**BEFORE THE HOUSE SUBCOMMITTEE ON ENERGY AND POWER**

**"American Energy Security and Innovation: Grid Reliability Challenges in a Shifting Energy Resource Landscape"**

**Responses to Additional Questions Posed to Dr. Jonathan A. Lesser, President, Continental Economics, Inc., subsequent to the May 9, 2013 Hearing.**

**Questions from the Honorable Edward J. Markey**

1. **In testimony before the Committee, you spoke of "The potential loss of thousands of megawatts of intermittent generation in a short time, which has occurred in the past."**

   a. **Have modern weather forecasting and grid planning and dispatch tools allowed grid operators to better anticipate and respond to changes in output from intermittent renewable generators?**

   b. **How much warning do grid operators typically have today regarding these types of changes in output and how does this compare with the amount of warning time operators have to deal with forced outages from conventional nuclear and fossil generators?**

**Response**

(a) It is unclear what "modern" weather forecasting and grid planning and dispatch tools are being compared with (e.g., the complete absence of such tools or something else). The answer depends on the nature of the intermittency. For example, a passing cloud can obscure the sun over a photovoltaic array, causing an almost instantaneous drop in generating output. To my knowledge, there are no forecasting tools that can predict such an event, other than direct observation several minutes before the event. Forecasters clearly can predict incoming storm fronts, etc., with some degree of accuracy beforehand, and thus have some ability to predict the output of intermittent renewable resources to a degree. As I stated in my written testimony, according to at least one peer reviewed study published by Forbes, et al., (2012), forecast and operational data in areas including Texas, as well as in European countries, do not support such forecast accuracy claims.[1] In other words, forecasting intermittent resource availability is <u>not</u> especially accurate. <u>Intermittent generators are far more likely to fail to comply with their day-ahead forecast</u>

[1] 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.

availability than traditional schedulable resources. This adds to the costs of integrating intermittent resources because inaccurate short-term forecasts of intermittent generation increase the overall cost of meeting electric demand.

(b) This question suggests an “apples to oranges” comparison that fails to recognize that wind generators can also experience sudden forced outages due to equipment failure. For a wind generator, a forced outage does not occur because the wind stops blowing. The definition of a forced outage is one that is unexpected. Therefore, operators typically do not have a “warning” for forced outages.

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2. **Two nuclear plants in Illinois have shut down abruptly in recent weeks, one with a capacity of over 2,200 MW and another with over 1,000 MW of capacity.**

   a. **What level of fast-acting reserves must be held in reserve around the clock, 365 days a year to ensure system reliability when large conventional power plants suddenly go completely offline in this manner?**

   b. **Do rate payers typically pay for these reserves?**

**<u>Response</u>**

(a) I am unclear as to what the term "fast-acting" reserves is intended to mean, but, for the purposes of this response I will assume that it refers to spinning and non-spinning reserves. Although frequency reserves, also known as automatic generation control (AGC), are the "fastest" type of reserve, in that AGC responds instantly to changing frequency and voltage caused by the constant fluctuations in supply and demand, it is not specifically designed to compensate for forced generator outages.

In addition, the reserve requirement is not solely a function of a particular contingency (in this case, the referenced shutdown of nuclear power plants). Rather, reserve requirements depend on an overall analysis of the system and its ability to meet the 1-in-10 year loss-of-load-expectation (LOLE) reliability standard. The impacts of a single contingency (N-1 event) on reliability and the need for spinning and non-spinning reserves depends on the location of the contingency (i.e., whether it occurs in a transmission constrained region requiring local generating resources), and the size of the overall transmission system in which the generating units operate. It is important to distinguish the forced outages sometimes experienced by conventional power plants from the general lack of availability associated with intermittent energy resources like wind and solar. For example, forced outages result in the unavailability of power production and occur very rarely during the course of a given calendar year. By contrast, my research has shown that intermittent wind resources are only available around 30% of the time during the year (thus unavailable about70% of the time). This is much higher than the typical forced outage rates for schedulable (predictable) resources, which typically have forced outage rates of 2-5% per year.

(b) Ratepayers ultimately pay for energy, capacity, reserves, and other ancillary services through the rates they pay. This is why it is so important to understand that the costs associated with integrating intermittent resources are substantially higher than those associated with doing so for conventional baseload resources for the reasons set out in my testimony.

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**3. Utilities can and do charge wind plants for integration costs. Do utilities typically charge the owners of conventional power plants for the integration costs associated with their forced outages?**

**a. Do you believe they should?**

**b. Why or why not?**

**Response**

(a) It is important at the outset to note that "integration costs," which deal with interconnecting a power source to the grid, do not apply to forced outages, which occur when an event, oftentimes external, may cause a conventional power plant to go offline. Furthermore, it must be noted that interconnection at transmission and distribution voltage levels are quite different.

I shall attempt to provide a general response discussing the case of a forced outage and then the more general issue of integration costs. To do so, assume a power plant is independently owned (i.e., not owned by the utility). We can consider the following two cases.

Case 1: assume the power plant owner has signed a firm power purchase contract with the utility, i.e., a contract that promises the power plant will deliver to the utility a specified amount of energy per hour. For ease of exposition, assume delivery is for a fixed amount in all hours. If a power plant owner suffers a forced outage, it would only pay the utility "damages" associated with the value of the undelivered generation, or would be required to provide an equivalent quantity of power. For example, if the contract was for 100 MW and the forced outage caused the power plant owner to be unable to deliver power for 24 hours, then the damages would be 100 MW x 24 hours = 2,400 megawatt-hours. If the market price of power during the outage was $50/MWh, the power plant owner would be required to compensate the utility in the amount of 2,400 MWh x $50/MWh = $120,000.

Case 2: assume the power plant owner sells energy into the wholesale power grid, e.g., the power plant owners sells all power into the PJM day-ahead and real-time energy markets. If, in the PJM day-ahead market, the owner schedules 2,400 MWh of electricity, but because of a forced outage, cannot deliver that power, then the power plant owner will be assessed a penalty by PJM. In addition, the outage will affect the power plant's equivalent forced outage rate – demand (EFORd), which will reduce its future capacity payments by reducing its calculated unforced capacity (UCAP) level. The power plant owner further loses all energy sales revenues in PJM for those hours.

Next, we can consider the more general issue of integration costs. Integration costs include the direct costs of interconnecting a generator to the power grid, whether at the transmission or distribution voltage levels, such as the cost of a substation needed to step up ("transform") the voltage output of the power plant (regardless of type) to the correct interconnection voltage. Integration costs also include indirect costs associated with ensuring interconnection of a specific power plant does not lead to reliability violations.[2] In other words, integration costs are those associated with "managing the delivery of energy."[3]

Typically, all commercial generation plant owners must pay the direct costs associated with interconnecting their power plants to the transmission or distribution system grid. In a RTO like PJM, transmission level integration costs are paid to PJM, and not an individual utility. Moreover, many of these costs are socialized across the grid, consistent with FERC policy. For costs that are not socialized, i.e., paid for by the transmission-owning utility, such utilities typically charge all power suppliers for those costs. These charges must be approved by the appropriate regulators. At the bulk transmission system level, they must be approved by FERC. At the distribution system level, they are approved by the appropriate state utility regulators.

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2 A power plant can have multiple individual generating units. For example, a wind power plant might consist of several hundred individual turbines.

3 NREL, "Eastern Wind Integration Study, February 2011, p. 31.

4. **On the PJM system, how do the changes in wind output over the course of an hour typically compare to the magnitude of changes in electricity demand over the course of an hour? Could you provide me with data that would allow me to compare these changes for an hour long period that occurs during:**

   a. **a typical spring or fall day**

   b. **a winter night**

   c. **a summer day**

**Response**

The change in demand from hour-to-hour in PJM depends on the time of day, not just the season. For example, the change in total electric demand between 3AM and 4AM is generally small. Based on data between January 1, 2009 and August 31, 2012, for example, the average change in demand between these hours was 1.06% (in absolute value). The average change in demand between the hours of 6AM and 7AM was 7.22%. The largest hour-to-hour change in demand over the entire 44-month period was 24.6%.

In contrast, the average hourly change in wind production between 3AM and 4AM was10.57%. On November 6, 2011, wind output decreased by 3,106 MW, or 49.95%, between the hours of 1PM and 2PM. Conversely, load decreased by 2.19% over that same time period.

I believe the conclusion from these data is obvious: the magnitude of wind generation variability is far greater on an hourly basis than the magnitude of load variability.

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5. **You testified at the hearing that "There is a small impact on emissions because of renewables, but it is very small because you have to operate the remaining parts of the power grid more inefficiently by cycling conventional plants up and down... it's less efficient, therefore there are more emissions."**

   a. **Are there any peer-reviewed studies that support this claim?**

   b. **The National Renewable Energy Laboratory (NREL) examined data from continuous emission monitors at nearly every fossil-fired power plant in the Western U.S. and found that renewable energy produces the expected emissions reductions and has no negative impact on the efficiency of other power plants. Do you disagree with NREL's conclusions? If so, please submit data and analysis to substantiate these views.**

<u>**Response**</u>

a) In my testimony, I was referencing a detailed study prepared by Bentek Energy, a highly respected provider of energy data and analysis. I do not know if the authors of that study have published their results in any peer-reviewed energy journals. In addition to the Bentek Energy study referenced in my testimony you can review the following peer-reviewed paper on the same subject matter. *See* Daniel Kaffine, Brannin McBee and Jozef Lieskovsky. 'Emissions savings from wind power generation in Texas.' *The Energy Journal*, 34(1): 155-175, 2013. Working paper version with MISO and CAISO at http://econbus.mines.edu/working-papers/wp201203.pdf. The study finds that "increasing wind penetration will likely require an increase in ramping of thermal generation, as the magnitude of shifts in wind speed is amplified into larger swings in aggregate wind generation. This increased cycling of thermal generation (in magnitude and potentially frequency) may erode the emissions savings per MWh of wind power as thermal generation is utilized less efficiently to accommodate wind." Importantly, the study concludes that the environmental benefits from emissions reductions in ERCOT fail to cover government subsidies for wind generation.

b) There is no reference to a specific NREL study, which makes it difficult for me to respond. Nor is it clear what is meant by "efficiency," although the typical measure of fossil-fuel power plant efficiency is the "heat rate," measured in Btus of fossil fuel input per kWh of generation. Moreover, because the western power system, especially the Pacific Northwest, contains significant quantities of hydroelectric power, the impacts of wind on emissions should be expected to be different than in the eastern power system, which is more heavily fossil-based.

   However, assuming the question refers to the paper by D. Lew, et al., "Impacts of Wind and Solar on Fossil-Fueled Generators," NREL Report No. CP-5500-53504, August 2012, which is the only NREL report I am aware of on the particular topic cited, there may be some confusion as to what the authors' analyzed. Specifically, the authors of this study used EPA emissions data from 2008 and applied it to the hypothetical conditions posited in NREL's Western Wind and Solar Integration Study (WWSIS). The WWSIS is a hypothetical analysis of power system operations under high wind penetration levels. Thus, Lew, et al., did not evaluate the actual operating efficiency of Western Systems Coordinating Counsel fossil-fuel plants in 2008. They used a production-simulation model and actual emissions data to predict how fossil-fuel generation operating costs and emissions levels would change under the high wind penetration levels assumed in the WWSIS. As the authors state on page 7 of that paper: "This is not a specific projection for the Western Electricity Coordinating Council. It is an example of how cycling might impact the emissions benefits of wind in a generic system with hourly generation based on the WWSIS results."

Finally, and contrary to the premise of the question, Lew, et al., concluded that cycling and startups reduced emissions benefits of wind, i.e., increased emissions and operating costs of western system fossil fuel plants in their simulation.

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