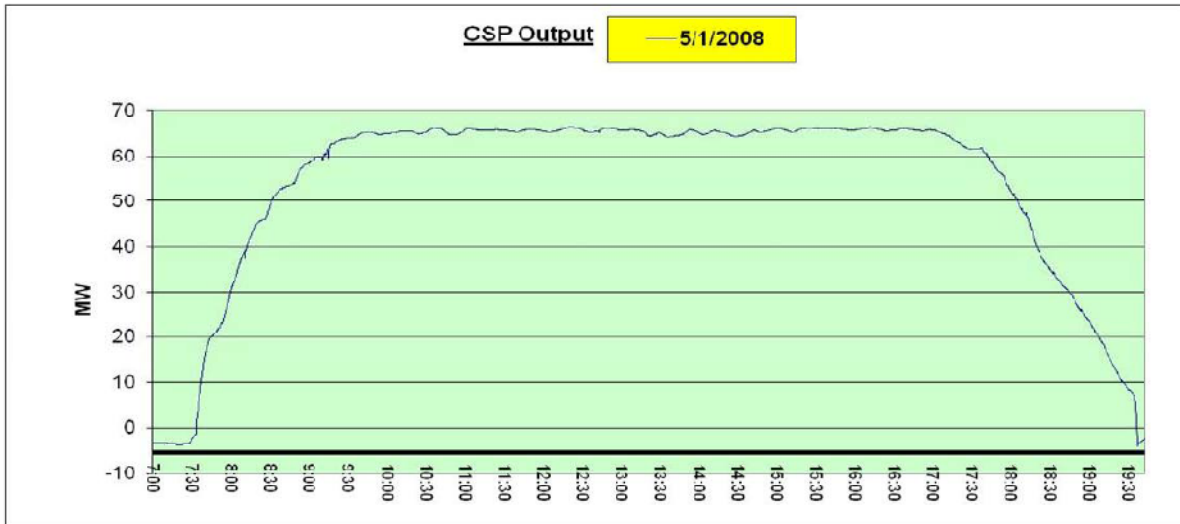
FIGURE 3
CALIFORNIA WIND GENERATION DURING 2006 HEAT WAVE



Source: NERC (2009), page 37.

FIGURE 4

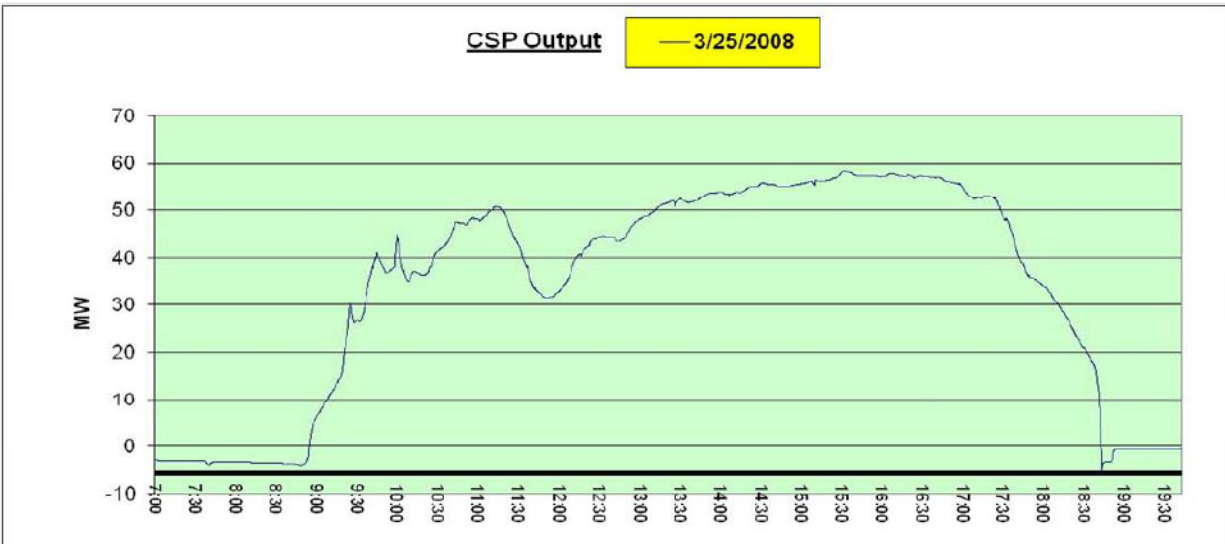
Parabolic trough CSP plant on a sunny day (Sampling time of 10 sec.)



Source: NERC (2009), page 26.

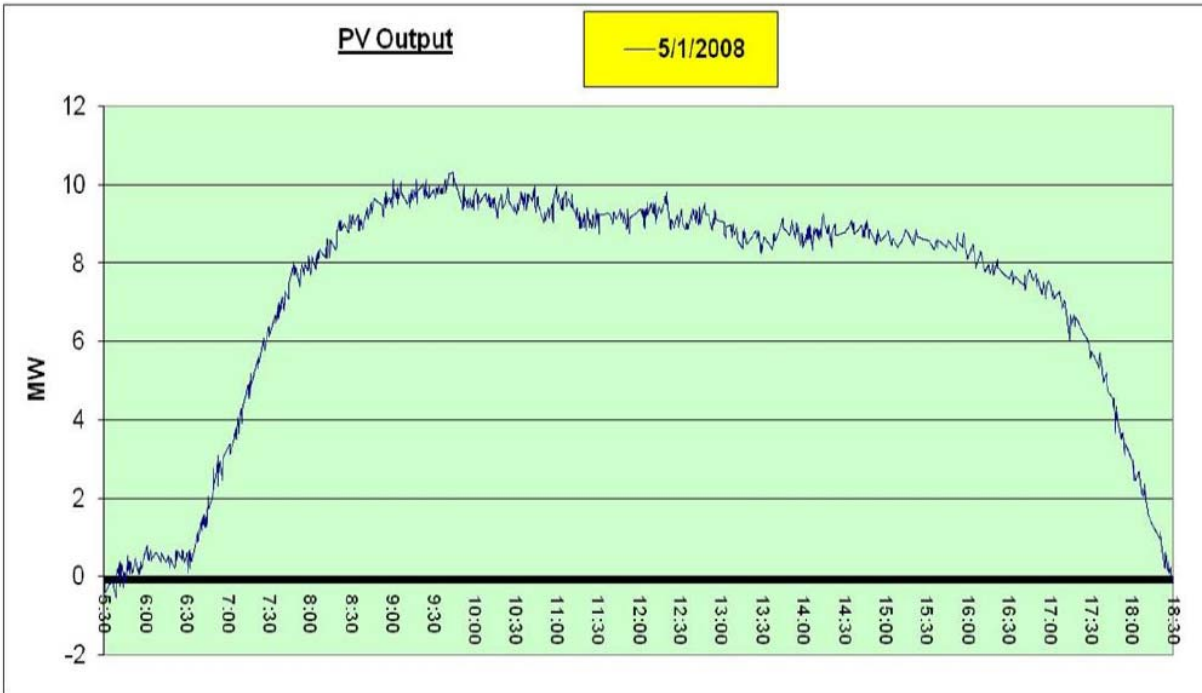
FIGURE 5

Parabolic trough CSP plant on a partly-cloudy day (Sampling time of 10 sec.)



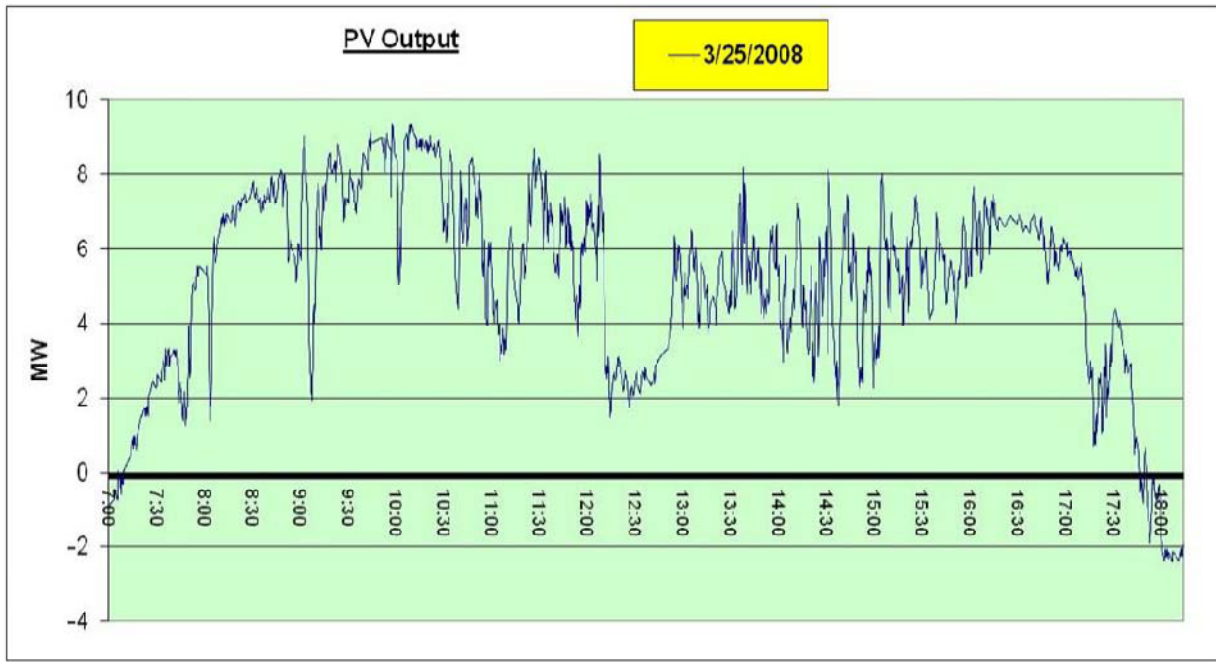
Source: NERC (2009), page 26

FIGURE 6

PV plant output on a sunny day (Sampling time 10 seconds)

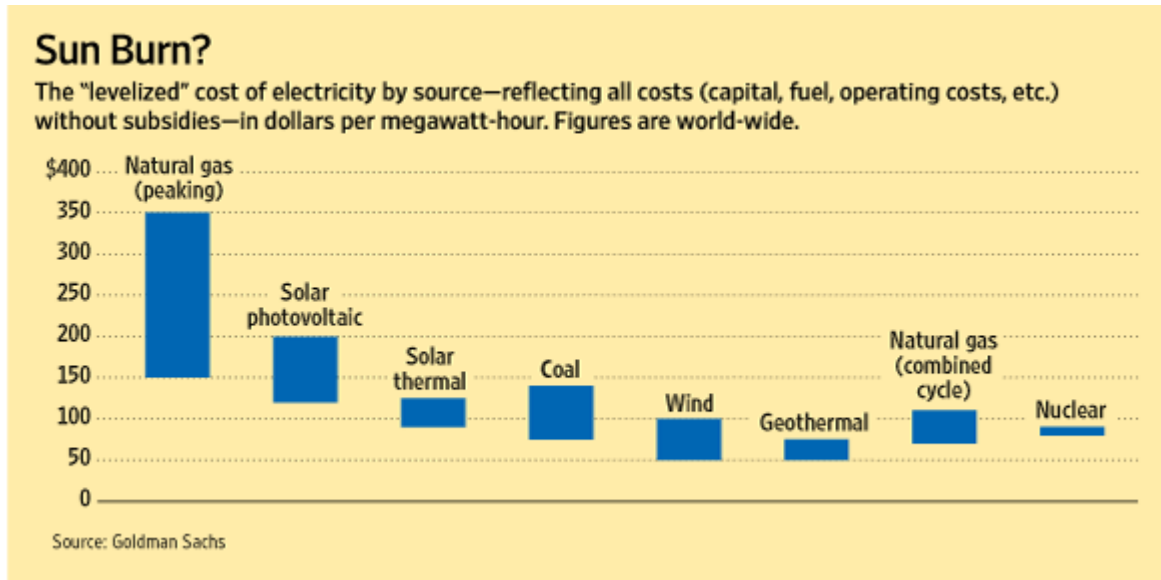
Source: NERC (2009), page 28

FIGURE 7

PV Plant output on a partly-cloudy day (Sampling time 10 seconds)

Source: NERC (2009), page 28

FIGURE 8



As printed in *The Wall Street Journal*, September 13, 2010, page R4.

<http://online.wsj.com/article/SB10001424052748703846604575447762301637550.html#>

REFERENCES

- Boccard, Nicholas, "Capacity Factor and Wind Power Realized Values vs. Estimates," *Energy Policy* 37 (2009), 2679-2688.
- ERCOT, "Wind Impact/Integration Analysis," February 27, 2009.
- Cory, Karlynn and Paul Schwabe, "Wind Levelized Cost of Energy: A Comparison of Technical and Financial Input Variables," Technical Report NREL/TP-6A2-46671, October 2009.
- Denning, Liam, "Power Investing," *The Wall Street Journal*, September 13, 2010.
<http://online.wsj.com/article/SB10001424052748703846604575447762301637550.html#>
- Joskow, Paul, "Regulation of Natural Monopoly," *Handbook of Law and Economics*, Chapter 16, A.M. Polinsky and S. Shavell, editors, Elsevier, 2007. <http://econ-www.mit.edu/files/1180> .
- Joskow, Paul, "Capacity Payments in Imperfect Electricity Markets: Need and Design," *Utilities Policy*, 16: 159-170, 2008.
- Joskow, Paul and John Parsons, "The Economic Future of Nuclear Power," *Daedalus*, Fall 2009, Volume 1, 45-59.
- Massachusetts Institute of Technology (MIT), *The Future of Nuclear Power*, 2003.
- Mount, Tim, et. al., "The Hidden System Costs of Wind Generation in a Deregulated Electricity Market," Charles H. Dyson School of Applied Economics and Management, Cornell University, WP 2011-01, January 2011.
- National Renewable Energy Laboratory, "Simplified Levelized Cost of Energy Calculator (Beta)," http://www.nrel.gov/analysis/tech_lcoe.html
- New England Wind Integration Study, Final Report, Executive Summary, prepared for ISO New England, December 5, 2010. http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_es.pdf
- New York ISO (NYISO), *Wind Generation Study*, June 2010.
- North American Electric Reliability Corporation (NERC), *Accommodating High Levels of Variable Generation: Special Report*, April 2009.
- Ontario Independent Electricity System Operator, *Wind Power Generation in Ontario*, <http://www.ieso.ca/imoweb/siteshared/windtracker.asp>.
- SunPower Corporation, "The Levelized Cost of Electricity from Utility-Scale Photovoltaics," August 14, 2008.
- Soloff, Charles, "Wind and Solar Resource Assessment for New England," American Solar Energy Society, 2010.

United States Department of Energy (USDOE), *2009 Wind Technologies Market Report*, August 2010.

United States Energy Information Administration (EIA), *Annual Energy Outlook 2010*, April 2010.