Summary of Discussion at DOE Workshop on Electric Transmission Development and Siting Issues

Thursday, November 15, 2018
National Rural Electric Cooperative Association Conference Center
4301 Wilson Boulevard, Arlington, VA, 22203
9:00 a.m. – 4:00 p.m.

On November 15, 2018, the United States Department of Energy's (DOE) Office of Electricity (OE) held a public workshop in Arlington, VA to foster dialogue on key issues affecting today's transmission system and to elicit stakeholder input from diverse perspectives. The information presented and discussed during the workshop will aid the Department in the preparation of its next National Electric Transmission Congestion Study, and it will generally inform the Department's consideration of current transmission-related issues.

Approximately 105 participants from many stakeholder sectors attended the workshop on site (see Appendix B for a list of attendees) in addition to others who joined via WebEx. The participants included DOE leadership and staff, researchers from national laboratories, representatives of industrial electricity customers, electric utilities, state utility regulators, other state officials, Regional Transmission Operators (RTOs) and Independent System Operators (ISOs), and other federal agencies.

The workshop was structured as three consecutive panels, each consisting of a moderator and four panelists. Each panel was asked to address several discussion questions pertinent to its topic. Each panelist was given 10 minutes to present the main themes of his/her responses to the discussion questions. A moderator then facilitated a discussion with the panel and elicited questions from the audience. In addition to seeking questions from the audience, DOE further invited workshop participants and other interested parties to submit written statements to DOE by November 21, 2018.

Below, this summary provides a panel-by-panel overview of the presentations by the panelists and the points and themes that arose in the ensuing dialogues. To help ensure the accuracy of this summary, DOE asked the panelists to review the passages pertinent to their statements and suggest changes if appropriate. DOE regrets any omissions or misstatements that may still appear concerning views expressed by other participants. Where appropriate, we have interpolated footnotes about views expressed by attendees in the form of written comments provided after the workshop. All Powerpoint presentations used in the workshop are available at https://www.energy.gov/oe/downloads/office-electricity-electric-transmission-issues-workshop-november-15-2018.

Unless explicitly stated, this summary is not intended to express DOE views on transmission matters, and it does not make policy recommendations.

1 DOE WELCOME AND PRESENTATION ON TRENDS FROM DOE'S *ANNUAL U.S. TRANSMISSION DATA REVIEW*

David Meyer, a senior advisor at DOE OE, gave brief opening remarks to kick off the workshop. He welcomed everyone and thanked the National Rural Electric Cooperative Association (NRECA) for the use of their conference facility.

Mr. Meyer introduced Catherine Jereza, a Deputy Assistant Secretary of DOE OE. Ms. Jereza opened the discussion with a presentation highlighting major transmission-related trends that are discernible in data published over the past several years by DOE in its *Annual U.S. Transmission Data Review* (TDR). She divided her presentation into three subsections, as shown below.

TRANSMISSION INVESTMENT

According to the Energy Information Administration (EIA), transmission investments by major electric utilities have grown significantly in the last 10 years. It has more than doubled from 2006 to 2016, from less than $10 billion in 2006 to $20 billion in 2016. A second EIA graphic shows that over this period transmission investment increased across all North American Electric Corporation (NERC) regions. However, it is unclear how much of this investment was essentially to sustain the existing system and how much was for additional system capacity, and whether the capacity added was enough or too much. Questions remain -- how would we know? What types of metrics would help answer these questions?

TRANSMISSION UTILIZATION

EIA has a new online tool (called the U.S. Electric System Operating Data Tool) that provides near real-time data on electricity flows on transmission lines. EIA and others are now able to analyze transmission utilization based on the amount of electricity flowing across the boundaries between the major balancing authorities in the United States.

Various other metrics pertaining to transmission utilization exist, including the following three examples:

1) The Western Electricity Coordinating Council (WECC)'s major transmission paths: a WECC graphic shows the percentage of the time during 2016 that individual paths were loaded to 75 percent or more of their maximum safe capacity.
2) The Eastern Interconnection's Transmission's Loading Relief (TLR) events, based on data developed by NERC and DOE: The graphic shows a decrease in the frequency and severity of TLRs decreased from 2007 to 2017. Market reforms and changes in institutional practices are key reasons behind this trend.

3) The economic cost of congestion by Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs): RTOs/ISOs have varying methods of calculating and presenting congestion cost, which makes direct comparison of congestion costs amongst regions difficult. However, in most regions, congestion costs peaked between 2012 and 2014.

Transmission Planning

Some metrics pertaining to transmission planning emerged from FERC Order Nos. 890 and 1000, which established requirements for regional transmission planning and cost allocation.[1] FERC Order No. 890 outlined general requirements for local and regional transmission planning and practices; FERC Order No. 1000 laid out specific requirements for regional planning, including the consideration of transmission needs driven by public policy, non-incumbent transmission development, interregional transmission coordination, and cost allocation.[2] FERC data indicates that as of October 2017, six out of 12 transmission planning regions had conducted competitive solicitation processes and that sometimes it can be difficult to distinguish incumbent transmission providers from non-incumbents.

In addition, some metrics were developed by FERC with the intent of measuring whether transmission investments were sufficient and cost effective. In the graphic shown, after adjusting for size, large and small transmission-owning entities appear to have invested in transmission to about the same extent. Further, TRE, SPP, and to a lesser extent MRO added proportionally more circuit-miles than the other regions. Some of this construction was presumably to link remote renewables to markets.

In considering the value of transmission going forward and the emphasis on electric grid reliability and resilience, important questions remain—what are the costs? Who is paying them? What changes should be considered and why? Are we building the system we will need for our future?

2 Panel I: Are There Unmet Needs for Additional Long-Distance, High Voltage Transmission Lines?

The discussion questions for this panel were:

- Are recent or current system-level trends (e.g., rising incidence of extreme weather, concerns about physical and cyber security, increasing reliance on distributed energy resources (DERs)) increasing or reducing the need for transmission capacity?
- Are we underbuilding (or overbuilding) long-distance, high-voltage transmission facilities, either regionally or inter-regionally?
- If so, what are the indicators? Please cite specific measures and explain how they support your assessment. If appropriate, clarify regions or projects to which your assessments apply.

[1] See FERC Order No. 1000 at https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf (accessed December 4, 2018) and FERC Order No. 890 at https://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf (accessed December 4, 2018).

[2] Ibid.

- What additional information is needed to provide further support for your assessments? Is this information publicly available?

Steven Naumann, Vice President, Transmission and NERC Policy, Exelon Corporation

Mr. Naumann expressed that in his view, transmission investments, whether for long-distance, high voltage (LDHV) lines or for other purposes, are driven by needs, including new threats, changing resource mixes, and state and public policy developments. Such needs, however, vary by region and thus the patterns of transmission investments are specific to each region.

Some of the key threats to the transmission system include weather-related events, such as extreme heat or cold, hurricanes, flooding, and windstorm, which utilities generally consider in their planning. In addition to weather-related events, however, there are emerging threats due to increased interdependency, changing technology, and cyber and physical threats. These emerging threats are influencing the development of future transmission systems – as planners strive to ensure that the systems will be resilient against a wide range of possible eventualities.

In addition to evolving threats, consideration of changes in the resource mix is critical to transmission planning. Specifically, an increased reliance on natural gas and the need to interconnect renewable sources are key concerns. Because the resource mix and load growth characteristics vary by location and the incentives for renewable generation are driven to a considerable extent by state policies, the need for new long-distance high-voltage (LDHV) transmission lines is dependent on location.

Similarly, state policies on the environment and energy efficiency also affect the development of LDHV transmission lines. The inclusion of carbon-free resources, the prospects for off-shore wind resources, distributed energy resources, and microgrids, as well as the continuous improvement in energy efficiency are key factors shaping LDHV development. Particularly, a reduction in the overall load growth forecast often means that transmission investment must focus first on meeting local needs.

In summary, even when transmission development is driven largely by local requirements, it is important to consider regional needs and plans, and look for ways to keep the entire system reliable and resilient.

Ed Tatum, VP for Transmission, American Municipal Power

Mr. Tatum said there has been significant transmission investment in the past 10 years, although the level has stabilized at about $20 billion/year in the last five years. The electricity infrastructure is aging and facilities are nearing the end of their useful life, which is the key reason behind continued transmission investment at this level.[3] AMP's members have been experiencing exponential increases in

[3] In response to DOE's invitation to workshop attendees to provide written input after the workshop, Joseph M. Power, Vice President for Federal Legislative and Regulatory Affairs, Ameren Services Company, cautioned DOE and others not to focus on the $20 billion investment number in isolation from the benefits the investment would provide. See Ameren Transmission Comments on November 15, 2018 DOE Workshop on Electric Transmission and Siting Issues.pdf .

the transmission rates of the incumbent utilities ranging from 99% to 217% increases over the recent eight-year period.

Within the NERC regions, PJM saw the most significant transmission investment between 1996 and 2006. PJM's planning process is in accordance with the NERC, PJM, and Transmission Owner (TO) criteria set forth in the FERC Order No. 715.[4] In addition to participating in PJM's regional planning, TOs can propose "supplemental projects" to address their individual planning needs that are outside of the regional transmission expansion plan or the NERC and PJM reliability need and are excluded from the Order 1000 competition requirements. These supplemental projects have been increasing significantly, resulting in a substantial shift from regional baseline projects to TO-driven supplemental projects.

In 2017, TO-initiated supplemental projects accounted for approximately 37 percent of the total construction cost in PJM. Of the total cost of transmission projects approved by PJM in 2017, 13 percent was for PJM baseline projects, 38 percent was for TOs' baseline projects, and 49 percent was for TOs' supplemental projects. In other words, over 87% of PJM transmission investment proposed in 2017 was transmission-owner, rather than RTO-driven. This trend of self-approved projects has also been seen nationally; as reported by Brattle, in the last four to five years, about 47 percent of the $70 billion transmission investment by TOs under FERC's jurisdiction was made without full RTO/ISO and stakeholder engagement.

Mr. Tatum said that these increases in transmission investment are resulting in significant increases in transmission rates. He added that, according to earning calls hosted by various investor-owned utilities, a number of these vertically integrated utilities have determined to shift a significant portion of their capital investments from competitive generation assets to regulated transmission assets, as a result of the higher risk associated with competitive markets and a perception that competitive markets have failed to provide adequate revenues.

In 2018, PJM expects to see the highest proposed transmission investment yet, reaching over $6.9 billion in total, including $5.5 billion in supplemental projects. Replacing aging infrastructure continues to be the main driver in transmission investment. This aging transmission grid was not designed to support free-flowing competitive markets or to be used as it often is today; therefore, it is important that future transmission investments consider the changing environment in which the grid will operate. Simply replacing 100 year-old facilities may not be the best solution to meet customers' transmission needs for the next 100 years. Tatum cited the paradigm shift to competitive markets, flat or negative load growth, an increase in intermittent and renewable resources, distributed generation, and smart grids as items that should be considered when addressing aging infrastructure rather than simply replacing aging facilities in kind.

In addition to the aging of transmission facilities, he saw several other key trends as noteworthy, including:

[4] FERC Order No. 715 available at https://www.ferc.gov/whats-new/comm-meet/2008/091808/E-2.pdf (accessed December 4, 2018).

- Current cost allocation mechanisms may be driving the types of transmission investments. It is unclear, however, whether current cost allocation practices are adequate to identify and measure true costs and benefits of transmission investments.
- Current RTO-specific Order 1000 rules may be driving the types of transmission investments to avoid competition.
- Generation and transmission operate in two distinct market-places. Unlike generation, transmission assets are regulated, and without them, competitive wholesale generation markets could not exist. Sound transmission planning must reflect the revised industry structure and recognize new drivers of competitive wholesale markets, public policy, and regional/interregional coordination.
- Interregional planning and coordination are difficult due to different planning approaches, models, FERC 1000 processes, and market rules among the various RTO/ISOs. Without a holistic regional and interregional planning process that utilizes common models, analysis techniques and rules, it is difficult to assess the adequacy of current transmission development. With the growth of transmission investments outside of regional planning processes, there is greater concern about potential stranded transmission investments and whether such transmission planning outside of the RTO/ISO processes is precluding more cost effective regional, interregional or alternative solutions.

KENNETH SEILER, EXECUTIVE DIRECTOR, SYSTEM PLANNING, PJM

Mr. Seiler discussed several key changes shaping the power industry today and how they affect an RTO's system planning. These changes include the advancement of power storage and alternative technologies, the growth and integration of distributed generation, the increase in natural gas and intermittent renewable resources in the fuel mix, and changing customer expectations. Transmission planning processes need to accommodate these changes, including that today's customers are often well informed and have high expectations about grid performance.

Mr. Seiler said that future challenges include changing load profiles, changing fuel mix, regulatory uncertainty, cyber and physical threats, as well as fuel security. Specifically, PJM completed a Fuel Security study in 2018 to investigate the fuel-supply risks in an environment trending towards greater reliance on natural gas.[5]

PJM determines the need for transmission expansion based on defined national (FERC/NERC), regional (PJM), and local Transmission Owner criteria (as defined in respective TO FERC Form No. 715 submittals). Regional Transmission Expansion Plan (RTEP) projects are approved by PJM's independent Board.

[5] "Fuel Security: Analyzing Fuel Supply Resilience in the PJM Region, Summary of Results, Conclusions, and Next Steps" PJM, November 2018, https://pjm.com/-/media/committees-groups/committees/mrc/20181101-fuel-security/20181101-pjm-fuel-security-summary.ashx (accessed December 4, 2018).

Alan Myers, Director, Regional Planning, ITC Holdings

Mr. Myers started his presentation by answering "yes" to the question posed to the panel as to whether there are unmet needs for additional LDHV transmission investments. As a brief look-back, for example, he noted that MISO's portfolio of multi-value projects (MVPs, approved in 2011) was designed to meet the needs of integrating multiple fuels, primarily wind, and to meet state renewable portfolio requirements, among other objectives. MISO's triennial review of the MVPs shows that the overall benefits have continued to grow beyond expectations, and that benefit/cost ratios have grown beyond the levels at which the portfolio was originally approved.

Looking ahead, there are opportunities for additional transmission investment, as shown in the significant amount of potential wind resources in the interconnection queues in SPP and MISO (more than 53 GW and 43 GW, respectively). This indicates an opportunity for regional and interregional interconnection coordination to connect new wind resources more efficiently and cost effectively. The need to integrate additional renewable resources is a continuing trend, in part driven by large corporate entities that have sustainability goals.

Mr. Myers said that numerous benefits are achievable through large-scale interregional projects, as detailed in the WIRES/London Economics Institute Study. The WIRES Study looked at benefits of two hypothetical projects: a transmission expansion in the Eastern Interconnect between PJM and MISO, and a new transmission line extending from the Rocky Mountain area to Southern California. The study found many quantifiable short-term, mid-term, and long-term benefits, including electricity market cost savings, increases in generators' net income, savings from efficient energy production, increased GDP, creation of new jobs, and reduced carbon emissions. A main conclusion of the study was that a well-conceived interregional transmission project can bring benefits that are "quantifiable, substantial, widespread, and long lasting."

He believes that a more holistic approach to system planning is needed to maintain or even increase optionality and respond to changing conditions and new threats. Continuing a more fragmented, incremental approach to system planning will impose higher long-term costs on customers. Policy makers and industry leaders must incorporate key investment drivers, including the need for increased system resilience, into their planning practices through a more comprehensive view of benefits and costs in both the project approval and cost allocation processes.

Panel I Questions & Answers

After the panelists' presentations, the moderator (David Meyer) presented some questions to the panel: What is the composition of the group of "supplemental projects"? Can that bundle be divided into categories? Is there any data to help us understand better what is included in the group?

Mr. Tatum responded that there is no easy way to identify what is included in the supplemental projects. In the transmission planning processes, FERC's Orders (888, 890, 1000) provide regulated transmission planning and cost allocation mechanisms to allow transparency and collaboration in regional transmission planning processes. However, he believed, as we move away from the processes provided by RTOs, there is very little transparency. PJM has a mechanism to determine whether proposed projects in the region are appropriate, but it does not apply to supplemental projects.

There are thousands of proposed projects, and while aging infrastructure is a main driver for many of them, it does not provide a full picture. Mr. Tatum explained that one of the main issues is that the electric infrastructure is used today (e.g., to support a competitive wholesale market) in ways that it was not originally designed or built to be used. Therefore, transmission planning may need to change significantly and consider a buildout in a scenario-based approach and deliberate whether to replace aging infrastructure in kind or with increased capability. Without fully knowing what is included in the TO-driven supplemental projects, it is unclear whether are we masking or missing opportunities for rational, regional, holistic regional buildouts.

Mr. Seiler added that risk is another important issue and asked the following questions: How much risk are we willing to take? What is the acceptable level of risk? What risks are customers willing to accept? What are we willing to pay for to mitigate these risks? All of these factors must be considered in transmission development.

Mr. Naumann agreed with Mr. Tatum that identifying the principal drivers of supplemental projects would not be easy, without knowing the details of each project. It is possible to get granular on each project, as each project is presented publicly at different PJM meetings. However, grouping them into categories can be challenging, because there are specific underlying conditions or reasons for each transmission project. "Aging infrastructure" is an overly broad term, and in many cases, it is a material condition (e.g., transformer degradation).

Mr. Meyer asked a follow-up question, "Are these new projects integrating new technologies?" and Mr. Naumann responded "Yes, where appropriate." He said, for example, large power transformers nearing the end of their life are being replaced with new transformers that are designed with bullet protection for the core and/or with higher DC current to better withstand the effects of geomagnetic disturbances (GMD). Some transformers are also designed to be moveable. The aging infrastructure is being updated or replaced with new technologies.[6]

Mr. Meyer then asked the panel: Why is there a relatively small number of proposed interregional projects? Despite direction in FERC Order No. 1000, are we simply not paying enough attention to interregional planning?[7]

[6] In response to DOE's invitation to workshop attendees to submit additional written materials after the workshop, Roger Rosenqvist of ABB Inc. contributed a short paper, "Use of New Technologies to Mitigate Visual Impact and Public Concerns Related to Siting of Transmission Lines." The text of the paper is available at Use of New Technologies to Mitigate Visual Impact and Public Concerns Related to Siting of Transmission Lines.pdf.

[7] In comments filed with DOE after the workshop, Joseph M. Power, Ameren Services Company, expressed the view that "concerns with Order No. 1000 and competitive bidding [for the right to develop needed transmission facilities] do not appear germane to DOE's effort at hand – the development of the congestion study with a national focus that may inform the designation of National Interest Electric Transmission Corridors." See Ameren Transmission Comments on November 15, 2018 DOE Workshop on Electric Transmission and Siting Issues.pdf.

Mr. Myers explained the reason there is little interregional planning might be that we are looking too narrowly in the regional processes. Even when projects begin as a part of interregional studies, they are often eliminated during the regional planning processes. Current regional processes are not well designed to look at interregional projects, nor are the metrics concerning costs, benefits, and beneficiaries. For example, the WIRES study cited many metrics that had not been considered previously. However, metrics are difficult to apply on an inter-regional basis because of different market designs, as well as varied practices concerning load flows and modeling across regional boundaries.

Mr. Naumann then discussed the challenge of cost allocation in interregional planning and asked, “Who is going to pay for what and what will have an impact?” Mr. Tatum explained that there is a difference between a project with short-term reliability drivers with little risk of unrealized benefits and a long-term, large project in which different regions may perceive different needs or benefits. Also, when a large project is cancelled, customers bear the cost of abandoned projects, and the history of these cancellations can discourage the planning of such future projects. Given such risks, the need for interregional transmission development must be justified. Interregional discussions are important in transmission development to overcome many regional differences.

Mr. Meyer presented the following question as he opened the discussion to questions from the audience: “Given the multiplicity of costs and benefits, are there undervalued projects? Many long-term benefits are difficult to estimate. Is that still a serious problem or is there a possible way to deal with it?”

Ms. Bess Gorman of National Grid asked, “Given the need for justification for transmission development, are we seeing any issues due to load forecast dropping and therefore possibly diminishing the need for proposed projects?” Mr. Naumann replied “yes”, as there is no guarantee on what is going to happen in the future. He said, for example, in PJM, certain proposed long-term projects with multiple stages were dropped when PJM’s forecast changed and the projects could no longer be justified. In his experience with PJM, in general, the longer the forecast, the greater the chance things can change during the process. However, such instance is project-specific and a lot depends on which states are involved.

Mr. Thomas Martinelli of ELCON thanked all four panelists for covering many of the points he wanted to raise. He delved deeper into two slides that showed transmission spending in PJM and shared detailed information on two states -- Delaware and Ohio. Specifically, Delaware saw a 50 percent increase in $/MWh in transmission cost in the last five years, and Ohio saw a 106 percent increase in transmission cost during the same period. The rising cost of transmission is a significant concern for large industrial customers; thus cost allocation in general is an important issue. Other key concerns for large industrial customers include minimizing stranded costs through improved project planning, as well as the risk of investing in a long-term project that can potentially look completely different in five years.

The panel responded that there is no perfect solution for the challenges of cost allocation. In addition, the exponentially rising cost of transmission could drive people off the grid, which raises concerns regarding stranded transmission investment. The panel pondered, “What happens if you just take out a line? Are there any reliability violations? Also, how much is all that underlying buildout masking what could be done to the HV system on a regional or interregional basis?”

Peter Behr (a reporter) asked whether, given current trends, high-impact, low-frequency (HILF) threats were increasing the need for transmission investment. The panel replied the short answer is "yes," however, that many HILF threats are local or regional issues. The panel explained that current forecast indicates we will see a continued trend of increasing transmission development, primarily driven by aging infrastructure and a changing fuel mix. With respect to mitigating HILF risks, one of the key issues is cost -- how much are we willing to pay to mitigate the risks?

Gary Trent of Tucson Electric Power presented two questions to the panel: First, in regional planning, did they see different cost-benefit ratios depending on the load areas (benefits in low-density loads vs. high-density load)? The panel replied that it depends on the driver of benefits. Certain projects are not driven by the density of load but by the opportunity to reduce the cost of delivery. Mr. Trent then whether there has there been an issue in terms of cost allocation between those that are subject to binding cost allocation versus those who are participating voluntarily. The panel explained that the issue can be a problem in areas where there is no organized RTO market (e.g., parts of the West).

The panel further emphasized that cost allocation must be reasonable and fair and explained that there are two basic ways to look at cost allocation. One way is that the beneficiary should pay; another approach is that the one causing the problem should pay, as in the case of the Artificial island project in New Jersey. Possible considerations for cost allocation include whether beneficiaries pay for the benefits they receive, or those that caused the problem pay, or whether there should be a hybrid of these two approaches. Continued collaboration is essential to address the cost allocation challenge.

Next, Julia Selker, a congressional staffer for Rep. Peter Defazio (D-OR), asked the panel: "What would policy certainty look like? What's the level of policy uncertainty that you can tolerate?" The panel responded that existing public policy and uncertainty about future policies have impacts on the bulk electric grid. For example, the Mercury Air Toxics (MATs) rule, affecting coal caused the retirement of 20,000 MW of coal-fired generation in five to six years. Also, state policies such as the Renewable Portfolio Standards (RPS) and tax credits for wind resources have added fuel types to the mix. In short, state and federal policies can add, move, or remove a fuel resource in the mix, and these changes affect transmission development.

In addition, there are other drivers such as technology and economics. These factors create uncertainty, which, in some cases, can induce a short-term view rather than a long-term perspective. More certainty is always better; however, there is no certainty in forecasting. This emphasizes the need to plan using scenarios to account for uncertainties and to reduce the risk of uncertainties in transmission planning processes.

Doug Patterson of Black Forest Partners asked the last question to the panel regarding potential undervalued benefits and the replacement of aging infrastructure. He asked "How and to what extent is the digital communication infrastructure important to the electric grid, and what benefits can it provide in terms of grid reliability?" The panel agreed that the use of certain new communication technologies can provide faster communication; however, the digitalization of communication can also present a risk to the electric power industry. There is a critical interdependency between the electric and communications sectors. The U.S. DOE, as the Sector-Specific Agency (SSA), has been working on trisector coordination among electric, communication, and finance sectors to coordinate and to share best practices in dealing with new threats and the critical interdependencies.

Recurrent Themes in Panel I Discussion

1. Transmission investment needs typically arise at a regional or local level. Inter-regional needs arise in special situations.

2. Lack of transparency regarding “supplemental projects” has emerged as a key issue. However, it is part of a larger bundle of questions about transmission investment: What are we getting for this large amount of money? What fraction of this investment is creating additional capacity? What fraction is going into innovative technologies? If we were to divide this investment into subcategories, what breakdown would be most informative? What kinds of data would we need for this analysis that are not available today?

3. Planners face many uncertainties. Uncertainties → use of multiple scenarios → need to manage risk → need for metrics → need for relevant data.

4. Problems persist about how to estimate benefits and costs, and achieve an appropriate distribution of benefits vs. distribution of costs.

5. The ongoing need for a robust grid means that some additional transmission capacity should be maintained as “insurance” against unforeseeable contingencies. How much insurance should we buy?

3 Panel II: Challenges to Building Transmission Facilities Where and When Needed: Permitting/Siting Issues

Julie Smith, Ph.D., a program management analyst in DOE’s Electricity Office, was the moderator for Panel II, which focused on transmission permitting and siting issues. As discussed in Panel I, state and local policies and politics are important in transmission permitting and siting, as are international protocols for developing transmission lines that cross international borders.

Ms. Smith introduced the panel’s four speakers, and asked them to respond to the following questions:

- Have recent worthwhile major transmission projects been thwarted by “pass-through” states?
- Or by anticompetitive owners of existing generation or transmission assets?
- Or by controversy over the proposed distribution of the likely costs or benefits of the transmission project?

- Or by other obstacles?

Rich Sedano, President, Regulatory Assistance Project (RAP)

Mr. Sedano discussed challenges in the permitting and siting of transmission facilities. Challenges can arise in developing interregional HV transmission lines as seen in the Eastern Wind Generation and Transmission (EWGT) Study. The EWGT study considered a series of scenarios to build LDHV transmission lines to connect large offshore wind resources, driven primarily by engineering and economic considerations; however, it became questionable whether states would approve such scenarios. The EWGT study concluded that many entities across the interconnection would need to collaborate to develop a broader interconnection-wide view of transmission system plans.

States also realized this challenge, as identified in a study conducted by the Western Governors' Association. States recognized that there is a need for institutional changes to consider the value of interregional transmission projects and to ensure that all important benefits are included in the regional planning.

Many transmission projects are underway today, as shown in the EEI's *Transmission Projects at a Glance*. CAPX 2020 -- a joint initiative of 11 transmission-owning utilities across multiple states in the Midwest to upgrade and expand the electric transmission grid -- is a success story. This project achieved the common regional goals of delivering renewable energy, maintaining system reliability, and keeping electric costs low. A sense of comity allowed this major transmission development project to succeed.

Another example is an independent transmission project called the Clean Line Plains and Eastern proposed by Clean Line Energy, an independent transmission company. This project was designed to bring wind resources in Oklahoma to load centers in the Southeastern and Mid-Atlantic regions via an existing grid. This project faced many challenges, including certain disadvantages in states with incumbent electric companies. States may need help addressing public interest issues as well as with technical assistance in appreciating and realizing all the benefits—including broader, sometimes uncertain interregional benefits—of such projects.

As demonstrated through these examples, while state siting bodies are well positioned to make judgements on regional transmission developments, they may need help in addressing regional and national benefits. As discussed in Panel I, the distribution of benefits is still a great challenge in today's environment of regulatory inconsistencies and uncertainties, and there is a need for a generic structure or approach to evaluate and distribute regional and national benefits.

Further, there is a room for improvement in public engagement. Transparency and engagement can help overcome any fundamental mistrust of institutional motives. There are opportunities to provide further technical engagement with states to help them break out of the "bubble" and with the public to help them understand broader benefits of regional transmission developments. Such public engagement can inform the public of regional and national transmission benefits as well as help raise awareness and build comity.

Dan Belin, Director, Electric Transmission, Ecology & Environment, Inc.

Mr. Belin highlighted the value of DOE's Integrated Interagency Pre-application (IIP) process in transmission development by comparing two transmission projects. The IIP is a voluntary process that is designed to provide a template to guide early coordination between project proponents and federal and state government in the review of transmission projects. The intent of the IIP process is to facilitate early coordination, information sharing, and better planning, all of which can help create a robust permit application and efficient National Environmental Policy Act (NEPA) reviews.

The two cross-border electric transmission projects—the Great Northern Transmission Line (GNTL) and the Northern Pass Transmission Line (NPT) had a lot of similarities. They were both market efficiency projects involving large, long HV transmission lines importing hydropower from Canada into the United States. Despite many similarities, one major difference between these two projects was in the length of time each spent in the permitting process. The GNTL completed the final environmental impact study (EIS) in about 18 months while the NPT took seven years to complete it. This was mainly because the utility planning the GNTL project utilized the IIP process whereas the NP did not. The way in which the GNTL project proponent engaged with stakeholders also complemented the early agency coordination achieved through the IIP process.

DOE's IIP process provides early coordination of all interested parties which can generate a lot of information and coordination in advance of application submittal. This process helps create a more complete permit application, which in turn shortens the permitting period. One of the key results from the IIP process is early public involvement. The GNTL had a robust public involvement process and held over 70 stakeholder meetings, through which they collected approximately 1,500 comments. Because these comments were addressed during the pre-application process, only about 250 comments needed attention during the EIS review. In contrast, the NPT had no public engagement prior to filing its application. The first opportunity for public to comment on this project was at the release of the draft EIS, at which time it received more than 9,000 public comments. These were major, substantive comments that, by law, had to addressed, which significantly drew out the process.

In addition to the IIP process, another key differentiator in these two projects was state involvement in the GNTL project. The GNTL conducted a joint state and federal process, in which the Minnesota Department of Commerce was a joint lead agency with DOE. DOE recognized an opportunity in the statutory timeline in Minnesota, which requires a route permit to be done in 12 months with a possible 3-month extension. States have fundamental siting and regulatory authority outside of public land, and in this case, Minnesota's statutory permitting timeline served as an advantage in the GNTL project, coupled with robust public engagement during the pre-application phase.

In conclusion, early public engagement and other pre-filing activities during the IIP process can minimize risk and expedite the project schedule, as well as help meet state statutory permitting timelines, meet policy goals and get new projects in service in a timely fashion.

GEORGEANN SMALE, SENIOR REALTY SPECIALIST, WASHINGTON OFFICE, BUREAU OF LAND MANAGEMENT, DEPARTMENT OF INTERIOR

Ms. Smale talked about the West-Wide Energy Corridors that were designated pursuant to Section 368 of the Energy Policy Act of 2005 (EPAct 2005).[8] In 2009, the Bureau of Land Management (BLM), and the U.S. Forest Service, in coordination with DOE, designated approximately 6,000 miles of federal land (5,000 miles on BLM public lands and 990 miles on Forest Service lands) across 11 western states as energy corridors. These corridors are considered preferred locations for siting future electric transmission and distribution lines, and oil, gas, and hydrogen pipelines.

There are 131 energy corridors in the West, and federal agencies are currently reviewing the corridors by region. There are six regions, and each is being reviewed for any potential additions, deletions, and revisions. Region 1 review has recently been completed, and the review of regions 2 and 3 are currently underway. Reviews of regions 4, 5, and 6 will be conducted next year.

With the designation of these corridors, BLM developed tools to help facilitate permitting of future energy projects. BLM's mapping tool shows existing energy infrastructure and land jurisdictions, which are essential for planning. BLM is also developing abstracts to summarize potential concerns in each corridor. These abstracts summarize the existing energy infrastructure in the corridor and identify potential resource conflicts that may limit future energy development in the corridor. A draft report will shortly be released to the public for comments.

Ms. Smale encouraged the audience to sign up on the website to receive notifications soliciting public input during the corridor reviews. Finally, she shared lessons learned from energy corridor reviews. She believes that these corridors need ongoing oversight after they have been designated. She also sees a need for policies that emphasize that these areas are indeed preferred locations for future energy infrastructure development as opposed to areas prioritized for resource conservation, as the corridor locations typically align with existing infrastructure. Ms. Smale stressed the importance of federal agencies' provision of robust support for these corridors and the need to develop policies for operations and maintenance activities in coordination with utilities and others.

BESS GORMAN, ASSISTANT GENERAL COUNSEL, NATIONAL GRID

Ms. Gorman provided an overview of challenges in the transmission line siting process. In general, the transmission siting process begins with first identifying the need[9] that the project would serve. Once the need is identified, state siting regulators evaluate the proposed project against other options and routing alternatives, and select the option that best addresses the need, minimizes environmental and

[8] West-Wide Energy Corridor Center, http://www.corridoreis.anl.gov (accessed December 4, 2018).

[9] Concerning identification of need (and in response to DOE's invitation to workshop attendees to submit written input after the workshop), J. David Stanfield, a member of the Dane County (Wisconsin) Advisory Committee on Energy Planning suggested "introducing a priority [criterion] for all energy related projects … comparing the proposed transmission investment with non-wire alternatives using the degree of reduction of CO2 in the atmosphere, and then using the traditional three criteria [reliability, resilience, and affordability]." See Comments on November 15, 2018 DOE Workshop on Electric Transmission and Siting Issues - J. David Stanfield.pdf.

social impacts, and ensures energy reliability, taking into consideration the cost associated with the project.

Ms. Gorman said one of the biggest challenges in siting is the time that is takes to get through the siting and permitting process. On average, it takes 12 to 24 months to prepare a siting application after a regional study has been completed. This phase can include consideration for routing, resource delineation, impacts of these resources, and expert reports. Once the application is filed, it takes about 12 to 30 months to receive approval. From the completion of a planning study, the siting and permitting process could take 20 to 40 months to reach a final decision, excluding an appeal process which could add several years.

During the pre-filing phase, numerous meetings are held with siting staff or counsel, as well as with public officials and boards to discuss the routing and its impacts. Some of the questions that are addressed in the pre-filing phase include: Are there any alternatives? Are there economic benefits? What benefits will the region gain? A lot of meetings are held with different community groups during this time. Once the filing of the transmission siting application has been completed, the subsequent activities include a site walk with regulators, local public hearings, discovery, testimonies, and adjudicatory hearings, possible intervention, and legal briefs by all parties.

Ms. Gorman discussed the key concerns that arise during the pre-filing period when projects extend across jurisdictions. The first is an increase in municipalities seeking impact fees. With a lot of competitive transmission projects underway, “pass-through” communities may feel overburdened and that someone else is likely to receive the principal benefits from regional projects. They are concerned about added costs to their communities as a result of these projects and would like to receive at least some of the benefits resulting from them.

Also, she added, there is likely to be an increase in community activism. People may speak up more than before; however, they may lack understanding of local benefits in regional projects. It is hard for a community to accept a project if it does not see benefits. People worry about many different impacts of transmission line siting, including tree removal, property values, and potential loss of business.

Another challenge is that siting regulators’ workload has increased, at least in some regions, due to an increase in electric and gas line projects and other generation projects. Last, some generators in pass-through states are intervening in support of some of the projects. These generators feel they are at risk of being curtailed or that they will be economically harmed with a new influx of load being introduced in their wholesale market.

In her conclusion, Ms. Gorman presented a set of questions for consideration: Can the project study phase be more integrated? Can we do more upfront reviews, analyses, and engagements with communities as we try to evaluate each project? Can we have more accurate cost and benefit evaluation? How can benefits be shared more equitably with those who are burdened by a project?

PANEL II QUESTIONS & ANSWERS

Julie Smith, the Panel II moderator, asked the first question: "DOE's IIP process provides a mechanism that brings together diverse stakeholders, including state and federal agencies, as well as project opponents, to allow early coordination and preparation in the pre-application process. Are the IIP process and other federal efforts to improve the efficacy and efficiency of the permitting process valid and useful?"

Mr. Belin replied that such government efforts to improve regulatory certainty are certainly worthwhile. One of the key challenges in transmission permitting and siting is the lack of consistent federal regulatory authority, and if that can be improved to provide more certainty, it would be invaluable. However, Mr. Belin cautioned that this could become "a solution looking for a problem" when the market moves beyond long-haul transmission to find more localized solutions. As a case study, he cited the Montana Alberta Tie Line (MATL) project. In this project, Mr. Belin explained, the developers realized the difficulty of building a long-haul transmission line, so that in their next project, they moved beyond long-haul transmission to focus on developing micro-grids and community biomass energy resources in remote communities as a better solution. He cautioned that while more regulatory certainty is valuable, questions will remain about whether and how it should be used.

Mr. Sedano agreed that regulatory certainty can be valuable to a certain extent but not in all cases. There is a revolution under way in distribution systems, coupled with the need to integrate new natural gas generation and various distribution-level generation resources into the grid. Another approach to achieving stability could be to manage these challenges at the distribution level.

Mr. Sedano believes that the transmission siting authority should stay in state government despite occasional difficulties in coordination among states and federal agencies. Federal agencies should share best practices and help states realize the values in economic, societal, and cost benefits, so that these important factors can be considered in the local decision-making processes. He further added that a holistic approach to transmission siting is essential, and that it might be useful to convene special meetings for siting with several agencies to provide technical support and assistance to states.

Next, Ms. Smith asked the panel whether they see value added by the pre-application process. Ms. Gorman responded with a resounding "yes," that there is a considerable benefit to doing extensive preparation during the pre-application process. Holding numerous meetings with all parties impacted by the project, including states, federal agencies, communities, and project opponents, provides an opportunity to engage, educate, and help them as much as possible.

Mr. Belin added that there is a growing complexity in the competitive solicitation space with the growth of distributed generation. Pre-application activities, by definition, mean activities carried out before you are rewarded with a contract. These activities translate to at-risk capital for the many developers that are competing for one solicitation. The "one decision principle" is highly desirable (e.g, FERC's authority in natural gas pipeline) and would be helpful in transmission projects.

Ms. Smith expanded upon this discussion and asked: "Is it one federal decision, or the principle or embodiment of coordinated efforts? What would be an ideal, generic approach or policy landscape where states and federal agencies can coordinate better? What would that look like? What are the essential components?"

Mr. Sedano said there are usually relevant indications long before a project happens. For example, the interconnection-wide planning activities supported under the American Recovery and Reinvestment Act of 2009 were welcome opportunities for greater coordination among the states in the interconnections. This allowed the consideration of political and engineering factors in the process and gave states the opportunity to consider different solution scenarios. The RTOs have good processes in this respect, but such practices are largely absent outside the RTOs. There may be a need to create institutions to better understand the vast information that is currently available but not processed well, and to help anticipate project needs or avoid certain projects as appropriate.

Ms. Smith asked Ms. Smale of BLM the following question: "Considering the value of coordinated national efforts as discussed in this panel and the effects they can have on local field activities in the West, is there a tension between national interests and local politics? How can early communication and coordination help? How could we improve this in the pre-application process without overburdening BLM?"

Ms. Smale replied that under Section 368, such concerns were to be addressed through amendments to agencies' land-use plans. She believes clarity in land-use planning is essential. BLM provides web applications that show impacts of planning and has a pre-application process for lines 100kV and above.

William Chambliss, General Counsel of the Virginia State Corporate Commission, asked about the implication that major transmission projects have been thwarted by state actions or by existing owners/operators or any other challenges. What projects, if thwarted, and by whom?

The panel gave some examples of projects that were denied, including the Clean Line project in Arkansas and Oklahoma and the New England Power Link project in Vermont. In most cases, including these examples, projects have been denied on the basis of the cost and benefit analysis. Market efficiency projects are more often denied than reliability projects, because it is more difficult to show the need or benefits from market efficiency projects. In large interregional projects, approvals and denials are often based on public sentiment rather than quantifiable data and analysis, because calculating benefits can be ambiguous. There is a distinct exception for projects where a clear national interests would be served; however, projects without sufficient "social license" are tough to get approved.

Next, Molly Sterkel of the California Public Utilities Commission noted that In California, there is concern about public availability of GIS information on proposed routes, and asked whether that is a concern elsewhere. Considering the importance of information transparency and the value of mapping, how do you deal with the issue of federally-designated critical electric infrastructure information (CEII), and the associated restrictions on its availability?

Mr. Sedano responded that while filing requirements are important, these requirements should be adjusted as technologies change. Mr. Belin acknowledged the challenges with the CEII designation and thought that providing varying degrees of specificity might be a possible solution.

Ms. Smith emphasized the value and power of visual information in transmission development. The use of GIS mapping tools can be effective in explaining the concept of need, as well as in making policy decisions. She expressed the view that while GIS mapping tools are invaluable, with respect to CEII, the question becomes how much detail is enough to enhance understanding and transparency, while respecting security concerns.

Doug Patterson of Black Forest Partners shared a success story of the IIP process. He sees many benefits from pre-permitting activities and affirmed that this process has achieved what it was designed to achieve.

Eugenia Gao of ABB, North Carolina, asked a question related to China's HV transmission map as shown in one of Mr. Sedano's slides. In contrast to China, permitting is one of the barriers to transmission development in the United States. She asked whether DOE has a plan to facilitate the use of best technologies (e.g., underground lines) to create a national-level grid.

Mr. Sedano responded that he believes that transmission development in the United States will always be state-based. While DOE can provide technical support to states to help them make good decisions, DOE has limited power to influence states' decision making. Mr. Belin affirmed that the U.S. federal government has little regulatory authority in transmission permitting. The concept of a "national grid" has been promoted in the past, but the real challenge is in who pays. Mr. Belin drew a comparison with Brazil, a country that has a rigorous regulatory process similar to that of the United States. Despite having a similar paradigm to the U.S., Brazil was able to smoothly execute a large 800-mile transmission project, because it had the "social license" and political power to complete the project.

Recurrent Themes in Panel II Discussion

1. Engaging all interested parties early in a transparent transmission project review process helps build trust and comity. Conversely, withholding key information and trying to steamroll opponents erodes trust, feeds resistance, causes delays, increases costs, and could even doom a project.

2. Constructive roles for DOE include:
    a. Focus analytically on how best to sustain the transmission sector's contributions to the economic efficiency, reliability, and resilience of the electricity supply system.
    b. Provide technical assistance on transmission matters to states and others.
    c. Play a convening role to facilitate dialogue and foster holistic thinking about transmission issues.
    d. On behalf of the Administration, develop concepts and procedures that will appropriately balance the need to protect CEII while maximizing transparency regarding the planning, financing, and operation of electric and related infrastructures.

4. PANEL III: ARE EXISTING REMEDIES ADEQUATE?

Joe Eto, a staff scientist at Lawrence Berkeley National Laboratory, was the moderator for Panel III, which examined whether existing transmission planning remedies or mechanisms were sufficient to address current issues and concerns. He cited the key questions for discussion below and asked workshop participants to focus on possible needs for federal actions, especially from DOE:

- Are regional transmission planning processes under FERC Orders No. 890 and 1000 sufficiently effective to address unmet needs?
- For merchant transmission lines being developed outside or in parallel with these processes, are the needs of pass-through states being balanced fairly and efficiently with regional and inter-regional needs?
- Are there other considerations that impede addressing unmet needs for additional long-distance transmission lines in a timely manner?
- Is federal action required to address any of the issues identified above? If so, what form of action is required?

ROB GRAMLICH, PRESIDENT, GRID STRATEGIES LLC

Mr. Gramlich's presentation focused on the challenges and possible solutions to improve the resilience and efficiency of the U.S. electric transmission grid. First, he discussed the benefits of interregional and regional transmission development. The average benefit-to-cost ratio of large regional projects is 3:1 in the Central region RTOs. Similarly, the results to date from the DOE-sponsored Interconnections Seam Study[10] found that the benefit to cost ratio can range from 2.5:1 to 3.3:1. Another study (performed by Dr. Christopher Clack for NOAA) looked at a long-term future EHV grid overlay to integrate a mix of natural gas and other generation resources and found that the project would reduce the cost of electricity by 10 percent.

Many FERC proceedings include comments about the benefits of transmission, including enhanced resilience. While it is difficult to quantify, these comments suggest that transmission provides resilience benefits. He also explained that congestion costs are rising whenever a lot of generation capacity is growing in one place while a lot of demand is growing in another location. He expects that congestion costs will continue to rise, because not many transmission projects are underway aimed at increasing delivery capability.

Mr. Gramlich believes large scale regional expansion can be realized through pro-active multi-benefit planning and broad beneficiary-pays cost allocation, and cited three cases—MISO's Multi-Value Portfolio VP, SPP's priority projects, and ERCOT's Competitive Renewable Energy Zones (CREZ) -- as examples.

Mr. Gramlich discussed three key barriers to transmission development: permitting, too-narrow planning, and cost allocation. A barrier in permitting exists for major, long HV transmission lines that cross many states, because there are many innate differences (e.g., interests, needs, approaches,

[10] See https://energynews.us/2018/08/01/midwest/transmission-study-points-to-potential-from-overcoming-grid-seams/ . The full results of the study have not yet been published.

concerns, etc.) in each state. Too-narrow planning presents another challenge. He believed that the RTOs' planning processes have not been comprehensive and have not proactively considered generation development in resource-rich areas. He further explained that benefits have been compartmentalized (e.g., economic, reliability, resilience, and generator connection) and that a proper cost analysis needs to consider them together. Finally, he believed, cost allocation is another significant barrier. FERC's generator interconnection policy allows participant funding even when many generators are connecting in the same area. The fundamental problem is, Mr. Gramlich said, "we are not connecting the whole planning process to the [interconnection] queue process."

Mr. Gramlich offered several possible solutions to address these barriers. First, he suggested improving the efficiency of the existing grid through power flow control, dynamic line ratings, topology optimization, and storage. He suggested that DOE can help by developing tools and methodologies for planners. Second, he recommended broad pro-active regional planning as another solution option. Broad, proactive planning should consider all benefits, incorporate known developments in resource areas, and possibly consider uncertainty and insurance value.

He suggested that DOE's Congestion Study could provide valuable guidance on quantifying benefits and providing information for applicants interested in possible corridor designation. He believes that the development of a common model and a common system for measuring benefits among different states and planning authorities through interregional planning would be essential to more fully realize all the benefits. He also viewed DOE's continued support and assistance in permitting processes (including National Interest Electric Transmission Corridors) would be valuable. He further suggested that DOE consider an application-based program, putting the burden on the developer to demonstrate a line meets criteria and to provide guidance on how to meet those requirements. Finally, Mr. Gramlich mentioned a broad "beneficiary-pays cost allocation" mechanism that considers all benefits as another possible solution.

Traci Bone, Attorney, California Public Utilities Commission

Ms. Bone presented findings implying the existence of a disconnect between transmission policies, planning, and projects. She focused on issues pertaining to FERC Order 890 on transparency in transmission planning, and specifically about her concern stemming from the way in which FERC is interpreting that order. The transmission policies have good goals, including grid modernization, competition, integrated planning, reducing electricity price, ending balkanization of the grid, and deployment of advanced technologies. However, Ms. Bone believes that there is a disconnect between these goals and the reality.

The reality is that the RTOs are reviewing through their planning processes only a fraction of the transmission projects that are built, and that the bulk of the remaining projects are being developed with limited or no RTO review for either need or cost. These are primarily end-of-life projects (i.e., repair or replacement of existing facilities), also known as "asset management projects" or "supplemental projects." The cost of these projects is passed directly into the rate base. For example, California's largest utility, PG&E, is currently spending approximately $750 million each year on these "asset replacements" projects, which account for approximately 63 percent of its total annual transmission investment. Of the $8 billion of capital investments PG&E made between 2007 and 2017, more than $5 billion or approximately 63 percent went for self-approved, asset management projects.

The cost of asset management projects is projected to continue to grow in California. Looking at the three largest utilities in California, PG&E anticipates about the same level (or 63 percent) of its total investment will be for these projects between 2018 and 2022; the share of asset management projects in SCE and SDG&E will grow from 19 percent and 12 percent in the last decade to 36 percent and 46 percent, respectively, in the next five years.

The same pattern is seen across the country with respect to growing cost of supplemental projects. In the last four to five years, 47 percent of the $70 billion in transmission investments by TOs within FERC-jurisdictional ISO/RTO regions were made without full ISO/RTO stakeholder engagement in the planning process. This number is expected to grow.

Ms. Bone explained that appeals to FERC have further confused the problem. In an August 2016 Order in the PJM region, FERC held that supplemental projects were subject to FERC Order No. 890, and thus the planning for those projects was required to be fully transparent to customers. Based on this order, a group of interested parties in California filed a complaint against PG&E, asking FERC to order PG&E to comply with Order No. 890 for all of its transmission capital additions that were not being reviewed by the CAISO. Many of these projects were the same types of projects as the supplemental projects addressed in the August 2016 PJM Order. However, in August 2018, FERC dismissed California's complaint, finding that PG&E's "asset management projects" are not subject to FERC Order No. 890 because they do not add capacity to the grid. FERC recommended instead that PG&E establish a voluntary process with stakeholders to provide some transparency regarding those projects. Furthermore, in October 2018, a FERC ALJ initial decision in PG&E's TO18 rate case found that PG&E's $750 million a year in spending on asset management projects is outside of the scope of that rate case. Ms. Bone asked the audience, with California's complaint on these issues being dismissed by the FERC, and found to be outside the scope of a rate case, "where do they need to go?"

PG&E continues to spend $750 million per year -- more than $2 million a day -- on these projects; however, there is no clear way to determine whether these investments are needed or cost effective. Ms. Bone asked stakeholders in the room to share their thoughts: Do you see this as a problem? If yes, why, and how do you solve it? If you don't think it's a problem, then why?

Ms. Bone explained that while most of these investments are justified, until there is transparency, we cannot know what is or isn't justified. As the Brattle Study shows, this is a national problem that impacts all RTOs, and the magnitude of the problem cannot be ignored. Ms. Bone believes that stakeholders need mandatory and comprehensive transparency on these projects as per Order No. 890, and that FERC is not properly interpreting its own order. In conclusion, Ms. Bone suggested that without the formal processes and transparency provided in Order No. 890, RTOs will not be able to deliver on the promise of an integrated transmission system. She asked people to reach out to her to share their thoughts.

Sharon Segner, Vice President, LS Power Development

Ms. Segner began by saying that LS Power agrees with a lot of the issues raised by Ms. Bone and discussed some of the trends and findings in the market place since the issuance of FERC Order No. 1000 in 2011.

Ms. Segner presented several key findings from the Brattle Group's preliminary report released in October 2018.[11] According to this study, U.S. transmission investments have grown from $2 billion per year on average in the 1990s to over $20 billion per year in the last five years, 85 percent of which was made within ISO/RTO regions. However, even five years after FERC Order No. 1000 mandated consideration of competition in regional transmission planning, an estimated 98 percent of ISO/RTO regions' transmission investment is still made outside of competitive planning processes.

Further, this study found that ISO/RTO-planned transmission projects not subject to competition have experienced cost escalations, with the final project cost (including inflation) exceeding the projects' initial cost estimates by 34 percent on average. Conversely, winning bids of competitive transmission projects, on average, have been priced 40 percent below the initial project cost estimate and have been accompanied by cost caps or other cost-control mechanisms. Finally, the Brattle study concluded that if the scope of competition for these projects could be expanded from 2 percent to 33 percent of the total transmission investments, customers would see an estimated $8 billion worth of benefits in over five years.[12]

Another benefit of competition in transmission development is that it brings commercial innovation. For example, 10 out of 11 proposed bids for the Duff-Coleman project in MISO had some form of price cap on their projects, including those from incumbents. This demonstrates that the market responds to competition by moving toward "cost containment bids," shifting cost risk from ratepayers to developers. Ms. Segner believes this finding is not unusual and that a similar trend may be seen across regions. She further asserted that a key issue and benefit of FERC Order No. 1000 is that while the Order currently does not bring wide enough competition, when competition is allowed, the market place responds with qualified bidders and with commercial innovations.

Competition brings consumer benefits and commercial innovations; therefore, the issue is not the existence of competition. The issue, she believes, is in the details of the legal and policy choices FERC made when transmission was originally opened to competition. The original vision of FERC Order No. 1000 was much greater than making only 2 percent of projects open to competition, which indicates that there are too many projects that are or are deemed exempt from competition in FERC Order No. 1000. The U.K. is in the process of creating its own version of FERC Order No. 1000. The key difference in their policy is that instead of linking competition to the notion of regional cost allocation as stated in

[11] "Transmission Competition Under FERC Order No. 1000: What we Know About Cost Savings to Date," as presented on October 25, 2018, the Brattle Group, http://files.brattle.com/files/14786_brattle_competitive_transmission_wires_10-25-18.pdf (accessed December 4, 2018).

[12] Ibid.

FERC Order No. 1000, their policy requires any project above a certain cost threshold must be open to competition.

Ms. Segner explained that since the issuance of FERC Order No. 1000, several states have passed Right of First Refusal (ROFR) laws that thwart the provisions in Order No. 1000 that were intended to prevent ROFR as a practice. As a result, projects that otherwise would be eligible for competition are not included in competition in those states. LS Power has filed a complaint in a circuit court, trying to overturn the ROFR law in Minnesota. This case is currently going through the legal process and they are awaiting the court's decision on whether Minnesota's ROFR law is constitutional. In addition, the U.S. Department of Justice, on behalf of the United States, filed a brief in this case in the circuit court stating that Minnesota's ROFR law is anti-competitive and that FERC Order No. 1000 is not consistent with state laws that provide a broad exemption for public utilities. The court's decision on this case will be informative in the national debate on whether the ROFR laws are valid.

In concluding thoughts, Ms. Segner highlighted LS Power's perspectives on paths ahead for competitive transmission in the United States in four key areas: First, focus on expanding the number of competition windows so that consumers can see the benefits. Second, FERC should continue to support cost containment and its strong role in the selection process, and RTOs should continue to develop the capabilities to analyze cost cap proposals and frameworks to compare cost estimates. Thirdly, FERC should support reducing exemptions provided for in FERC Order No. 1000 to open competitions for transmission development, particularly in MISO and ISO-NE, where opportunities should be expanded. Further, FERC should both oppose changes in cost allocation that limit competition and address the interaction between regional planning and supplemental projects. Finally, Ms. Segner underscored her company's view that state ROFR laws are unconstitutional.

Omar Martino, Director, Transmission Strategy, EDF Renewables

Mr. Martino discussed what he regards as the principal problems and their solutions in today's electric transmission development and siting processes. He divided them into in three key areas: non-transmission alternatives, economic upgrades, and reliability upgrades.

First, Mr. Martino asserts that transmission providers are not taking full advantage of non-transmission alternatives that can bring considerable economic benefit to customers and grid users. He believes there is a need to embrace new technologies that can help improve electricity reliability and increase load-carrying capacity. These technologies include, but are not limited to, dynamic line ratings, phasor measurement units, and conductors that can tolerate high temperatures. Mr. Martino suggested conducting an analysis on how much capacity can be increased in the transmission system as a result of implementing these technologies. He believes a significant level of additional capacity can be achieved with a minimum level of investment.

Secondly, transmission planners have inadequate congestion review protocols to identify areas in need of economic transmission upgrades. As a possible solution, Mr. Martino suggested RTOs and utilities adopt a common set of triggers to identify congestion, such as price differentials between trading hubs, the curtailment level of a transmission element, or the amount of regional redispatch.

Mr. Martino also believes that RTOs do not have adequate flowgate definitions that include all the transmission lines. To resolve this issue, he said transmission providers should be obligated to define flowgates covering all the facilities under their control, including 100 kV or 69 kV lines.

His fourth issue is that most transmission planners do not have a mandate to adopt quick solutions for regional and interregional transmission needs. As a solution, Mr. Martino recommended that transmission planners annually assess the need for “quick hits” or targeted market efficiency-type of projects on a regional and interregional basis.

The fifth problem, Mr. Martino said, is that existing participant funding mechanisms are not effective. He believes that transmission planners should be directed to adopt more robust participant funding provisions that will incentivize investment.

The sixth problem arises when transmission providers fail to include proper levels of future generation in transmission planning models. As a remedy, Mr. Martino suggested that transmission providers be required to file with FERC the protocols that they use to define the consideration of future generation in their planning models.

A seventh key challenge is that transmission benefits are defined too narrowly. To address this issue, Mr. Martino believes that transmission providers should be required to apply a 1.0 benefit-to-cost ratio, define long term benefits on a 30- to 40-year basis, and include all economic market impacts that can result from an upgrade.

Mr. Martino explained it can be a problem when transmission planners apply a distribution factor (DFAX) that is too high, resulting in an underbuilt grid, excessive curtailment and congestion, as well as unnecessarily high LMPs, and recommended the mandated use of 3 percent to 5 percent DFAXs.

He cited some case studies to support his statements. In one case study dealing with the WECC markets, a lack of coordination in regional transmission planning and generation interconnection resulted in failure of transmission providers to meet their study deadlines. This, in turn, created a significant backlog in interconnection queues. There is also a concern about transparency about the queue. While “first come, first served” is the basic principle of transmission service policy, the reality is that queues are sometimes opaque. Mr. Martino suggested that DOE and FERC hold a technical conference to discuss possible ways to better sync the interconnection queues with transmission planning.

In a second case study about SPP congestion, SPP studies had identified that an area that would likely experience thermal overloads and excessive congestion due to wind projects that had interconnected to this part of the grid, as well as new transmission facilities to address these issues. These studies, however, either did not require a solution or identified a need date many years after the congestion became problematic. As a result, individual generators were forced to pay for a transmission upgrade to cure a pre-existing problem that they did not create.

Mr. Martino also cited the following additional problem areas and suggested possible solutions.

- Transmission providers allow operating guides to persist instead of building reliability upgrades to address the problems targeted by these guides. Solution: Require transmission providers to publicly post operating guides so they are transparent and remove operating guides after three years, incentivizing the approval of reliability upgrades.
- Transmission planners are not addressing pre-existing conditions. Solution: A holistic approach is needed that equitably considers near-term reliability and generation interconnection needs.
- Transmission planners are not applying consistent NERC criteria. Solution: DOE or FERC should hold a technical conference to discuss adopting uniform best practices.

PANEL III QUESTIONS & ANSWERS

The moderator for Panel III, Joe Eto, asked the panelists: "Are beneficiaries not perceiving the benefits accurately? Or is the mechanism by which they are paid not adequate? Or are there other disconnects?

Mr. Gramlich explained that it comes down to how we are doing planning and cost allocation. While the concepts are generally in FERC Order No. 1000, the Order did not address interregional planning in detail. Further, the planning guidance has weakened over time, and the benefits have become compartmentalized. The general policy in cost allocation is that beneficiaries should pay. Therefore, we need to do a true cost-benefit analysis for transmission planning and consider all benefits, so that we can allocate cost to the beneficiaries as well as possible.

Mr. Eto asked a follow-up question concerning the scope of benefits and uncertainty of benefits: How do you address which benefits people are prepared to recognize and what process should be used to incorporate these benefits? How do you address the fact that benefits hinge on expectations for the future, but people have different perspectives about the future?

Mr. Gramlich responded that transmission planning is about the future, and that uncertainty is unavoidable. Given the uncertainty, he believes, we need to consider what the risks and potential for stranded costs are for each project. He explained that we should look at the benefits and costs of the additional transmission that we think we will need, and know, with a degree of confidence, that the generation potential in any given area is appropriately included in the planning process. However, there is often a disconnect between the interconnection queue and the planning process.

Mr. Eto asked the panel whether FERC reviewed TO-driven supplemental projects when costs were allocated locally. Ms. Bone replied, "Essentially, no." She said, for example, PG&E had more than 800 "self-approved" projects that were expected to come online next year and which did not go through CAISO's review. The only way to challenge them is through a "prudency examination" at the FERC, which is done on a case-by-case basis. With more than 800 projects a year, she believes, prudency review is not feasible. Ms. Bone also discussed a recent case in which the California PUC made the argument that PG&E's processes for identifying these projects were "not just and reasonable"; however, FERC decided that was outside of the scope of its Order 890.

Mr. Eto, as a follow-up, wanted to know how regional allocation with respect to carveouts (i.e., projects deemed exempt from open, competitive processes) should be addressed. Ms. Segner explained that the key problems are both the carveouts themselves, and the number of carveouts. There are carveouts that are already regionally planned and cost-allocated, which therefore, should be open to competition but are not. She also believes that the number of carveouts should be reduced significantly.

Mr. Eto asked then how one would address the issue of asset replacement. Ms. Segner believed that asset replacements should be regionally planned.[13] She said while a TO should determine whether an asset that is nearing its end of life should be replaced, and once that determination has been made, RTOs should address what the right solutions might be through a regional planning process.

Turning to Mr. Martino, Mr. Eto asked why the solutions put forward in his presentation were not being implemented. Mr. Martino responded that RTOs and utilities may not be used to new ways of thinking, and that we need the right culture and mind set to make these changes. He asserted that new technologies are out there, but utilities do not want to take risks. Mr. Martino believed that we need to cultivate the leadership, guidance, and culture that will promote such changes and suggested that the cost-benefit principle is a good incentive to consider changes.

David Weaver of Exelon thanked the panel but asserted that this was a very one-sided panel. He concurred with Mr. Gramlich that it is relatively easy to move forward with upgrades for reliability, but that it becomes difficult to push forward projects needed for security and resilience reasons. He also agreed that supplemental projects should be transparent, which is why Exelon works hard to ensure transparency. At PJM planning meetings, Mr. Weaver explained, all supplemental projects are presented, and stakeholders are given an opportunity to review and comment on them.

Mr. Weaver believes transmission investment is important. Utilities face challenges in determining whether to invest above and beyond reliability requirements, but they work hard to ensure that their investments support robust markets and modernizing and securing the grid. That is why 25 percent of today's investment is focused on modernizing and protecting the system. He asserted that we need to start making investment decisions supporting economic growth and thanked the panel for the opportunity to express his belief that utilities are doing their part.

The next question came from Joe DeLosa of the NJ Board of Public Utilities, who focused on the inherent uncertainty of benefits. He asked how analysts should address any negative benefits (e.g., increased congestion) and inherent uncertainties associated with projects intended to enhance market efficiency.

The panel responded that all costs and benefits should be accounted for. The problem with benefits is that the term varies by region. A market efficiency project is often a "case of first impression" for many of the states; therefore, RTOs/developers should approach with them caution and diligence. PJM is working to reform how market efficiency projects are justified.

---

[13] In comments filed with DOE after the workshop, Joseph M. Power, Ameren Services Company, expressed the view that the regional planning process entails costs for the participants, and that therefore projects not likely to provide regional or inter-regional benefits should not be included in the process. See Ameren Transmission Comments on November 15, 2018 DOE Workshop on Electric Transmission and Siting Issues.pdf.

Mr. Martino believes that the issue is that costs and benefits are not captured correctly through the metrics that are used, and that there is a need for a uniform platform across regional markets to apply the right metrics and overcome gaps that exist in today's models.

Mr. Tatum applauded the panel and offered his final thoughts and questions on what may need to change in the current RTOs processes. He pointed out that the current market system is now 22 years old, and continues to evolve. The ISO/RTOs were created to allow competition and ensure a grid that is effective and efficient through planning and collaboration. With the change in the paradigm, there are more players in the market, which makes collaboration more difficult. To find a way forward, he believes we need to have processes that will enable transmission to facilitate effective competition, and that to ensure effective competition, we need to ensure that beneficiaries are indeed beneficiaries. He affirmed this can only be achieved through openness and transparency.

Recurrent Themes in Panel III Discussion

1. Give new attention to improving metrics and methods for evaluating the benefits and costs of transmission investments.
2. Such evaluations will hinge on assumptions – and stakeholders will disagree on the reasonableness of the assumptions. Transparency about assumptions, methods, data, etc. is essential to gain stakeholder and public acceptance of analytic results and proposed projects.
3. Uncertainties will linger, and create risks that must be managed and mitigated to a reasonable extent.
4. Cost containment is an important means of mitigating risk to ratepayers. Competition for the right to develop transmission facilities is a demonstrated means of cost containment.
5. The rate of adoption of innovation (technological, market, or regulatory) is slower in this industry compared to others. Opportunities to accelerate this rate prudently should be explored.