U.S. Department of Energy
Electricity Advisory Committee Meeting
National Rural Electric Cooperative Association Conference Center
Arlington, VA
June 19, 2019

Meeting Summary

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Meeting Summary

This Electricity Advisory Committee (EAC) meeting was the second to take place in 2019. Assistant Secretary Bruce J. Walker of the Department of Energy's Office of Electricity (OE) and Assistant Secretary Daniel Simmons of the Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) provided updates on the relevant programs and initiatives taking place in their offices. Randy Horton of the Electric Power Research Institute provided a presentation on the damage that could be caused to the grid by a high-altitude electromagnetic burst. Howard Gugel of the North American Electric Reliability Corporation (NERC) provided an introduction to bulk power operating reserves, which set the stage for the day's panel session on optimizing bulk power operating reserves. The panel moderator was Darlene Phillips of PJM Interconnection, and panelists were Henry Lee of Hawaiian Electric Company, Adam Keech of PJM Interconnection, Erik Ela of Electric Power Research Institute, and Clyde Loutan of California ISO. The panel was followed by an extensive question-and-answer session.

Welcome, Introductions, and Developments Since March 2019 Meeting

Michael Heyeck, EAC Chair, welcomed everyone, covered several housekeeping items, and turned over the floor to Christopher Lawrence, Acting Designated Federal Officer (DFO) for the EAC. Mr. Lawrence thanked and acknowledged the members of the EAC, DOE staff, contractor support, the National Rural Electric Cooperative Association (NRECA), and the past DFO, Lawrence Mansueti. He briefly described the role of the DFO, whose primary duties are to facilitate transparency, maintain the public process, and ensure compliance with ethics laws. He noted several housekeeping items, including that copies of all needed materials will be available on the website. He then officially convened the meeting and handed off to Mr. Heyeck.

All members introduced themselves. Mr. Heyeck thanked all attendees for their time and service, and noted that panels have moved from a focus on PowerPoint presentations to more discussions. He thanked Lola Infante for surveying approximately 13 EAC members for feedback about ways to improve the Committee. He then invited Assistant Secretary Walker to present his update on DOE OE programs and initiatives.

Update on DOE Office of Electricity (OE) Programs and Initiatives

Assistant Secretary Bruce J. Walker began by discussing the development of OE's five-year strategy, for which he wants to leverage the expertise of the EAC. He wants OE to work more closely with the EAC, particularly on grid modernization and on the applied sciences work DOE is doing. Grid modernization efforts within DOE span several offices, including OE, EERE, Office of Fossil Energy, Office of Nuclear Energy, and the Office of Cybersecurity, Energy Security, and Emergency Response (CESER). As OE continues developing its five-year strategy,

the EAC should expect to hear more about it from Assistant Secretary Walker. He hopes to hear more from the EAC as well.

Assistant Secretary Walker offered an update on the priorities OE has been working on. On storage, he received the recommendations from the EAC March meeting, and met with DOE's storage team. Recently, he signed off on the Grid Storage Launchpad (GSL) initiative. The goal of the GSL is to enable a significant push to develop grid-scale storage; the initiative will be a public-private partnership. To that end, his office laid out goals for 2023 to drive down costs for chemistry-based technologies at manufactured scale in an attempt to increase utilization. Included are technologies using zinc manganese oxide, low-temperature sodium and sodium iodine, and aqueous soluble oxides. Reduced costs would be on a cell basis, not for the entire system.

Assistant Secretary Walker stated that storage will play a key role in OE's activities going forward not only from a national security perspective, but also to facilitate integration of renewables and contribute to reducing or eliminating reliance on spinning reserve capacity.

He further stated that he would like to eliminate the concept of "least cost." He thinks the industry does itself a disservice by relying on this concept and a corresponding regulatory model that has not adapted to the times or the different types of technologies that are being integrated onto the grid. He thinks the concept limits thinking for something as critical, valuable, and versatile as storage.

Moving on to OE's sensing portfolio, Assistant Secretary Walker announced the issuance of a $6.7 million funding opportunity called "The Electric Grid of Things: Integrating Networks of Sensing, Intelligent, Trustworthy Machines." The funding opportunity is meant to reward innovative approaches to interfacing with the advanced and rapidly developing technologies typically found in industrial, commercial, and residential settings. It looks to the development of new approaches, methodologies, tools, techniques, and systems that maximize the bidirectional exchange of grid services, while optimizing connectivity and information exchange at the interface between the grid edge and the industrial internet of things. They are looking for universities to lead this effort, working with industry partners and the National Labs. The deadline for submissions is August 30.

OE is undertaking two new initiatives. The first, working through the Electricity Subsector Coordinating Council (ESCC), involves high-fidelity, high-speed sensors that have not yet been commercialized. Building on correlation modeling done by the Electric Power Research Institute (EPRI) in the 1990s, and using modern computing power in conjunction with the sensors, the initiative aims to enable detection of events that could cause wildfires and adjust the system to prevent them.

The second initiative is an artificial intelligence program that uses adaptive relaying to manipulate elements of the relaying system in real-time to minimize, avoid, and disrupt

potentially widespread power outages. This technology would have been able to mitigate or even prevent the Northeast blackout of 2003.

Turning to the North American Energy Resilience Model (NAERM), Assistant Secretary Walker noted they are still on track to launch a static version by October 1, 2019. The static model will focus on the interdependencies of the transmission system as well as the oil and natural gas system at the bulk-power scale. They are working closely with ESCC and the Oil and Natural Gas Subsector Coordinating Council on the effort. Recently they have also engaged the administrator and staff of the Transportation Security Administration to gain a better understanding of the pipelines. Edison Electric Institute, American Public Power Association, and NRECA have provided input on defense-critical aspects. NERC has provided insight into capabilities that exist with the regional transmission organizations (RTOs), independent service operators (ISOs), and balancing authorities.

Significantly, OE has received some commitments from Congress, subject to further appropriations, on continuing to transition the static model into a real-time model over the next 18 to 24 months. There is much excitement within OE about the transition to something more operationally capable.

On the topic of defense-critical infrastructure, OE continues to work with the Department of Homeland Security (DHS) across the 16 critical infrastructure types. Most notably, OE produced its second iteration of defense-critical electric infrastructure throughout the United States and North America, now with a critical interdependency component. The previous focus was on the National Nuclear Security Administration (NNSA) and Department of Defense (DOD) sites. This focus has expanded to include DHS, in order to understand the critical interdependencies between different facilities and types of infrastructure.

Participants have identified several pilot sites within the DOE and NNSA footprint for strategic uses of existing technologies. They are trying to expedite broader utilization of technologies that currently exist only in the National Labs. They are taking a hard look at supply chain components applicable to the bulk power system for both oil and natural gas as well as the electricity sector.

Finally, OE is working with power market administrations (PMAs) on broadband strategy, primarily related to fiber optics capabilities that exist on the transmission system. The ability to supply utility information securely is critical to national security. The PMAs have been able to execute that and are now identifying gaps and working with partners across the federal agencies to address them.

Questions and Answers

Q1. Wanda Reder asked Assistant Secretary Walker to talk a little more about OE's five-year strategy and some of the goals they are laying out.

Assistant Secretary Walker said they have not yet identified specific goals as their process is still in the preliminary stages. He said OE's baseline responsibility is national security, especially related to defense-critical infrastructure that cuts across the 16 kinds of defense infrastructure for which DHS is responsible. He said an important thing that came out of the preliminary goal-setting discussions he had with his leadership team the previous day is the importance of industry to the success of their goals. OE engages with many stakeholder consortia—NERC, FERC, EAC, trade associations, etc.—and recognizes their good work. The diversity of the stakeholders they work with is their strength. Being able to communicate out threats is important, particularly as DOE is part of the 16 intelligence community agencies. Communicating threats to industry and working in lockstep to address them is important. Over the next six weeks they will lay out goals, and over the next 12 to 18 months they will develop short-term deliverables to enact within the five-year window.

Q2. John Adams said he assumes the resiliency model will show them things they haven't seen before related to privately owned infrastructure. He is concerned that any national security mitigation strategy will involve spending money that some board of directors will have to approve. He asked if Assistant Secretary Walker had any thoughts on addressing this.

Assistant Secretary Walker replied that, back in March, they held a joint technical conference with FERC as one mechanism to incentivize cybersecurity investments. They have been working with Congress to get more funding specific to those types of investments. They are looking at many sources to provide funding in this area, including leveraging dollars in broadband strategy through the Federal Communications Commission and rural spending through the U.S. Department of Agriculture. He said that OE's spending on national security should be socialized, especially considering the minimum number of assets deemed critical to national security. OE will continue to evaluate this and work with private and public asset owners to fully understand the physical and cyber vulnerabilities. He said it is fortunate there are very few critical sites across the country.

Q3. Shaun Mann asked about energy cost targets for different chemistries and whether OE has looked at the costs of achieving market-based deployments.

Assistant Secretary Walker replied that they have looked at existing deployments of vanadium and lithium, and newer technologies under development have different risks and capabilities that make comparisons difficult. OE is trying to find cheaper materials and longer-duration storage, such as sodium and sodium iodine. From an environmental and risk standpoint there are battery technologies that are better than lithium-ion and come from elements that are much more abundant.

Q4. Laney Brown asked about risk and storage, and about what analysis was done to support the price points and risk profiles of different storage technologies.

The Assistant Secretary responded that each technology goes through rigorous safety testing. About one-third of their spending goes toward safety testing. Technologies are put through various scenarios that could occur, and DOE works with fire departments and other agencies to develop safety ratings. That being said, there have been equipment failures in the past. Sodium, sodium-iodine, zinc-manganese oxide, and other technologies should minimize the risks.

Seeing no further questions, Mr. Heyeck thanked Assistant Secretary Walker.

Update on the DOE Office of Energy Efficiency and Renewable Energy (EERE) Programs and Initiatives

Daniel Simmons, Assistant Secretary for EERE, provided a quick overview of his office. EERE works with renewables and load, but not the bulk transmission system, which makes collaboration with OE important. EERE spends more than $100 million per year researching batteries for electric vehicle applications. Pumped-storage hydropower is also a key technology in their portfolio, and one of the largest sources of energy storage on the grid.

EERE focuses on three key areas:

- Affordability—They work to continue driving down the costs for sources of generation and the costs of things that use energy (e.g., combustion vehicles and energy efficiency in buildings).
- Integration—Low-cost renewables only matter if they can be integrated into the grid cost-effectively. Renewables need to produce more grid services.
    - Overall, flexibility through the grid is key. They can have flexibility on the generation side, but because they have important loads, they look for how to increase flexibility of those loads.
        - As an example, over 80% of electricity consumption occurs in buildings and over 70% of energy consumption in buildings occurs during times of peak demand. They ask what is possible in this domain to make buildings more flexible in their consumption of electricity.
        - This is not just demand-side management 1.0 (e.g., shedding load or two-way communication controlling water heaters). They are looking at low-cost sensors and controls. Their top goal is not to shed load, but to increase flexibility and determine what is possible in the building space.
- Energy storage—EERE has a new initiative called HydroWIRES (Water Innovation for a Resilient Electricity System), which looks at the value of hydropower from a flexibility standpoint. In the past, pumped-storage hydropower was dispatched twice a day, but now

it may happen more than 30 times a day in extreme cases, so there may be a potential application for balancing.

Assistant Secretary Simmons said it is important for EERE to work with OE in overlapping areas, such as storage. Advanced energy storage is a DOE-wide initiative to increase coordination.

Questions and Answers

Q1. Kimberly Denbow asked if EERE is considering renewable natural gas. She asked if when Assistant Secretary Simmons refers to energy storage, he is referring strictly to electricity. Ms. Denbow commented that energy storage can also encompass natural gas and liquid hydrocarbons.

Assistant Secretary Simmons responded that EERE works on biogas, but it so far hasn't been a large area of research for EERE. There are many opportunities, however, because natural gas is a flexible fuel. In terms of storage, Assistant Secretary Simmons generally means energy storage. The hydrogen fuel cell office is looking at envisioning what a hydrogen economy would look like, because hydrogen provides another opportunity for energy storage. For a long time there has been an emphasis on fuel-cell vehicles, but Assistant Secretary Simmons believes they need to think broadly about the potential for a hydrogen economy. It is important they do more research to drive down costs.

Ms. Denbow followed up that other DOE offices have a role in whether natural gas becomes renewable. She said there are plenty of opportunities for joint research and development ventures.

Q2. Delia Patterson asked if there is a public webpage for the HydroWIRES initiative. The answer is yes.

Q3. Lisa Grow said the relicensing process for hydropower is expensive, messy, and hampering development of the resource and its integration. She commented that hydropower is one of the biggest batteries, yet nothing faces the same licensing hurdles and nothing faces similar attacks.

Assistant Secretary Simmons expressed his support and understanding, saying the Water Power Technologies Office is working to reduce regulatory barriers.

Q4. Mr. Mann referenced the Advanced Research Projects Agency-Energy (ARPA-E) Renewable Energy to Fuels through Utilization of Energy-dense Liquids (REFUEL) program and said it seems like a great complement with EERE. He asked if there is any intention to expand EERE's hydrogen work to include more focus on ammonia, especially in reciprocating engines.

Assistant Secretary Simmons responded that it is certainly a possibility. Considering that liquifying hydrogen is expensive, ammonia could serve as an energy carrier. Their hydrogen fuel cell technology office is very engaged in thinking about the future of energy carriers. There's also currently a lot of international emphasis around hydrogen, including in a recent memorandum of understanding on hydrogen signed by China, the United States, and the European Union.

Q5. Ms. Reder asked if Assistant Secretary Simmons could comment on aggregators and where they fall in the DOE portfolio.

Assistant Secretary Simmons said that is more of an OE issue. His office hasn't worked with aggregators.

Q6. Mr. Adams asked whether market designs and electricity pricing are working properly, considering that Assistant Secretary Walker would like to do away with the concept of least cost. Assistant Secretary Simmons commented that no new pumped-storage hydropower is being built in the United States.

Assistant Secretary Simmons answered yes, but the grid of the future needs a different market design.

Q7. Mr. Heyeck said it is amazing we have alternating current (AC) and direct current (DC) inefficiencies at the end-use level. With solar panels we generate DC and convert to AC with many end-use devices converting to DC. Can we think about separate DC outlets and for larger buildings make microgrids just using DC as source to outlets?

Assistant Secretary Simmons said it is an area of interest. Loads are now DC and they have DC generation, so incurring conversion losses is an issue.

Q8. Mr. Heyeck commented that in the Energy Information Administration's *Annual Energy Outlook 2019*, the transportation sector's carbon footprint is not declining much.

Assistant Secretary Simmons said DOE works with car companies and utilities on an initiative called U.S. Drive to collaborate on precompetitive research. One thing American car companies stressed to DOE is the importance of achieving carbon dioxide emissions reductions in liquid fuels. The electricity sector has historically been a target for greenhouse gas emissions reductions, but the transportation sector will be a major area for those efforts as well. A lot more research is required for cost-effective, lower-greenhouse gas fuels.

Mr. Heyeck thanked Assistant Secretary Simmons.

Presentation on Electric Power Research Institute Report on Electromagnetic Pulse

Dr. Randy Horton, Senior Program Manager at the Electric Power Research Institute (EPRI), presented on the effects to the transmission system of a high-altitude electromagnetic pulse (HEMP) caused by the detonation of a nuclear weapon at high altitude or in space. A HEMP can impact electronics, and damage relays, transformers, and other components of electric infrastructure. EPRI conducted a study on the topic and published a technical report that is available on their website. The report is intended to inform the electric utility industry and other stakeholders about the potential impacts to the transmission system of a HEMP and describe mitigation options. Dr. Horton's full PowerPoint presentation to the EAC is available on the EAC website.

Questions and Answers

Q1. Mladen Kezunovic asked if there were any recommendations to create or revise industry standards.

Dr. Horton replied that their report did not include those kinds of recommendations.

Q2. Ms. Patterson asked if the report was peer-reviewed.

Dr. Horton responded that yes, three weapons labs and DOE peer-reviewed the report.

Q3. Flora Flygt asked what the risk is of a HEMP-causing destructive device being used.

Dr. Horton had no comment.

Q4. Arthur Kressner asked if there is any risk to the public.

Dr. Horton responded that there is not a risk in terms of radiation or fire from the heights at which a HEMP-causing weapon would be detonated.

Q5. Mr. Heyeck remarked that rehabilitating a control house costs a lot of money. His prior employer pursued remaking the control house at a factory and dropping it in to replace the old control house. The new control house can be better protected for HEMP issues if standards are developed. The other issue is that design can save the grid from an E1 burst but may not be able to save the critical loads. We tend to focus on the grid but not critical loads.

Dr. Horton said he thinks long-term there will be a lot more research into protecting critical loads.

Q6. Ms. Brown asked if they are considering how a regulated utility can justify investments related to this and if EPRI is looking for synergies when upgrading infrastructure that provide co-benefits.

Dr. Horton responded that EPRI does not weigh in on policy; they only provide technical input. Hardening options could mitigate other things as well but could also cause unintended consequences.

Q7. Clay Koplin asked if the transformer is damaged from the pulse directly or from the induction of the wires leading into the transformer.

Dr. Horton said they weren't seeing damage to the transformers. It could be a different story at the distribution level, but their report looked at transmission.

Mr. Heyeck thanked Dr. Horton and moved to a break.

Introduction to Bulk Power Operating Reserves

Howard Gugel, Vice President and Director of Engineering and Standards at NERC, presented on bulk power operating reserves. He outlined the three types of reserves—frequency, regulating, and contingency. He noted that the term "spinning reserves" is beginning to be replaced with "quick injection reserves" to account for the fact that a lot of new generation coming online does not spin (e.g., batteries or solar panels). Mr. Gugel's full PowerPoint presentation is available on the EAC website.

Questions were held until after the panel presentations.

Panel Session: Optimizing Bulk Power Operating Reserves

Darlene Phillips, Director of Strategic Policy and External Affairs at PJM Interconnection, moderated the panel discussion. Panelists were:

- Henry Lee, Director of System Operations, Hawaii Electric Company
- Adam Keech, Vice President of Markets, PJM Interconnection
- Erik Ela, Principal Technical Lead, Electric Power Research Institute (EPRI)
- Clyde Loutan, Principal, Renewable Energy Integration, California ISO

Mr. Lee's Opening Remarks

Mr. Lee began the panel discussion by providing an overview of Hawaiian Electric, which serves 300,000 customers on the island of Oahu and has 740 megawatts of renewable generation (out of

a total generation capacity of approximately 1,225 megawatts). He discussed the operating challenges that incorporating renewables present in the form of uncertainty and variability. He went on to define operating reserves as contingency reserves plus regulating reserves, and noted that frequency response, as defined in Mr. Gugel's presentation, is something they include under contingency reserves. He described how they determine the amount of regulating reserves needed. In the past, the method was deterministic and based on worst-case variability. This method typically led to oversubscribing the amount of regulating reserves they carried. Around 2015, they began working with EPRI to look at more dynamic methods. Last, working with EPRI and others, they are working on a DOE-funded project called Operational Probabilistic Tools for Solar Uncertainty (OPTSUN), the end goal of which is to come up with a tool to improve forecasting methods and allow for true stochastic optimization of regulating reserves. Mr. Lee's full presentation is on the EAC website.

Mr. Keech's Opening Remarks

Mr. Keech discussed reserve markets and how they have been evolving. In general, PJM has two real-time reserve requirements: contingency and synchronized. Contingency, or primary, reserve is the total capability they have available both online and offline within 10 minutes. It is required to be 150% of the largest generating unit in PJM's jurisdiction. Synchronized reserve corresponds to what Mr. Gugel described as spinning reserves, and must be 100% of the largest generating unit.

Mr. Keech noted that if all the states in PJM's jurisdiction meet their required Renewable Portfolio Standards (RPS), there will be 200% more wind generation on the system in the next 10 years.

Over time, PJM has observed they get value from having additional reserves available beyond the minimum requirement. They are trying to figure out how to value those additional reserves and redesign how they procure them. They also are trying to model the procurement process based on the minimum requirement, and the value to reserves beyond that minimum requirement based on uncertainty. PJM recently made an aggressive filing with FERC to change the demand curve they use for purchasing reserves to more accurately reflect that value. The new, more graduated demand curve would take into account the probability that the net load error exceeds a certain quantity. To establish this probability, they look at load forecast error, solar and wind forecast error, and the expectation of conventional generation failure, based on historical data. For corresponding graphs, please refer to the EAC website for Mr. Keech's full presentation.

Dr. Ela's Opening Remarks

Dr. Ela began by providing a definition of operating reserves, which he summarized as flexibility in operational time frames. He noted several commonly overlooked uses for operating reserves, including overflow of the transmission system, avoiding price spikes, and reducing production costs. He provided an example of how operating reserves can reduce production costs.

Dr. Ela then described the three central reserve needs. The first two relate to the fact that generation resources are scheduled in finite time intervals, which in the United States is 5 minutes. Variability in demand within these time frames is called intra-interval variability, while variability between time frames is called inter-interval variability. These two forms of variability create the need for reserves. The third need for reserves is due to the uncertainty of demand and the uncertainty of generation caused by variable generation sources (e.g., renewables).

Dr. Ela went on to describe operational and market mechanisms that can be used to ensure flexibility:

- Address uncertainty through increased reserve.
- Value reserve above minimum requirements through design of operating reserve demand curve.
- Price opportunity costs of ramping, using multi-interval settlement.
- Represent uncertainty explicitly, using stochastic multi-scenario market scheduling.
- Make sure flexibility is built.
- Let demand provide flexibility inherently, using real-time demand pricing.
- Flatten the cost curve with correct incentives.
- Reduce uncertainty directly through enhanced forecasting.

Finally, Dr. Ela described EPRI's Dynamic Assessment and Determination of Operating Reserve (DynADOR) model, which forecasts operating reserve, particularly for systems with large amounts of wind and solar generation. Simulation studies have shown simultaneous reduction in cost and increase in reliability metrics.

Mr. Loutan's Opening Remarks

Mr. Loutan opened by emphasizing that market designs were not created with variable generation or renewable resources in mind. They were designed for controllable supply and dependable demand. With the large amount of renewables on the grid—during midday on weekends when loads are low and solar generation goes up—there is so much generation that it creates control performance issues. He went on to show a slide depicting the "duck curve" of net load dipping on a typical spring day. The mismatch between solar generation and load is a major challenge, and storage would provide much greater control.

Mr. Loutan continued by asking what the optimum level of operating reserves is. For California ISO (CAISO), the amount they need to ramp down or up around sunrise and sunset can exceed 15,000 megawatts. In terms of flexible capacity, even having a large amount does not ensure an operator will know when to dispatch it, due to deficiencies in market design.

Mr. Loutan concluded by providing several recommendations:

- Renewable resources, including storage devices, must provide essential reliability services, including voltage control, frequency control, and ramping capability.
- Impose a steady-state ramp rate of 10% of P max to help manage variability in real-time,
- Reduce dead bands on renewable resources and storage devices from 0.036 hertz to 0.016 hertz.
- Propose governor-like droop settings on renewable resources and storage devices from 5% to 4% during normal operating conditions.

Questions and Answers

Q1. Ms. Phillips asked how we should be thinking about reserves, given the uncertainty, the changing nature of spinning reserves, and the challenges presented by variable generation to N minus 0 operations.

Mr. Loutan noted that while there are several standards that deal with N minus 1 and how much reserve an operator needs to carry, when conditions are N minus 0, the natural variability and uncertainty is just something operators have to deal with. Going forward, people will need to think about something beyond traditional automatic generation control (AGC). The millions of electric vehicles (EVs) anticipated to come online may be able to help feed back onto the grid. Mr. Loutan noted his organization is working with a vehicle manufacturer on a pilot program to show that vehicles can provide regulation frequency response and ramping capability.

Mr. Loutan continued by saying that traditional markets need to be redesigned. There is nothing in market design today that allows units to reverse course after they are locked in for a time interval. He asked how they can tie system frequency back into market operations.

Mr. Gugel said, setting market issues aside, what they have seen in last few years has caused them to rethink generation. Along the lines of what is happening in CAISO, they are seeing generation units that were designed to operate in a different performance mode than what is needed for the modern grid—they were designed for distribution connection and local control. They are working with the Institute of Electrical and Electronics Engineers (IEEE) to design new performance parameters for some of the new asynchronous generation that is being connected to higher voltage. Beyond NERC reliability standards, there should also be IEEE performance standards.

Dr. Ela said he thinks it is important not to think of this as a static or minimum requirement. Instead, he wants people to think about it probabilistically and ask how much it costs to supply more or less than whatever target amounts are. He noted that he tried to coin the term "smart reserve" to correspond to the idea of "smart grid," and emphasized that one needs to think about all the things that are needed, not just a single number.

Mr. Keech said that whether you are looking at the operations or markets aspect, everything starts from compliance with the NERC reliability standards. He is glad to hear from Mr. Gugel that NERC is reevaluating some of the reserve-related standards. In terms of reserve procurement, PJM's focus as a balancing authority is on reliability and NERC compliance. Markets are intended to reflect operator actions that follow NERC compliance and reliability. He said it is good to step back and look at the problem and ask whether they have the right reserve products and whether they are still the products that are needed. He said we set ourselves up for success when we crisply define the problem.

Q2. Paul Hudson noted that the Electric Reliability Corporation of Texas (ERCOT) has started discussing future ancillary services. He then asked whether we have the governance structures in place at RTOs and ISOs to respond rapidly enough to the changes that are occurring out at the edges of the grid. He remarked that in terms of market design changes, we're well behind in thinking through how to price reserves and various ancillary services. Could the panelists speak to the governance issue and the pricing regime around ancillary services?

Mr. Keech said that on the regulatory architecture question, it is difficult to move quickly in the energy market space. PJM has a stakeholder process determined by their governing documents, 13 different states, and the District of Columbia with differing objectives. Then FERC's jurisdiction overlays all of it. Multiple levels of governance need to be navigated and it is difficult to move quickly through the process, which limits the ability to design the market in an adaptable way.

Speaking to the pricing regime around ancillary services, Mr. Keech said they are trying to fix the demand curve structure they currently have to better value marginal megawatts based on the probability of the uncertainty in the system exceeding the amount of reserves they currently have. The new demand curve should correct a lot of the reserve market pricing issues they have today. Other changes in the energy market space deal with how they handle nonconvexities in pricing. However, on that issue he believes they are not at a point where stakeholders accept it or where FERC accepts it.

Q3. Assistant Secretary Walker said he wants to add some context to what initiated the discussion about bulk power operating reserves. He said the solution sets used to address problems today are decades old. The most severe single contingency component is built on the old N minus 1 minus 1 model and it still counts on fuel-secure generation. Going back two decades, 5% of generation was fed through natural gas pipelines. Now, according to latest NERC number, it's 43%. He suggested that the single most severe contingency would not be the loss of a transmission line or a generator, but rather the loss of a pipeline that feeds into the system. In addition, the Office of the Director of National Intelligence's (ODNI) 2019 Worldwide Threat Assessment report found that there are clear cybersecurity vulnerabilities with natural gas pipelines. He asked how the operating reserve concept takes that piece into account. He stated that from a national security standpoint the integrity of a system in the face of the loss of a pipeline is a major concern.

Mr. Gugel responded that one of the limitations they have with reliability standards is that NERC has to be careful with what it writes before coding in the standards. They have to understand all the science and implications involved. Further, the single worst contingency criterion relies on historical events and doesn't provide a future projection. He referred to Transmission Planning Standard (TP) 01, which addresses planning for the loss of a pipeline or multiple units and involves corrective action plans that are available to system operators.

Mr. Loutan commented that CAISO works with gas companies to make sure they have enough gas supply to support the gas fleet in meeting ramping requirements. If the gas supply was knocked out, however, that's a different problem.

Dr. Ela said EPRI has been working with one balancing area to apply methods relying on temperature assessments to help explain what reserve needs will be, whether through cold temperature outages or demand for natural gas. Cold temperatures might require a different reserve need than normal temperatures, and using the temperature method can help inform the best technology to rely on.

Mr. Keech said one thing they are working on at PJM, as part of the reserve filing they just submitted, is implementing a new operating reserve market in real-time for 30-minute operating reserves. One of the intents of that product is when they have identified potential threats to natural gas supply, they will increase the reserve requirement so that they schedule enough 30-minute reserve to cover the potential loss. Another initiative they haven't been fully successful with yet is to price gas contingencies in the energy market. For example, if they had five generators tied to a pipeline with a known credible threat, they would set prices that would incentivize those generators to reduce their output to minimize the potential impact. As another item, a recent fuel security analysis they conducted looked at approximately 300 different scenarios to see at what point PJM would encounter major reliability issues. The analysis found that they don't have issues at this point, but there could be in the future. They have begun a stakeholder process to try to work through the problem. He noted there is a similar discussion happening at ISO New England.

Mr. Lee remarked that Hawaii's situation is unique in that they do not have major gas pipelines. Their natural gas comes in by ship, and they carry several weeks of fuel reserves onsite at their plants for when shipments are delayed. He also noted that the state passed legislation calling for 100% renewables by 2045.

Q4. Mr. Koplin remarked that most of the discussion has been on load-following generation. He said there is a lot of opportunity around flexible loads—storage, thermal loads, and pumped hydropower. New infrastructure challenges may also offer opportunities—for example, inverters can operate at a zero power factor. There is potential to use those assets to correct system power factor, creating more flexibility in the grid than we realize. He asked Dr. Ela what the technical barriers are to dispatching things like pumped hydropower in the current grid architecture.

Dr. Ela responded that the challenges for pumped hydropower are similar to existing generation. The challenge relates to communications with smaller devices and scaling that up to a point where the ISOs care about it. He thinks there is a lot of progress toward getting ancillary services from distributed resources. The challenges of communication, observability, monitoring and knowing how the distribution system might handle the services provided to the bulk power system is a larger question. The challenge is around distributed resources and getting them to provide the same services we rely on from bulk utility connected resources.

Mr. Loutan commented that on the distributional side they have several initiatives and models that address allowing aggregation and distribution load to participate in the market. They look to shift and shape loads. They created a system for loads to provide spinning reserve in the ISO market, but no one bid into that system. One of the biggest barriers they see today is coordinating between transmission and distribution and logistics around response time. Mr. Loutan further commented that CAISO found 60% of installed solar capacity could provide frequency response and other services, but there was no incentive to do so because there was not compensation for it.

Mr. Gugel referenced the inverter comments made by Mr. Koplin. Mr. Gugel said there is the potential to operate at zero power factor, but he does not know if the existing deployed technology has that capability. It is a possibility for the future.

Mr. Keech added that he doesn't doubt they could figure out how to make something like that work for solar from an engineering perspective, but he questions whether it would be cost-effective.

Q5. Jeff Morris asked if panelists could talk about the lack of probabilistic algorithms to help with visibility on the grid and the need or want to access probabilistic algorithms to provide a better look over the horizon.

Mr. Loutan referred to work CAISO did with the National Labs on predicting frequency needs on the load. They were only able to predict with reasonable accuracy out to 2 1/2 minutes. Being able to predict needs further out would be a big help. The bigger problem, he said, is rooftop photovoltaic (PV) because they have no visibility, making it very difficult to balance and control the entire system. Real-time control performance standards offer a way to adapt to the new dynamics of rooftop PV and other renewables.

Q6. Drew Fellon asked about the potential to use commercial buildings as a generation resource. He asked what the pros and cons to that in the marketplace are, whether it is scalable yet, and how to incentivize customers to become a part of the solution.

Mr. Loutan responded that there is only so much that can be done with AGC. Where he thinks industry needs to head is to better utilize homes and EVs. His vision is that when an EV gets parked at home, the owner specifies the amount of charge they need for the next day. The utility

would use additional capacity to control frequency, and at the end of the month would send the owner a check for proving frequency control. Mr. Loutan said part of his job is to minimize curtailment, and one way to do that is to utilize all the other devices on the distribution system to help control the grid.

Mr. Loutan continued that CAISO has two or three programs that allow people to aggregate loads and participate in markets, though certain subsets are not going to be economical. The last piece they are working on is how to do that with load, storage, and rooftop PV combined. He said he could see different buckets for different applications.

Mr. Keech remarked that one limit to demand participation is that people are not exposed to wholesale prices. They are not exposed to volatility. In a lot of cases there is no need to do anything.

Dr. Ela noted that energy is different from services. A lot of reliability services are a quarter of a penny per kiloWatt-hour. The question is how to scale that up enough to create an incentive.

Q7. Bob Cummings referenced Assistant Secretary Walker's emphasis on reducing the need for reserves. In the future, faster injection of energy will be needed, which will not come from traditional governors. They have a 6-second response time when a 3-second response is needed. Absent adding a gas pipeline to the contingency list, Mr. Cummings said to imagine an inverter as a contingency. That exposure is bigger than a pipeline in some instances and happens faster. Faster response is needed and will not come from spinning fossil fuel generation. Curtailing solar and wind can respond much faster, and some of NERC's testing has supported this. There needs to be a market for curtailing wind and solar, because there is no carbon footprint to that curtailment. Mr. Cummings commented that it is imperative to figure out an equitable method of doing curtailments.

Mr. Loutan agreed. He hopes Bob will support CAISO in their recent FERC filing.

Mr. Gugel said he wouldn't couch it as curtailment but as creating headroom. The idea is that whatever has been curtailed needs to be available to be dispatched.

Mr. Lee said Hawaiian Electric's systems are small. It has reached the point that the largest contingency they experience—because renewables have offset the need to run conventional generation—is that frequency moves very fast. Where in the past they didn't have to load-shed, now they do. The only way to address that is to depend on inverter-based technology. They are trying to acquire storage systems that provide fast frequency response.

Q8. Tom Weaver commented that the EAC should be thinking about operating reserves across the entire United States. California's and Hawaii's situations are not typical and the answers will be different in different places.

Mr. Weaver continued by saying the discussion has centered on market incentives for the supply side. When he sees those extreme situations represented by the duck curve, he wonders if there is a way to site energy intensive loads in areas so that the intensive loads would have low energy costs when there is excess generation, with the idea they could be curtailed if needed. The concept wouldn't be about making them curtailable so much as filling that gap and lowering the depth of the ramp rate.

Mr. Loutan mentioned the time-of-use rates, which incentivize when loads come on the system and help raise the belly of the duck.

Q9. Mr. Adams said he thinks they've been talking around the elephant in the room, which is that we don't have time-of-day rates. He gave the example of his EV, which puts load on the system when demand is the greatest when he gets home in the evening. He knows these issues and still does it because there are no incentives not to. The current pricing scheme does not match supply and demand.

Mr. Keech replied that the dynamic we have now is a market with non-uniform prices. Load acts rationally based on retail prices, but irrationally based on the wholesale prices. He stated that actions like FERC Order 745 are a Band-Aid fix.

Mr. Loutan added that when CAISO went from 14,000 megawatts to 21,000 megawatts of wind, the natural diversity of the geography minimized variability. CAISO has seen the opposite with solar—flexibility drastically increased. Trying to minimize flexibility for different mixes of renewables is difficult.

Mr. Gugel mentioned the difference between California and the Midwest. While the technology may not be driven to make changes in the Midwest, by installing some of these fast injection resources it is possible to reduce operating reserve requirements. That makes more efficient use of one's entire fleet by relying more on fast injection resources.

Q10. Mr. Heyeck remarked that the conversation reminded him of issues they had talked about in the 1980s. The paradigms used today are so dated that today's conversation should no longer be about AGC but about something more esoteric. Mr. Heyeck further remarked that under-frequency load-shedding and grids of frequency deviation are based on a paradigm developed in the 1950s. He thinks we should ask what the grid can tolerate and what the carbon footprint would look like if one uses headroom to offset fossil fuel spinning reserves. Data analytics can help answer these questions. He stated the EAC needs to prioritize which issues it wants to engage the DOE and National Labs to work on.

Mr. Loutan responded that CAISO has worked with the National Labs on incorporated probabilistic forecasts to tell them how much flexibility they will need the next day. They did not get the probabilistic load piece figured out before running out of funds. If they can predict frequency of net load 5 to 7 minutes out, that would modify the way the market works today. He

referred back to rooftop PV, saying they need something to tell them how much generation they can expect. Rooftop PV is going to become a huge problem for folks.

Mr. Gugel said he thinks better models are needed. Analysts don't know what load looks like today, and don't have good models for inverters. Generation and load have changed dramatically over the last 20 years. Analysts don't know how to study the system because we don't have adequate models.

Q11. Dr. Kezunovic asked whether the solutions are more in markets and pricing, more in the technology of monitoring and predicting, or more in the probabilistic tools. If the EAC had to make a recommendation, he asked how it would prioritize those three. In a different context—e.g., municipalities—they are putting more effort into monitoring their customers and utilizing prediction.

Mr. Loutan said he thinks it's going to be a while before they can figure out how to incorporate actual frequency into decisions made 7.5 to 10 minutes earlier. It goes hand-in-hand with probabilistic forecasts.

Dr. Ela said it takes a lot of work to figure out what the challenges are and what needs to be done. The market solutions do not always come from independent entities.

Q12. Mr. Mann said that because EAC is an advisory committee to DOE, we're talking about issues that DOE has been thinking about for a long time. He believes the core of figuring out how to solve these problems is being as technology-agnostic as possible—by defining the problem with equations and letting technologies compete. Mr. Mann stated that he did not have a question.

Q13. Ms. Reder said at the distribution level there are tools that are beginning to allow good forecasting at the customer level. Imagining the future, she asked what the distribution-transmission interface would look like. She asked how the panelists envision that interface.

Mr. Loutan responded that there is a lot of work going on in distribution right now, but unless one understands transmission it will not work. Making the two work together will be difficult. He asked where the demarcation line is between transmission and distribution.

Mr. Keech responded by asking whether it is possible to propagate transmission-level market rules onto the distribution system. He asked if distribution locational marginal pricing would work in that context. He said the concept exists with pricing congestion on distribution feeders and locational incentives for distributed energy resources based on energy prices on the distribution system. It is an enormous nut to crack.

Mr. Gugel noted that the more generation that gets driven down to distribution level, the more critical the conversation will be between transmission and distribution.

Dr. Ela said a key will be how comfortable system operators are with passive response. The things that respond to price today are things the system operator has control over. Testing to see how reliable forecasting and existing controls are for accommodating variable resource passive response is important. Setting a price and letting people respond will mean one will not know how they will respond. There could be big price swings.

Mr. Lee said the distribution question is still a big one for Hawaiian Electric. There is a lot of desire to democratize the power industry and embrace distributed resources. They installed their first distributed energy resource management system and are working to connect it to their AGC and EMS to attempt to do frequency regulation. From their perspective, something that helps stabilize the system is better than nothing. In the end it might come down to pricing those resources based on how much they contribute to a needed function.

Q14. Mr. Cummings said distributed energy resource management systems are going to become crucial, whether they are owned by a third party or operated internally, to understanding more about one's distribution system. He did not have a question.

Ms. Phillips thanked panelists.

Wrap-Up and Adjourn

Mr. Heyeck said he appreciated Mr. Lee's observation that we may not want to start with the market until we understand what the grid is, and what it will be. Mr. Heyeck thinks the analytics and modeling parts are where they need to start. From there, the marketers can develop the principles to work with it.

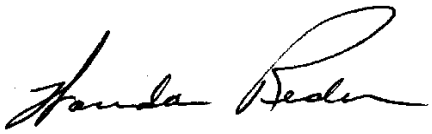
Assistant Secretary Walker thanked panelists and said he is encouraged by the conversation taking place. He looks forward to receiving recommendations.

With Mr. Lawrence's consent, Mr. Heyeck closed the meeting until 8:00 a.m. Thursday.

Respectfully Submitted and Certified as Accurate,

Michael Heyeck
The Grid Group, LLC
Chair
DOE Electricity Advisory Committee

07/29/2019
Date



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