CONTINENTAL ECONOMICS

BEFORE THE HOUSE ENERGY AND POWER SUBCOMMITTEE

"AMERICAN ENERGY SECURITY AND INNOVATION: GRID RELIABILITY CHALLENGES IN A SHIFTING ENERGY RESOURCE LANDSCAPE"

TESTIMONY OF

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SUMMARY

Federal and state policies that subsidize development of intermittent generating resources, especially wind generation, reduce the reliability of the power system because of the inherently volatile nature of the output of such resources.

To compensate for this reduced reliability, power system operators must increase reserves of fossil-fuel resources, primarily gas-fired generating plants, to compensate for the ups-and-downs of intermittent resource availability, including the potential loss of thousands of megawatts of generation from intermittent resources when conditions change (i.e., the wind stops blowing or the sun stops shining). These additional reserve requirements increase reliability-related integration costs, which are socialized across all customers. As more intermittent resources are built, they increase the severity of reliability issues and increase per megawatt-hour integration costs, as well as total integration costs.

Compounding these reliability problems are policies that socialize the costs to build of new high-voltage transmission lines needed to connect intermittent resources, especially wind generation. Because wind turbines require a lot of land per turbine, wind facilities are typically built in rural areas far from urban load centers, because land is so much cheaper. When wind turbines are built in these locations, new transmission lines must often be built to connect them to the power grid. And, because they are so far away from load centers, there are significant line losses, which reduce the actual amount of electricity delivered to customers. Moreover, wind generation, by far the largest intermittent resource, with over 60,000 megawatts of installed capacity, tends to produce the greatest amount of electricity when the demand for electricity is lowest (at night, and in spring and fall). As a result, wind power is exacerbating economic losses of traditional "baseload" generating units that are designed to run around-the-clock, and are a crucial element of providing reliable, low-cost electricity.

Subsidies, such as the wind PTC, plus socialization of reliability-related and transmission integration costs, means that intermittent generation developers pay only a small fraction of the true costs they impose on the electric system. This is having adverse economic impacts – causing traditional generation resources to retire prematurely because of artificial price suppression – and thus further exacerbating reliability issues, and suppressing new generation investment. Left unchecked, these subsidies for intermittent generation will reduce reliability, lead to higher electric prices, and reduce economic growth and job creation.

Therefore, I recommend that (1) To the extent possible, require <u>all</u> generators to pay for the reliability-related integration costs they cause, rather than socializing those cost across all electric consumers; and (2) Eliminate <u>all</u> subsidies paid to electric generators, whether they are intermittent resources or schedulable resources.

I. INTRODUCTION

Good morning. My name is Jonathan Lesser. I am the President of Continental Economics, Inc., an economic consulting firm specializing in energy and regulatory matters. I appreciate the invitation from the Committee to testify today regarding the costs and the reliability implications of integrating "intermittent" generating resources.

By way of background, I began my professional career almost 30 years ago, as a load forecaster for Idaho Power. In my work for government, industry, and as a consultant, I have been involved with, and researched, many facets of the electric industry, as well as corresponding policy issues, at both the national and individual state levels. These issues have covered: (1) the "nuts and bolts" issues involved in regulating and designing electric rates; (2) electric industry restructuring, and the introduction of wholesale and retail competition; (3) environmental regulations affecting energy resource development and use; (4) the costs and benefits of renewable generation; (5) the economic impacts of electric competition; and (6) the economic consequences of energy subsidies.

I have testified numerous times before state regulatory commissions, before the Federal Energy Regulatory Commission, before legislative committees in many other states, and before international energy regulators. I have co-authored three textbooks, including *Environmental Economics and Policy*, *Fundamentals of Energy Regulation* (for which my co-author and I are now preparing a second edition), and *Principles of Utility Corporate Finance*.

I am appearing before the Committee today on my own behalf and the views expressed in my testimony are mine alone.

My testimony this morning focuses on “intermittent” generating resources – primarily wind and solar photovoltaics (PV) – their impact on electric system reliability, and the costs that must be borne to “integrate” such resources onto the power grid.

In the next section of my testimony, I provide background information on what “integrating” these intermittent resources means in terms of how the power system operates. Next, in Section III, I explain why integrating intermittent resources is more costly than integrating traditional fossil, nuclear, hydroelectric, and, indeed, any generating resource that can be operated on a continuous basis. In Section IV, I discuss some of the “myths v. facts” associated with the costs of integrating intermittent resources. Section V offers my policy recommendations on how to address these resources to ensure that the overall reliability of our electric system is not compromised.

II. WHAT “INTEGRATION” OF INTERMITTENT RESOURCES MEANS

Intermittent power resources are defined as resources that cannot be scheduled to provide a known quantity of electric power at a given time. There are two primary categories of intermittent resources that are the focus of integration studies and reliability concerns: wind and solar PV power. Wind turbines, of course, can only generate electricity when the wind is blowing. Solar PV can only generate electricity when the sun is shining.

In contrast, fossil-fuel, nuclear, and hydroelectric power (with storage dams, such as Grand Coulee Dam on the Columbia River) can be scheduled. For example, barring the very low chance of a forced outage, a modern natural gas-fired combined-cycle generating unit will provide power around-the-clock, and can be ramped up or down quickly to meet the ever-changing demand for electricity. Similarly, the amount of power produced by a hydroelectric plant can be varied simply by changing the amount of water that flows through the turbines.

Integration costs can be broken down into two main categories. The first category includes the costs of ensuring the power system is operated safely and reliably from moment to moment. The second category includes the costs of connecting resources to the power grid, called "interconnection costs," specifically building new transmission lines and substations to deliver electricity from individual generating units to load centers.

Integration and Power System Reliability

To operate a power system, the supply of electricity must continuously match demand. If demand exceeds supply, voltage and frequency drops. For example, you may notice that, when the compressor motor in your refrigerator starts, the lights in your home dim slightly. When the compressor starts, the demand for electricity increases suddenly. This causes a momentary drop in voltage, which causes the lights to dim. If power supply exceeds demand, it can cause voltage levels to increase. If the voltage is too high for the lights in your home, they will burn out, because too much electricity is being delivered to it.

Because the overall demand for electricity changes from minute-to-minute, power system operators must continually adjust electric supply to maintain voltage and frequency within operating limits. If they don't, there will be a blackout. The constant changing of electric supply to match demand is called "load following." The most common method for load following is called "automatic generation control" or AGC. (It is also called "frequency reserve.") Today, AGC consists of computer software installed at certain generating plants whose output can be increased or decreased constantly in response to changing demand. Basically, what happens is that the AGC software increases or decreases the speed of a generating turbine: when demand increases, the turbine speed is increased, just like the engine in your car speeds up when you press on the accelerator; when demand decreases, the turbine speed is slowed.

In addition to needing to adjust electric supply to meet ever changing demand, power system operators have to plan for contingencies, in other words, unexpected events. For example, on those hot, sultry August days in Washington, DC, the demand for electricity peaks because of air conditioning load. Power system operators must ensure there are sufficient resources to meet that peak demand. If a generating plant breaks down unexpectedly on that same day, there must be enough reserve capacity to take up the slack. Thus, there must always be generating capacity held in reserve, either generating units that can be switched on quickly, mechanisms to reduce demand, such as reducing electric consumption at a large manufacturer, or both. And, in fact, in the regional power system that includes DC, called PJM, both types of reserves exist.

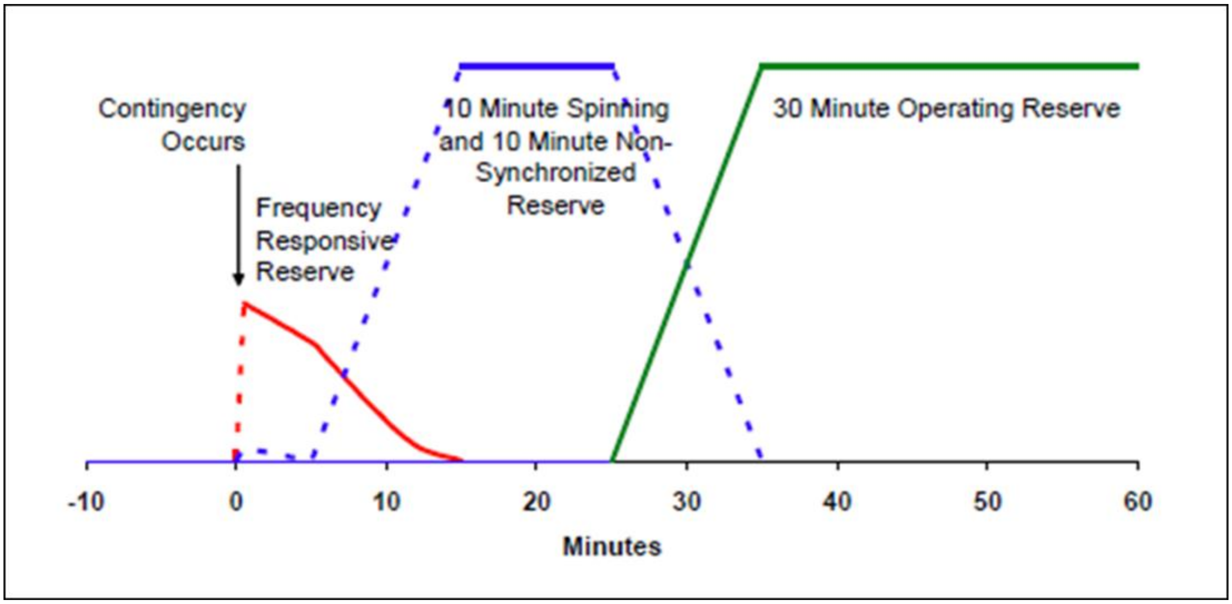
These additional reserves come in three different flavors: spinning, non-spinning, and operating reserves. Spinning reserves are generators that are running, but not connected to the grid. They are the electric equivalent of your car engine running, but the car is in neutral gear. If you need to move, all you have to do is put the car in gear (or press on the accelerator) and away you go.

Non-spinning reserve refers to generators that are not running, but can be brought on line very quickly, generally within 10 – 30 minutes. The vehicular analogy for non-spinning reserve is finding your keys, walking out to the car, starting the engine, and driving off. You can do it relatively quickly, assuming you can find your keys, but it is certainly not as quick as if you were already in the car with the engine running. The final category of reserves are called operating reserves. Operating reserves are generators that can be brought on line, but which require at least

30 minutes to do so. For example, as a private pilot, I can tell you that you don't simply jump into an airplane, start the engine and fly off as quickly as you can drive off in your car.

Figure 1 provides a chart showing how the four different types of reserves work together.

Figure1: The Four Types of Reserves



Gas-fired generators provide most reserve capacity because they can be started, stopped, or ramped up and down fairly easily. In contrast, coal and nuclear plants are designed to run around-the-clock, generating the same amount of power all the time. Starting up a nuclear plant, for example, takes several days, and a baseload coal plant can take many hours. Although the output of both types of generating plants can be adjusted, doing so increases the "wear-and-tear" on them and raises their operating costs.

Intermittent Resources Increase the Need for Reserves

Given this description of the four types of power system reserves, it is not surprising that intermittent resources like wind and solar PV cannot provide those reserves by their very nature. Because you cannot count on the wind blowing at a certain time on a certain day, a wind turbine cannot be relied on to provide electricity if suddenly called on. And, if you have a sudden need for backup generating capacity after dark, solar PV cannot help.

In fact, intermittent resources increase the need for reserves. The reason for this is that, not only must system operators ensure the reliability of the electric system by (1) addressing constantly changing demand, (2) having enough reserve capacity to meet demand when it is at its highest, and (3) planning for low-likelihood contingencies, they must also (4) cope with the wide swings in output from intermittent resources. That, in a nutshell, is what integrating intermittent generating resources is all about, and why integrating intermittent resources is both challenging and costly.

The integration challenge is exacerbated as the quantity of intermittent resources increases on the power system. For example, peak electric demand in PJM is over 100,000 MW in the summer. If PJM system operators had to integrate 10 MW of solar PV, doing so would be trivial. The amount of solar PV is so small that its impact on the overall PJM system would be negligible.

However, the integration challenge becomes and is far more difficult and more costly to address as the quantity of intermittent resources increases. Today, wind generation, with over 60,000 MW installed, is by far the largest intermittent resource and is clustered in the windier regions of the country, including the Pacific Northwest, Texas, and the Midwest. Texas, for example, has over 12,000 MW of wind generating capacity, California over 5,500 MW, and Iowa has over

5,000 MW. There is about 7,000 MW of wind in the Pacific Northwest that the Bonneville Power Administration must integrate. The Midwest ISO (MISO), which spans across 15 states, including most of Illinois, Indiana, Iowa, Michigan, Minnesota, and Wisconsin, integrates over 12,000 MW of wind capacity.

Some Examples

The magnitude and concentration of wind generation in these states has made integration more difficult and costly, and posed challenges for maintaining overall system reliability. The problem stems from huge swings in wind generation in very short periods of time. For example, on October 28, 2011, wind generation decreased in MISO by 2,700 MW in just two hours. In ERCOT, on December 30, 2011, wind generation decreased 2,079 MW in one hour and over 6,100 MW between 6AM and 4PM that day.[1] Still another example took place on October 16, 2012. On that day, wind generation on the Bonneville Power Administration system was 4,300 MW, accounting for 85% of total generation in the pre-dawn hours. The next day, wind generation fell almost to zero.

Not only do such large swings in generation by intermittent resources pose reliability concerns, so does the pattern of generation availability. Whereas solar PV tends to provide the greatest amount of generation on days when power demand peaks – such as those hot, sultry, and windless August days in DC – wind generation tends to be least available when demand is greatest, and vice-versa, as I have documented in my own published research.[2]

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1 *See* "In a first, wind exceeds hydro in BPA region," Platt's *Megawatt Daily*, October 19, 2012, p. 9.

2 Jonathan Lesser, "Wind Generation Patterns and the Economics of Wind Subsidies," *The Electricity Journal*, Vol. 26, No. 1, January/February 2013, pp. 8-16.

Chicago's experience during last summer's heat wave provides a compelling local example of wind power's failure to provide power on the hottest days. During this heat wave, Illinois wind generated less than 5% of its capacity during the record breaking heat, producing only an average of 120 MW of electricity from the over 2,700 MW installed. On July 6, 2012, when the demand for electricity in northern Illinois and Chicago hit a record of over 22,000 MW, the average amount of wind power available on that day was a virtually nonexistent 4 MW.[3]

Integration and Interconnection Costs

By definition, generating resources that are part of the "bulk power system" are those which are electrically connected to the power grid. A regional system like PJM or MISO, for example, has hundreds of generating plants, whose operations are all coordinated by system operators.

Historically, most generating plants were built near load centers. For example, generating plants were built near DC along the Potomac River to provide electricity to the city. Building generating plants near load centers reduces costs in two ways: first, it reduces the amount of power that is "lost" over transmission lines because of electrical resistance and, second, it reduces the need to build miles of transmission lines to deliver power to those load centers.

Today, new gas-fired generating plants are built near load centers. The plants have small footprints and are clean. In New York City, for example, new gas-fired generators have been built in Brooklyn and Queens, both to meet growing electric demand and to replace the generation from old, inefficient and highly polluting oil-fired plants.

[3] Jonathan Lesser, "Wind Power in the Windy City: Not There When Needed" *Energy Tribune* (op-ed) July 25, 2012.

Although solar PV can be installed on rooftops, wind generators are typically built in remote regions. There are several reasons for this. First, wind generators have to be built where the wind is, which tends to be more remote areas of the Midwest and western Texas. Second, wind generation requires a lot of land area because wind turbines cannot be sited too closely together. (Otherwise, they interfere with each other's air flow, and reduce generation.) Because land is generally expensive in populated areas, wind generation developers have thus located turbines on low-cost land far from load centers.

As a result of locating wind generation (and some solar facilities) in remote areas, billions of dollars must be invested in new transmission lines to deliver that power to cities and towns where the electricity is needed. Texas, for example, has built a series of transmission lines, called CRES, to connect wind generation in west Texas to the population centers in eastern Texas. Total cost so far: $6.9 billion.

III. THE COST OF INTEGRATING INTERMITTENT RESOURCES

As discussed in Section II, to ensure system reliability, operators must ensure there is enough reserve capacity to meet contingencies. As more intermittent resources are added to the power system, one of the most important contingencies has become the potential lack of supply from these resources. Again, given its magnitude, wind generation is far more of an issue than is solar PV. Second, the costs of building new transmission lines to connect intermittent resources to the power grid must be included.

The potential loss of thousands of MW of intermittent generation in a short time frame means that system operators must increase the quantity of available reserve capacity. This means the need for spinning, non-spinning, and operating reserves increases, which increases costs. It is as if thousands of vehicles are required to have their engines idling, waiting for the possibility they will be needed.

Furthermore, the variability of intermittent resource output increases the costs of load following. Not only must system operators compensate for constant changes in electric demand, they must also compensate for constant changes in intermittent resource output. As a result, more gas-fired generators must be sped up and slowed down to ensure supply and demand match. That's costly, more so than simply operating a generator at a constant rate for long periods of time. Operating gas-fired generators in this way is inefficient (like stop-and-go driving in the city), which increases costs and air pollution.

In regions with wholesale electric markets, such as Texas, the Midwest, and PJM, system operators use next-day forecasts of generator availability and demand to determine how they will ensure the power system can meet demand and operate safely. For these planning efforts, it is also crucial to forecast intermittent resource availability, because those forecasts determine the quantity of reserve generating capacity that system planners must ensure is available "just in case."

Although even wind advocates acknowledge wind's inherent intermittency, they claim wind generation can be predicted accurately several days in advance, allowing system operators to reduce, if not eliminate, the impacts of wind's volatility.[4] However, forecast and operational data in areas including Texas, as well as in European countries, do not support such forecast

[4] *See, e.g.*, M. Delucchi and M. Jacobson, "Providing All Global Energy with Wind, Water, and Solar Power, Part II: Reliability, System and Transmission Costs and Policies," *Energy Policy* 39 (2011), pp. 1170-1190.

accuracy claims.[5] In other words, forecasting intermittent resource availability is not especially accurate. This adds to the costs of integrating intermittent resources because inaccurate short-term forecasts of intermittent generation increases the overall cost of meeting electric demand: system planners either must reimburse other generators who had been scheduled to operate, but were not needed because actual wind generation was greater than forecast, or reimburse those generators because they had not been scheduled, but were required to operate because actual wind generation was less than forecast.

Integration Cost Estimates

There have been a number of studies of the costs of integrating wind generation. In 2011, the National Renewable Energy Laboratory (NREL) published its Eastern Wind Integration Study (EWITS), which focused on the integration costs associated with maintaining system reliability.[6] In December 2012, the American Tradition Institute (ATI) published a study that also estimated the additional costs associated with building transmission lines, power losses along those lines, and the additional fuel costs associated with operating fossil-fuel generation needed to "firm up" intermittent generation.

The studies show that reliability-related integration costs increase on a per megawatt-hour (MWh) basis as more wind generation is added. This makes intuitive sense: very small amounts of wind or solar PV will have little or no impact on overall system reliability. However, as more and more intermittent generating resources have been added, their adverse impacts on reliability

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5 K. Forbes, M. Stampini, and E. Zampelli, "Are Policies to Encourage Wind Energy Predicated on a Misleading Statistic?" *The Electricity Journal* 25 (April 2012), pp. 42-54 (Forbes et al, 2012).

6 NREL (National Renewable Energy Laboratory), Eastern Wind Integration and Transmission Study, February 2011, NREL/SR-5500-47078. Available at: www.nrel.gov/wind/systemsintegration/ewits.html, www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf

have increased. These impacts will only become more pronounced, and the integration costs incurred to maintain system reliability larger, as more intermittent resources are added to the power grid.

Based on the NREL study, which reported a range of reliability-related integration costs between \$1 per MWh and \$12 per MWh, a typical cost estimate for reliability-related integration costs of intermittent generation is \$5 per MWh. In Texas, for example, applying this value to the 12,000 MW of installed capacity, and assuming a 30% capacity factor (where a generator running around-the-clock for an entire year would have a 100% capacity factor), this implies integration costs of over \$150 million per year – costs that must be paid by electric consumers in Texas to ensure reliability.

The 2012 ATI study estimated the costs of the additional fuel consumption associated with having to cycle fossil generators to meet changing intermittent resource generation levels, as well as the additional costs associated with building new transmission lines and the power losses on those lines. In some cases, there may be sufficient existing transmission capacity to avoid the need to construct new lines. However, even if that is the case, there will still be line losses whose costs are part of integrating intermittent resources located far from load centers.

Using data from EWITS, they estimated the cost of new transmission lines built to deliver power generated by far-flung wind units to be \$15/MWh. They also derived an estimate of \$12/MWh as the cost of the line losses, for a total of \$27/MWh. If we apply these values to Texas, where transmission was built specifically to deliver wind generation to load centers hundreds of miles away, the additional cost is over \$850 million per year. Thus, the reliability-related and transmission/losses costs for Texas alone are \$1 billion per year.

IV. SUBSIDIES AND COST SOCIALIZATION ARE EXACERBATING INTEGRATION COST ISSUES

The fact that integrating intermittent generating resources is more costly than schedulable resources is not the reason for this hearing. Instead, this hearing seeks to examine the reliability challenges of integrating these resources. The issue of maintaining the reliability of the power system in the face of the shifting energy landscape, as the hearing's title frames it, and the resulting integration costs can be traced directly to (1) subsidies designed to incent construction of intermittent resources; and (2) socialization of integration costs.

Consider the following analogy: long-haul trucks typically are assessed road taxes based on their weight. The reason is that, the heavier the truck, the greater the damage caused to roadways. Assessing road taxes based on the damages caused makes intuitive sense, both from the standpoint of economic efficiency and fairness. Thus, the fact that long-haul trucks cause more road damage than passenger cars is not an issue because truck owners pay those costs. There may be disagreements as to whether the taxes are set correctly, but the "user pays" principle is reasonable.

In the case of intermittent resources, however, the subsidies and mandates designed to incent their development, such as the wind production tax credit (PTC) and individual state renewable portfolio standards (RPS), plus the socialization of integration costs among all users, has increased reliability concerns. In other words, we have put into place policies that exacerbate inefficient investments because they do not require intermittent resource developers to pay the full costs of their investments. As Commissioner Donna Nelson of the Texas Public Utility Commission stated last year:

> Federal incentives for renewable energy … have distorted the competitive wholesale market in ERCOT. Wind has been supported by a federal production tax credit that provides $22 per MWh [now $23 per MWh] of energy generated by a wind resource. With this substantial incentive, wind resources can actually bid negative prices into the market and still make a profit. We've seen a number of days with a negative clearing price in the west zone of ERCOT where most of the wind resources are installed … The market distortions caused by renewable energy incentives are one of the primary causes I believe of our current resource adequacy issue … [T]his distortion makes it difficult for other generation types to recover their cost and discourages investment in new generation.[7]

Subsidies Contribute to Premature Retirement of Schedulable Resources, Which Reduces System Reliability

Although not specifically limited to wind generation, approximately 75% of the total PTC credits claimed to date have been for wind generation.[8] The magnitude of the PTC subsidy—far larger than any other form of production based energy subsidy[9] has incented thousands of MW of wind generation.[10] Therefore, I will focus my testimony on its impacts on system reliability.

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7 Chairman Donna Nelson testimony before the Texas Senate Natural Resources Subcommittee (September 6, 2012), transcribed from http://www.senate.state.tx.us/avarchive/ (emphasis added).

8 M. Sherlock, CRS. "Impact of Tax Policies on the Commercial Application of Renewable Energy Technology," Statement Before the House Committee on Science, Space, and Technology, Subcommittee on Investigations and Oversight & Subcommittee on Energy and Environment, April 19, 2012, p. 3.

9 U.S. Energy Information Administration, "Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2010," July 2011. www.eia.gov/analysis/requests/subsidy/.

10 For, example, the American Wind Energy Association states, "Equipped with the PTC, the wind industry has been able to lower the cost of wind power by more than 90%, provide power to the

Currently, the PTC is $23 per MWh. Because it is a tax-credit, on a before-tax basis, it is over $35 per MWh. That amount is actually higher than the market price of electricity in many regions, because of low natural gas prices. Basic economic principles state that you don't operate your plant if doing so costs more than the value of the output you produce. For example, an old, inefficient generating plant that consumes $50 worth of fuel to generate one MWh of power will not generate if the price of electricity is less than $50 per MWh.

With the PTC, however, the economics change. If that same generator received a $35 per MWh tax credit, then it makes economic sense to operate as long as the price of electricity is at least $15 MWh ($50 - $35 = $15). The cost of operating a wind generator is close to zero.

It turns out that electric market prices can actually be negative. Although that sounds impossible – why would anyone ever pay you to use their product? – it happens in the power industry. The reason is that baseload generators cannot just be switched on and off at will. Thus, these plants will continue to operate regardless of the price of electricity.

Now, if there were no PTC, then wind generators, which can be switched off at will, would not generate any power whenever prices were negative. However, with a $35 per MWh PTC, they will continue to generate as long as the price of electricity is greater than -$35 per MWh. Coupled with the fact that wind generation tends to produce the greatest amount of power at

equivalent of over 12 million American homes, and foster economic development in all 50 states." *See*, AWEA Fact Sheet, "Federal Production Tax Credit for Wind Energy." http://www.awea.org/issues/federal_policy/upload/PTC-Fact-Sheet.pdf .

night and in Spring and Fall, when electric demand is lowest, the wind PTC has greatly exacerbated the number of hours where electric prices are negative.[11]

Although negative prices may sound like a great deal, from a reliability standpoint, they are harmful. The reason is that the more hours of the year prices are negative, the greater the losses to fossil fuel generators who must run, and the greater the likelihood they will shut down because of uneconomic subsidies provided to intermittent generating resources. For example, last October, PPL corporation announced it was considering shutting down its Correte coal-fired plant in Montana because of subsidized wind generation, stating:

> "Wind farms can make a profit even in low demand time of the season . . . because they can pay people to take their electricity . . . What we want to see is a level playing field for our plants. What bothers us is that there are actually companies paying people to take their power"[12]

Last December, the company announced it was selling all of its Montana generating plants, including Corrette, because it cannot operate the generating units profitably. .[13]

As schedulable generating plants shut down because it is uneconomic for them to operate, they jeopardize reliability, and increase the costs of maintaining reliability because additional gas-

11 *See* F. Huntowski, A. Patterson, and M. Schnitzer, "Negative Electricity Prices and the Production Tax Credit," The Northbridge Group, September 14, 2012. http://www.nbgroup.com/publications/Negative_Electricity_Prices_and_the_Production_Tax_Credit.pdf. *See also*, Testimony of Public Utilities Commission Chairman Donna Nelson, Before the Texas Senate Natural Resources Subcommittee (September 6, 2012), transcribed from http://www.senate.state.tx.us/avarchive/.

12 T. Howard, "PPL Montana Officials Discuss Potential Shutdown of Corette Plant," *Billings Gazette* September 21, 2012.

13 M. Dennison, "PPL Montana putting its Montana power plants up for sale, industry sources say," (Helena) *Independent Record*, December 23, 2012. http://helenair.com/news/local/ppl-montana-putting-its-montana-power-plants-up-for-sale/article_9e7f6c22-4ca5-11e2-8e7e-0019bb2963f4.html.

fired generators must be placed on stand-by or operated at a higher cost. Thus, rather than being able to schedule a "least-cost" mix of baseload (round-the-clock), intermediate, and peaking generators, those operators will have to meet electric demand with a more costly mix of resources, and spend more to ensure there are sufficient reserves to meet all contingencies.

Subsidies Incent Inefficient Development of Intermittent Generating Resources, Which Exacerbates Reliability Concerns and Raises Integration Costs

Subsidies promote development of generating resources that would not otherwise be competitive. And, on a per-MWh basis, intermittent generating resources receive the largest subsidies by far. At a pre-tax value of $35 per MWh, the PTC is often greater than the market price of electricity. For example, in 2012, the overall average price in the PJM electric energy market was $33.11 per MWh – less than the PTC![14] A subsidy that is greater than the average market price introduces huge market distortions.

Consider an analogy: suppose the government subsidized gasoline to such an extent that consumers paid a price of just one penny per gallon. The amount of driving and total gasoline use would skyrocket, increasing congestion, sprawl, damage to highways, and air and water pollution. The market for fuel efficient vehicles would quickly collapse.

The PTC, coupled with socializing almost all of the reliability-related integration costs caused by intermittent resources, is driving huge levels of investment in intermittent resources, especially wind generation, exacerbating reliability issues and raising integration costs still further. As more wind generation is developed, it is built in locations with less favorable wind conditions

[14] *See* PJM, 2012 State of the Market Report, p. 51. Available at: http://www.pjm.com/~/media/documents/reports/state-of-market/2012/2012-som-pjm-volume2-sec2.ashx

and thus lower overall economic efficiency. This is not unusual – it makes sense to develop the lowest cost resources first, because they provide the greatest return on investment. But when such a large percentage of development costs are socialized – the PTC is paid by taxpayers and integration costs (reliability-related and new transmission lines) are paid by all electric consumers – the result is inefficient investment that would not take place but for the subsidies.

There is justification for the socialization of some transmission-system costs, because transmission capacity provides for reliable electric service, which is a public good. Thus, to the extent that additional transmission capacity increases system reliability, a reasoned economic argument can be made that, because all users of the transmission system benefit from improved reliability, the costs should be shared among all users. In essence, this is a beneficiary-pays approach to cost allocation. However, subsidized (and unsubsidized) intermittent generation does not improve reliability. In fact, it reduces reliability because of its inherent unpredictability/variability, which requires additional back-up generation and raises integration costs.

Despite this adverse reliability impact, the costs of new high-voltage transmission capacity built to deliver intermittent resource-generated electricity onto the power system are still socialized among all users, who then incur yet more costs to maintain the reliability of the power system because it is adversely affected by the intermittent resources. The net effect is to increase the magnitude of the costs that are socialized because subsidies encourage excess intermittent resource development.

V. MYTHS AND FACTS

Many (but not all) proponents of intermittent resources employ a variety of justifications for their continued subsidization. These include: (1) that it is necessary to protect "infant" industries so they may become fully competitive in the market, (2) that geographic dispersion of intermittent resources smooth's out the ups-and-downs of their output (*i.e.*, if the sun is not shining or the wind is not blowing in location A, they will be in location B); (3) that intermittent resources will lead to energy "independence" from Middle East oil; (4) that price "suppression" caused by subsidized intermittent resources benefits consumers; and (5) that intermittent resources are helping the economy by creating new "green" industry and "green" jobs. None of these arguments has any basis in fact.

The "Infant Industry" Myth

The first proponent of the "infant industry" argument was none other than Alexander Hamilton, over two centuries ago, to justify tariffs that would protect U.S. industries from imported goods. However, the reality is that intermittent generation resources have been subsidized since enactment of the Public Utilities Regulatory Policy Act of 1978. Production and investment tax credits have been in place for over two decades, since the passage of the Energy Policy Act of 1992. And, 30 states plus the District of Columbia have RPS mandates and eight others have RPS goals. No other forms of generation have ever been provided with both production subsidies of their costs and mandates that they be used. After 35 years of subsidies, and 60,000 MW of installed capacity, it is difficult to argue the wind industry is in its "infancy." In fact, the U.S. Environmental Protection Agency considers wind a "mature industry." Moreover, unlike solar PV, the prospects for further reductions in wind generation costs are likely small.

It is certainly true that other generating resources have been subsidized. None, however, have been subsidized to the extent of intermittent generation, with direct production tax credits and usage mandates. The way to eliminate the adverse effects of subsidies – be they for energy, agriculture, or housing – is to eliminate subsidies. In an April op-ed in the *Wall Street Journal*, Patrick Jenevein, the CEO of wind generation developer Tang Energy, said the following:

> If our communities can't reasonably afford to purchase and rely on the wind power we sell, it is difficult to make the moral case for our businesses, let alone an economic one. Yet as long as these subsidies and tax credits exist, clean-energy executives will likely spend most of their time pursuing advanced legal and accounting methods rather than investing in studies, innovation, new transmission technology and turbine development.[15]

In other words, Mr. Jenevein stated an obvious, but unspoken truth: the presence of subsidies drives developers to devote their efforts to continuing those subsidies, rather than improving the efficiency of their product.

The Geographic Dispersion Myth

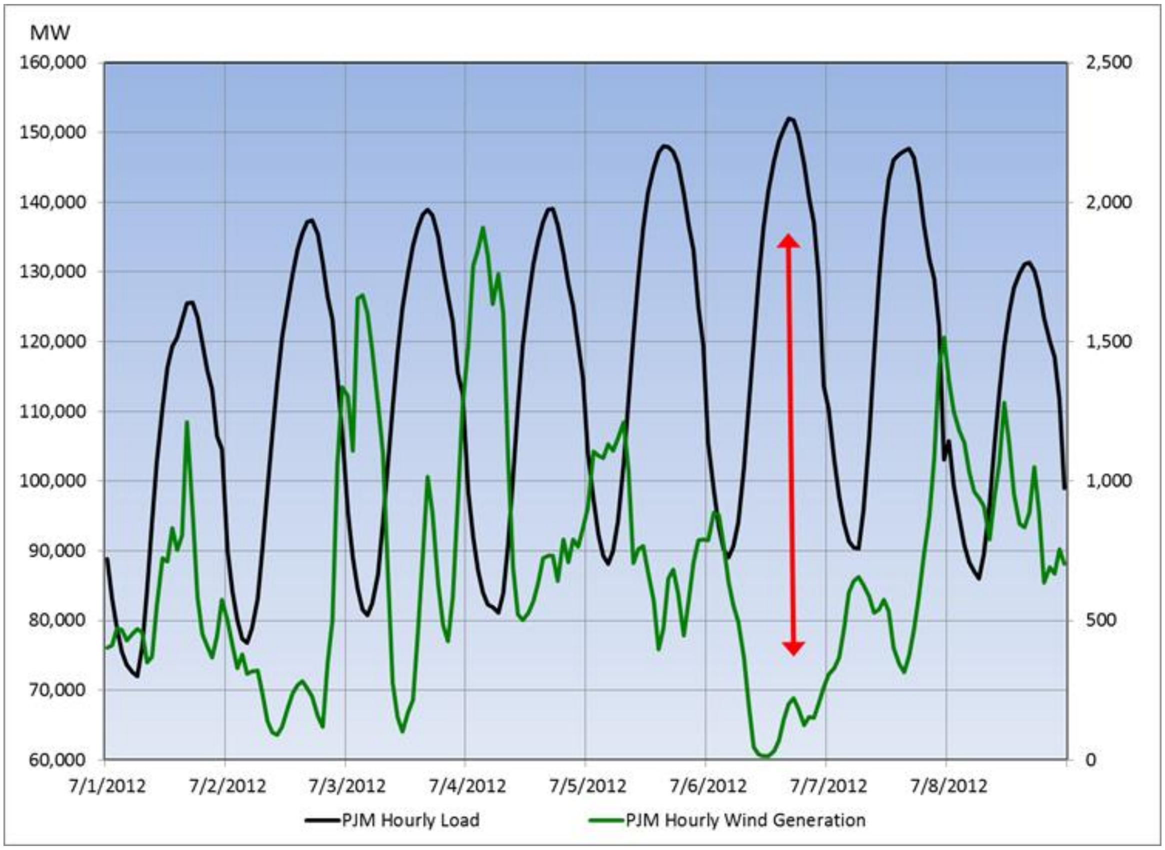
Yet another myth is that the broad geographic dispersion of intermittent resources reduces, or eliminates, the variations in output that exacerbate reliability problems. My detailed research[16] of wind generation over a four-year period in Texas, the Midwest, and PJM shows this to be false. Figure 1, for example, compares wind generation throughout all PJM – which extends

15 P. Jenevein, "Wind subsidies: no thanks," *Wall Street Journal*, April 2, 2013. http://online.wsj.com/article/SB10001424127887323501004578386501479255158.html.

16 *See* J. Lesser, note 2, *supra*.

from Michigan in the north, to Kentucky in the southwest, to Virginia in the southeast – and hourly loads during the week of July 1-8, 2012, when the eastern half of the country was suffering a heat wave.

Figure 1: PJM Hourly Load and Wind Generation, July 1-8, 2012



The figure clearly shows the huge volatility of wind generation from hour-to-hour. Worse, it shows an inverse relationship between wind generation and electricity demand: the greater the demand, the less the amount of wind, and vice-versa. From a reliability standpoint, this is the worst sort of generation pattern: when demand is at its highest, you want to have as much generation available as possible to meet that demand.

Moreover, this same pattern is repeated throughout the year. Geographic dispersion does not reduce the volatile ups-and-downs of intermittent resource output.

The Energy Independence Myth

Still another myth is that intermittent resource development will promote independence from Middle East oil. This argument is clearly false, because the amount of petroleum used to generate electricity is negligible. Thus, until electric vehicles replace the majority of internal-combustion vehicles on the road, the idea that intermittent generating resources will help secure energy independence is clearly false.

The Price Suppression Myth

Intermittent generation developers (and other developers who receive subsidies to development generating plants) point to the "benefits" of lowering or "suppressing" market prices. Although artificially reducing prices may sound like it benefits consumers – it imposes far greater long-run costs.

In a recent research paper,[17] Pennsylvania State University professors Briggs and Kleit examined this issue. Their work finds that the "benefits" of price "suppression" quickly disappear, as government intervention drives out otherwise economic existing generation and hinders the development of new resources in all states within the market. The reason is that subsidies, and

[17] R. Briggs and A. Kleit, "Resource Adequacy and the Impacts of Capacity Subsidies in Competitive Electricity Markets," Working Paper, Dept. of Energy and Mineral Engineering, Pennsylvania State University, October 22, 2012 (Briggs and Kleit). http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2165412

even the threat of future subsidies, drives legitimate competitors out of the market, reducing unsubsidized supplies. Investors become far more wary of providing capital for new development, leading to an increase in financing costs and, again, less investment in the market. While subsidies benefit intermittent resource developers, they harm competitive markets and, thus, raise prices for consumers: the few benefit at the expense of the many.

Thus, when government intervenes on behalf of one generator it drives out other generators, taking with it not only competitive generation capacity, but also the jobs and tax base associated with generation that exits the market. Most importantly, they find that the adverse long-run impacts in all states far outweigh any short-term "benefits" of temporary price reductions.

<u>The Green Jobs Myth</u>

Finally, there is the "green" jobs myth, that subsidizing green energy, including intermittent generation, will create economic growth. Basic economics shows that this, too, is another myth.[18]

You may have read about studies promoting the jobs potential of renewable generation and energy efficiency programs. Such programs, these studies conclude, will foster new industries and create thousands of new well-paying jobs. The more stringent the requirements and mandates, the greater the economic growth. The fatal flaw of these studies is they typically assume that the money to pay for these mandates falls from the sky. In reality, the money comes from all of us in the form of higher electric costs, higher taxes, or both. It is as if the sponsors of those studies conducted a cost-benefit analysis and completely ignored the cost side. Such an

18 *See* J. Lesser, "Renewable Energy and the Fallacy of 'Green' Jobs," *The Electricity Journal*, Vol. 23, No. 7 (August/September 2010), pp. 45-53.

analysis will always conclude the benefits are greater than the costs, because you have assumed there are no costs.

A number of European countries, including Denmark, Germany, and Spain have tried to do so with renewable energy mandates. As a result, Danish businesses and consumers pay the highest electric rates in the world. Germany and Spain have limited their renewable programs, because the programs have been so costly and the resulting job creation so limited. They, too, pay very high electric rates that have damaged their competitiveness.

The fact that higher electric costs reduce economic growth and jobs is really just basic economics. For example, in April 2010, the Rhode Island Public Utilities Commission (PUC) rejected a proposed power purchase contract between Deepwater Wind (a small offshore wind development) and National Grid. One of the reasons cited by the Rhode Island PUC was the job-killing effects of higher electric prices:

> It is basic economics to know that the more money a business spends on energy, whether it is renewable or fossil based, the less Rhode Island businesses can spend or invest, and the more likely existing jobs will be lost to pay for these higher costs.[19]

The Rhode Island PUC was not rejecting wind generation per se; it was rejecting a specific project that was far more expensive than other wind generation alternatives, and more expensive than the market price of power.

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[19] *In Re: Review of New Shoreham Project Pursuant to R.I. Gen Laws § 39-26.1-7*, Docket No. 4111, Report and Order, April 2, 2010, p. 82. Subsequent to rejecting the proposed contract, the Rhode Island legislature passed a law that, in essence, mandated the Rhode Island PUC to approve the contract.

Subsidizing intermittent generation leads to higher long-run electric prices, reduced reliability, and greater integration costs to restore reliability. Higher electric prices reduce job growth. Despite the temptation, you simply cannot subsidize your way to long-term economic growth. That is the ultimate “free lunch” assumption, and it is simply untrue.

VI. CONCLUSIONS AND RECOMMENDATIONS

As the Committee addresses these issues, I offer the following conclusions and policy recommendations:

1. To the extent possible, require all generators to pay for the reliability-related integration costs they cause, rather than socializing those cost across all electric consumers. Because intermittent generation has higher per MWh, integration costs than schedulable resources, requiring those generators to bear the costs they cause makes greater economic sense than further subsidizing them.

2. Eliminate all subsidies paid to electric generators, whether they are intermittent resources or schedulable resources. The subsidies provided by the PTC and state RPS mandates are especially distorting to markets, because of their magnitude and because they are production based, e.g., generators receiving this credit are incented to generate power even when power is not needed. Subsidizing intermittent generation is exacerbating reliability problems, causing increases in integration costs, and jeopardizing the stability of competitive electric markets. The wind PTC is especially egregious, because in many cases it is larger than the actual market price of electricity. Continuing subsidies for intermittent resources will lead to higher electric prices and reduced system reliability.

Thank you for the opportunity to testify before the Committee today.