Responses to Stakeholder Comments from 8/14/08 Meeting

Introduction

The National Renewable Energy Laboratory (NREL) held a stakeholders meeting in Denver on August 14, 2008, concerning the Western Wind and Solar Integration Study (WWSIS). The study will examine the grid operating impacts of up to 30% wind and 5% solar in the WestConnect footprint, and up to 20% wind and 3% in the rest of WECC that is outside WestConnect. NREL invited meeting attendees to submit written comments and questions, and they are reproduced below, along with answers from NREL and its partners in the study.

Tom Ferguson, Xcel Energy

The variability in wind generation seems unrealistic to me. I think it deserves close scrutiny.

After the August 14th meeting, 3TIER found that an error had occurred in some of the large data transfers and has rerun their mesoscale numerical weather prediction (NWP) model for approximately 1/3 of the data. NREL and Northern Arizona University are validating this new dataset. GE is redoing their analysis with this new dataset.

I think sub-hourly analysis is critical before making statements about the feasibility of large scale PV installation.

We agree. The current state-of-the-art in solar mesomodeling is hourly resolution. NREL is working with developers to obtain sub-hourly PV output data and determining whether it can generate sub-hourly data based on these data sources plus the existing hourly database. NREL will report back to the Technical Review Committee on its progress.

It should be made clear which operational costs of renewable integration are not captured in the study.

The study assumptions will be made clear in the draft and final reports.

Tom Wray, SunZia Southwest Transmission Project

The intra-hour intermittency of wind generation and how this intermittency accumulates, thereby creating system-wide stability impacts, has given rise to the importance of regulation services on the grid to accommodate these higher levels of wind generation. We can refer to the recent scramble that occurred inside ERCOT to re-establish system bus voltages during an N-1 event there.

We agree that the intra-hour impacts of high penetrations of wind can be significant, and that will be a special focus of the WWSIS. The study will include a statistical analysis that will evaluate how much additional ancillary services may be necessary to accommodate high levels of wind and solar generation. In general, we note that previous wind integration studies have shown that wind generally has less impact on the minute-to-minute impacts (i.e., the regulation time frame) and greater impact in the load following and unit commitment time frames.

It seems to me there are at least two challenges that we face: (1) the reliability impacts of this intermittency as it relates to degradation of bus voltages, power factor and frequency; and (2) the economic consequences of LSEs not being able to rely on wind generation as a dispatchable resource in the first place, and thus requiring the investment of capital for ancillary generation with higher capacity factors to make the wind resource, in effect, "dispatchable". This latter result is at least an unintended consequence of the nation's growing dependence on renewable resources, but an operating reality to maintain the electrical integrity of the grid, nonetheless.

With regards to the first point, please note that the WWSIS will not be considering reliability factors such as bus voltages, power factor and frequency impacts, but as you probably know, WECC is studying some of these issues and is considering a revised grid code for wind. In addition, the NERC Integrating Variable Generation Task Force is also studying these and other issues and will be releasing a report with recommendations by the end of the year.

Concerning the second point, the WWSIS report will include several recommendations on measures utilities, regulators and policymakers can take to accommodate higher levels of wind and solar penetration, while maintaining the reliability and security of the interconnected power grid. This will most certainly include a greater emphasis on procuring flexible resources in resource procurement, consider whether additional amounts (and perhaps types) of ancillary services are necessary and taking measures to extract more flexibility out of existing generating units. We note, though, that the goal of incorporating wind is not to add additional ancillary services to make wind generation more dispatchable, but to determine what additional measures may be necessary to maintain overall system reliability as more wind and solar generation is incorporated.

It would indeed be a helpful practical result of the study if a recommended practice or guide could be developed, both for system operators and system planners, to determine the proper mix of wind generation connected to a given regional transmission network, and firming generation (typically fast-starting simple cycle gas turbines), that would be necessary to maintain system integrity and operability during N-1 events on the system. Certainly, due to the peculiar reliance wind has on meteorology and what would normally be considered force majeure events in a pro forma PPA, it is a natural aspect of the wind generator's operation. The fact that the wind generator's "fuel" is both costless and without ultimate depletion, is somewhat displaced by the consumption of natural gas to make it hospitable to the grid in the first place. Perhaps the folks at GE might be able to formulate an operating nomogram or planning guideline that would provide instruction in this situation, which in my view, is only going to become more prevalent with increasing renewable generation penetration levels.

The WWSIS report will include recommendations on ensuring reliable grid operations with higher levels of wind and solar generation. The report will not specifically look at N-1 events but will examine times of potential system stress, such as high levels of wind generation at minimum load. The WWSIS report will also estimate WECC-wide system operating cost impacts (and savings) from higher levels of wind and generation, and the WECC-wide effects on system dispatch and what is displaced by higher levels of wind and solar generation. Preparing an operating nomogram or planning guideline is beyond the scope of the WWSIS project but may be a worthy follow-up project.

Finally, regulators often come to rely on the science that we develop for situations like this, upon which they craft a system of orders, rules and tariffs that send pricing signals to system users that result in market behavior the regulators seek to achieve as a matter of policy. One policy signal this study might "send" to the FERC, for example, based on the study work being done here, is to recommend the mix of wind generation connected to the grid and the level of regulation generation that the wind generator would be responsible for arranging to ensure grid integrity and reliability; whether the regulation service can be self-supplied or purchased apart from the wind generator itself; whether this arrangement should be compelled by tariff or order; what kind of regulation service would be needed (i.e.: spinning reserves, load following, etc.); whether this regulation service should be wholly-contained in an ancillary tariff or rolled up into the OATT, itself; if the latter tariff arrangement, how the variable costs (i.e.: fuel) are to be recovered by the transmission owner-provider provider; etc.

Most of this is beyond the scope of the WWSIS project but could conceivably be addressed by other stakeholders or market participants in a separate study, in state proceedings, or in filings before FERC. We note that the study will not recommend the proper mix of wind and solar to the grid; instead, the amount of wind and solar helps formulate the scenarios that will be studied. Based on statistical analysis and production simulation model runs of these scenarios, the WWSIS report will include recommendations on, among other things, the level and type of ancillary services that will be needed to ensure safe and reliable grid operation with higher levels of wind and solar generation.

<u>Charlie Smith, UWIG</u>

I am concerned over lack of a sub-hourly data for PV at any relevant levels of aggregation. This lack of data should not be allowed to jeopardize the integrity of the analysis and results. If the data is not available, PV should be removed from the analysis, or held to a sufficiently low level that the lack of data does not affect the credibility of the work…For the future high solar scenario, I am concerned about 10% solar on top of 30% wind, especially if half the solar is PV, given the lack of subhourly data. I would consider something closer to 20 or 25% wind with 10% solar, with the 70/30 split between thermal/PV, and that is assuming the subhourly data problem can be resolved. If not, I would consider waiting to analyze PV until a credible data set is available and stick to the solar thermal for now.

NREL is exploring its existing sub-hourly PV data from AZ and CO, trying to supplement this with additional PV output data, and seeing if it can combine these subhourly data with the hourly solar mesomodel data to model larger penetrations of PV credibly. This analysis will be discussed with the TRC when completed. NREL agrees that if PV cannot be credibly modeled, the penetration levels of PV will be limited or the scenarios will be modified.

In the mesoscale modeling, the frequency of use of the Reanalysis data set to "nudge" the results of the simulation back on track should be investigated. My recollection of the MN work is that the model was nudged multiple times per day, and I will look into that. I am concerned that nudging every 3-4 days may introduce significant errors at the time seams, if indeed that's how often it was done.

3TIER, NREL's subcontractor on the WWSIS project, explained that a problem with nudging is that the data must be nudged towards some kind of measurement, unfortunately the data that could be used for nudging is coarse resolution and guessing the interpolation between the observed record from which the nudges would be derived is potentially as dangerous as the problem it is trying to solve – especially for a study where variability is key and we are trying to avoid simple interpolation.

3TIER utilizes NCEP/NCAR Reanalysis 6-hour data which is then downscaled by the Numerical Weather Prediction (NWP) model to a finer temporal and spatial resolution. This output is then compared to a sparse set of observed measurements during that time period from various locations and this comparison is used to adjust the final model output, using basic Model Output Statistics (MOS) equations. Due to computing limitations, the NWP model was run in four spatial domains. 3TIER also runs the model in 4 day blocks, throwing the first day out as the model 'spins up' and using the remaining three days of output. The spatial and temporal blocks are then all blended to eliminate seams.

I would like to better understand how the lack of model output statistics (MOS) correction for the forecast data set affects the error of the day-ahead forecast, and the implication for the scenario results.

The mesoscale model data has not had any advanced model output statistic (MOS) correction applied to it and often the application of MOS can significantly improve a forecast. The result is that these forecasts will be conservative measures of 'state-of-the-art forecast' accuracy. This will mean that the results of the study will be somewhat conservative as well when using this set of forecasts. However, four different forecasts were provided, including a perfect forecast of hourly behaviour. This will serve to bound the results and a true state-of-the-art forecast system (with full data availability to provide an advanced MOS correction) will be somewhere between the two.

<u>Mark Russell, Salt River Project</u>

The Black and Veatch Arizona Renewables Study was mentioned as a point of concern. The availability of the National Solar Radiation Data Base and the 3TIER study will provide a more robust picture of the available wind and Solar in Arizona. Will the 3TIER wind database be made available to the wind development community?

NREL has put the 3TIER wind data on its website at: http://www.nrel.gov/wind/westernwind/ . Solar radiation data for 2004 and 2005 is available on the National Solar Radiation Database web site at http://rredc.nrel.gov/solar/old_data/nsrdb/ . The license that we received for the 2006 solar

data allowed us to use 2006 data only for the WWSIS. The concentrating solar power output was creating by running the solar data through the Solar Advisor Model:
https://www.nrel.gov/analysis/sam/
The PV output was creating by running the solar data through PV Watts:
http://www.nrel.gov/rredc/pvwatts/
In the next few months, NREL will make the PV and CSP power output (and eastern US wind data) available on a website so that users will not have to do the power conversion runs themselves.

Has there been an analysis of the use of low wind turbines that can be utilized in lower wind regimes and be feathered during high wind events?

Low-speed wind turbines have not been analyzed because the dataset showed that the wind resources were more than adequate for this study. For simplicity, a single turbine, the Vestas V-90, was assumed for all of the wind plants in this study. Curtailment and ramp rate limits will be examined in the WWSIS project, which presumably will involve feathering of the turbine blades, among other things.

This study is reflecting a lot higher wind and solar resources numbers than have been previously seen. I think that the differences between this study and the Black and Veatch study can be explained by the development of better modeling and this should be done.

The solar and wind modeling will be discussed in the WWSIS report. Modeling of the solar resource and conversion to power output has not changed for this study. Time-series mesomodeling of the wind resource on this scale is new, however, and validation of this new wind data is important. If an extensive validation finds this wind data to over- or under-estimate the wind resource, GE will run a sensitivity analysis using a modified wind dataset.

Assuming a 30% wind penetration in the study area and 20% wind penetration outside of the study area facilitated a scenario where peaks could be dumped throughout the WECC. A worst case scenario should be created where the rest of the WECC is as or more saturated than the study area. This would require each transmission area to absorb its own spikes.

WWSIS is focused on WestConnect. A 20% renewables penetration was created for WECC to match up with other WECC studies underway and to test the difficulty of integrating higher levels of wind and solar in WestConnect if WECC also has significant amounts of renewables. For the WWSIS project, a study requirement is that WestConnect has to provide its own balancing and reserves: interchanges with utilities outside the study footprint can only be done hourly.

In talking to my planners they plan for peak based on the hottest day of the year and reserves are based on that. I think this analysis should look at the worst day for spikes and the worst day for dips.

The WWSIS will definitely look at these periods. A primary aim of the WWSIS project is to look at “interesting and extreme periods” such as peak demand and minimum load periods and determine the effects of more wind and solar generation on those periods. In addition, GE will conduct an ELCC and LOLP analysis for three scenarios to determine the capacity value of wind and solar.

Overbuilding the wind projects throughout the study area and requiring them to feather their outputs during high wind events would flatten the spikes.

The Mega project scenario probably comes closest to the idea of overbuilding wind projects and relying on curtailment when needed. The WWSIS will look at curtailment and other wind mitigation options throughout all scenarios of the study.

I would like to see all the cost numbers in the operational analysis be removed and strictly look at resources requirements. As was mentioned in the meeting, all the economics are not being identified and some stakeholders may improperly interpret the information.

This comment will be taken under consideration. Under GE's contract with NREL, GE is to make a "best effort" at estimating the combined wind and solar integration costs for regulation, load following and unit commitment and to provide justification if providing a cost estimate is not possible. While there is a tremendous amount of data and results coming out of this study, NREL's philosophy is to be as open as possible with data and results. NREL agrees that misinterpretation is a potential issue and that it is essential that all assumptions and costs be explained and documented.

<u>California Public Utilities Commission</u>

Based on the August 14 presentations, it appears that some scenarios to be considered, particularly those not incorporating "mega-projects," will not assume addition of electric transmission capacity beyond what is already in place or planned. Could you confirm that this is true, and if so, is this expected to lead to significant curtailment or dumping of wind (and solar) energy in the production cost modeling?
Some results presented on August 14 (e.g., "Operational Impacts", including wind/solar-driven energy displacement and spot price changes) appear to come from WECC-wide production cost modeling under a base case plus three levels of wind/solar penetration. For these simulations, were no major transmission additions assumed beyond what is known today, and how much potential wind/solar output was curtailed/dumped due to congestion? Were the transmission paths whose transfer capability was modeled so broad as to exclude other transmission constraints (e.g., at lower voltages or within-area transmission) that would further constrain delivery especially at high wind/solar penetration levels such as the 30% wind scenario?

The preliminary results presented at the August 14th meeting focused on the base case and "in-area" scenarios, whereby the 30% wind and 5% solar targets had to be met within each transmission area. Other than a transmission line connecting northern and southern Nevada and some additional transmission in Arizona, no additional transmission was added. All transmission lines in WECC were modeled, and all transmission constraints were respected. The "in-area" scenario was a starting point for analysis. For the other scenarios it is likely that significant new transmission will be added. The analysis did not include curtailment but this and other wind control measures will be studied as part of the project for every scenario.

On August 14, there was discussion of alternative assumptions regarding how much of the transmission capacity needed by wind/solar generation was assumed to be available to that generation (as opposed to being reserved for other uses, apparently). Can you confirm that this issue applies to spreadsheet-type (or at least, not involving production cost modeling) analysis of different load areas' (e.g., Arizona) least-cost selection of within-area versus external wind/solar resources, and does not apply to production cost modeling?

Yes, the discussion on August 14th was in reference to allocating solar and wind generation between areas, and how much transmission would be necessary if solar and wind could access existing transmission versus the amount of new transmission that would have to be built if existing transmission is not available. More scenario refinement is necessary, but this does not involve production cost modeling. The production cost modeling is applied once the scenarios are fully defined.

For production cost modeling, will all transmission be modeled as available to the lowest cost generation in each hour (as if scheduled based on energy bids), as long as reliability/security constraints are met, or will transmission capacity be allocated in some other manner?

Energy will be scheduled and dispatched on a lowest cost basis, respecting transmission constraints and reliability requirements.

Will the relative merits and selection of within-area versus outside-area wind/solar procurement be evaluated using production cost modeling (as opposed spreadsheet-type analysis apparently presented on August 14), and if so, will existing/planned and/or assumed new (e.g., mega-project) transmission be modeled as available to the lowest-cost (lowest-bid) energy, or will it be allocated in some other manner?

Once the scenarios are fully refined, production cost modeling will be employed on all the scenarios, which at this point will also include mega-projects and local priority scenarios. High solar and high capacity value scenarios are under discussion. For all scenarios, energy will be scheduled and dispatched on a lowest cost basis, respecting transmission constraints.

Can you provide some insight into how these integration requirements and costs will be assessed? For example, will the requirements and costs be based on load following and regulation requirements involving increased deployment of operating reserves?

The study will include assessment of increased regulation and load following reserves, and the costs of these reserves, due to the higher wind and solar generation.

(How) will the assessment consider the need to procure (build or purchase) additional flexible generation, as opposed to obtaining the required integration services (e.g., regulation and load following) from existing or already-planned generation?

The WWSIS will estimate how much additional regulation and load following will be necessary to incorporate higher levels of wind and solar generation but an inventory of existing sources of regulation and load following reserves will not be conducted. Broad recommendations on how to incorporate higher levels of wind and solar generation will be offered, including recommendations for procuring greater levels of regulation and load following reserves from existing and new sources, should that be found to be necessary.

Will the integration cost assessment include the energy penalty for a less optimal (in terms of energy cost) dispatch of the balance of system due to redeploying reserves?

No.

To what extent will the assessment of integration requirements and costs utilize production cost modeling versus other analytic tools (e.g., other tools to assess new capacity requirements, intra-hour issues)?

In addition to production cost modeling, statistical analysis will be conducted to estimate the impacts on hourly and sub-hourly variability from higher levels of wind and solar generation. For specific events, 1-minute quasi-steady-state analysis will be conducted to look at impacts on a regulation time scale. In addition, GE will conduct Effective Load Carrying Capability (ELCC) and Loss of Load Probability (LOLP) analysis to determine the capacity value of wind and solar generation. New capacity requirements to maintain reliability and reserve margins are an input for all of the scenarios. For 2017, 10,000 MW of new generation was added, 80% of which was gas combustion turbines.

Will integration services (such as flexible generation committed to provide regulation and load following) be assumed to come from the source areas of wind/solar generation, the load/destination areas, within individual balancing areas, or more broadly from either the entire study footprint or WECC overall? To what extent will transmission constraints influence this sourcing of assumed integration services?

Ancillary services will first be provided on a control area by control area basis, then WestConnect-wide. Transmission constraints are incorporated and recognized in the production cost modeling.

It was mentioned that the wind/solar data will soon be available on a website. Could you provide any additional information on the timing and web location of this data?

NREL has put the 3TIER wind data on its website at: http://www.nrel.gov/wind/westernwind/ . Solar radiation data for 2004 and 2005 is available on the National Solar Radiation Database web site at http://rredc.nrel.gov/solar/old_data/nsrdb/ . The license that we received for the 2006 data allowed us to use 2006 data only for the WWSIS. The concentrating solar power output was creating by running the solar data through the Solar Advisor Model:
https://www.nrel.gov/analysis/sam/
The PV output was creating by running the solar data through PV Watts:
http://www.nrel.gov/rredc/pvwatts/

In the next few months, NREL will make the PV and CSP power output (and eastern US wind data) available on a website so that users will not have to do the power conversion runs themselves.

Will available data include just the basic wind/solar resource data involving multiple parameters for numerous geographic cells, or will it also include the processed data such as the synthetic wind and solar "generation projects" that were:
1) developed as a menu of candidate resource options for use in the study, by applying various exclusions, criteria or screens to the wider set of resource data, and/or
2) actually selected for inclusion in particular analytic scenarios.

All of the more than 32,000 wind sites that were considered for inclusion in WWSIS and successfully passed various exclusion screens are available on the website. It will not note which wind sites were selected for each scenario.

The 10, 20 and 30 percent wind penetration scenarios (with corresponding solar levels) discussed on August 14 apparently assumed that all of the wind/solar generation procured to meet penetration targets for individual "areas" in the study footprint came from within those areas, unless the wind/solar "menu" of generation projects for a particular area was too limited. Can you confirm that this is true?

Yes. Preliminary results for the baseline and in-area scenarios were presented at the August 14th meeting. The in-area represented the transmission areas within WestConnect. For the in-area scenario, renewables within those areas had to be selected for meeting the 30% wind and 5% solar targets, i.e., they could not be imported from other areas. Some solar was imported to help Wyoming meet its in-area solar requirement.

Future scenarios are stated to include a "local priority" scenario. This seems to imply that going forward, the more basic (non-local priority) wind/solar penetration scenarios will have load areas selecting their wind/solar resources on a WECC- or footprint-wide basis, not within areas as was apparently done for the August 14 presentations. Is this true, and more specifically, how will wind/solar resources be selected for the "non-local priority" scenarios?

The in-area scenario selects the best wind and solar sites from within each transmission area to meet the 30% wind and 5% solar targets. Such a restriction is removed in other scenarios, meaning that renewables could be transmitted to other areas. In the mega projects scenario, which is almost an opposite case, those sites with the lowest delivered cost of energy (cost of electricity plus cost of transmission) are selected. In the local priority scenario, which is in between the mega-projects and in-area scenarios, sites within an area are given a bonus (as they receive the benefits of the increased employment, increased tax revenues, etc.) and then sites are selected based on least delivered cost of energy.

Information provided on August 14 indicates that among the "areas" defined and analyzed within the study footprint is an eastern Idaho/southwestern Wyoming area. Is this area part of the actual WestConnect footprint, and if not, why was it included in the study while other non-WestConnect areas were not?

Good point. This area has been removed.

Mark Graham, TriState

What does it mean that "subhourly variability is accommodated by WestConnect"? Generator ramp rate limitations must be respected in this analysis.

We wanted to address a concern that WestConnect would try to export its variability to the rest of WECC. We are allowing for hourly interchanges outside of WestConnect but not subhourly interchanges. So the subhourly variability (all the regulation reserve needs, etc) must be accommodated in WestConnect in this study. Yes, we are respecting generator ramp rate limitations, minimum turndowns, etc.

With respect to the wind data, please explain how "Model errors can be systematic and show a characteristic pattern (such as slower ramp rates)". How much could the models tendency toward slower ramp rates bias results of the analysis? Is there a way to adjust for this ramp-rate-error post-process? Was the meso-data compared to actual for any site?

Numerical Weather Prediction (NWP) models can be tuned to exhibit steeper ramps and can also be dampened to exhibit slower ramps. However, the point of this statement was to highlight the reason that SCORE-lite was used in the study. NWP models tend to be a little too smooth, especially given that there are small area effects that speed or slow winds within the area covered by an NWP grid cell, SCORE attempts to fix this problem. Furthermore, the tuning of these models is extremely important and the availability of measured wind data to help in that calibration process is critical. The mesodata was and is being analyzed in excruciating detail by 3TIER, NREL, and partner institutions. 3TIER has created validation reports comparing 30 met tower wind measurements to the mesodata. NREL is comparing wind speed measurements for a number of towers and also wind power output for Colorado, Wyoming, New Mexico and Texas. In these comparisons, the size and number of ramps is being examined in detail. Additionally, NREL is undertaking a validation of the mesodata against the NREL validated wind maps. Results from this will take several months, and if modifications are needed to the mesodata, GE will run a sensitivity analysis showing the impact of a revised mesodataset.

In GE's scenarios, please explain how you anticipate that generating unit minimums will be accommodated for simulation of off-peak and shoulder-period operation

In the production cost modeling, minimum turn-downs, ramp rates, and other generation limits are inputs and are respected in the analysis.

In GE's statistical analysis, the average daily profiles are interesting, but do not reflect chronological or intermittent characteristics of wind production very well. Are these averages going to be used in the impact study? In slide 24, the load up-ramp rate appears to be just under 10% of the 20 GW net load. Is this typical? Would fast load up-ramps, such as the one shown on *slide 30, ever result in loss of load? The information shown on pages 42-44 is particularly interesting.*

The primary purpose of the statistical analysis is to gain understanding and insights into the characteristics of the wind profiles, solar profiles, and load profiles. The statistical analysis shows average trends in variability as well as extremes. It shows diurnal, seasonal, annual, and regional patterns in load, wind, and solar profiles.

Other types of analysis in this project, including production simulation and quasi-steady-state time simulation, use actual load, wind, and solar MW profile data, not statistical data. The impacts of ramps of particular magnitudes and rates will be evaluated with respect to the capability of the interconnected grid's ability to accommodate those ramps.

The wind profile data used for the analysis presented on August 14 was found to have errors. The wind profile data has been recreated and the analysis is being repeated, so we won't comment on specific numerical results in the August 14 slides which were based on the erroneous wind data.

In GE's operational impact analysis, What impact would increasing ramping have on maintenance cost of the various generating types shown on slide 4? (particularly gas-driven facilities) Heat rates of ramped gas units would be higher than base loaded units. Was additional cost due to lower efficiency operation of ramped gas plant reflected in this analysis? Was higher NOx production that would be experienced at non-optimum power output reflected in the charts shown on slide 8, 9, and 10? Were dispatch costs included in this analysis? (cost of operating at minimum, cost per start, etc.)

The multi-area production simulation (MAPS) program was used to calculate the operating costs and emissions for generating units with WECC. Modeling of individual generating units accounts for the fact that efficiency (heat rates) and emissions do not vary uniformly with load. The cost and emission effects of operation at non-optimum power output are reflected in the analytical results. The modeling of generators also includes dispatch costs, including operating at minimum output, cost per start, lead time for start, etc.

Feedback:
It would be helpful if analysts for this study effort could examine and report effects that would be expected during off-peak periods more closely. This has been identified in previous studies as a potential problem area. The goal here would be to determine what generating unit characteristics would be required to balance wind 24-7, at the different penetration rates studied. Perhaps there are technology improvements GE or other manufacturers could suggest that would increase effective ramp rates, allow gas generating units to operate more efficiently at low output levels than they do today, and other improvements that would allow them to operate at very low capacity schedules, perhaps even down to 10-15% of nameplate, so wind could more easily be accommodated. This comment may be a suggestion for further study. It is also a challenge to the generating unit design and manufacturing community.

Yes, off-peak periods have shown to be challenging in some regions for wind. This study will examine the needs to maintain reliability 24-7 at the different penetration rates, and mitigation options may include more flexible generation, changing existing operational practices, or other ideas.