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Comparing the Costs of Intermittent and Dispatchable Electricity Generating Technologies

by

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DISCUSSION DRAFT

COMPARING THE COSTS OF INTERMITTENT AND DISPATCHABLE ELECTRICITY GENERATING TECHNOLOGIES

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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. They also overvalue wind generating technologies compared to solar generating technologies. Integrating differences in production profiles, the associated variations in the market value of the electricity supplied, and life-cycle costs associated with different generating technologies is necessary to provide meaningful 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, 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 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.

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DISCUSSION DRAFT

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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). 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. Wholesale electricity prices reach

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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. 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. 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.

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 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 to implicitly overvalue intermittent generating technologies compared to dispatchable alternatives.[3] This problem is easily remedied by integrating generation output profiles for each

[3] Exactly the same mistake is associated with "stacking" of levelized cost calculations from lowest to highest to create "supply curves" for reducing CO_2 emissions by increasing the penetration low-carbon electricity generation

technology with the associated expected market value 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 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.

This paper focuses 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? Among other things, proper 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) to properly measure the costs per unit of CO_2 avoided by policies that favor intermittent generating technologies like wind and solar, making it possible transparently to compare the cost of reducing CO_2 emissions using renewable energy subsidies and mandates with the cost of reducing CO_2 emissions in other ways (e.g. energy efficiency, investments in nuclear power). The proposed "market valuation"

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technologies, including nuclear and carbon capture and sequestration, along with end-use electricity efficiency improvements.

enhancement to levelized cost comparisons that I will propose also provides a consistent framework for evaluating the short run technical and economic issues associated with integrating large amounts of intermittent generating technology into electric power networks since the resolution of these issues must take into account the output profiles of intermittent generating technologies as well. I do not opine here on whether the policies for promoting renewable generating technologies are good or bad, but focus on the appropriate 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 to purchase a specified fraction of the electricity they sell to retail consumers from qualifying renewable electricity generation technologies, and long-term contracting requirements for renewable electricity suppliers that are not applicable to non-renewable generation sources.[4] The primary renewable generating technologies of interest to utilities are wind generation and various solar electric generating technologies and I will focus on those technologies here. Other technologies that may

[4] The primary federal incentive is 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 go into service in 2009 and 2010 an alternative subsidy framework is available.) 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.

satisfy renewable electricity criteria include geothermal, small-scale hydro, biomass, methane from waste dumps, tidal power, etc. 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 CO_2 emissions and/or, as now seems most likely, administrative regulation of CO_2 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 technologies --- wind and solar in particular --- into electric power networks (e.g. USDOE (pp. 62-67), NERC, ERCOT, NYISO). 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).[5] The technical challenges, and the associated costs, arise because of the production characteristics of wind, solar, and some other renewable generating technologies. 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

[5] The studies are of varying quality and comprehensiveness and the estimated integration costs for wind vary by roughly a factor of, 5 with $10/MWh of wind generation being the highest incremental integration cost reported so far.

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 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 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 dispatchable in the traditional sense. 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.[6] 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

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

connected to the grid are summarized very clearly in recent studies and reports (e.g. NERC, USDOE, ERCOT and NYISO).

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 demand in real time and meeting 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?

Proponents of renewable electricity generation often argue that one or another renewable technology is now or soon will be "competitive" with conventional generating technologies (or that they would be competitive if we took the value of CO_2 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 20+ cents/kWh (escalating at 3.5% per year) suggest that wind energy at these locations is more than three times the wholesale market price for electricity at these locations in 2009.[7,8] This price is not close to being competitive with conventional dispatchable generation and is a costly way to reduce CO_2 emissions. If wind is displacing

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[7] SNL Energy *Electric Utility Report,* August 16,2010, page 46, page 22. These reported prices are much higher than the average prices paid for wind generation reported elsewhere in the U.S. See USDOE, page 41.

[8] 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

CCGT generation in New England at an incremental cost compared to a conventional alternative of say, 12 cents/KWh, then the implied price of CO_2 is about $300/ton.[9]

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.[10] The *Wall Street Journal* 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 is very competitive with most conventional alternatives, but solar has significantly higher levelized costs (Demming).[11] 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 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

[9] Studies of the integration of large scale wind generation in Texas and New England indicate that wind generation will largely displace natural gas fueled generation rather than coal fueled generation. (See ERCOT and NYISO) The CO_2 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 CO_2 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 CO_2 emissions, so the net effect of increasing wind generation by a factor of 7 is a 2% reduction in state CO_2 emissions from what they would otherwise be. See NYISO.

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

[11] One of the comparison technologies is natural gas peaking turbines. As a will discuss comparisons between an intermittent technology and a dispatchable technology that is built specifically to very high peak period demand during a small number of hours in the year is not 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.

set of assumptions one chooses about capital costs, operating costs, fuel costs, capacity factors, etc., so that their respective levelized costs can be compared.[12] 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.

In the rest of this paper I will show that conventional "levelized cost" calculations that have been used for decades in the electric power industry to compare conventional dispatchable generating technologies with one another are not particularly useful for comparing the economic attractiveness of technologies such as wind and solar with conventional dispatchable generating technologies such as nuclear, coal, and CCGT. Comparisons of the average annual price paid for intermittent generation with the overall average annual wholesale market price for electricity are flawed for similar reasons. Nor will competitive procurement programs that choose renewable generating projects based on the "least cost per MWh supplied" over the life of a long-term contract produce an efficient portfolio of renewable generating units.

The primary reasons that levelized cost comparisons between intermittent and dispatchable generating technologies are not meaningful 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

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

almost zero.[13] 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 intermittent generating technologies can vary widely depending when the electricity is produced and the production profile of intermittent generating technologies do not follow standard economic dispatch patterns.

These output and electricity price variations are not captured by traditional "levelized cost" calculations or traditional "least cost/MWh" competitive procurement mechanisms, even those that adjust for differences in utilization (capacity) factors between intermittent and dispatchable generating technologies. As a will show, 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.). 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 generating 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).

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

I suggest that levelized cost comparisons be replaced by a market-based or "power system" framework for evaluating the economics of all generating technologies. This is essentially the same as the approach an investor in unregulated generating units that must sell power into the wholesale market would take to evaluating investment alternatives.

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 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 other capital 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).[14] 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 CO_2 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 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

[14] Updating portions of MIT (2003).

wholesale market prices that could profitably support investments in new merchant generating capacity.[15] 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 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.

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[15] 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.

However, the usefulness of simple levelized cost "rule of thumb" comparisons breaks down when the generating technologies being considered have different dispatch capabilities, capital/output ratios, and production profiles. When comparisons are made between generation technologies which are dispatchable by the system operator based on real time economic and reliability considerations and "intermittent" generation whose output is based on exogenous factors like wind and insolation and do not reflect traditional scheduling, economic dispatch and network reliability considerations, the value of the output they are expected to produce must also be taken into account along with their respective life cycle costs. Looking only at levelized cost comparisons tells only part of the story. Other things equal, the production profiles for intermittent and dispatchable generation and the value of the electricity they produce are likely to be very different, making comparisons based on levelized cost alone meaningless.

It is especially important to get more accurate measures of the economic value of intermittent technologies because many intermittent technologies benefit from direct subsidies (tax credits, renewable energy credits and loan guarantees) and indirect subsidies (renewable purchase mandates). If these technologies are truly competitive with conventional dispatchable alternatives the subsidies are unnecessary. If they are not, taxpayers and consumers should be aware of how much they are paying in hidden subsidies in an effort to force these technologies into the system. Moreover, if the primary motivation for promoting renewable technologies is to reduce GHG emissions, it would be helpful to know how much relying on these technologies costs per ton of CO_2^e removed. This would help policymakers to determine if subsidies and mandates for renewable energy technologies represent the least costly way to achieve GHG reduction goals.

SIMPLE NUMERICAL EXAMPLES

Let us begin with an extremely simple characterization of an electric power system. 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 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 plant runs 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 capacity factor is assumed to be 30%.[16]

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

[16] 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. (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.

cost per MW/Year for the dispatchable technology and the operating costs of the intermittent technology are assumed to be zero.

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 estimated levelized cost by assuming higher capacity factors than are likely to be achieved in reality.[17] The political 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.[18] Adopting better methods for comparing the economics of different generating technologies can help to improve the level of discourse about them.

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 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, <u>cannot</u> be dispatched based on traditional economic dispatch criteria and runs, in the case of

[17] Boccard finds that actual realized capacity factors fall short of forecast capacity factors for wind generators.
[18] This observation applies to both renewable and conventional generating technologies.

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 inconsistent with the performance of wind generation in California (see Figure 2 and Figure 3).[19] The revenues, costs and profitability of 1MW 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 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.[20]

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 50 hours during the peak period (a 17% capacity factor during peak hours) and for 2578 hours during the off-peak period (a 45% capacity factor

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[19] 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).

[20] Placing a price on CO_2 might change this conclusion but this could only be determined by adding assumptions about emissions and CO_2 prices. If the dispatchable technology is nuclear then CO_2 pricing would actually make the dispatchable technology more attractive since it would displace more existing fossil generation per MW of capacity.

during off-peak hours).[21] 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 some output 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 technology than for wind, though solar technologies still do exhibit intermittency. 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.

[21] This is roughly equal to the peak period capacity factors for wind generators in New York, though the off-peak capacity factors in New York State appear to be closer to 30% than 45% (NYISO, page 95).

The intermittent technology now has a peak period capacity factor of 87%, limited only by the availabilty of the wind or insolation to drive the turbine. 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 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 <u>base load</u> 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 CO_2 displaced by different technologies can be easily measured.

This framework can be used as well to design better competitive procurement systems and can be employed to shed more light on other issues that have been associated with the growing reliance on intermittent generation. Indeed, many system operators are already using this framework to identify technical issues with large scale deployment of intermittent generation and to measure the costs networks are likely to incur to respond to intermittency in order to maintain reliability criteria (e.g. ERCOT). The framework can also be used properly to measure the 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 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.

OTHER ISSUES

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 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 when it is available. 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 project 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.[22] 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

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

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.

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 incorporate 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 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. 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 CO_2 emissions combined with proper pricing of grid services and backup capacity (through proper capacity payment mechanisms) would yield superior economic and environmental outcomes.

TABLE 1

HYPOTHETICAL LEVELIZED COSTS COMPARISON

	Base Load	Intermittent
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

<u>CASE 2</u>

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:	50 MWh
Off-peak:	2578 MWh
Revenues:	$107,620/MW/year
Costs:	$150,000/MW/year
Profit:	-$42,380/MW/year

TABLE 3C

HYPOTHETICAL VALUATIONS OF INTERMITTENT AND DISPATCHABLE GENERATION WITH THE SAME LEVELIZED COST

<u>CASE 3</u>

Dispatchable MWh supply:

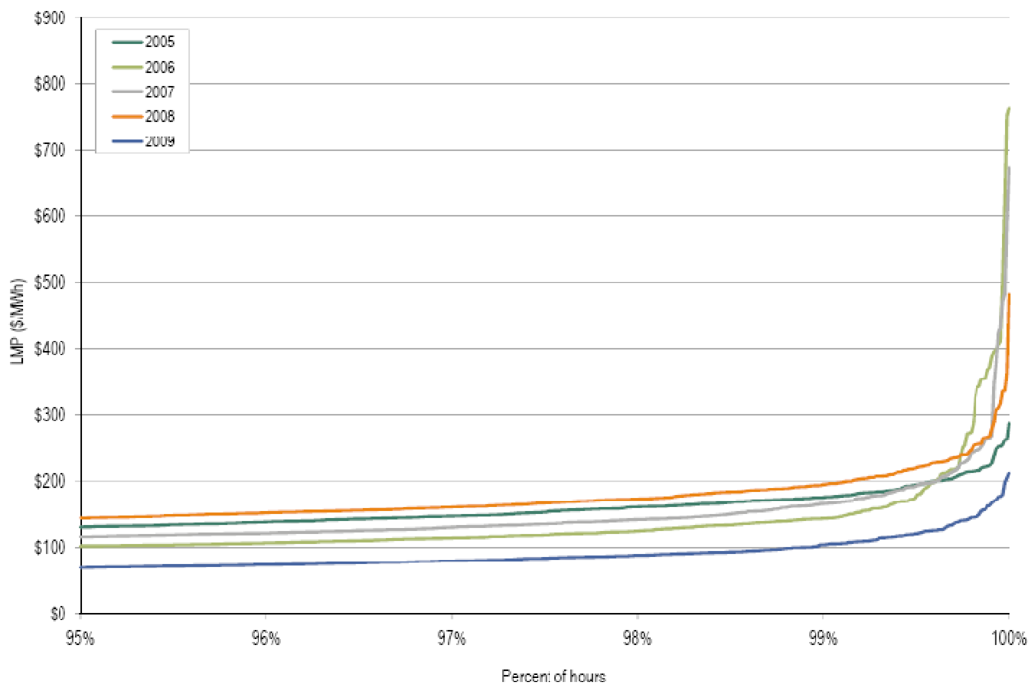
Peak:	3000 MWh
Off-peak:	4884 MWh
Revenues:	$465,360/MW/year
Costs:	$457,680/MW/year
Profit:	$7,680/MW/year

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

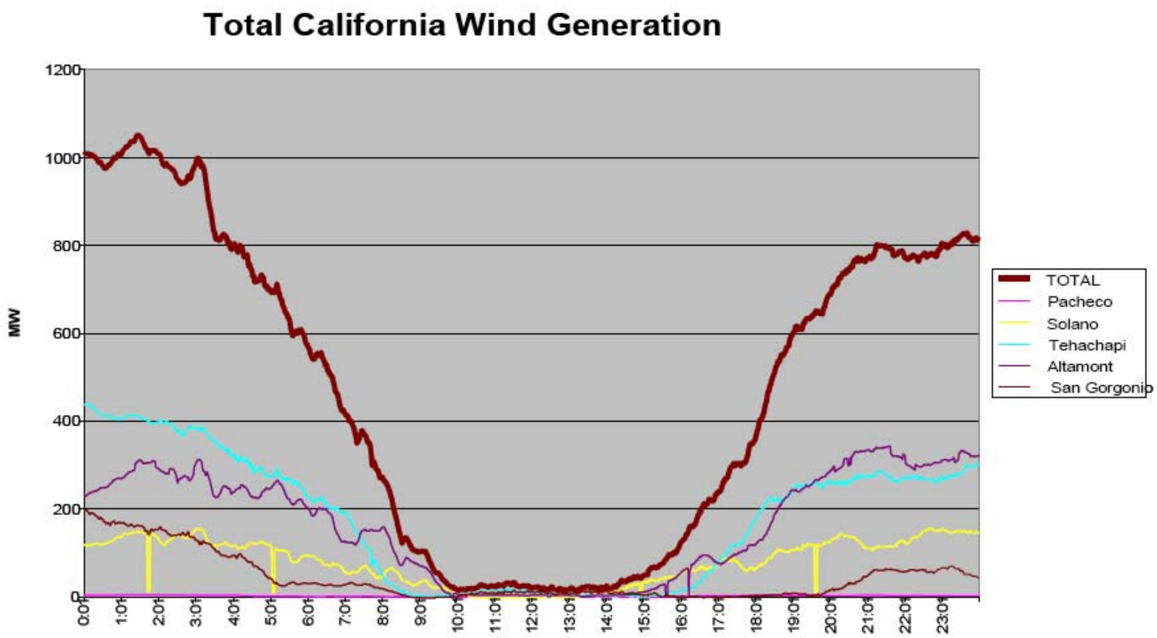
Top 5% of Real Time Energy (only) Prices in the PJM RTO[23]



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

[23] Note that this excludes capacity payments and payments for ancillary services.

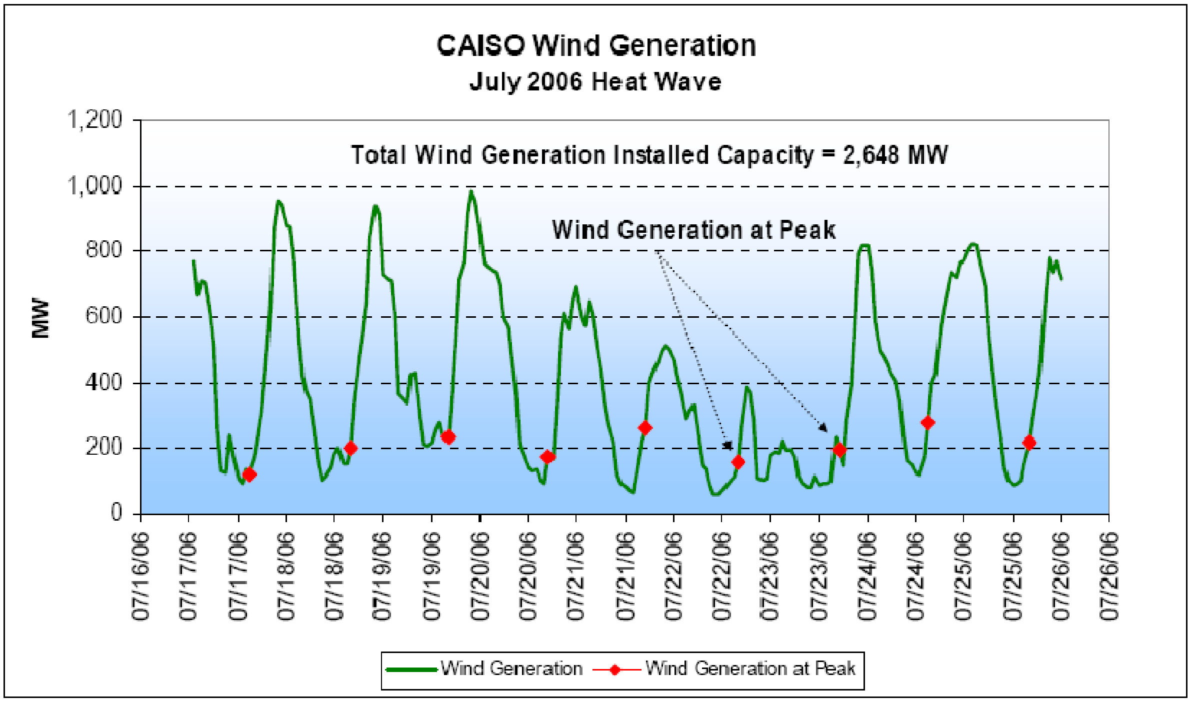
FIGURE 2



Source: NERC (2009), p.16

FIGURE 3

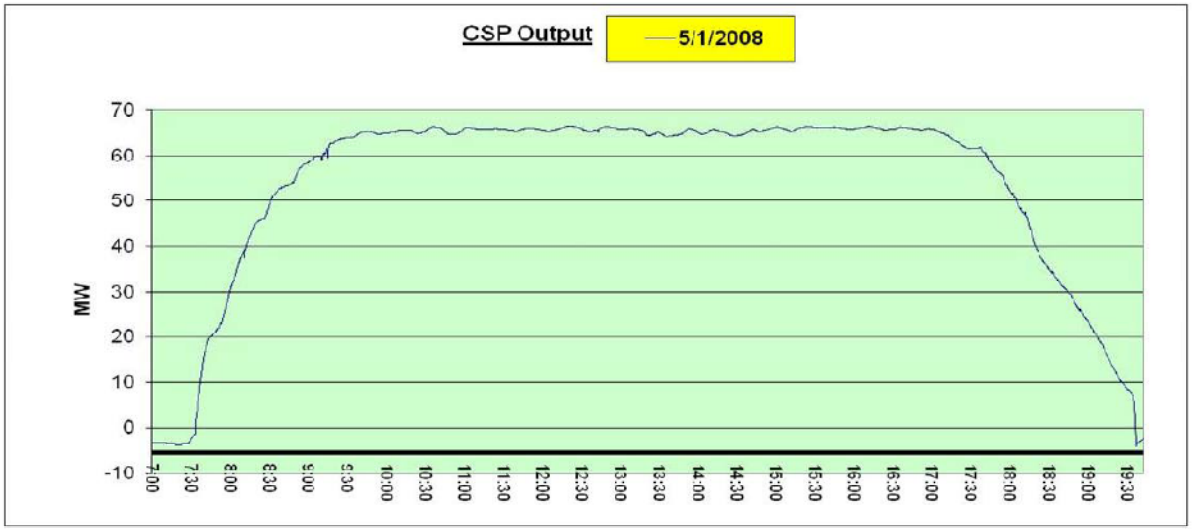
CALIFORNIA WIND GENERATION DURING 2006 HEAT WAVE



Source: NERC (2009), page 37.

FIGURE 4

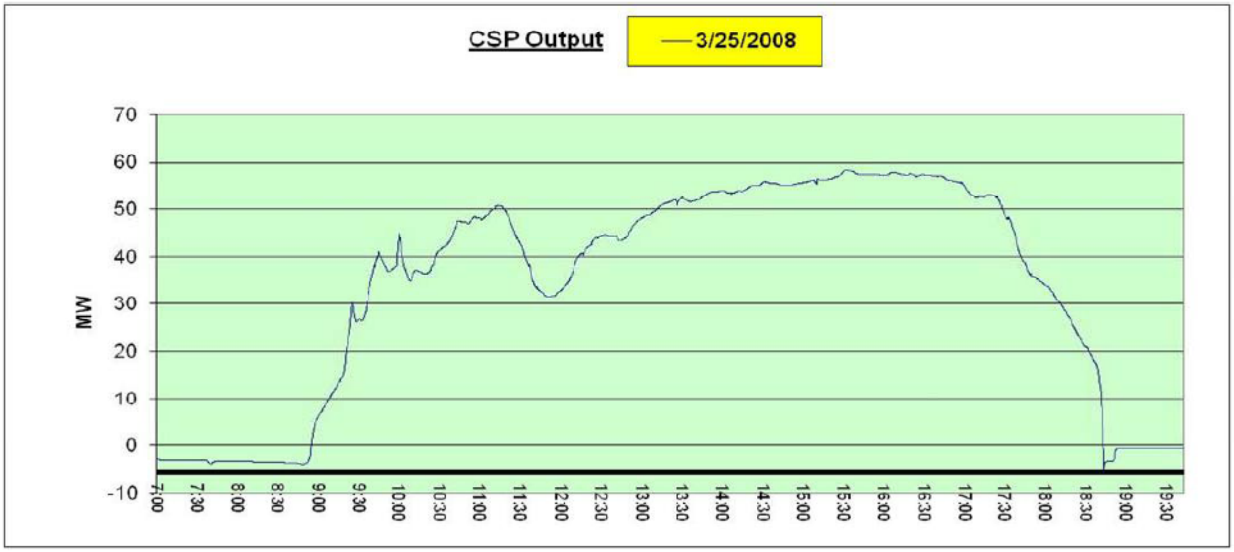
Parabolic trough CSP plant on a sunny day (Sampling time of 10 sec.)



Source: NERC (2009), page 26.

FIGURE 5

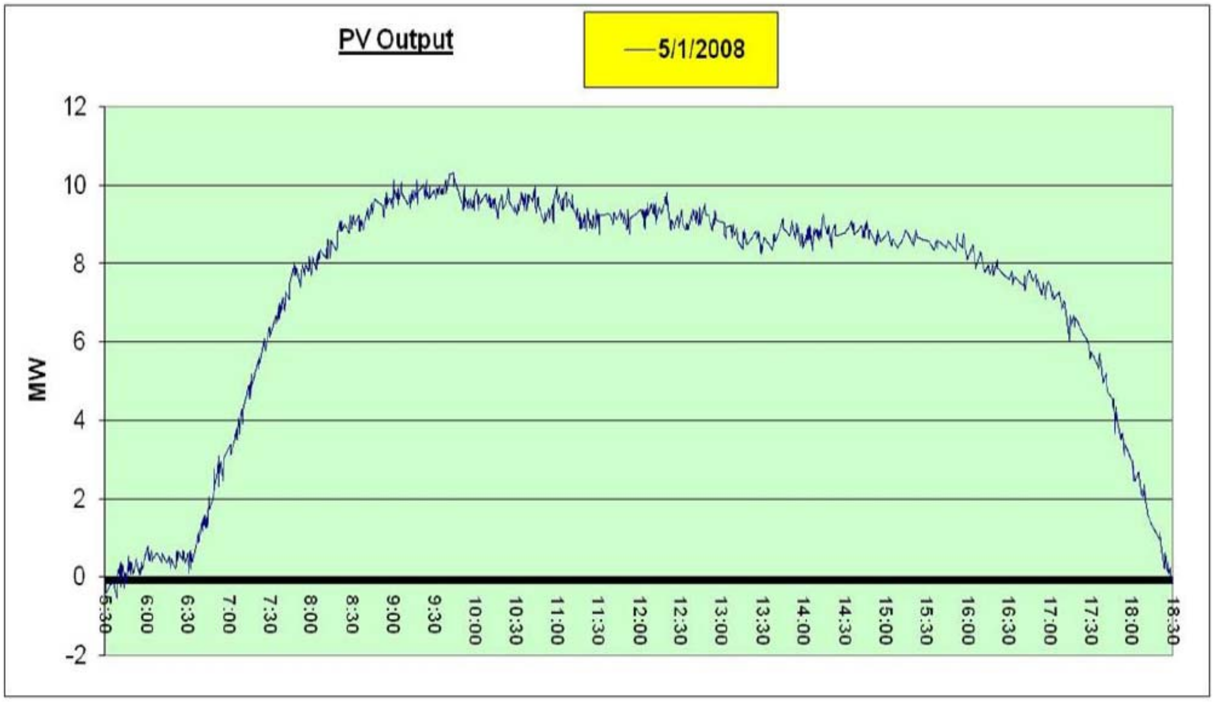
Parabolic trough CSP plant on a partly-cloudy day (Sampling time of 10 sec.)



Source: NERC (2009), page 26

FIGURE 6

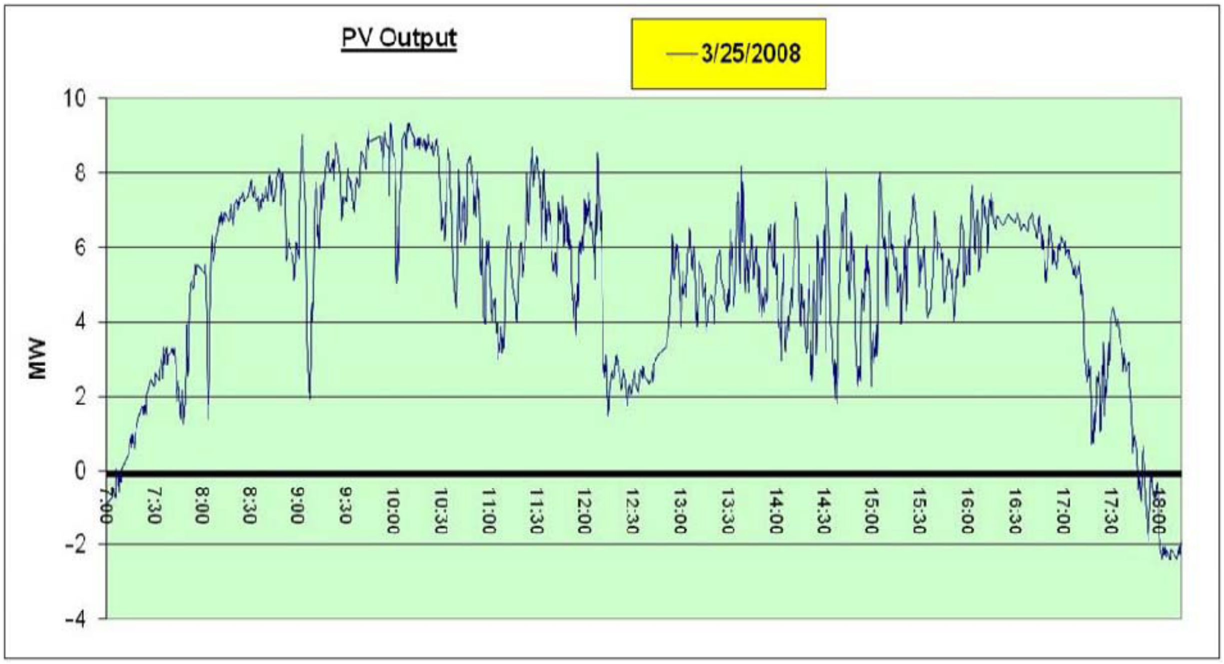
PV plant output on a sunny day (Sampling time 10 seconds)



Source: NERC (2009), page 28

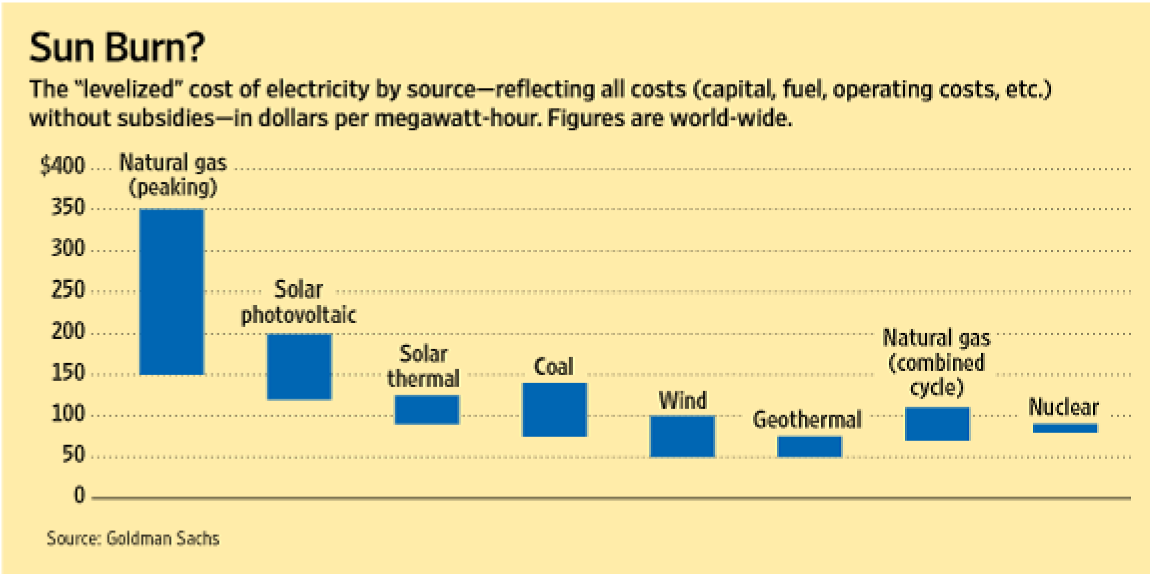
FIGURE 7

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



Source: NERC (2009), page 28

FIGURE 8



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