FEDERAL ENERGY REGULATORY COMMISSION

TECHNICAL CONFERENCE

Grid-Enhancing Technologies

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888 1st Street NE

Hearing Room One

Washington, DC 20426
SPEAKER LIST

Samin Peirovi, Moderator

Christy Walsh

Commissioner Glick

Jeff Dagle

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Jack McCall

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Jignasa Gadani

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Jeff Webb

David Patton

Hudson Gilmer

Charles Bayless

Frank Kreikebaum

Adrienne Collins

Jeff Hackman

Robert Bradish

Anjan Bose

Brett Wangen

Jeff Webb

Andrew Clarke

Michael Kormos

Babak Enayati
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Pablo Ruiz, NewGrid
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Charles Bayless, National Rural Electric Cooperative Association
Frank Kreikebaum, Smart Wires
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Jeff Hackman, Ameren
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Anjan Bose, Washington State University
Brett Wangen, Grid Subject Matter Experts on behalf of Western Interconnection Regional Advisory Body

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Michael Kormos, Exelon
Babak Enayati, National Grid
Betsy Beck, Enel Green Power North America
Joseph Abhulimen, California Public Utilities Commission
Public Advocates Office
MR. PEIROVI: Good morning.

Thank you for coming. I'm Samin Peirovi from the FERC's Office of Energy Policy and Innovation. Welcome to today's workshop on grid-enhancing technologies. This workshop will discuss our definition of grid-enhancing technologies, how they are currently used in transmission planning and operations, the challenges to their deployment and implementation, and what, if anything, the Commission can do regarding those challenges.

So, we have three panels today and two panels tomorrow. We'll allow each panelist up to 7 to 10 minutes for opening statements in Panel 1. And in the other panels today, we'll allow 2 to 3 minutes for opening statements.

All materials received from speakers have been posted on the pages on FERC.gov, on the calendar pages, and will be posted on e-library, under Docket Number AD19-19.

Now, first allow me to introduce the representatives at our side panels, our side tables. The side tables are set up for the following entities: The Pacific Northwest National Laboratory, Potomac Economics, Monitoring Analytics, PJM, NYSO, Southwest Power Pool, CAISO, MISO, that's it. So, they're going to be set up on either side of us here. Thank you, and they may weigh in on
and throughout the workshop as they would like.

The first panel will include presentations from National Lab and industry experts, providing an overview of various types of grid-enhancing technologies, followed by a short discussion. Panel 2 will discuss the capabilities and challenges of grid-enhancing technologies from an operational perspective. This panel will include short presentations on the values, benefits and costs associated with operating the transmission system with different types of grid-enhancing technologies.

Additionally, this panel will explore current deployments of grid-enhancing technologies, and what actions, if any, the Commission could take to help alleviate any operational challenges or concerns. Presentations will be followed by a facilitated discussion.

Panel 3 will explore how grid-enhancing technologies are currently implemented in transmission planning processes across the country. Panelists will be asked to give their perspective through presentations and through discussion on how various types of grid-enhancing technologies can be evaluated, alongside more traditional system projects in existing transmission planning processes.

In addition, this panel will consider what challenges exist in current transmission planning processes.
So, this workshop is complimentary to relevant responses in the Commission's inquire on transmission incentives in Docket Number PL19-3 and the recent Technical Conference on managing transmission line ratings in Docket Number AD19-15.

And again, I want to thank all the participants for being here today for what is sure to be a useful day of discussion. I'd like to first recognize Commissioner Glick, who's here today, and turn to him if he has any opening remarks.

COMMISSIONER GLICK: Quickly, and thank you very much, appreciate it. First, I want to thank Samin and the whole team for putting together a very, really good set of panelists. I think we're going to hopefully learn a lot in the next couple of days.

I think everyone here obviously, and everyone else around the Commission agrees that we need to do a lot more to have additional transmission built -- additional transmission capacity built. But we also need to do a lot more to improve the efficiency of our existing grid.

And, as Samin mentioned, he had a really helpful Technical Conference in September on dynamic line ratings, ambient adjusted ratings and I think it was a good learning experience for us all in terms of looking at one particular type of grid enhancement technology, but I think there's a whole bunch of others that I know we're going to be looking
at today.

Now, I think everyone knows that the Energy Policy Act instructed FERC to incent utilities to take actions to improve the efficiency of the grid. And also, in Order 1000, we essentially tried to lay the ground work for better consideration of non-transmission alternatives, which obviously includes grid-enhancing technologies.

And I think we've certainly made some progress in those areas, but we have a lot more progress to be made I think in both Order 1000 and with regard to the incentive instruction that we received from Congress back in 2005.

So, I think today, and tomorrow is going to be a very helpful mechanism for helping us learn more about these technologies -- the pros and the cons, and what we can do to remove the barriers to them. And I look forward to -- I don't know if I'm going to be able to sit through as many panels as I can and learn as much as we can over the next two days, so thank you very much.

MR. PEIROVI: Thank you, Commissioner Glick, for those remarks and for helping frame the discussion today. Now, let me close with a few housekeeping items. This workshop is being webcast and transcribed. Please do not bring food or drinks, other than bottled water, into the hearing room.

Please silence your cell phones if you have not
done so already, and there are bathrooms and water fountains behind the elevator banks on each end of the building. Please keep in mind that this workshop is not for the purpose of discussing pending proceedings.

If a pending proceeding before the Commission is mentioned, we will have to interrupt the discussion to steer away from it. So, we have a lot of ground to cover in a short amount of time today. With that in mind, we'd like panelists to keep their comments within the topics laid out for each panel. If the discussion begins to stray outside of the scope of the panel, or outside of the scope of the questions, we may interject to bring the discussion back on topic.

For panelists at the main table and side tables, if you would like to be recognized to speak during the Q and A portion of each panel, please turn your name tent to the side. Be sure to turn on your microphone and speak directly into it. We are -- it looks like we're sharing a few mics, we've got two mics, so be sure to pass it down and turn it off when you're not speaking to eliminate background noise as much as possible.

Finally, please do your best to avoid excessive use of acronyms or abbreviations. I know that's kind of hard, but especially in this industry, but we would appreciate that. So, let's start.
Panel 1: Overview of Grid-Enhancing Technologies

MR. PEIROVI: Our panelists for the first panel are, starting from my right, let's go from my right here, Jeff Dagle from the Pacific Northwest National Lab, Pablo Ruiz from NewGrid, Swaraj Jammalamadaka, from Apex Clean Energy, Jack McCall from Lindsey Manufacturing.

Again, please try to keep your opening statements to within no more than 7 to 10 minutes each and we'll kick it off with Jeff Dagle.

MR. DAGLE: Thank you, good morning. My name is Jeff Dagle. I'm an electrical engineer with 30 years of experience at the Pacific Northwest National Laboratory operated by Battelle for the U.S. Department of Energy located in Washington State.

This morning I'm going to discuss the DOE Grid Modernization Initiative, some perspectives associated with resilience, and discuss a few specific examples of grid-enhancing technology.

I have a clicker here, right? Okay. In January 2016, DOE awarded over 200 million dollars for 88 projects launching the Grid Modernization Initiative. Seven additional projects were launched in September 2017, 30 million dollars for resilient distribution system field demonstrations. Another round of projects will be awarded soon.

I currently serve on the leadership team for 13 National Laboratory consortium, conducting a substantial portion of this work. We are following a multi-year program plan available on the DOE website, DR on the slide.

Also, as is illustrated in the figure, the program is focused in the following six areas: Device and integrated systems testing, sensors and measurement technology, system operations, power flow and control -- that's the one I lead, planning and design tools development, security and resilience, and institutional support, recognizing that changes will ultimately need regulatory adoption.

With the recent addition of the generation-focused DOE offices in the grid modernization initiative, we will be reorganizing the program plan according to reflect these technologies.

The goals of this research collectively are to enhance the resilience, reliability, flexibility, security, sustainability, and affordability of our electrical infrastructure.
In 2017, the National Academies released a report "Enhancing the Resilience of the Nation's Electricity System," available at the website indicated on this slide.

This report does a great job summarizing the current state of the power system and technology options for enhancing resilience, which I will discuss in a moment.

Specifically, there's a chapter devoted toward making our communities more resilient. There is another chapter for the bulk system. There's a chapter on enhancing response recovery. Throughout the report, and summarized in separate sections, specific findings and targeted recommendations are provided.

The report addresses the challenges of defining resilience metrics, which are fundamentally different than traditional reliability metrics. The report also introduces some thought-providing ideas. One example -- traditional reliability enhancement is funded by ratepayers. In the future, considering the societal benefits, perhaps resilience investment could be a blend of ratepayer and taxpayer funding. There is some precedence for this, including state grants to shore up resilience following superstorm Sandy.

The National Academies report was based on this resilience framework. We consider all stages of the event, before, during, and after, with a feedback loop.
incorporating lessons learned.

Fundamentally, resilience is the ability to reduce the magnitude and/or disruption of events. Resilient infrastructure can anticipate, absorb, adapt to, and rapidly recover from a disruptive event. We must consider all hazards, spanning security and naturally occurring events.

And while it is important to think creatively, envisioning a wide range of possible threats, and to understand potential mitigation options, good resilient design principles should adopt to unenvisioned events; things that might occur beyond our design basis threat.

A well-designed system will have certain attributes, such as graceful degradation, segmentation, reducing criticality of individual assets, plans for flexible recovery -- these things will help regardless of the specific scenario. I love General Eisenhower's quote: "In preparing for battle, plans are useless, but planning is indispensable." It's all about preparedness.

Here are some examples of grid-enhancing technologies from the National Academies report. Enhancing the robustness of individual components is a key attribute for improving resilience. Distribution automation is a broad category of technologies associated with automated switching and monitoring to quickly isolate and recover the system.
Distributed energy resources is an interesting area. With older integration standards that compelled DER to trip off during an event, these technologies didn't contribute to overall system resilience. But with newer standards that specify ride-through capabilities, and further, ongoing research that shows DER can be used to facilitate blackstart restoration, these technologies are poised to substantially enhance resilience.

Enhanced modeling and simulation can also dramatically enhance resilience. For example, the U.S. Department of Energy is currently embarking on the development of a cross-sector North American Energy System Resilience Model.

Wide area monitoring control for real-time situational awareness, advanced operational tools, or for model validation, have always been a key component of enhancing the reliability and resilience of the system. One notable example is the DOE-EPRI North American SynchroPhaser Initiative, focused on enhancing the deployment and utilization of wide-area time-synchronized high-speed measurements.

Intelligent load shedding and adaptive islanding are technologies that can reap the advantages of large-scale interconnected power systems during normal operations, but quickly isolate problems before they cascade during
emergency conditions. Controlled islanding is preferable to an uncontrolled cascading failure.

The best way to secure your critical substations is to not have any critical substations. Architectural considerations to reduce the criticality of individual components is associated with key research activities currently underway by DOE.

Whether it is fuel delivery or communications, reducing the dependency on supporting infrastructures is also important. This includes fail-safe communications, and fuel-secure or dual fuel generation.

And finally, cyber resilience. All utilities understand cybersecurity, particularly the mandatory cybersecurity requirements. But not everybody has a robust cyber resilience plan. Assume your system is lost and then what? Like a blackstart restoration for your critical cyber systems. It is an area that warrants greater attention.

Finally, I want to mention that I am honored to be co-director along with Dr. Anjan Bose at the Washington State University of the new Advanced Grid Institute. We hope that you will be hearing much more about this joint institute in the not too distance future, as we focus our research to drive greater innovation and collaboration with others helping to solve the most pressing national challenges in this technical arena.
Technological advancements will continue to make our electric power infrastructure more resilient, reliable, flexible, secure, sustainable and affordable. I have found it challenging to cover as much as I could pack into seven minutes. Hopefully, my remarks this morning have been helpful to providing an overview that the other speaks will delve into greater detail.

MR. PEIROVI: Right on time, Jeff.

MR. DAGLE: You have 15 seconds, actually, just kidding, so thank you very much.

MR. PEIROVI: Now we'll move on, thank you, Jeff, move on to Pablo.

MR. RUIZ: Good morning. I was asked to explain transmission topology optimization, also known as topology control and transmission switching. This is one of the technologies listed for discussion in the workshop. This is a software technology developed with DOE ARPA-E support. It is deployable today, relying on existing hardware without the need for new hardware.

Usually at any point in time, there are very few binding transmission constraints. The vast majority of the transmission licensed transformers have unutilized capacity. Topology optimization is software that automatically finds the reconfiguration steps, can route flow around the very few congested elements increasing the utilization of the
rest of the grid.

In a sense, it is like a Waze obligation for transmission operators. This slide has a case study of the historical instance of the SPP real-time market from March of last year. Different colors in the slide show different prices, variations in colors show congestion.

The left-hand side, we have the historical case with three binding constraints -- three congested constraints. You can see those with the color gradients.

On the right-hand side we see what has happened with the topology optimization. The two most severe constraints, the one in Kansas and in southeast Oklahoma, we have been fully relieved. And we'll focus on the latter one on the Oklahoma constraint to explain how to illustrate how topology optimization works.

By the way, I will note that this particular constraint was the third most congested constraint SPP in 2018. The constraint monitors the flow in the 138 kV lines for the outage of a 345 kV line, the 345 lines in the diagrams are the thicker lines with larger arrows. The 138 kV lines for the remaining thinner lines with smaller arrows.

Topology optimization so far found a number of single action solutions, and what they do -- as you can see on the right-hand side, is they detected an opening, a 138
kV line a few substations upstream of the binding constraint, can re-route enough power to fully relieve both the overload and the congestion with the subsequent economic benefits. And I'll note that SPP did develop an operating guide based on this analysis.

The reconfigurations that implemented by switching circuit breakers, open or close, which is analogous to diverting traffic flow away from congested roads to make traffic smoother and minimize the delays for all drivers.

Switching circuit breakers is an extremely reliable operation as documented by CUS surveys, and it's very low-cost to such an extent that they are usually referred to as "no cost actions." Reconfigurations can be very effective, as we saw in the first couple of slides. The main challenge is finding the very few beneficial ones among the universe of possible reconfigurations.

Traditionally, this search has been done based on operator or engineer experience, a daunting task, given the complexity of the system. This has limited the use of reconfigurations. Topology optimization supports software that provides very fast search of reconfiguration options. Operators can then further analyze these options if needed before deciding whether or not they should implement a reconfiguration.
The reconfiguration search includes the level of the assessment consisting of contingency analysis in connectivity evaluation to ensure that the reconfigurations are feasible and they're all specific contingencies, and do not lead to additional radial load beyond the use of specified value. As mentioned in the previous slide, further analysis of transmission stability can be performed if needed, using tools specific for those analyses.

Adapting the grid configurations to best address system conditions provides many reliability and economic benefits which we have quantified working with several system operators, and transmission owners. We will highlight this morning three such benefits.

In terms of grid resilience with reliability and security impacts. In several historical cases with overloads during extreme weather events, including heatwaves, cold snaps, wildfires, we have found configurations that provide relief of those overloads in some cases, complete relief.

In terms of transfer capability improvements, we have quantified an increase of 4 to 12 percent in the capability of very broad, large interface constraints in Great Britain working with National Grid and these improvements are for binding constraints under outage conditions. So, that also relates to the resiliency and
reliability benefits.

In terms of economic efficiency, we have estimated over 100 million dollars per year in congestion cost savings from using topology optimization in PJM real time markets under historical conditions. These savings are in addition to use of the technology in other markets such as day ahead market and other processes, such as unit commitment or similar operational processes.

The applications can be used -- the technology can be used in a variety of business processes in different time scales from long-term planning to real time operations, although this is mostly an operation support technology.

From an ease of implementation point of view, the low-hanging fruit are processes like seasonal contingency planning for which ERCOT uses the technology, has been using it for a couple of years in outage scheduling and coordination. These two processes take place in the months to days ahead.

Topology optimization relies on existing infrastructure to provide significant benefits under all system and ambient conditions, complimenting other grid enhancing technologies such as dynamic line ratings and powerful control in other FACTS devices.

At the very high level, there are three barriers to adoption, and these tend to be common to all grid
enhancing technologies. First, there's an incentive problem which the one proposal addresses where they share benefits incentive approach.

There are also questions on market and regulatory policy which would be good for the Commission to address. One such question is whether operators should prioritize "no-cost" actions over costly actions whenever they have such choice in all decision-making processes.

And the third barrier is the fact that integrating grid-enhancing technologies to operations processes does require adjustment to those processes, and as such, they need staff and stakeholder time and dedication which can be sparse, given other ongoing efforts. It would be useful for the Commission to comment on relative priorities and also in terms of this prioritization, we do suggest a staged deployment, beginning with pilots to show the minutes before a broad deployment and also starting with the low-hanging fruit type of applications such as outage coordination that involve operating rights as needed.

This concludes the presentation. I look forward to the Q&A session, thank you.

MR. PEIROVI: Thank you, Pablo. Moving on to Swaraj.

MR. JAMMALAMADAKA: Thank you. I'm Swaraj Jammalamadaka, Vice President of Transmission and Market
Fundamentals for Apex Clean Energy. For those of you who don't know, Apex Clean Energy is a clean energy independent power producer headquartered in Charlottesville, Virginia. Since our inception, we bought about 5,000 megawatts of clean energy generation in service, and we operate across all the ISOs, so we appreciate the opportunity to be here and be part of this discussion. And our view and our deliver is mostly going to be from a view of generation developers involved in the changing fuel mix and how the transmission has impacted our business.

So, just a couple of facts on the state of the transmission system. Again, mostly known, the U.S. infrastructure, the transmission side, as of 2018, 65 percent of the transmission lines and transformers are 35 years and older, and 60 percent of the circuit breakers are 40 years or older. There's nothing wrong about that, it just shows a little bit on the rigidity of the infrastructure and how it's able to meet either today's or future needs.

A majority of the congestion as we see on the transmission network is caused by less than 10 percent of the transmission elements. Generally, large capital infrastructure projects are proposed to solve these congestion bottlenecks. The electric grid of the future will need to be sufficiently flexible, responsive and
reliable to support an evolving fuel mix.

Congestion-free energy delivery, we see that as some of our customers are Army bases. We want to make sure that we are able to deliver to our customers without any congestion in the market and should be able to respond to quickly, to system contingencies.

One thing we have seen over the last many years is that the power transmission capability on regional export interfaces is generally not limited by the thermal capability of the conductor, it's mostly a system limit of an example being the panhandle interface in ERCOT, or the Minnesota/Wisconsin export in MISO.

So, mostly an interface consisting of multiple 345 or high voltage lines, typically limited by a system operating limit that is not reflective of the conductor's actual current carrying capabilities. So, the above challenges that you know, that I've just referenced, do present an opportunity for the deployment of grid-enhancing technologies into the flexibility and resiliency of the grid while maintaining system reliability.

So, speaking a little bit about transmission utilization, so this is a simulation -- a market simulation of 400,000 hours, or the next five years. And what we've noticed is from a learning factor, the median value is less than 20 percent, and all the facilities that you see on this
map right now are actually those facilities that the load is
less than 20 percent across the entire annual five year
timeframe.

This list increases significantly when we
actually raise the learning factor over 50 percent. It's
pretty much 85 percent of the facilities if you were to
increase the loading factor to 50 percent. Just to make it
simple, I've just shown a snapshot of eastern MISO and all
of PJM, the lines in green are MISO and the lines in gray
are PJM.

So, and if you look at historical, the numbers
even more, you have almost just in PJM over 1,200 facilities
that are loaded less than 20 percent. So, from a generation
developer's perspective, and we can get hit with congestion
in the market, it's a little concerning to us that they have
lines right next to us that are not loaded anywhere close to
their capability, but we still experience congestion in the
market. So, there's definitely a need for technology that
can either read out this flow, as Pablo mentioned, or
technology that can control hard flow on the AC system.

As everyone is aware, the AC transmission system
is the flows on the AC transmission are determined by the
dispatch -- generation dispatch. And, if you want to change
the flow on an AC transmission element, you have to change
the generation dispatch to read out these flows.
There's definitely a lot of value for equipment on the AC system that can hold flow to a desired level on a transmission facility. So, talking a little bit about transmission adequacy, I think all of the transmission security, I think it's time we discuss about transmission adequacy and enhancing the resiliency and the flexibility of our transmission system.

We have what we believe should be a definition of enhancing technologies, so technologies that provide an ability to control our direct power flows through the transmission grid while increasing transmission adequacy and enhancing system reliability.

These technologies as mentioned, can influence the electronic transmission system, this enables the ability to either hold available power on transmission facilities. The benefits again, that can be used to alleviate congestion, respond to contingency events and mitigate power quality issues on the customer side of things.

Both hardware and software technologies can qualify as grid-enhancing technologies. Following our few areas of technology that APEX is currently aware of and is pursuing them or deploying them on our transmission facilities to connect to the system are the network.

Again, three classifications. Flow control devices we talked about, so any devices that can read out
flows on the transmission system. Typically, this has been
done as a large capital infrastructure on the substation
side, using FACTS devices, like synchronous condensers or
static watt compensators, or statcoms.

So, these devices provide support at substations
in the middle of a long line to provide support to either
push or pull power as desired on transmission facilities.
Historically, it's been done through that, but obviously for
this technology we have distributed CD reactors and line
reactors that can in real time change the physical
characteristics of the line and through our topology
optimization and through advanced software, can read out
power as desired to send power into areas that are not being
utilized.

Dynamic line ratings -- this has been discussed
at length, so I won't go into that, but definitely a
low-hanging fruit value add to unlock additional capacity on
existing infrastructure. Topology optimization -- Pablo
just spoke about, is a network's solution to optimally
activate or even deactivate facilities to maximize low
energy delivery while maintaining system security.

So, this is a borrowed slide of value stream and
beneficiaries. It's from the operating report to the U.S.
DOE. It highlights the entire value streams and the
stakeholders involved within the transmission process.
So, asset management, renewable integration, congestion relief, economic efficiency and reliability and security are all of the value streams that can be impacted by grid enhancing technologies. The ones in green are the parties to likely benefit financially or operationally from grid-enhancing technologies.

The ones in yellow is a dependent situation, so depending on the situation there's a benefit power loss and the ones in red is a loss in the current situation. So, if for generation it comes off of revenues, definitely reduces the need for having a lot more reserves on your system.

There's one more slide that I've borrowed. I think it's interesting to look at the influencers on the transmission infrastructure. So, you have different stakeholders and -- who influence the kind of investment that goes into either technology or the transmission infrastructure.

I think it's a great slide that showcases the different push/pulls off of macro of the transmission industry. With this, I'd just like to go into the path forward as a new developer, what you see as a path follower to the grid, and some technologies that should be included as part of our long-term transmission processes as part of possible mitigation for any violations that are seen on the system.
They should also be investigated as mitigation for all transmission access planning process such as generation, interconnection, transmission service, to maximize existing system. Economical analysis of what is required to enable power flow controller to MISO RTO level will definitely be needed to figure out what are the needs. Design and establish protocols of coordination and control required between all the stakeholders in the industry and there's definitely a need to evaluate existing market design construct to enable a flexible grid, either through grid-enhancing technologies or any other software control that will be required to maintain a flexible grid.

With that, I conclude my presentation. We appreciate the opportunity of being part of this discussion, thank you.

MR. PEIROVI: Thank you, Swaraj. Now, we'll close the opening statements with Jack.

MR. MCCALL: Good morning Commissioners and Commission staff. Thank you for inviting me to speak on the subject -- thank you. Thanks for inviting me to speak at this Conference. My name is Jack McCall, I am the Executive Vice President at Lindsey Manufacturing, a dynamic line rating provider, as well as the current Chair of the WATT Coalition.

FERC staff has proposed a definition of
grid-enhancing technologies or GETs. And I do point out
here that this speaks only to the transmission grid only.
The specific definition that FERC has laid out is that GETs
should not be a traditional transmission investment and the
technology should increase grid reliability and/or economic
efficiency.

I suggest expanding this to include resilience
and situational awareness as performance characteristics.
Additionally, they should provide information and/or operate
in real time or near real time.

Three technologies primarily, have been under
discussion as providing these benefits. They are dynamic
line rating, or DLR, network topology optimization, and
power flow control. All three meet these requirements.

DLR was widely discussed during FERC's line
rating Technical Conference in September. In summary, using
live data from sensors mounted on a transmission line, and
combining it with live weather data, DLR systems compute the
line's actual power handling capacity.

Transmission capacity forecasting, or TCF, is an
extension of DLR. Forecast weather data is added to the DLR
developed model, providing the ability to forecast line
ratings for us in the day ahead market. The feedback loop
provided by live conductor data is an essential feature of
DLR and allows it to provide a line's true capacity.
DLR does not increase a line's capacity, but rather reveals when a line has more or less power handling capacity than assumed. It is well established that more capacity is available on most lines 95 percent of the time. DLR provides the opportunity to improve reliability, improve resilience during major events, and improve economics by reducing grid congestion and reducing energy costs to consumers.

Topology optimization was discussed by Mr. Ruiz earlier in this panel. In summary, it is a software system which determines in near real time how to optimize the power transfer capacity of the grid by determining which circuit breakers should be opened and closed. This is again, as he indicated, to a Waze-like rerouting of traffic on a system of roads.

Like DLR, topology optimization is not a traditional transmission investment. It offers to increase grid reliability, resiliency and economics. By nature of its near real time simulation, it can also be viewed as providing situational awareness.

Power flow control refers to technology, as we've heard, that can increase or decrease the amount of power that flows over a transmission line. These technologies again, do not increase line capacity, but rather modify a line's electrical characteristics to increase or decrease
Traditionally, this type of control has been provided by phase angle regulators, capacitors, and other devices installed in substations. These are slow-acting devices, not truly suitable for real time operation. They are also considered traditional types of investment.

New power electronics-based power flow devices, which provide real time response are now available, specifically, these would include distributed reactances, which can reduce power flow on a line. Two FACTS devices are also available, static synchronous series compensators, or SSSCs, and unified power flow controllers, or UPFCs.

Both devices can operate to increase or decrease power flow in a line. You'll hear more about these in Panel Session Number 2, during Mr. Kreikebaum's talk. This table summarizes how these three technologies fit into the proposed definition of grid-enhancing technologies. It seems that they are all non-traditional investments, they offer significant benefits to the grid and provide the situational awareness and real time control needed for a modern grid.

To summarize all of these using the traffic analogies which we all seem to be so fond of in these last couple sessions, DLR can show more capacity than is available. We can show that more capacity is available than
assumed, hereby seeing more lanes.

Topology optimization acts to completely open or close off routes to power flow, and power flow control encourages power to flow or not to flow along certain paths by making those routes more or less attractive, electrically speaking. For completeness, Lindsey suggests three additions to the list of grid-enhancing technologies as has been discussed so far.

These would be systems to monitor transmission assets, provide awareness of long line performance, via the application of PMUs which was discussed earlier and systems to possibly provide dynamic relay settings.

This chart shows how they would fit into the definition requirements. Asset monitoring of medium to large power transformers is already common in the industry. These systems provide real time situational awareness of the health of these long lead time assets and allow for pre-emptive repair and/or replacement before failure occurs. This increases reliability and can save the utility and consumer money. Similar monitoring of transmission assets is not as common. DLR's systems can also offer transmission asset monitoring capabilities by monitoring conductor behavior and tracking when asset shortening events, such as severe icing or thermal overloads have damaged the conductors.
Additional systems could be used to monitor transmission tower structures for damage, willful or otherwise, that could result in premature power failure. Such failures cause significant damage and often power outages. The tower pictured here collapsed as a result of the tower still being stolen off of the tower, weakening it so it collapsed in a less severe wind event than the tower was originally designed for.

While DLR provides insights on shorter, thermally limited lines, long lines are usually limited by voltage drop effects. Voltage collapse during system events can lead to instability of the grid and widespread power outages. PNUs provide the situational awareness into the performance of longer lines. This can assist in preventing major system events, increasing reliability.

Dynamic relay setting is a fledgling technology and would be applicable only after other grid-enhancing technologies are more widely deployed. The concept is to dynamically adjust the settings of protective relays in real time, based upon transmission line capacity, network configuration and the statute of dynamic power flow controls.

Modern relay communication protocols are available that can support on the fly setting changes. This would be a natural last layer to place on top of other
technologies to reduce or limit outages and deliver a truly
optimized grid. This would be an excellent area of R&D for
the DOE's National Laboratories.

Changing focus, speaking for both WATT and
Lindsey, we do not believe that ambient adjusted ratings, or
AAR, should be considered a grid-enhancing technology.
During the previous Workshop, significant time was spent
discussing AARs by utilities which have deployed some form
of AAR on their systems.

We recognize the familiarity, assumed simplicity
of implementation, and perceived low cost of AAR is
appealing. However, AARs do not provide situational
awareness, merely a perception of that. More importantly,
AAR is implemented today can produce line ratings
significantly less conservative than expected under certain
weather conditions -- this being the result of sole
dependence on prevailing ambient temperatures without
feedback mechanism of resulting line behavior.

Detailed comments on this subject have been
submitted to the FERC in WATT's response to the previous
Conference's questions. But to briefly summarize, base or
static line ratings are known to assume very conservative
weather conditions, including both low wind speed and high
ambient temperatures.

A 2006 Joint Task Force between the IEEE and the
European based organization CIGRE, produced a report called "TB 299", detailing the weather inputs needed to properly develop line ratings. The document discusses base ratings or static ratings, ambient adjusted, and real time -- that is DLR, rating methods.

Pertaining to ambient adjusted ratings the report states, "Unless real time rating systems are used, the wind speed should be based on the assumption of a more conservative effective wind speed than used in base ratings."

The report further states that adjusting line ratings on ambient, "Can be considered justified if based on an adequately conservative wind speed, for example, zero wind." As wind has a much greater impact on line ratings than ambient, this would suggest the temperature only based AAR is implemented today is less conservative than base ratings where wind speed is not adjusted.

To explain, under normal operating conditions, most transmission lines operate well below 80 percent of base rating. A 10 to 20 percent error in an ambient adjusted rating will not be noticed under these conditions. However, under retail wheeling and contingency conditions, lines are often operated up to their limit.

Error from ambient only adjustment therefore is less conservative and can increase the risk of clearance
violations or conductor damage. In contrast, the feedback
given by DLR considers all the weather parameters,
measures and monitors line behavior, provides true
situational awareness, and actually reduces risk during
contingency conditions.

Again, using our traffic analogies, AAR is akin
to saying if it is the weekend, traffic should be light, so
I can drive faster. DLR would also consider that it's a
holiday, there are some accidents on the normal route, and
that it's snowing. AAR is akin to generalizing while
ignoring other relevant, easy to obtain information.

In summary, grid-enhancing technologies share
common operational benefits by optimizing the capacity and
capabilities of the existing transmission assets. DLR can
be seen as a backbone. The instrumentation and methods used
by DLR properly identifies the true capacity of thermally
limited transmission lines.

Topology optimization software and real time
power flow control devices then provide the tools to
effectively control and route power to lines that have more
capacity from those that do not. Wide deployment of GETS
will dramatically reduce congestion, reduce costs to
consumers, increase reliability and resiliency and enable
better economic dispatch, thank you.

MR. PEIROVI: Thank you all for the opening
remarks. We'll move on, we've got quite a bit of time for
Q&A, which is good. I'd like to start with Commissioner
Glick to see if he has any questions?

COMMISSIONER GLICK: That's okay, I'll leave the
rest for everybody else. Mr. Jammalamadaka, did I get that
right?

MR. JAMMALAMADAKA: That's right.

COMMISSION GLICK: I thought your presentation
was very interesting. That map you had out there showing
how much of the transmission lines are only the load is 20
percent or less, and you mentioned that there's a number of
others at 50 percent or less.

I'm just wondering -- actually I want to address
it to all the panelists, why you all think that we haven't
adopted, or utilities haven't adopted these -- it would be
the purchasing the hardware, or the software, or deploying
the software to improve power flow controls and manual
reconfiguration, things like that. Why haven't we done more
given the lack of use of the existing grid?

MR. JAMMALAMADAKA: So, my view might be a little
biased on this one, but I'll try to be open-minded on that
one. So, the majority of the times the grid-enhancing
technology also looks very similar to transmission in terms
of delivering benefits.

So, the company that is enabling the technology
might not be the beneficiary. The beneficiary might be
someone significantly different. And in most of these
markets, especially in vertically integrated systems. The
concept of opening up additional transmission for someone
else's benefit during the age of open access, is still
something that I believe utilities are not embracing, and at
an ISO level, it mostly comes down to their dealing with a
bigger issue on cost allocation with transmission, how to
build transmission.

So, they see that as a bigger problem to first
solve than to figure out how to actually capture this
low-hanging fruit. So, that's just my view of these things
that it's very similar to how a transmission system is. The
beneficiaries are very different from the people that are
embracing the technology.

COMMISSIONER GLICKMAN: Anybody else?

MR. DAGLE: I could provide a perspective here.

Yeah, I think the cost of these grid-enhancing technologies
has been coming down. But historically, I think there has
been a cost barrier to implementing, you know, things like
face-shifting transformers and those types of things that
can redirect power flow on the network.

And I think part of the answer -- I think another
part of the answer too, is that a lot of times the grid
assets, in terms of the transmission facilities and things
that are needed, they're based on a post-contingency
analysis. And so, during normal day to day operations, if
you just look at the asset utilization, you might see, you
know, relatively low numbers, but yet those resources are
really designed and justified based on a post-contingency
situation, so I think that's another part of the answer.

MR. RUIZ: Yeah, let me follow-up. Actually,
I'll address Jeff, your last point. The number of congested
constraints -- usually congestion, or binding elements are a
result from post-contingency conditions. And even under
those conditions the utilization is quite low.

Just to follow-up on Swaraj's point on incentives
and also on Jeff's comments on the fact that the costs have
gone down. Technology has also improved significantly over
the last 10 years, so these technologies were not available,
at least in the form that they are today, 20 years ago, for
sure.

And also, even though the technologies can be and
are quite effective and reliable and have a lot of benefits,
their use does require an adaptation of processes. This
would require operators and utilities to make a concerted
effort to embrace them. And, as we all know, we all have
competing priorities, so that's also a barrier that affects
the development of the technologies.

MR. MCCALL: Just to reaffirm Pablo's point.
Technologies have developed quite a bit over the last decade where 10 years ago, for example, dynamic line rating was not really useful and that it only provided the real time information. We discussed that during the last Conference.

The real time is not fast enough for those operations. Also, I think the EMS systems needed some additional maturing and capabilities and capacities. The competing systems available today are much more sophisticated than they were 10 or 12 years ago.

So, therefore, I think there's two things -- the technologies have advanced quite a bit, the capability of our systems to adopt them, and deal with them in a real time is also -- so there.

MR. PEIROVI: As you can see, we have a competing hearing. I'm not sure who -- just kidding. Commissioner Glick, do you have any other questions?

COMMISSIONER GLICK: No.

MR. PEIROVI: Okay, thank you, thank you for that. I'm going to start with kind of a general question. Many of you already touched on this, but I want to get your reactions on our -- FERC's staff preliminary belief that grid-enhancing technologies, or what we're calling grid-enhancing technologies, should include as many technologies as possible that meet two criteria.

One, that it should not be a transmission
investment like a new transmission lined or substation. And

two, that it should enhance the existing transmission system
by either increasing the reliability or by increasing the
economic efficiency of the existing transmission system or
both. How do you react to that preliminary definition? I
know Jack already touched on that specifically, and
explicitly, but how do the rest of the panelists react to
that preliminary definition that we think should -- and to
Jack's additions to that preliminary definition.

MR. DAGLE: Well, from my perspective, certainly

if you can adopt technologies, you know, reaping what the
so-called low-hanging fruit where you can have
cost-effective technologies to make better utilization of
our existing infrastructure. That's clearly very important.

And I think some of the comments that were made
by the panelists is that, you know, the technology has been
advancing in terms of capability, the costs have been
decreasing, you know, in terms of historical things. So,
anything that we can do to sort of encourage those types of
technology deployments, I think we're better off.

The other sort of comment I would make is that I
believe personally, that we're entering a realm of subject
to uncertainty for our electrical infrastructure, and so
things that we can invest in now, that enhances the overall
flexibility of our existing infrastructure is a sound and
prudent path to go forward. It's sort of like
future-proofing the grid, and we're not really locked into
other assumptions about the development or deployment of our
generation technologies.

We're, you know, if the delivery infrastructure
has maximum flexibility, then we're poised to be able to
better accommodate future scenarios, so it's what I call
future-proofing the grid. And so, technologies that we can
do along those lines is, I think, a really good idea.

And I guess before I pass the mic off, when new
transmission is needed, and I do believe that new
transmission will be needed for things like incorporating,
you know, remote renewables and things like that, you know,
the focus should be on just because there isn't adequate
transfer capacity in that area, but generally shoring up
areas where, you know, there's under-utilization, things
like that. That's where these non-wires technologies have a
lot of merit.

MR. PEIROVI: Thank you, Pablo?

MR. RUIZ: Yeah, I support Jeff's comments in
terms of the definition, it's a sensible one, and I also
support Jack's additions to it.

MR. PEIROVI: Swaraj?

MR. JAMMALAMADAKA: We are fully in support of
Jack's comments and Lindsey's comments on the definition.

MR. MCCALL: Yeah, and just to underline Jeff's comments, there is uncertainty in the future, and that's one of the reasons that we feel that, excuse me, resiliency needs to be added to that definition because it's the resiliency that's really going to -- that these technologies offer in terms of those "what if" events that really is going to address the changes that are going to occur in the future and the uncertainties, whether it be a cyberattack, or storms, or weather-related, or what have you.

So, looking at these technologies in terms of resiliency as well as reliability and economics should be key.

MR. PEIROVI: That's a great segue Jack, because Jeff did mention defining resilience metrics. Can you expand on that and tell us about how to define resilience metrics, and more generally, how to define the benefits of what we're calling grid-enhancing technologies?

MR. DAGLE: Sure, yeah, it's a challenging area and a lot of research is currently underway to develop resilience metrics, and so we're not there yet in terms of having, you know, sort of a framework for how we can accommodate this. I would still characterize those metrics as still very much under the belt in the phase with various research projects underway at DEO and elsewhere.
One of the things that we really focus on in terms of reliability metrics is measuring, you know, customers that are out of service a number of times and the duration of outages and things like that. Those are the traditional reliability metrics that we're all familiar with.

The challenge with resilience is that you're really trying to measure preparedness to events that, you know, haven't or may never occur, but you still can have some resilience attributes, so to say, on the system.

So, in my opinion, I think you're really needing to look at scenario-based analysis to really understand how your, you know, how your system is able to withstand these types of events. And you know, in prior presentations, I've offered a thought exercise.

You know, if you think of two identical utilities in every respect, with equal reliability metrics, and everything about these organizations are exactly identical, but yet when organization decides to cross-train their employees so they can understand better cyber awareness, or a better emergency preparedness training, and things like that and the other one doesn't.

Clearly, that resilience metrics should somehow capture that and yet, you know, that's kind of hard to do by just looking at sort of the outward operation of the utility
entity. And, the perfect nirvana, if we can get there, is if we have these metrics that kind of capture all these things that we can do, then organizations can do a cost benefit analysis to prioritize which resilience metrics, or measures that we undertake to improve the resilience metrics.

And, you know, it's challenging and we're not there yet, but fundamentally, I think it needs to be a scenario-based analysis, where we look at different types of events and how the system would respond to those events and then try to quantify the impact of that, if anybody has any additional comments.

MR. PEIROVI: Thank you, Pablo, Swaraj, Jack, any comments on that? Thank you. That was good, thank you. I have a question for Jack. Are there any -- can you expand on any metrics to measure grid flexibility and incremental contribution of grid-enhancing technologies?

MR. MCCALL: Boy, that's a good question. We've discussed before looking at reduction in congestion, which I do want to kind of briefly, in one of the comments that Swaraj made during his presentation, which is the under-utilization of lines, which is true. Lines are quite heavily under-utilized most of the time.

But the congestion really comes about during the contingency conditions, and that's when we're really --
that's when the lines are expected to be loaded up to the 
maximum, whether it's an N minus 1, or N minus 2, or 
whatever it happens to be. So, I know it's -- you know, we 
usually find it unusual when we have presentations and we 
show how a line is loaded and it's, you know, running at 20 
or 30 percent of its capacity, and it's, you know, and 
you're still looking at trying to apply dynamic line rating 
to it, but that addresses that.

In terms of other metrics for reliability, let me 
pause on that one. I'll pass it over to anybody else if 
they've got that, and I'll come back to that if I --

MR. JAMMALAMADAKA: From our perspective it's 
mostly the cost irrespective of any metric. So, it's before 
the technology and not from the technology whatever metric 
you come up with either to meet -- either to quantify 
flexibility or resiliency. There's a cost add, or a benefit 
add that these technologies provide.

So, yes, they can be benefit metrics, but I think 
from a quantification perspective of why we need 
grid-enhancing technologies, that you can't -- it mostly 
comes down to the economics of that situation.

Because you can have a really expensive fix to a 
resiliency event that will be actually mitigated for that. 
The way we think of it as delivering to our customers. So, 
there can be really defined metrics on, for example,
carrying ancillary, so this is a cost of carrying additional reserves. In an interconnected system, do you really need to carry the largest contingency as your reserve to actually meet that, and what's the cost of doing that?

And if you have grid-enhancing technologies, that is actually the deals -- the cost of carrying this additional reserve. So, there are a few things that you can compare.

MR. PEIROVI: Thank you.

MR. RUIZ: To follow-up on metrics, on the efficiency side, one metric that is quite encompassing is the cost of being able to manage constraints. That has a different flavor, or a number of additional sub-metrics. The costs of -- the market costs of congestion is one of them because of potentially out of market commitments.

Maybe another one, that's on the efficiency side. On the reliability side, I think the ability to relieve post-contingency, or even best case overloads, is one could mention that in terms of the MVA, or the percent of relief. One can also look at it from the point of view of frequency of overloaded events. So, those are two additional metrics.

MR. PEIROVI: Thank you.

MR. MCCALL: One other thought -- it can be computational intensive, but for any of these technologies, if you look at what the L&P's are at any given location,
both with and without those technologies being existent, or being deployed, that could be looked at as a financial indicator of what the benefits of deploying those technologies would be.

MR. PEIROVI: Thank you. Let me open it up to other Commission staff members, and see if my team and fellow staff have any questions.

MR. KOLKMANN: I'm wondering -- so, we spoke at the last Conference, we spoke about DR, so we'll leave that off to the side for a moment. But, for the other grid enhancing technologies, I'm wondering if people can weigh in on how frequently you actually see these technologies operationalized, if at all?

MR. DAGLE: Well, I think broadly, you know, things like static compensators, and things like that, you know, there are quite of few of those deployments for you know, voltage control and things like that. As it relates to, you know, some of the power flow control technology, you know, in terms of you know, capacitor, you know, or static capacitors or things like that, I think the challenge with those is that the you know, I'm not personally aware of a lot of that deployment and I think it's primarily the technology readiness level and the cost hasn't quite got there yet where there's a lot of marketable at this point in time.
MR. JAMMALAMADAKA: So, we answer that, so the slide which we showed you was in 2024, so just talking from an inverter-based generation perspective, MISO is expected to have about 33,000 megawatts of inverter-based transmission by 2024.

PJM is at 35,000, ERCOT is at 44,000 megawatts. SPP is already getting some hours at 70 percent of enabled penetration. So, with increased amount of inverter-based generation coming in out of the system, we're already seeing a significant value being assigned in certain markets to these grid-enhancing technologies, but they've been the traditional solutions, like the high cap incentive, solutions like the synchronized condensers and the stack coms and SVCs, or static work compensators as Jeff mentioned.

So, we see that we already are seeing this being proposed in our catalogue and there's a advancement of the technology and we believe that's going to happen a lot more in other markets too. So, definitely the next five years, the amount of inverter-based generation coming into the system is extreme and most of these generations is coming into areas where there's a need for system strength, and that system strength needs to come from a specialized piece of equipment and these technologies, like especially the severe and serious reactors.
They can provide the means to push or pull power and to dynamically change the physical characteristics of the system for that condition that is needed. So, we really see the need coming in in the next five years.

MR. MCCALL: Looking at it from a bit of a historical perspective, you know, 30-40 years ago, the deployment of a static compensator or something like that, on the grid was like wow, somebody is going to be putting in a static compensator.

It was a pretty major deal. There were only a couple suppliers out there. There was one place in the country every three or four years. Today, they're pretty, you know, those types of technologies are fairly commonly accepted, everybody's familiar with them. You mentioned statcoms, you know small statcoms in the, you know, 5 to 10 million dollar range are regularly deployed in conjunction with wind farms to enable them to connect to the grid.

And I think as we start looking at less expensive types of power flow control devices, in particular, whether it's distributive reactances or static synchronous capacitors, or UPFCs, and the price point of those comes down, it's going to enable us to start deploying those. So, today there may not be a lot of these deployed and operational, but I do see that the trend in terms of the increased flexibility that they offer, the
lower price point that they're at, the smaller footprint that they take, the fact that they're not going to require their own substation, like a static compensator used to require years ago with acres and acres of filtered capacitor banks and stuff like that, will definitely turn the tide.

So, I would not look at the fact that some of these technologies are not widely deployed now as any sort of a measure that they are not useful technologies. The usefulness is nascent, and they just need to be deployed.

MS. GADANI: Good morning, thank you for being here. I'm Jignasa, Director of the Policy Office. I had a question in trying to understand the definition that -- so, staff put out a definition. Again, it's a proposed definition, it's not a traditional transmission investment, and it should enhance existing economic efficiency or increase reliability. I think Jack, you added a couple of additional elements to it. I think what I'm trying to figure out is sometimes the Commission will put out a definition instead of saying, "Here's exactly the types of technologies that fall under the definition," but it feels like sometimes when you do that you have this issue of which technologies are ready and need some criteria to be in that bucket, but it does give you clarity and certainty if you know what's in that bucket versus having a definition that
someone can check off.

And as technology develops or gets to a point where it's ready to meet those criteria, you can say, "Okay, it qualifies." From your perspective, in your experience, who has the responsibility to show that those metrics are met. Who would be the right entity to say if the Commission put out a definition, here is how this technology meets that definition?

MR. JAMMALAMADAKA: So, I would say there are processes existing today. I mean, the ISOs in certain regions are the transmission planning entities that rule on transmission plants, whether it meets certain criteria or not. I believe that can be expanded for them to evaluate whether this technology is grid-enhancing or not within their planning processes, so.

I don't see -- it's just an incremental change from an ISO-RTO perspective, actually rule on that. The reliability is still -- and there can be criteria in force within the NERC practices to actually enforce the reliability need. But from a classification need whether it's grid-enhancing technology or not, I believe the ISOs and RTOs are the best suited to work with the technology infrastructure to enable that.

MR. MCCALL: I applaud the idea of having a definition rather than defining a list, because that picks
winners and losers right off the bat. I think for -- I think as technology gets developed, you know, nobody is going to introduce a new technology and the industry is going to embrace it without years, just I mean, we all have been in this industry, it's very conservative.

Everybody is going to want to try it. It's going to be piloted, it's going to be you know, dozens, hundreds of papers are going to be written, blah, blah, blah, blah, blah, and by the time you're done with that, it's going to be apparent whether or not a technology fits in a particular category -- oh, this does provide situational awareness, or this provides some economic benefit, or this does what have you.

And then there's going to be, I think, a common sense of agreement in terms of whether it might fit some of these definitions. I think the technologies that we've talked about today, DLR power flow control grid optimization, they all have demonstrated over many, many years, sometimes decades, of studies and involvement by utilities around the world sometimes that they do provide these benefits and they can clearly be put in there.

I think new technologies, as they come about, it's only going to be the study of them, the piloting of them, and it's going to determine whether or not they actually produce those type of benefits that will enable
them to fall in.

But I do feel that just having a definition is the correct way to go, rather than trying to pick a technology or two, or five.

MR. RUIS: I agree on that. One small comment following-up on those comments relating to a planning authority, simply the ISO RTO in those areas would be a good institution to validate these technologies. Some of these technologies though are more operation's focused than planning focused, so the balancing and the planning authorities may have other -- at the very least, a partial role in commenting the usefulness and whether the technologies fit the criteria. And that, I guess, would apply not only to the RTO areas, but broadly.

MR. DAGLE: I guess at a small fact data I agree with all the previous comments. You know, maybe another point to keep in mind is be clear about the benefits that these technologies are, you know, trying to achieve, right? So, in that definition, and how you value that, you know, try to have the benefits clearly defined.

MR. PEIROVI: I'd like to turn, seeing no other questions from my fellow staff members, I'd like to turn to the representatives of the RTOs and ISOS on the side tables, or David Patton, who's on the left there representing Potomac Economics. Do you have any thoughts, specifically,
well on what was said at this panel, but specifically on the implementation of a benefits approach, or the implementation of, you know, maybe a defined metrics approach? And we'll pass the mic down, sorry about that. And I'll pass this mic if --

MR. HERLING: Yeah, this is Steve Herling with PJM. There was a lot of discussion at one point or another about kind of average utilization of transmission lines over entire years, reliability criteria and resilience metrics. When you start looking at these devices, you really need to look at when you have a problem that needs to be resolved, which to me, would focus you on when you have reliability issues which could manifest themselves as congestion, or especially when you have resilience issues and the indicator of value, really, has to be based on the performance of the device under a defined set of circumstances

Reliability criteria -- you know, we have a lot of experience evaluating transmission assets as they perform with respect to violations or reliability criteria. That's how we select winners in our solicitations. The same can be applied to all of these devices, but you need to focus on when you have a defined problem that needs to be resolved.

Resilience is the trickier one, and I then I agree. We're still working on what the metrics for resilience might look like and that's when you start looking
at could you start moving some of the megawatts around onto
these under-utilized assets to enhance the performance of
the remaining assets, and therefore the resilience of the
grid. So, it's got to be performance-based when you need
it.

MR. WEBB: Just, I actually had a question for
Pablo on the new grid approach, whether or not -- I think
the way you described it was more of an advisory tool that
can help optimize what the transmission operator might do.
Are you thinking of it also in a more advanced mode, where
it would somehow automatically implement the switching?

MR. RUIZ: Certainly not at this time.

MR. WEBB: Yeah, I think that could be a step
level change in complication. I'm sorry, I'm Jeff Webb, the
Senior Director of Transmission Planning at MISO, sorry. I
guess the other question that FERC staff asked about who
should decide whether something fits the proper definition.

I think that's also a complicated question
because it -- maybe it depends if we're talking about
whether it needs to be isolated in definition from other
types of transmission for other types of treatment. And I'm
not sure we've resolved, or even addressed. Maybe we will
later in one of the panels today, you know, whether they
should get other types of treatment.

But I'm not -- I think the RTO sort of like Steve
was alluding to, is really well suited, once you have an
established technology that has been thoroughly -- is
mature, then the RTO can put that in its tool bag if you
will, along with the collaborative planning processes to
determine, for example, whether they should be selected as
the right solution to the right problem.

Deciding if it fits a certain definition is a
different question and I'm not sure that should be the RTO,
it might better be the asset owners.

MR. PATTON: Yeah, I had two quick questions.
I'm David Patton, President of Potomac Economics, and we're
the independent market monitor for ERCOT New England, New
York and MISO.

So, with regard to defining technologies, my
predilection would be to put them into two buckets, one that
involves equipment and capital investment, and then the
other that involves software and optimization. There may be
a resistance to dividing the two.

But I know in the context of the RTOs -- a lot of
our recommendations over the years have been recommendations
to improve the optimization of the system in a variety of
ways and they do a lot of independent things to improve the
optimization of the system.

And when I listen to Pablo's topology
optimization, I don't really see how it's different than
other optimization improvements. In fact, if they were to implement it, I think it would have to be implemented in their current set of models and tools because they, for example, MISO New York both run models every 15 minutes to optimally commit gas turbines, often for congestion relief. And you'd want to -- or, optimally schedule imports and exports, or do a variety of other things, and so you'd want to make switching decisions in the context of all these other decisions.

So, it looks to me like an incremental enhancement to their software. So, what is the advantage of treating it -- or maybe there is no advantage, treating topology optimization differently than any other forms of optimization that their software attempts to handle, recognizing that they may not know how to implement this at the moment.

MR. PEIROVI: Thank you for the question, David. Pablo, if you like, I will note that we're running a little low on time, so please keep your remarks relatively short.

MR. RUIZ: Sure, so certainly it is optimization. It is optimization that enables this ability on operational options of the options that are now visible, by and large today, to the operators. And that brings a lot of benefits as we discussed before. In the end it's certainly software optimization, it has to be integrated, as I mentioned
before, in the different processes.

Some processes require less integration, those are the days ahead and months ahead. Certainly, the closer to operations and to real time, a stronger degree of integration is required.

MR. PATTON: Okay, and I guess the reason I'm inclined to advocate for separating the two -- I don't know that giving -- it feels like the incentives that are appropriate for software is much different than for capital investment. Like I would never advocate that any of the things they've done in the past improve the optimization of the system, that they should somehow keep a portion of the savings that they achieved by doing that.

MR. RUIZ: I think the key difference is the set of incentives that the asset owners have. So, in terms of the traditional market resource optimization, the assets, the asset owners collect revenues in the market. This technology is explicitly about optimizing the grid, which is owned by -- the transmission owners have a very different set of incentives.

MR. PATTON: Okay, so it would be less incentive to implement the software and more an incentive for the TOs to allow their switches to be opened and shut at will by the RTOs?

MR. RUIZ: Except the TOs are not market
participants by design, so.

MR. PATTON: Okay.

MR. PEIROVI: Jack, we're a little bit over time.

MR. MCCALL: Just one short comment to Jignasa's point. I think both this question and one of the previous questions begs that there probably needs to be an expanded definition as to what should be considered a traditional transmission investment, so that that enables you to bisect that more clearly.

MR. PEIROVI: Good point, thank you. And thank you to our panelists and to our side tables as well. That concludes Panel 1. We'll be back for Panel 2 at 11 a.m. That gives us about a ten minute break, thank you.

(Break 10:51 a.m. - 11:00 a.m.)

Panel 2: Grid-Enhancing Technologies in Operations

MR. PEIROVI: Alright, please be seated. We'll get started with Panel 2 shortly. Alright as people are shuffling in, I'll give a quick -- so, for those in the room, the TVs are not working, unfortunately, so we won't have for those who are in the back, you won't be able to see the panelists. I'm sorry about that, but for those on the webcast, I guess the TVs are usually used for the webcast, but unfortunately, they're not working today.

Let me reiterate what Panel 2 is about real quick. Panel 2 will discuss the capabilities and challenges
of grid-enhancing technologies from an operational
perspective. This panel will include short presentations on
the values, benefits and costs associated with operating the
transmission system with different types of grid-enhancing
technologies.

Additionally, this panel will explore current
deployments of grid-enhancing technologies, and what
actions, if any, the Commission could take to help alleviate
any operational challenges or concerns.

Presentations will be followed by a facilitated
discussion, much like the first panel. Our panelists for
today are starting with the folks on my right, Hudson Gilmer
from LineVision, to the left of him, Charlie Bayless from
the National Rural Electric Cooperative Association;
Frank Kreikebaum from Smart Wires, Adrianne
Collins from Southern Company, Jeff Hackman from Ameren, Bob
Bradish from AEP, or American Electric Power, Professor Bose
-- Professor Anjan Bose from Washington State University and
Brett Wangen, representing WRAB, or the -- well he's, sorry,
he's representing two entities, Grid Subject Matter at
Experts on behalf of the Western Interconnectional Regional
Advisory Body, sorry about that.

So, with that we'll start with a quick opening
statement from each panelist starting with Hudson over there
on the right, thank you.
MR. GILMER: Thank you so much. My name is Hudson Gilmer, Co-Founder and Chairman or Co-Founder and CEO of LineVision, also Vice Chairman of the WATT Coalition. I want to start by thanking Commissioner Glick and FERC staff for organizing this event.

So, LineVision's mission is to bring the benefits of sensors and advanced analytics to every transmission line, and those benefits include increased capacity. They include enhanced safety and asset health monitoring. I had the privilege of speaking at the September Conference, where we spent a lot of time talking about dynamic line ratings and the advance, or the incremental capacity made available through DLR, so I won't spend time talking about that.

But I want to focus maybe on something that hasn't really been touched on on the first panel, and that is the safety benefits of these technologies and transmission line monitoring, in particular. So, I'm sure everyone is aware of recent events in California and the wildfires and the power shut-offs that we would argue have occurred largely because of unmonitored power lines.

When we look at actually some data that PG&E provided following the most recent storm, they talked about identifying 41 instances of damage to their equipment from the storms and they also talked about the process that they traditionally use which involves annual patrols and they
talked about what those patrols consist of.

These are walking, driving or helicopter inspection of lines. So, this is the current state of affairs for many of our utilities and this is how situational awareness is gathered on these lines. So, by adding this grid-enhancing technology, like transmission line monitoring, we're able to continuously monitor these lines and we can detect anomalies -- anomalies related to clearance violations, when the lines are hanging too low.

Blowout -- when high winds are causing the lines to blow too close to vegetation or to other lines and create a risk of arcing, galloping, icing, all of these conditions. And ultimately, improve the safety and reliability of the grid.

So, the other benefit, as was mentioned by Swaraj in the previous panel, is that these same transmission line monitoring systems can monitor the health of aging assets. So, Swaraj mentioned that more than half of all circuit miles of transmission were built 40 or more years ago.

And today the standard practice -- the utilities don't have a great way of monitoring the condition of these aging lines and so, the best way to do that is what's called destructive testing which involves de-energizing a line, dropping it to the ground, cutting out a section, sending it off for lab testing and then splicing that line back
together and re-energizing it.

So, with transmission line monitoring systems, we can provide our clients with continuous monitoring and also an assessment of the remaining asset life in forming their decisions on whether they can safely extend the useful life of those assets or prioritize repair or replacement.

So, we're optimistic that it's a matter of time, particularly as the costs of these systems come down, as the technology improves and as awareness of the risk of business as usual becomes greater, that these technologies and transmission line monitoring in particular, will become best practice in the industry and appreciate the opportunity through this event to communicate that, thank you.

MR. PEIROVI: Thank you, Charlie?

MR. BAYLESS: Good morning and thank you for having me. I'm here on behalf of NRECA, but I work for one of the NRECA's larger members -- the North Carolina Electric Membership Corporation. And I'll give you a little context through my comments. Let me give you a little background on NCEMC, which is the G&T cooperative in North Carolina. It's the only G&T in North Carolina representing 20-fold distribution co-ops and 5 partials.

Now, collectively the co-ops in North Carolina have a million meters and 2.4 million customers. We have a peak load of 3,500 megawatts and 450 megawatts of DER in our
system, so about 12 percent of our peak load is DER on the system. And we see that DER growing in the upcoming years. It's going to be everything from solar developers to people putting thermostats and water heaters in their house. Now, I think the important thing about this is that the majority of the DER growth that is occurring and will occur in the upcoming years is on the distribution system.

And this is really going to be positioned, the distribution system, to be a resource in the future. Through a coordinated control -- the development of a distribution operator which can coordinate and optimize all the DER on the distribution system.

The distribution system can really be looked at as an asset in the future, once the steps are gone through to develop a distribution operator. But before the true potential of the distribution system or the resource can be realized, there needs to be coordination, communication with the transmission system.

This isn't only in planning. This is planning and operations both. The distribution system will have the ability to alleviate congestion, reduce overloads, help with voltage support through the deployment of batteries, the curtailment of load through demand resource devices. But we really need the coordination between the distribution system and the transmission system before this can be realized to
its full potential, and without the coordination between the
two entities, DER will go underutilized on the distribution
system.

This is capabilities that are out there right now
and is already installed and paid for. The transmission
system could be overbuilt if capabilities in the
distribution system to alleviate congestion and other things
as realized, and generation could also be overbuilt in the
future if the capabilities of the DO aren't utilized.

So, you know, my main point is future
coordination between the DO and the TO needs to happen to
prevent the money being spent needlessly on the transmission
system and you know, allowing the DER on the distribution
system to be properly utilized.

MR. PEIROVI: Thank you, Frank?

MR. KREIKEBAUM: Thank you for organizing this
workshop and for the opportunity to participate in this
important discussion. My name is Frank Kreikebaum. I am
the Senior Vice President of Products and Solutions at Smart
Wires. And my team works with 98 utilities around the world
that have deployed or are currently seeking to deploy Smart
Wire solutions.

Smart Wires is the world leader in modular power
flow control. This technology enables utilities to unlock
spare capacity that exists on their systems today, and thus
save consumers money by reducing transmission capital costs,
generation production costs, and generation capacity costs.

Smart Wires solutions are quick to install and
easy to scale or re-deploy. And this provides valuable
flexibility to today's grid. Smart Wires works, as you
heard earlier, by changing line reactants and this in
essence, adds a valve to the transmission or distribution
system to push power off of an overloaded asset, pull power
on to an underutilized line, or relax stability constraints
on the system.

This increases overall power transfer capability
by improving the utilization of the existing grid. There
are other, older technologies that have some of the
functionality of Smart Wires devices, but they require
longer lead times to install, are more expensive, and we
have found -- and our utility partners have found, are less
flexible.

In working with 98 utilities around the world,
the biggest reflection I have to share today is that there's
a massive opportunity to improve the utilization of today's
grid in both other countries and in the U.S. Next year, we
are very pleased that a transmission owner in the United
Kingdom will install a series of Smart Wires projects that
will increase transfer capacity on their system by 1.5
gigawatts.
This will be accomplished at a fraction of the cost and time compared to building new infrastructure and will save U.K. consumers hundreds of millions of dollars. Additional gigawatts of transfer capacity have been identified by this utility as feasible to deploy in future years.

This volume of spare capacity in the U.K. is not unique. For example, each year Trans Grid in Australia, reports the maximum utilization of its transmission facilities. And to account for the need of transmission facilities to provide reliability services during times of extreme conditions, this calculation takes into account system loading at each time step of the year -- 30 minute timestep, and all contingencies that could have occurred in that timestep based on their reliability standards.

The latest version of this analysis, which was released in their annual planning report, shows that the median transmission facility would have been 65 percent utilized, if the worst contingency had occurred at the worst moment in time over the entire year.

That means significant capacity was available, even in these extreme conditions to provide societal value. We have run a similar analysis to this for multiple transmission owners in the United States, using the same criteria of evaluating and considering all contingencies,
and we have found that the median utilization was significantly less than 50 percent.

Smart Wire's solutions are already commercially proven, they're cost-effective, and they can be operated using today's operational practices and software tools. That said, we know it takes time and effort by each utility to assess and integrate new technologies. Advancement of operations in operations are required to capture the full benefit of these solutions.

But even without capturing the full benefit of the solutions, given the underlying available system capacity, power flow controls should not be dismissed as a marginal solution.

In summary, Smart Wires can provide gigawatts of additional power transfer by improving the utilization of today's grid. The grid will require significant expansion, especially as we work towards electrification of other loads. But if we fail to make full use of the grid we have today, we will not be acting in the best interests of the public.

I welcome your questions and look forward to the coming dialogue, thank you.

MR. PEIROVI: Thank you, Frank, Adrianne?

MS. COLLINS: Good morning, my name is Adrianne Collins and I'm Vice President of Power Delivery for
Southern Company Services. As one of the nation's largest energy providers, Southern Company operates 7 regulated utilities serving 9 million customers in 9 states.

In addition to its traditional regulated utilities, Southern Company owns a growing competitive generation business, a nationally-recognized provider of customized energy solutions, natural gas storage facilities and mobile communication and fiberoptic businesses.

Southern Company supports the Commission's commitment to developing a comprehensive understanding of grid-enhancing technologies, including the benefits and challenges they may provide. This commitment is underscored by the topics and questions that will be explored over the next two days by various stakeholders whose unique perspectives will inform our collective understanding of these technologies.

I appreciate the opportunity to participate in this workshop, focusing on how such technologies can provide a greater value to the electric utility industry. Southern Company enjoys a long-standing commitment to innovation. This year marks our 50th anniversary of research programs, which encompasses more than 10 R&D centers, as well as numerous collaborative partnerships with the U.S. Department of Energy, National Laboratories, and the Electric Power Research Institute, just to name a few.
As a vertically integrated company, Southern Company is uniquely positioned in industry to invest proactively in R&D across generation transmission and distribution, and we are actively engaged in R&D piloting and scaling of new technologies.

We have and will continue, to implement and leverage these technologies across our system where appropriate. Based on our experience with grid-enhancing technologies, here are a few of our key observations.

First, we cannot stress enough the importance of providing technology options that maintain operational flexibility based on the identified needs of a project or system condition. Second, we also strongly emphasize the need for these technologies to integrate robust security and hardening measures in their development.

In support of system resilience, these features must be tested and proven prior to wide-scale implementation. Ideally, grid-enhancing technologies must increase the safety, security and reliability of the electric system, while simultaneously putting downward pressure on rates for the benefit of our customers.

Successful implementation of grid-enhancing technologies must be measured strategic, and balanced against rapid changes in the energy industry, which includes uncertain demand, a changing resource mix and evolving
customer expectations.

Southern Company encourages continued collaboration between our industry partners and stakeholders as we seek to future develop and implement these solutions. We also encourage the Commission to continue its focus on ensuring bulk power, system reliability, and promoting regulations that recognizes regional differences and allows for operational flexibility when applying these technologies.

While we recognize there are no one size fit all solutions, the continued development of a suite of grid-enhancing technologies will provide greater reliability for our customers and the efficiency of the electric system. I look forward to contributing to this timely and worthwhile discussion, and I'm happy to answer questions as we proceed. Thank you.

MR. PEIROVI: Thank you. Moving on to Jeff?

MR. HACKMAN: Thank you, good morning. I'm Jeff Hackman, Senior Director of Transmission Operations and Technical Services for Ameren Services Company. Ameren thanks the staff for holding this workshop to discuss the important concepts relating to grid-enhancing technologies. First, I'd like to suggest that grid-enhancing technologies for transmission have been around ever since transmission was developed from switched capacitors to
face-shifting transformers, from solid state FACTS devices and now to newer technologies.

Transmission operators have always embraced the prospect of being able to increase efficiency and especially control flows and voltages on the transmission system.

Grid-enhancing technologies can allow cost efficient, creative solutions to solve old challenges as well as the new challenges that have come about with energy source changes, transmission system evolution, and as Charles noted, the development of an interactive distribution grid.

It is worth noting that the underlying principals for grid-enhancing technologies have been, and should continue to be to increase efficiency, improve reliability, and increase the capacity of the system all to increase value to the customers.

From a transmission operator's perspective, grid-enhancing technologies should be considered alongside that of new lines and substations. Grid-enhancing technologies can produce solutions when line development routing challenges are present. It can aid when generation is retired, because these technologies can ensure that existing transmission is used efficiently.

One interesting new option offered by one of these new technologies is that the devices are mobile and can be installed to solve temporary challenges that may go
away when future generation is retired, or when planned
transmission or generation is added.

This is a real benefit to the whole concept of
grid-enhancing technologies. Ameren has installed old and
new technologies and has plans for more. One of my other
responsibilities at Ameren is leading transmission business
development. We are active in offering solutions in MISO,
PJM and SPP, but we're not limited to those regions.

And we have offered grid-enhancing technology
devices as solutions in both MISO and PJM because they are
appropriate solutions that would deliver great value to
consumers in those regions. In fact, one recent current
proposal addresses a long-standing issue in one of those
regions, and has a benefit cost ratio over 100, far
exceeding the nearest solution.

One last benefit that merits mention as a
transmission operator, and other panelists have mentioned
it, but as a transmission operator, it's really important to
me -- and that's the idea of resiliency. Newer standards
and regional and local planning criteria do a great job of
giving transmission operators robust transmission systems to
operate.

However, many events occur which are more
devastating than those planned -- hurricanes, wildfires,
widespread ice storms, and even the acts of evildoers can
impair the transmission system far beyond any planning criteria.

In those times, operators have had very few tools to manage traditionally, like load shedding and switching. However, with the advent of these new grid-enhancing technologies which can be variably and dynamically dispatched, operators could better utilize the remaining grid following extreme events.

I thank you for the time today and I look forward to the robust panel discussion later.

MR. PIEROVI: Thank you, Bob?

MR. BRADISH: Is this on? Can you guys here me?

MR. PIEROVI: Make sure the switch is flipped, got it now?

MR. BRADISH: Yeah, okay, thank you. Good morning. My name is Bob Bradish. I'm the Vice President of Transmission Planning and Engineering at American Electric Power. Again, and I'd also like to thank you for the opportunity to participate in this important dialogue.

AEP is one of the largest electric utilities in the United States, so we deliver electricity to more than 5.3 million customers in 11 states. AEP owns and operates the largest electricity transmission system with over 40,000 miles of lines.

And these assets are located in now four RTOs or
ISOs, including PJM, SPP, ERCOT and the Midcontinent. The technologies that we've deployed, although after hearing the first panel, they may be considered old school, but we've deployed just about every grid-enhancing technology that's come our way that's been proven.

That includes serious compensation, both capacity and inductive, some compensation, SPV, SPC, statcom's, synchronous condensers. We had three HDC back to back facilities for power flow control. We have fade shifting transformers, we even have a variable frequency transformer on our system.

We consider bold transmission, although that maybe not to the classification here, also as a grid-enhancing transmission of its unique physics, and quite frankly, we also use energy storage as part of a transmission asset.

So, I think we've hit all of the physical assets out there, and from an operational perspective, our operators do use something called ambient adjusted ratings that I believe Lindsey wasn't pleased with, but we do use them. We've been using them for many years, apparently at our own peril, but we can apply them though to 40,000 miles of lines at fairly relative low cost, and so they do add additional capability.

And then we certainly do -- our operators
We're always scanning the environment for new cost-effective ways to serve our customers. We are certainly looking for new technology to bring to there. We are constantly collaborating with vendors on innovative technology. There is no shortage of folks knocking on our doors, talking to us about the newest technology, and we certainly listen and talk.

That process, however, for us, is very structured and requires support from several groups within our organization. The planning group has to be engaged. The engineering team has to be engaged, operations needs to be engaged, and so does field services.

We have to have a comprehensive look at any new technology coming our way, so we understand its full implications of what may or may not happen when we deploy the technology. And given the responsibility of needing to keep the lights on 24/7, we believe it's prudent for us to have a respectful, conservative risk posture when deploying new technology.

Piloting new technology with unproven performance...
is a challenge. It is in our history, never a straight line from design to deployment. Another concern that comes up is operational complexity. Operational complexity increases the risk profile of the system, so as we deploy these devices -- more and more devices with active controls, you are making it more challenging for operators.

And an operator's experience and the tools they use need to keep up with the new technology and that's a big challenge for us. We have to be able to at least model the equipment that is deployed on our system, and certainly, operators need to understand its full implications of how it functions.

AEP strongly supports implementation of technologies that working together, improve the resiliency, reliability and operability of the grid. Technologies that are targeted to address deficiencies and reliability, improve system inefficiencies and reduce the cost to consumers should be applied as specific system needs and circumstances dictate.

The choice among competing technologies should be driven by relative performance and cost. With that, I'd like to thank the FERC staff again for organizing this workshop and allowing us to participate. I look forward to the dialogue.

MR. PEIROVI: Thanks Bob. Moving on to Professor
MR. BOSE: Good morning. I'm Anjan Bose, and I feel very privileged to be the only professor at this panel session, but that also means that I don't representing either a technology vendor or any part of the grid, so you take -- so, I'm the only person responsible for these opinions that you're going to hear.

I do have some written comments and I could speed read them in three minutes, but I thought instead, I'd let you read my gripping text on the web and I'll just make two or three -- three points.

The first thing is that the grid advancing technologies are controlling something, right? Voltage, power, current, or topology or something like that, to an end. And you could -- any control technology can be implemented two ways. One is local. That is the measurement is local, the control is local and hence it's easy to do.

And almost all grid-enhancing technology used to date has been local. So, think about fax devices, or go back further and think about a transformer -- face-shifting transformers. These are all doing some local things. And if you look at the new technologies coming in, they're also controlling local because they're easy to implement.

And I will predict that you're going to see lots
more of them because these technologies are getting cheaper, getting more flexible, all of the things that have been already said. The potential of this technology is not in local control. It's when you have dozens of these things, if not hundreds of these things controlling the grid.

To sum up the optimization, let's say you're going to use the transmission system utilization better. You're going to make it better. How are you going to do that if you can use a whole bunch of these things? You can't do it by changing the power flow on one line because if you do that for 37 lines, they will fight each other, right?

So, you've got to coordinate this thing. So, the problem of doing wide area monitoring and control is out there and it has two major obstacles. One is that any of wide area monitoring and control requires communication. So, that brings another dimension to this thing. So, communication means how fast in the data, how fast you get the data, how fast you get the signals, and then of course, not to mention cybersecurity which comes into the picture if you're going to communicate data.

But the other bigger problem is analytics. How are you going to do this? Control many, many things to do the control of the grid, or a section of the grid, a wide part of the grid? That means you have to have some
automation and optimization and analytics built into these
controlled systems, and that problem is out there. Very few
people are looking at it. Nobody has solved it, right, so
let me put it out there.

The next one I want to make is I know it's not --
I shouldn't be mentioning distribution in this FERC
building, but it has been sort of raised on the side. You
know, somebody mentioned that there is a huge amount of
generation coming in which will be connected to inverters.
Well where are they going to be? They're not going to be on
the transmission. Most of them are not going to be on the
transmission system, they're going to be on the
distribution system.

And so, these inverters are what we are talking
about in terms of grid-enhancing technologies. So, a big
pile of these grid-enhancing technologies are going to be in
the distribution side. So, whether FERC has anything to do
with it or not, the system will have to deal with it and
deal with it well because now FERC is allowing all these
resources to bid into the market and play in the market, so
somewhere the grid has to be operated to maintain that.

And, of course, I'm not even bringing the
customer side of these things, okay, that's a whole
different ballgame. But here, I will end with three reasons
why I think the Commissioners said things are not moving in
very speedily.

One is that automatic control and EMS applications will have to be changed, will have to enhance these technical analytical techniques into the EMS which can be done overnight. A lot of problems to be solved. A bigger time scale is getting the operators trained to be able to handle these extra set of things, even the only thing they do, even if it's all automatic, and the only thing they do is override it, or allow it.

They still need to be trained and that takes even longer. And finally, most of the cost justifications that are being used today to put in these technologies, is on the basis of the cost of transmission, the cost of the market utilization, and so on. But the major advantages have been mentioned -- reliability, flexibility, security. These are the ones, and there is no direct cost benefit from that to any of the stakeholders.

There are a lot of cost benefits to society, which is why we want these things, but not -- I'll stop there, thank you.

MR. PIEROVI: Thank you Professor. Moving on to Brett?

MR. WANGEN: Alright good morning, my name is Brett Wangen. I'm Vice President of Power System Services for a company called Grid Subject Matter Experts. I'm here
today, however, on behalf of the Western Interconnection Regional Advisory Body, WIRAB.

I'd like to talk today about an underutilized grid-enhancing technology in the Western Interconnection phase or measurement units and SynchroPhaser applications. Insurance and lessons learned -- I think there's been a lot of work done in the west implementing SynchroPhaser technology programs that have been supplemented by the DOE and we could maybe share some lessons learned, that might improve programs going forward.

So, the experience from the Western Interconnection perspective, in 2010 the U.S. Department of Energy provided seed funding to incentivize and increase the adoption of PM use throughout the Western Interconnection. That was widely successful. Today, there's over 790 PMS's that have been implemented over the past couple of decades, most of those being implemented over the last decade.

And that really enables new technologies and it enables both technologies for the planning processes, improvement of models, real-time monitoring capabilities, so really the technology and capabilities are there and enabled through PM use and SynchroPhaser applications.

But regardless of the potential, SynchroPhaser applications have not gained a lot of traction, primarily on the Western Interconnection, from my perspective, primarily
the lack of traction, certainly in the real-time operation space.

Some of the lessons learned from the Western Interconnection's experience with SynchroPhaser deployments include the following: First, maintenance of PNU's has not been a priority and data quality has suffered. This results in a lack of operational confidence in the data and the tools.

Number two - P&E data and SynchroPhaser applications, usage has been limited by a perceived lack of need to monitor beyond traditional thermal voltage instability constraints.

Third - innovation, new technologies, and new ways of thinking about grid operations can be a major hurdle for the utility industry, requiring significant change management and training.

And fourth - system operators are now accustomed to mandatory reliability standards. While good and needed, this often results in a wait for the requirement approach to the adoption of new technology like SynchroPhaser applications.

A recent change in the Western Interconnection is the regional variance associated with IRO 2-6, which goes into effect on January 1st, 2020. You might not be very familiar with that, but what it does is it requires for the
first time that reliability coordinators in the west use
some SynchroPhaser applications to monitor inter area
oscillations, so that's unfortunately again, a requirement
was needed for that new technology to be pushed in the
control rooms, but it is a step in the right direction.

So, while I encourage the FERC Commissioners and
the electric industry to continue to explore how
SynchroPhaser technology can be used to enhance grid
reliability and to support the deployment of other
grid-enhancing technologies, with high penetrations of
solar, wind, storage and other resources going in, it's
going to be critical for operators to have this fast
high-resolution data from PMEs to understand how the system
is truly operating, and how to respond to those behaviors.

WIRAB also believes FERC can learn important
lessons for the design of incentive programs from the
Western Interconnection's deployment of SynchroPhaser
technology. In sum, grid-enhancing technology should come
with the expectations that the technology be
well-maintained, and that information and data gained from
the deployment be shared with others in the industry, with
the appropriate data protections of course, and these types
of requirements help to ensure that these incentive programs
provide benefits to both the ratepayers and taxpayers and
further the public interest, thanks.
MR. PEIROVI: Thank you. Okay everyone, I'm sorry for the short nature of the comments. We wanted to jump right into the Q&A so, thank you for keeping your opening remarks short. I wanted to touch on a little theme. I've seen that everyone agrees -- mostly agrees on the benefits.

But I've also seen a lot of folks talk about the challenges, specifically the deployment challenges or the implementation challenges once they are deployed. So, can you touch on -- let's start with actually for the floor. For all the panelists, let's start with just touching on what you know, what's the answer to this, right?

Like more coordination? And once they're implemented, how to coordinate between technologies and between asset managers or -- and what could FERC possibly do to help with those challenges?

MR. KREIKEBAUM: So, I can speak to some of our experience outside the U.S. Most of our customer base is outside the U.S. even though we're a U.S.-based company, and with U.S. created technology. What we've generally seen is that once a utility in a region tries out the technology -- at least our technology, and they've done the pilot and they've done the first real project, there tends to be a ripple effect where other utilities in the region will learn from that, and it facilitates and eases that adoption
process.

So, really finding ways for the beachhead project to occur in each region, each ISO, is really important in our experience, and shared learnings across those regions tends to dissipate the need as Anjan pointed out, there's -- to get the full benefit of these technologies, you need to do a lot of work in the operational timeframe, but you don't have to do all that work to get some benefit and the low-hanging fruit can be achieved without huge investments.

So, you can start to separate the big investments from the small investments when the utilities you are sharing peer to peer how they overcame some of those initial challenges.

MR. PEIROVI: Thank you, let's move down the line to Adrianne.

MS. COLLINS: Thank you. So, first I would just like to say I think the importance for Southern, who is a vertically integrated company, again, is the flexibility to be able to evaluate the grid-enhancing technologies, and to be able to identify the best locations and solutions for them while also ensuring the most cost-effective location for our customers.

So, in regards to the challenges associated with it, it goes back to having the ability to really pilot and understand how these grid-enhancing technologies will
operate in our system, right? So, being able to have status
and being able to understand where they are, we have
visibility. That we also have understanding of their
behavior, right, the predictability. How are they going to
operate on our system? And their ability to control them.

And when you take all that in mind it kind of
comes back to some of the key things that we talked about.
We have to ensure that they are reliable. We understand how
they are going to operate and behave on our system, and that
they're secure.

The complexity comes when you have multiples of
these devices on the system and being able to ensure the
security and the reliability as someone as an operator is
need to operate the system. So again, that is where from
a vertically integrated company, the fact that we are the
investor, the owner, and the maintainer, we're able to
manage all these different applications, but do again feel
the need to have the opportunity to pilot these
technologies so that we can see what operational flexibility
that we have with them, and then continue to advance these
good enhancing technologies to be able to implement them.

MR. HACKMAN: Thanks. I would echo what Adrianne
has said, you know, from a transmission owner and operator's
perspective. We have to be a given that they work, right?
We just can't take all newcomers. They've got to work and
Bob mentioned that as well.

I mean he's had a whole lot of experience trying things out. Not everything works. So, you have to be sure it's going to work, and you have to be sure that it doesn't jeopardize reliability. But I would pick upon something Doctor Patton had said in the first panel and Doctor Bose said here -- that they really do have to be integrated, whether they're integrated in a vertically integrated operation like Southern's, or whether it's in an RTO.

They have got to be part of the solution matrix.

I mean you can't optimize one line as Doctor Anjan -- Doctor Bose said, sorry. And it's really important and Doctor Patton commented it has to be part of the solution, right?

If you're going to use them, you've got to make sure you're not turning on gas turbines to solve a problem that these would solve the problem because you're going to get the costs anyway. It's really important.

So, when I think about what could FERC do, it's really just like we did when we first started in the energy markets, it has to somehow be supportive, it has to be kind of accepted that the RTOs can and will and figure out how these things can work in the RTO environment.

The challenges are not insignificant right?

We've got FTRs and ERs, I'm sure you heard about that at the first panel in September. There are a lot of financial
consequences to all of these decisions, but if we don't think that they're going to work they won't, but they've got to be fully integrated. That's all I have.

MR. BRADISH: Yeah, just echo some of what I said earlier. And first of all, I agree with what Frank said about scenario number one, right? Scenario number one is a little scary because you don't really know what you're getting.

You know, the vendor has all good intentions, but we've gone down that road many times and many times you have not implemented anything until you get scenario number 4 or 5 because the first few just don't work properly.

So, you do have that concern and I would agree once you get a technology that's out there, it's proven, it's got some performance metrics around it, it's got costs metrics that are around it, then you can take a much harder and deeper dive and look at it a little closer.

And then the second piece of that is again, echoing what Jeff and Adrianne said about -- and Doctor Bose said earlier, it gets harder to operate the grid with more of these on it. And you need to elevate it from individual control to a much higher level of control, or else you will have these devices fighting against each other.

And so, that becomes a challenge. They also interact with other devices on the system in interesting
ways, and so you've got to be able to handle that. And you've got to be able to model these things. You have got to be able to model their full capability.

And so, the modeling now with where we've gone with technology, we're using tools that you know, time -- the main tools that you know, model things in increment steps of you know, milliseconds, microseconds. I mean we're taking really short time periods because we want to look at the interactions of very fast acting controllers on the system to see what's going on.

That type of analysis takes time. And it takes skilled people to actually do that type of analysis. So, when you bring this new capability, you've got to really be able to model it, you've got to be able to do the analysis around it, you've got to see how they're going to interact -- number one, with each other locally, and then you've got to have a broader scheme more regionally to look at how these devices are managed together as one.

And we have fighting today with devices and stuff, and we don't have nearly the penetration that's coming out way.

MR. PEIROVI: Can you expand on that? The fighting on the devices, to that point.

MR. BRADISH: Yes, you'll have devices that want to -- and we've put what we call reactive power controllers
on because you will have devices that will want to push output, you know, reactive power over here and this other device, the way it's set will start pulling it in and then all of a sudden you've got this big push of reactive power across your system because these two aren't coordinated. They don't have the right settings, they're not working together.

We had that with power plants on our system. We had power plants that were electrically close together and they're exciters. Again, old school stuff, but exciters had to be tuned so that the power plant -- one wouldn't just dump a whole bunch of reactive power in and the other one sitting very electrically close, just pulls it right off the grid again.

So, these devices need to be set and work together or else you will get these things, where they will act against each other.

MR. PEIROVI: Sorry, staying on that. So, you don't really see something that FERC could do? It's kind of just a case by case solutions-based?

MR. BRADISH: Yeah, I think the issue there is making sure we have the right information available to us, so maybe one area, right? One of the challenges we have is actually getting the detailed models, so the vendors don't want to provide that because it's proprietary.
So, they don't want to give us the details of how their model works, so what they do is they package up a black box. They send it to us, we do an analysis, we say hey, we've got this problem. We said they said well, send us back the black box. They go into the black box, they make some tweaks, they send it back to us, they said we have fixed it.

And then we find another problem and we do this back and forth. And the reason being is they don't want you to see what's inside their technology, their controllers, because it's proprietary. And you might take that information and somehow share with a competitor some way, somehow. So, those types of things where we can get insight that maybe a challenge but getting insight into the actual workings of the technology because we are going to get more and more of this but being able to understand it and model it would be helpful.

MR. PEIROVI: Thank you Bob. Professor Bose, it looks like you disagree.

MR. BOSE: Only slightly. But let me start with this. I think FERC can help break the chicken and the egg problem by essentially, you know, the PMU is the greatest example of this. Where we have known about the benefits of PMU since the '90's. Nobody put them in except for a couple of companies, and then DOE put a lot of money into it to put
in a lot of PMUs.

And even though we knew all this potential, nobody was ready to use it as Brett pointed out. We still have needing to use it. So, what I'm saying is that you know, FERC can encourage to put these technologies in. Until they're in, nobody's going to build the applications needed for them, okay?

What we're doing now is in onesies and twosies, saying if you put this particular technology in at this place, we're going to solve this one problem, but that's not what -- that's not FERC's business, that's the individual company has to do that.

The second thing is again, another thing that I'm taking off of Brett is that FERC has to encourage some of these solutions because a wide roll of ABB changed their optimal power flow to handle a whole bunch of these newfangled equipment, unless there's some need for it. And some of the needs has to do with reliability and security and not just decreasing the congestion of this one point.

And that's again, something that FERC can do and then to base that log jam that you mentioned Bob, about you know, all this proprietary things that we can't look at the inside, so we can model it, so we can put it in a tool, we can't then use it for -- I mean, this I think FERC can do very easily because if it is needed for their reliability of
the system, FERC has the ability to require it.

MR. GILMER: Alright, just a couple comments here to you know, the solution or the problems or the obstacles that are in the way to truly implementing some of this technology. I think the first thing that comes to mind is when you have panels like this for example, you're bringing the experts to the right room?

These are the people that are understanding that they have the resources of their companies to implement some of these things. They're already doing it. They have experience. I would encourage FERC to invite the folks that aren't volunteering to counter these sessions. Invite some smaller utilities. Invite some folks that frankly are really behind the ball.

In my role as a consultant, and frankly, before my consulting time, I was at PECO Reliability for over a decade and I saw a lot of -- entities aren't ready for some of this -- some are not, again that you see at the table and others are very advanced in their capabilities, but if I had a nickel for every entity that doesn't have a good model, or doesn't run information yet, or doesn't do this or that, you'd be surprised.

And yes, the standards are there to make sure they're doing those things, but I don't think the standards are there to say how good they do it, or how well they do
it, and if there are things that FERC can do to sort of
encourage that, mandate that, whatever, but just to kind of
get -- I guess my underlying point is simply get operators
to a consistent level. I don't know that that's out there
today.

So, that's the first thing. And then sort of
major issues, I think taking some comments from the previous
panel about you know, it's not often times the operator, the
transmission operator or even their RTOs, ISOs problem to
solve all of this, you know, when you look at what they're
dealing with, they're dealing with the major issues.

They're looking at interconnection, reliability,
operating limits and what do I need to do to resolve those
issues? Stability limits on my system, major congestion, so
if there are smaller issues or pockets that are not creating
major operational issues, or there's operational procedures
that seem to be taking care of it, that tends to mean that
that's going to take a back seat.

And I think that's appropriate. I don't know
that I'm advocating for FERC to do much with that, but
that's just, I think the reality of it, they have to
prioritize and the big issues. And what comes to mind there
is again, in the west, in the desert southwest, there's you
know, some eye rolls that exist, and major investment in
transmission, face shifters, static bar compensators,
things like have been implemented to resolve those congestion and reliability issues. But again, they're major issues and they do have all the focus.

MR. PEIROVI: Moving down the line, I see Hudson and Charlie have something.

MR. GILMER: Sure, just maybe building on some stuff that has been -- okay, just build on Frank's comments. I think there's a few things here. One is that these are solved problems and a lot of these technologies have been successfully deployed and put into operations outside of the U.S.

And so, I think you know, but saying that is also not to trivialize the steps that are required in order to implement them in our systems here. So, first I think we can look to how they have been implemented elsewhere in Europe and Australia, et cetera. But then, I think there has to be a phased implementation and that typically in our experience, you know, we work closely with EPRI.

We work with the National Labs, produce data on the performance and security of systems with those bodies, and then we have pilots. And the pilots allow the utility to get comfortable with the technology before it's put into operations, before it's integrated into systems. Then there's an opportunity to say okay, let's use this, perhaps only in contingency situations, not in day to daily
operations, and that can provide a lot more flexibility.

We've had utilities who struggle with getting scheduled outages and having additional capacity through things like dynamic line ratings can enable that, even if it's only being done for specific objectives like obtaining scheduled outages. And then the next step is to operationalize it and I can only speak for the transmission line monitoring technology, but what I can say there is that there is not an additional layer of optimization going on.

So, what we're doing is providing a line rating, just like the existing line rating except that it's updated more frequently into the EMS, and have developed protocols for integration into those EMS's, sums, and topi systems to make that work and not create a tug of war between different technologies.

And then finally I do think, you know, there needs to be a shift, you know, if we're focused only on the pilot and we're focused only on solving small problems at the local level, that kind of hides the bigger opportunity that we all need to be working towards, which is really what's the benefit if these technologies are rolled out system-wide?

That has to be the end goal, and I think as was mentioned earlier, there's a lot of opportunity for FERC to drive adoption of these technologies, thanks.
MR. BAYLESS: So, what can FERC do? I think the first thing FERC can do is just be supportive. You know, the distribution system, going forward, needs to be considered. In some states you have very large integrated, vertically integrated utilities that control the vast majority of customers in the states.

In other states, like North Carolina, between the co-ops and municipals, somewhere around 40 to 50 percent of end use customers are not represented through a vertically integrated utility but are co-op or municipal customers. And in states like that you just have this ability of the distribution system.

Now, I'll agree with most people down here that it needs measurement and verification and needs testing. It is not going to be a short process to figure exactly what the distribution system can bring to the transmission and generation system. NCMC has started working with PJM and right now it is a very manual process that's slowly over time going to go to a more of an automated process, and go from high level 5 megawatt sites, down to 1 megawatt and eventually get to individual consumers, but that will take a lot of time, coordination and testing and verification of the capabilities.

But I really think you know, the talking to the distribution system and figuring out the capabilities
because of the benefits, just can't be systematically
dismissed and FERC should just be supportive of this
coordination between distribution and transmission system
going forward.

MR. PEIROVI: Thank you. Staying with the theme
of kind of the challenges and in a world where more of these
devices are implemented, I'd like to invite the side tables
to join in on those themes and anything that was said about
that. Yeah, introduce yourself please, we know you but.

MR. DAGLE: My name is Jeff Dagle, Pacific
Northwest National Lab. I heard that phrase pilot project
several times from the panel and in my experience there's a
lot of pilot projects that don't end up, you know, changing
the world. You know, getting from scenario number 1 to you
know, scenario number N, I think is still a big challenge.

And how do we sort of nurture that eco system of
vendors and users to fully develop to deploy in useful
technologies? And so, I think maybe one specific thing that
we could think about is how do we capture and disseminate,
you know, best practices we could learn from these pilots
and deploy those in, you know, helping to grow these
technologies, so I'll offer that and see if anybody has a
reaction.

MR. GILMER: Jeff, I just want to agree with you
on that. You know, we certainly see a contrast between our
activity in the U.S. and our activity outside of the U.S.

Here, most of our engagement to date unfortunately has been pilots. And many of those pilots haven't had a clear set of criteria to say if you achieve "x" then it moves beyond the pilot, and so that's something that certainly we're working more on going forward with -- to make sure that there's a road map, there's clear definition of success in the pilot and a path to deployment beyond that because you know, there's -- I had one utility client of ours refer to innovation theater.

You know, as a younger company you can get stuck in innovation theater and just doing pilots and it's a very expensive way to run a business.

MR. HERLING: Yes, Steve Herling with PJM. I'll just reinforce a couple of things that were said. Obviously, we're concerned about having large numbers of these devices each individually trying to solve one problem fighting with each other. We need to kind of make that leap to what Doctor Bose was discussing, which is looking at these devices as a group, with a control function based on the grid.

But right now the devices are being presented to us one at a time, often in our competitive solicitations to solve one problem and we have to compare them to -- there are a number of greenfield transmission solutions, upgrade
transmission solutions, so our evaluations right now are
based on one device solving one problem and we're not yet,
you know, making that leap to a grid solution.

MR. PEIROVI: Thank you Steve. How is that
different than say a new transmission line or a new
substation being built?

MR. HERLING: Oh, it's not, except that as you
start to select you know, the first device for this problem,
the first device for this problem, eventually you're going
to get to that situation where you have now selected a dozen
solutions in a given area, each for individual problems
through a competitive solicitation.

But we haven't yet tried to look at the
interaction between all of these devices and our EMS and all
of our other control algorithms. So, you know, while our
Order 1,000 competition is focused on one problem, one
solution, we need to get ahead of the bigger grid solution
before we find ourselves having selected 100 of these
things, and then realizing we didn't look at the bigger
picture.

MR. PIEROVI: Thank you. I didn't see you
Adrianne.

MS. COLLINS: Thank you, I just wanted to share a
reaction or kind of a perspective. There are times where we
have piloted some of these grid-enhancing technologies and
you know, we've proven that they work, and we really want to be able to utilize them as a tool in our tool belt, right?

Here is an option for scenarios, but as we have evaluated them as we consider the customer in mind, trying to do a full scale deployment on our system is not cost-effective for our customers, but we do see the value in being able to implement them as a need basis, and something that we'll utilize if the technology will provide that solution for our system.

But some of these again, yes, we have proven them, you know, we have shared that they have proven themselves, but we just don't see the full scale deployment because again, back to customers and not being cost-effective to deploy throughout the entire system.

MR. PEIROVI: Thank you. Seeing no other comments from our side tables, I'd like to shift gears a little bit to I think what Bob mentioned which was storage is a transmission asset. Under what circumstances Bob, and others, we'll start with Bob, under what circumstances is an electric storage resource operated such that it acts as a transmission asset?

MR. BRADISH: So, the one -- we have one deployment now that was put in a situation where you had a load on a long radial line and that area was growing. That line was also aging, and so we actually put a battery in.
And these are low, you know, this is 4 megawatts. These aren't big deployments.

So, these are really batteries that are from a cost-effective perspective, it's more cost-effective to put the battery in, than to bring in, you know, maybe to rebuild transmission lines that are serving an area, stuff like that. So, where we tend to be focused is on more on the edges of our grid where we have small loads, where it's just more -- simply more cost-effected to bring in the battery and provide the same level of reliability to the customer than perhaps a transmission solution -- than a traditional transmission solution might be. That's what we're deploying today or looking at them.

MR. PEIROVI: Thank you, Charlie?  

MR. BAYLESS: Charlie Bayless, NCNCCI, I think we've seen basically the same thing. We've been studying batteries for some of our distribution members that actually own transmission who have experienced an outage for a very short period of time. It may be a summer peak where the maximum capability of the line is being exceeded for a few hours by just a few percent, and it's cheaper to go in and put a battery on that transmission line -- a 5 megawatt battery, than rebuild the entire line to upgrade the capacity of the line.

So, situations like that, short times, just if a
few hours a year, it's cheaper to deploy a battery.

MR. PEIROVI: Jeff?

MR. HACKMAN: Thanks. I think there is another option, you know, that might be in FERC's arena, which would be where an energy storage device might be able to participate in the market as market environment, you know, bidding generation and/or load when it's charging.

But the inverter component, for instance, could be considered a transmission asset, so that in places where you need that, you know, that dynamic response, perhaps some portion of the battery could be reserved, you know, maybe temporary, making numbers up on the fly, 10 percent of the battery is dedicated to transmission, 90 percent of the battery plays in the market and you would look at the streams of income differently from the, you know, from each of the parts of the investment and you could put it in places where like a fax device or something where you need some kind of a dynamic, you know, reactive response.

So, we're certainly looking at those things. You know, you'd already see it if you thought of how to solve it, I promise, because we'd be number two. But I think that is out there, and it's really just a matter of, you know, getting the right location with the right -- right now it's battery chemistry because you can work the things to death, right?
But I think long-term that's a real possibility and that's something FERC should be thinking about and entertaining, even though it may be a combination device when it's installed, portions of it could be split apart and I'd liken it to one of my favorite subjects here which I spent most of my FERC time is Schedule 2 payments right? So, how we try to carve up a power plant into what portion contributes to reactive, so.

MR. KREIKEBAUM: So, we see fair bit of projects where storage is being deployed for resource adequacy and Smart Wires is a possible solution to provide the transmission capacity to bring distant generation to provide resource adequacy. And there are a couple of things that are applicable both to storage and at least, power flow control.

One is the rate of progression of technology improvement is very fast. So, if we were having this panel five years ago, we would be talking about distributed reactors. You heard a little bit about that earlier in the first panel. And those products -- that was our first generation product, has one 600th the capability of our current product.

So, it took 600 of those devices to have the capability of our current product. And that's over the course of five years. Storage has had similar metrics of
improvement, so when we're talking about writing rules about what technologies are in or out, or we're talking about evaluating a technology, it's very important to be asking for the latest assessments of technology capacity when things are moving that quickly.

The other factor is it's important that all solutions be considered. Sometimes a proceeding will start in a state Commission or somewhere else where they'll come in with a solution already in mind. So, we want you to do "x", we want you to do "y", and if you look holistically across the solution set, you'll find it actually wasn't the best solution for a number of those projects.

So, there was a reference earlier to a PJM competitive project -- a market efficiency project where a Smart Wires solution had a benefits cost ratio of 110 to 1. And the storage project, I think the highest benefits cost ratio was 20 to 1 or 10 to 1. So, if we would have forced that decision to say well, storage only solutions, we would have achieved a solution that penciled, but you wouldn't necessarily have achieved the best benefits, and we understand we need to look at many different facets of a technology, not just benefits cost ratio.

We need to look at total benefits where we also did quite well, but we need to look holistically at solutions, I think, rather than forcing a specific solution.
MR. PEIROVI: Thank you, David?

MR. PATTON: Yes, I found the discussion of storage confusing because I think some people are talking about storage assets in ways that it's indistinguishable, just from generation, modes flow on the line versus others may be talking about storage like Jeff, being operated in a way that actually changed the operation of the transmission system, and I think that's an important distinction because it's -- if you start designating storage as a transmission asset for doing something that a gas turbine could do, that can start very quickly, and push back on the flow on the line, then you're fundamentally eroding the signals to invest in storage versus many other technologies that can provide the same benefit.

So, I don't know if there's a convenient way to distinguish between the benefits of storage that would make it a transmission assets, but perhaps thinking about if there are attributes that would allow you to rate transmission facilities at a higher level than you could rate them at without the storage asset, you know, that would certainly be something that would be somewhat different than what a traditional generator could achieve.

MR. PEIROVI: Adrianne?

MS. COLLINS: So, just piggybacking off of that.
I think from a transmission asset, I think you would have to be intentional of the purpose of the particular energy storage. So, for instance, if you wanted to address a transmission constraint, then that energy storage solution may be a solution, but I think the intent would be that's what it's there for.

But you're not going to utilize that energy storage system to do something else, right? That is the intent and purpose of it is associated with a transmission constraint, and again, back to fact that we need to ensure a reliable system, that should be the use of that battery storage system before that particular scenario.

So, I can see the use of energy storage being available in a variety of solutions, I think we just have got to be cautious not to intermix those that could cause a concern ensuring the reliable operation of the bulk of power system.

MR. PEIROVI: Thank you, Jeff?

MR. HACKMAN: Actually most of my point was already brought up, but I do think that it does matter whether it's, you know, for a transmission benefit, you know, versus something like a generation-type thing.

You know, maybe one very narrow esoteric example is whether it's been some work done. BPA had a project in the '80's where they used storage to dampen the inter
oscillation of the Western Interconnection and EPRI and others have done studies of similar types of things and DOE has supported some work along those lines.

And so, those are specific deployments where you're providing an ancillary service or some other grid benefit that could be done, but triggering off of something that Jeff said, often times you might put in a storage device as multiple purposes, right?

And I personally believe that, you know, a multi-purpose facility makes a lot of sense because then you have multiple benefit streams that you can use to justify the costs, and so maybe we'd have to parse out, you know, what function is a transmission asset and which function is not a transmission asset and figure out a way to rationalize that.

MR. PEIROVI: Thank you, let's turn to my fellow staff members starting with Jignasa.

MS. GADANI: Thank you. This has been a great conversation. I just want to switch gears a little and pick up on Steve's point about evaluating solutions and doing it in coordination so that you know what's happening. That seems like a pretty comprehensive analysis that would need to be done. Any thoughts from you or others on where you would get the relevant information and you couldn't have it at once, but could you evaluate a solution and then build on
when the next solution comes along, use the underlying analysis to build on it?

Is that an option? Where would you get the information and who would do the evaluation?

MR. GILMER: You're raising a lot of good questions and I don't know that I can answer them right this moment. The challenge with the first device is you can always look at it in isolation and how it performs with respect to a given market efficiency problem, or a given reliability criteria violation.

The challenge in terms of fairness is if I hypothesize that some day there will be many more of these and therefore I have to -- for this device, I have to do a big body of analysis about the kinds of complexities that might arise, whereas if somebody proposes reconducting a line, I don't, because it's a tried and true solution.

Yeah, it puts us in an interesting situation because our planning process is all carved in stone in our operating agreement. You know, same thing happens with the storage conversation that we were just having. If you're trying to solve the problem that Bob is describing where you have a small, local load issue and the transmission owner knows that load inside out, they can design a solution you know, fairly easily, that probably will have legs to serve for years.
But if it's in the middle of a backbone grid, and it's a first contingency problem, we'd now have to start looking at a multiple number of hours to see, you know, how effective is that solution over a period of time, or even if it's 100 percent dedicated to a transmission issue, forget about markets, okay?

If it's an N minus one minus one criteria issue, you may have a completely different set of analyses that have to be done. So, similar to your question where you can hypothesize where these problems may take us if you implement more and more of these devices over time, but none of that is baked into our planning process today.

We need to do a lot of homework to figure out how we would even do the evaluation and then in fairness, what do we have to make available to proposers of solutions so that they can do the same kind of analysis before to make an intelligent proposal in our competitive solicitation?

So, it works both ways. We have to design an analysis procedure and then we have to make it, you know, for transparency's sake, we have to make it readily available to all of the entities that might want to propose solutions in a competitive framework.

So, there's a lot of work to be done here, solving one problem with one solution, we can look at you know, a solution based on storage against a solution based
on Smart Wires, against a reconductor, against a green field line, and we can figure out costs and we can figure out performance, but when you extrapolate this into the future, we have a lot of work that needs to be done, first internally and then ensuring that our stakeholders have the ability to replicate that kind of work and make smart proposals.

MR. HACKMAN: I'd just like to respectfully respond just -- the challenge with doing -- looking at the entire situation first is that you're picking the winners, you know, to I think it might have been Frank or someone else's comment down there. I mean that's the challenge.

For us, when we propose solutions, we have to assume that it's kind of like when organized markets rolls out. No disrespect to you, Doctor Patton or MISO, but when the iteration of the MISO market, the one that I'm most familiar with, from when we were proposing it until what it is now. It is a quantum leap difference.

I mean the optimization routines, the different ways that you know, generator economics are protected. It is an evolution. And to imply that we're not smart enough to figure it out, if we start with one seems kind of like not American. I'm just thinking that we can solve this problem.

It's really not, you know, we've got people like
Doctor Bose. We're done, that's all we need, and Jeff, and
maybe all the rest of you, too. Lots more than me. I'm an
operator guy. So, but I think the thing is like energy
storage, if we don't allow the first one, we don't ever get
the second one. We don't even have a problem to solve and
so every time we propose a solution and it's derailed
because it's the first, we don't get the second.

MR. PEIROVI: Professor Bose?

MR. HARLING: Can I just make one quick response
to that? First of all, I agree with what Jeff is saying and
we will pick the winner in that one situation based on that
one situation. That doesn't mean I'm not going to have a
headache thinking about where we're going to be 10 years
from now when we do have a hundred of them. But we agree
entirely. You've got to do the first one based on the first
one.

MR. BOSE: I just wanted to make a point that
actually that train has already left the station. The thing
is that we can solve problems one at a time with one
solution at a time, but actually we can't go on like this
for very long because as somebody pointed out, these things
will fight each other.

You know, you -- and we're already seeing some of
this. Again, I bring the Western system where there are now
more than a hundred RAS schemes, what we call RAS schemes,
they're a special protection schemes, and there are some
issues there as to whether these things can operate
independently and not get into trouble.

So, now think of hundreds of these, but the idea
that you already have hundreds of facts and devices coming
into the system. That train has left the station. You are
going to have distributed generation and not just a few
dozen central generators to optimize. So, we've got to
figure out how to handle these large numbers of distributed
generators and distributed controlling loads. They're all
going to play in your market, they're all going to be part
of your grid.

And the only tools we have to handle it are these
controllers to manage these things. So, this is laying out
a picture, not a -- it's not that we don't know how to
approach it. It's just that we haven't done it yet.

MR. PEIROVI: Frank?

MR. KREIKEBAUM: So, I fully appreciate the
conversation we've had about operations and how do we
integrate with more complexity into the operations. I spent
7 years doing a PhD where I developed one tool in the
academic environment to do one part of the operational
problem to integrate power flow control.

So, I totally get that there's challenges here.
But I think we also should look at the way that some folks
are handling those challenges. So, look at Australia, 
there's been a lot of talk about automatic control volt 
sources -- centralized control, Bob talked about a voltage 
controller.

The Australian operator said, "We'd really like 
to have that. It's a real impediment to our grid. Let's 
ask the EMS vendor to create a tool." They asked the vendor 
to create a tool, they ran the tool for a period of time 
where all it did was recommend settings to the operators. 

We think if you did this with this voltage 
controller and this with this generator, you'd be in a more 
optimal place. They ran it like that for a while and then 
the operator said, "This has been giving us good 
recommendations. Let's let this tool issue the commands on 
its own." It took a while to build that trust, but they 
earned that trust.

They haven't done that with power flow control 
optimization in Australia, yet they're moving forward 
quickly with applying power flow control in some of the most 
critical interfaces. They recognize that, as we do, this 
crawl, walk, run mentality of there are certain things we 
can do now with the systems we have now. There are certain 
things we can do later with our first enhancement, and 
there's things we can do later with the end game 
enhancement.
And they're deploying, as they can, with the tools they have, and investing in additional tools to get more out of their system. And I really think we need to keep that in mind, so we don't get hung up, as Jeff said, on final, ultimate solution and not be making progress today with the technologies we have at our disposal.

MR. PEIROVI: Thank you, this is definitely a very fundamental and difficult set of issues. I want to thank you for that. Noting that we started a little bit late, we can go over a little bit if my fellow staff members have any other questions. If you don't, I have one additional question.

I'm a little bit interested in a little bit more of an expansion of what Adrianne said. Adrianne, if you don't mind expanding a little bit on your -- what you've seen as a representative of a vertically integrated utility, how your decision-making has changed as new technologies come forward?

MS. COLLINS: So, I'd like to start back, and something came up with the prior panel and I think we've touched on it here a little bit earlier, right? So, you know, there are grid-enhancing technologies that at one time now are commonplace. They were cutting edge at that particular point in time.

So, I think it's incumbent upon us to evaluate
each one of the technologies that are out there, and as we identify where they are from a Southern perspective, is where are they best suited to be put onto the system? You know, and for us again, it could be at a generation transmission or a distribution level, but really has to take into consideration the customer being the end of mine in terms of the cost. And I think as the grid continues to change and evolve, back to ensuring the reliability of the system and the security.

So, when I think about some of the applications that we are currently piloting and evaluating as understanding really what are the impacts on the system, the entire grid? So, some of the utility scale battery energy storage that we've got going on, really understanding the enhancements, the software and hardware that are going on with those, so we can understand what impacts that they have on our system and where are they best suited?

And do we need to deploy them at a wide scale, or are there specific applications that are better suited for those? So, I think again, it's just an evaluation of each -- looking at each individually, looking where they make sense for us, and then sharing those perspectives with others where they may see those benefits, whether it's on an individual application or when it is truly maybe something that they ought to look at wide-scale.
But I just do think it's very important that we go back to it's got to be safe. It's got to be reliable. It's got to be secure and it's got to be for the benefit of our customers. And I think again, there's value in implementing those in our systems, but we've got to do it in a balanced approach.

MR. PEIROVI: Thank you. That concludes our second panel. We'll break for lunch and start with Panel 3 at 2:00 p.m., thank you.

(Break 12:33 p.m. - 2:03 p.m.)

Panel 3: Grid-Enhancing Technologies in Transmission Planning

MR. PEIROVI: Alright, thank you. I hope everyone had a good lunch. We'll start with Panel 3. Let me reiterate what Panel 3 is about. So, Panel 3 will explore how grid-enhancing technologies are currently implemented in transmission planning processes across the country.

Panelists will be asked to give their perspective through short presentations and through discussion on how various types of grid-enhancing technologies can be evaluated alongside more traditional system projects in existing transmission planning processes.
In addition, this panel will consider what challenges exist in current transmission planning processes. With that, let me remind you to keep your remarks relative short, 2 to 3 minutes, your opening remarks, and then we’ll drive right into the discussion portion.

Let me introduce the panelists. Unfortunately, Betsey Beck was not able to make it today, so we've got five today. Let me start with Jeff Webb from the MISO, Andrew Clark or Drew Clark from Duke, Michael Kormos from Exelon, Babak Enayati from National Grid, and Joseph Abhulimen, from the CPUC Public Advocates Office. Thank you, and let's begin with Jeff.

MR. WEBB: Is this on already, okay, good. Alright, thank you. And I'm not a professor, so I will try to speed read through my prepared remarks. Thank you, we appreciate the opportunity to participate in this discussion about incorporating grid-enhancing technologies into the transmission planning process.

We also believe that improving the efficiency of the existing grid is an important part of developing a cost-effective transmission grid for both the near and the long-term planning horizons. I'll speak briefly to three main topics here. Briefly, on the MISO planning process.

Secondly, the grid technologies that we've typically seen proposed, many of which you've heard about
this morning already, and how these newer operational grid
technologies might fit into future plans.

And then lastly, that the note on the planning
challenges that we currently face at MISO, in particular.
So, regarding the planning process, MISO's annual regional
planning process considers all upgrade needs and available
solutions, and these run the gamut from small to large
solutions, near-term to long-term to best identify the
alternatives that ensure reliability and the lowest
delivered cost to customers.

This process includes multiple opportunities for
all stakeholders to participate in the process of proposing
solutions to transmission issues, whether these are driven
by reliability, congestion, energy policy goals, or
customer's demands for cleaner, lower-cost energy.

Our planning process results typically in between
3 and 4 billion dollars annually in improved transmission
investment, and this includes a wide mix of projects, lower
cost and more substantial. In 2011 for example, we included
a 6 billion dollar multi-valued project portfolio that
provided a step change in the regional transfer capability
to address new generation portfolio requirements.

So, we've seen improvements over time in grid
technologies. There's been a fair amount of discussion
about that this morning. Of course, in addition to the
newer operational technologies that are the prime focus of this workshop, we too, have seen implemented, more conventional, I would say non-transmission line grid-enhancing technologies such as had been mentioned today, phase angle regulators, serious capacitors and inductors, back to back voltage source converters, and so on, all of which improve grid control, or increase transfer capabilities.

And these have been the grid-enhancing technologies of choice. And in addition, these generally are of higher cost and higher capacity perhaps, than we may be able to extract from grid-enhancing technologies of the newer variety.

We have not yet seen proposals for the newer technologies that we've heard about today in the planning process, and we expect this is primarily for the reasons that have also been discussed at pretty good length in the earlier panels, that being that they are not yet well understood in terms of their capabilities, their effectiveness, their overall cost to implement and any potential risks and complications to their application which involved things like the need to integrate them with other data coming in in operations, both for reliable operations and market operations.

I would also say that transmission
reconfiguration and switching is also considered in the
transmission planning process and optimization algorithms
could provide some advantage here in selecting which of
those might be most effective in the planning horizon.

However, I will say that there's a tendency in
the planning horizon to prefer capacity additions to
increasing the burden on operators to rely on
ever-increasing numbers of operational steps to maintain
grid reliability.

We think the planning objectives should drive the
best solution. For example, if your objective is to provide
long-term capability to deliver say, 50 gigawatts of new
generation resources over time, and expedient low cost means
to improve transfer capability of the existing transmission
grid may not be the feasible or cost-effective solution.

If, however, you've got a congestion issue in a
localized area, in delivering an exist fleet, a near term
low-cost operational solution might be just the right
answer.

Turning quickly to storage, we are beginning to
see proposals for energy storage as assets to improve grid
performance in addition to the market participation model of
Order 841, and MISO's been developing policies for
consideration of storage as transmission where appropriate.

We see opportunities for storage as transmission, when due
to its unique characteristics, it can best resolve
transmission issues in ways beyond what it could provide
simply by performing in the markets as an electric storage
resource under the Order 841 market participation model.

Such characteristics could include its ability
most likely, to very rapidly discharge or charge, in order
to address system stability, or avoid load curtailments by
maintaining post-contingency loading and voltage levels, in
many cases, at the second contingency level.

And lastly, our most pressing challenges that we
see, you know, while we're not focused on these types of
technologies, obviously, generation technologies have also
advanced and these have created sweeping changes in the
generation portfolio.

At MISO we have more than 90 gigawatts of
renewable resources seeking to interconnect, 52 of those are
in solar facilities, 23 gigawatts is wind and what we're
seeing there is as we continue to see this sort of evolution
from fossil fuel to renewable resources, these are
inverter-based technologies, and these themselves, put
additional stresses on the adequate performance of the
transmission grid.

When we've looked at these studies, we've seen
that we may need, in addition to significant new
transmission capacity line upgrades, we would also need some
of the more conventional larger scale voltage controlling
devices, since inverter-based technologies require a strong
system voltage source to maintain their operability.

We would be considered if incentives designed to
promote more efficient use of the existing grid did so at
the expense of developing the larger scope upgrades that are
needed to meet the scale of new resource developments that
we're seeing.

So, to sum up, generally we believe that the new
technologies mostly could become part of the toolbox for
consideration in the planning process, but importantly, only
when they are more mature in their applications, in
understanding of their total cost to implement, and how to
model them, and any risks that they may come with their
deployment.

We also think that the existing planning
processes are well positioned to include these on an equal
footing with other solution options in transmission to meet
the short and long-run system needs. Thanks for this time.

MR. PIEROVI: Thanks Jeff. Moving on to Drew?

MR. CLARKE: Thank you. Andrew Clarke,
Integrated Planning Coordinator, working in the Integrated
Duke Energy appreciates the Commission's initiative to
explore new technologies to increase the efficiency of the
grid, and thanks the Commission for the opportunity to
participate on the panel addressing the incorporation of
grid-enhancing technologies in the transmission planning
process.

First, I would like to provide some background on
Duke Energy's integrated system and operation's planning
strategy and goals. In 2016, with the significant
transformations underway in the energy and electric utility
sector, Duke Energy recognized the need to look at future
planning in a different way.

Duke Energy's developing ISOP framework envisions
optimizing capacity and energy resource investments across
generation, transmission, distribution and customer
solutions for the benefit of our customers. Through ISOP,
Duke Energy's electric utilities are developing new ways to
evaluate different technology alternatives to help us
determine which ones can be effectively deployed for the
benefit of our customers and in which scenarios they will
perform optimally.

Energy Storage, particularly battery energy
storage, is technology that is gaining significant momentum
for evaluation, is the potential solution to transmission
and distribution reliability issues, and grid enhancements.

While Duke Energy has several battery storage
projects installed at the distribution level, or to function
within microgrids, through ISOP, Duke Energy is developing
new methods to evaluate battery energy storage as a non-wire
solution for transmission system contingencies.

Other technologies evaluated include intelligent,
transmission grid controls. While transmission grid
controls and switching devices certainly provide value,
sometimes at a lower cost or easier deployment than capacity
upgrades, it is important to recognize that they cannot be
effective in all situations.

Finally, I would like to touch on some of the
challenges encountered while evaluating these technologies,
from planning to deployment, potential ways that FERC could
provide additional clarity. One of the challenges Duke
Energy faces as it is developing and implementing this
framework is the uncertainty on how non-traditional
solutions, such as energy storage would be classified by
regulatory bodies.

There are implications with cost recovery, NERC
transmission planning standards, transmission operator
control, evaluating the costs of new technologies in
comparison to traditional solutions, and any potential for
stacking the service capabilities in order to more fully
capture benefits across generation, transmission, and
distribution on behalf of our customers.
It is also important to recognize that different technologies or solutions may be more effective in different situations. Therefore, we would like to stress that the utilities should have the flexibility to determine the most appropriate options, or grid enhancing solutions available, given the site specific circumstances and issues that needs to be addressed.

Duke Energy appreciates the opportunity to participate in these important discussions and to share our experience with our recently formed integrated system and operations planning program, along with our perspectives on how to plan and deploy grid enhancing technologies that make sense for our system and our customers. I welcome any questions you may have, thank you.

MR. PEIROVI: Thank you Drew. Moving on to Mike.

MR. KORMOS: Thank you and thank you for the opportunity to share Exelon's experience in both our internal look at grid enhancing technologies as well as our experience in the PJM process.

And I'll probably take a little bit of a change. We have filed comments. I'm just going to try to summarize them in that I probably looked it at more versus grid-enhancing technologies as sort of conventional versus non-conventional solutions only because I think there are a lot of grid-enhancement technologies, SCCs, PARs, conductor
technology that have sort of made that leap that they're
more in the conventional.

And I think what we're still looking at in these
particular technologies that have been discussed are sort of
the non-conventional ones where they're solving the problem
in a slightly different way, and I think that just adds
interest into how we look at them.

So, I think our experience with these is
internally starting with, you know, sort of coming up with
the cost benefit analysis. You know, first of all from a
cost-effective perspective, most of these just simply are
not at the commercial scale to drive the cost down to where
they frankly are competitive. In most cases, what we are
seeing is they're getting better, but they're not quite
there.

But then on top of that, when you throw in trying
to look at the benefits of them versus other options that
you may have available, I think that's really where it sort
of becomes more interesting of a conversation because the
benefits, particularly in the planning world, are not one
for one with the conventional technology.

So, I think if you look at things like storage
devices, we have a continuous argument of well how big a
battery? Is it a two hour battery, a four hour battery, a
six hour battery, an eight hour battery? When you're trying
to look 10 years out in the future, none of us really know what size the battery needs. That really then sort of skews then, you know, versus you reconduct our line, you know exactly how much capacity you have and it you have it 365 days a year.

Same thing with some of the other technologies. I think we talked in the facilities rating conversations, things like dynamic you have to plan for the worst case, but even some of the flow devices, flow devices where again, when you're looking at something that doesn't necessarily create any additional capacity, uses existing capacity, it's a great thing and I don't want to knock it except in the planning world when you're looking at a set of scenarios that are fairly wide and fairly extensive, how do you decide how much benefit that provides versus some of the more traditional?

So, I think that's where we've really just struggled even internally, and you know, our -- I think our experience has been we've been able to do some pilots, we've been able to start looking at these on a smaller scale, probably the most recent we've brought to the Commission was a super conductor we did in our comment footprint where again, now one of the big benefits there was a very big influence of money by DHS to help offset the cost to our customers, but also it was on a scale where again we were
actually looking at a problem that was probably not typical mainstream.

It was more of a delivery to the distribution and looking at the ability to solve it a little differently. So, I think there are struggles there and then I think, you know, to go where the conversation is, then when you participate in a planning process through an RTO, all of the issues we just discussed, which I would say are challenging when we just look at these individually.

I think it magnifies in the planning processes of the RTO by nature. They are supposed to be very transparent. They are now very competitive, and therefore forcing anything other than the least cost, most cost-effective, raises a lot of issues, particularly when it's not your project that's picked, and somebody is potentially looking at other potential technologies or being picking those.

You know, and that's not to say we don't. We have submitted Smart Wires. Other companies in PJM have submitted Smart Wires as a solution into the PJM open windows. To date, none of them have been chosen, but I don't think that's anything other than a fair evaluation based on costs versus benefits.

We've had many discussions with PJMs about battery solutions at the transmission level. We've had more
success at the distribution in Exelon. We've put batteries on our distribution system. Transmission -- we have a long conversation about some of the limitations there as again how you look at them at a transmission perspective.

But, even there, most of it is just cost. The batteries are significantly bigger to solve transmission problems and distribution problems. And then throw in that competitive nature that we now experience through our open window process. I think that is in fact, adding sort of another dimension.

And so, I don't necessarily think it's an issue we can't overcome. I have my buddy Steve Herling over there who's older than me and been around longer than I have. But I can remember conversations we had about SPCs. So, the first ones we've put on there, and just the risk, and they were so expensive, and would they really work, and would power electronics really be the future?

And I would say, you know, we have gone past that in that we put SPC's in everywhere, that there's a voltage problem because again the technology is there. So, and that happens through a natural progress. I realized in some cases, probably slower than some would like, but I do think the planning processes do work in most cases to get a lot of those technologies there.

I'll probably stop there and just wait for
questions.

MR. PIEROVI: Thank you. Moving on to Babak,

thank you.

MR. ENAYATI: Good afternoon and thank you for
the opportunity to participate in this panel session. My
name is Babak Enayati, and I manage National Grid's
Technology Deployment Team.

National Grid is an investor on utilities focused
on transmission and distribution of electricity and gas.
National Grid has more than 7 million gas and electricity
customers in the U.S. serving communities of over 20 million
residents.

National Grid has committed to increasingly
deploy new technologies to enhance transmission network
reliability and operations. These new technologies enable
National Grid to integrate more renewable generation, to
deliver low carbon resources, reduce the costs, serve the
customers, improve asset management decision-making,
reducing the asset operations and maintenance expenses, and
enhance system resiliency and outage restoration. This
presentation endeavors to brief the Commission on three
areas: dynamic transformer ratings, substation automation
and energy storage.

So, starting with dynamic transformer ratings, to
compare the benefits and challenges of dynamic transformer
rating or DTR and the static transformer rating, National Grid installed DTR technologies on two transmission transformers. These technologies we deployed measure the temperature of the coil and oil, dissolve gas and partial discharge to estimate the true MVA of the transformer.

National Grid's DTR technologies have been in service since July of 2019 and since then, we have observed several challenges and potential benefits.

So, starting with challenges number one -- cyber security. Not all DTR vendors have their equipment certified to meet the utilities' digital risk and security requirements and so integration to energy management system or EMS may require additional time and resources.

Number two -- real time system operation based on true MVA versus static MVA. So, currently most utilities utilize static MVA for operations. And the static MVA ratings are defined based on the worst operating conditions and the transformer cooling systems. So, utilizing true MVA requires changes on the data management and the operations processes.

In terms of benefits, condition-based versus time-based maintenance. The DTR technologies provide full visibility over health of the transformers which allows maintenance based on the transformer condition. Therefore, the required time and resources for operation and
maintenance is reduced, and the asset life is increased.

The second benefit, enhanced real time operation capability. During times when power flowing through the transformer is expected to exceed the static ratings, DTR technology can assist the operator in making proper real time switching decisions.

And last, renewable integration. Additional transformer capacity allowing higher integration of renewable generation on the electric transmission system.

So, second on new gen substation automation, National Grid has committed to increasing the deployment of digital substation technologies. Digital substation technologies allow us to build stations quicker, at lower costs, and with a smaller environmental footprint.

These substations also allow for greater repeatability and engineering optimization by leveraging industry standards and modern digital software-based designs. Enhanced monitoring and remote connectivity facilitate the reduction and even elimination of some maintenance.

These digital substations are also highly adaptive, enabling optimization power flows, even with the increase of variable, renewable power. This means less cost and more clean energy for our customers. National Grid is committed to embracing digital technologies in the future on
future projects with nearly 200 digital substations planned
to be deployed in the next 10 years.

And the third on the agenda is energy storage, so a few words on that. National Grid is actively pursuing
energy storage on its network to cost-effectively resolve transmission needs and provide network transmission and
distribution reliability benefits.

National Grid has many energy storage initiatives in development, including the Nantucket Island Battery Energy Storage System. National Grid recently commissioned the battery energy storage system, 6 megawatt, 48 megawatt hour facility, which reliably defers capital investment, and along the complementary facilities, resolves reliability issues affecting services to the island of Nantucket.

National Grid has studied other parts of our transmission system and concluded that energy storage can be utilized to cost-effectively address transmission needs in specific circumstances.

More generally, National Grid has found that energy storage can offer a variety of benefits and challenges. With respect to benefits, an energy storage resource by itself, or in conjunction with power flow controller devices, may be the least cost solution to address case-specific reliability issues on the transmission network. It can also provide power quality grid support
services like Volt/VAR.

With respect to challenges, number one, cyber security again. Cyber section for integration to the energy management system presents challenges as some energy storage inverters are manufactured outside the country. Cyber security standards need to be frequently updated to maintain the resiliency of the electric grid.

Some RTOs and ISOs, regional planning processes also do not consider energy storage as a potential solution to identified reliability needs.

And last, due to the -- last challenge, due to the variety of storage inverter designs and proprietary information protected by the manufacturers, lack of standard storage models poses challenges to the utilities to properly model energy storage for their planning studies.

And I'll conclude by some recommendations. So, we encourage the Commission to continue to explore policies that would drive adoption to improve system operations and create economic benefits. National Grid believes that the Commission should allow utility ownership of energy storage and should permit energy storage resources to participate in wholesale markets.

Furthermore, National Grid believes that the Commission should provide incentives for substation automation and should look specifically at new ways to
incentivize advanced technologies like DTR that will make the grid more efficient and improve operational flexibility.

Well, thank you for the opportunity and I look forward to participating in Q&A.

MR. PEIROVI: Thank you, Joseph?

MR. ABHULIMEN: Thank you, good afternoon and for the opportunity to participate in this forum and to present some perspectives in these issues. My name is Joseph Abhulimen. I serve as the Supervisor for the Transmission Planning and Police section at the Public Advocates Office in San Francisco.

The Public Advocates Office is the independent consumer advocate within the California Public Utilities Commission, which is established by the California state statute to represent the interests of customers to obtain the lowest possible rates for service, consistent with reliable and safe service and the state's environmental goals.

As part of this mandate, the Public Advocates Office actively participates in the California Independent System Operator transmission planning processes and in the California PUC's permitting process for transmission infrastructure.

According to a report that was published by
Brattle Group in November of 2018, investments in transmission have grown by approximately 12% nationally within the last 10 years, and approximately 10% in California during the same period.

So, this level of transmission investment accounts for approximately 10 to 12% of a typical electric customer's bill in California, so it is important for the Public Advocates Office to participate in CAISO's transmission planning processes and in the California PUC's permitting process in order to evaluate and recommend the most efficient and cost-effective solutions, such as new transmission technologies and non-wire alternatives to address identified transmission needs and to lower costs for ratepayers.

The Public Advocates Office generally supports cost effective grid enhancing technologies that can effectively integrate into the existing electrical grid and to respond quickly to changing energy demand. These new grid enhancing technologies should make the transmission system more efficient with little or no energy losses, improve electric system reliability and resiliency, reduce utilities' transmission, operations and maintenance costs, reduce peak demand and encourage energy conservation, and increase integration of large renewable energy systems.

So, I look forward to discussing some of these
factors with the panelists, as well as the audience, thank you.

MR. PEIROVI: Thank you, everyone. Let me first recognize that Commissioner Glick is in attendance here and turn it over to Commissioner Glick if he has any questions or remarks or both.

COMMISSIONER GLICK: I don't have any questions but thank you.

MR. PEIROVI: Thank you. Let's kick it off now. Let me give you a more general question to kick it off and then we will disburse our question among my fellow staff members and among the side tables.

First, give me a quick kind of specifically for storage, what proposed uses or services of an electric storage resource would help determine its eligibility to be considered a transmission asset for purposes of transmission planning? And we'll start in the same order that we went in opening remarks as long as you have something to respond to.

MR. WEBB: yes, this is Jeff Webb with MISO. As I mentioned in my opening remarks, we are cognizant of the gray line between how you would apply a device like storage that obviously, can operate in markets and earn revenues through that mechanism, or has potential to provide an optimal transmission solution in certain circumstances.

And I don't believe that we know the full realm
of those circumstances because even though the technology itself is well established. It's particular applications for transmission planning. We probably haven't seen all the possible opportunities there. But one of the things that we do think should be the case is that if since the device can support the grid both through market operations and potentially as a transmission asset, if the situation -- if the planning issue that you're looking at is something that could reasonably be addressed by the device acting as a market asset, and typical in that would be sort of an N minus 1 thermal-type condition where, by virtue of its ability to compete on offering energy into the market, in doing so it would relieve the -- provide a counter flow, or something like that, just as almost every other generator on the system does today from time to time.

Then it should not be eligible for cost-based recovery. It should take the normal route, we think. So, what does that leave us with. What we've seen so far, is that we've seen a good application, we believe, where the device -- because of its ability to quickly, very quickly, discharge can be used as a post-contingency operation where you can wait for that second contingency to occur before you have to take action after the first in advance of the second.

For example, you may, if you can't handle a
double contingency situation because of stability, after the
first contingency, you have to take some kind of an action
that could include load shed, or reconfiguration of the grid
in a way that puts load at risk. If you have a quick-acting
device that can inject energy quickly for some reasonable
period of time where you can take those operating steps that
you need to handle the second contingency, you can wait for
that second contingency to occur, and the probability of
being -- the number of hours that you're going to be in that
second contingency is near zero compared to the first
contingency condition.

So, in that kind of a case, we would also compare
that to other possible solutions to resolve that problem.
But then we would treat it just like any other, that
evaluation, just like any other transmission solution --
what is its long-term costs in solving that solution? Does
it do it robustly, those types of comparisons.

And there's other things we have to take into
consideration for storage. It's degradation of life, and
there are costs associated with that, we have to consider
sort of the life-cycle cost of that device, which has a
typically shorter life than a transmission line per se.

But we think all of those things are achievable
in the planning process and when we see those circumstances,
we should be able to apply -- extract that value from the
device.

MR. PEIROVI: Thank you.

MR. CORBETT: So, we believe that the primary use case would likely drive the consideration as a transmission planning asset. We're still evaluating potential use cases as part of the ISOP framework, however, something that comes to mind would be flexibility and operations, increased availability of outage scheduling, upgrade deferral at an increased reliability.

Regardless of use case though, certain criteria, we believe, will have to be met with would be that they would have to be able to reliably operate to meet whatever the need we're trying to solve is, implementable in time to solve the need and valued appropriate for our customers to make sure it makes sense.

Another area we believe will be necessary is a full transmission operator control. Transmission system contingencies aren't always predictable, and as such, we need to make sure that the operator has control to be able to utilize a grid-enhancing technology to be able to solve the problem should the need arise.

MR. KORMOS: I feel like we had a whole Conference on this a couple months ago. To me, I think it may be a little more simplified in that I think at the end of the day if it solves a transmission planning criteria
violation that's the most cost-effective, it's a
transmission solution and it should be treated like any
other electronic device, cap, whatever you want, if it is
the most cost-effective way to solve that particular
transmission planning violation criteria that somebody is
looking to solve.

That we should clearly treat it as a transmission
asset. I think the question comes in is if it is only the
most cost-effective because it participates in other
functions that may be market-based rates, what does that
that -- what happens then?

And I think we proposed back then that again, I
think there is nothing, no reason we shouldn't be
considering that. I think you will find they are more
cost-effective in more situations if we can look at those
other revenues, as simply offsets to the cost.

You know, to me I think that was one of the
things we proposed back in the storage Conference was again,
the model where if the primary purpose is for reliability
criteria violation in the planning process, you put it in as
a transmission asset. If it has the opportunity to offset
some of those costs, very much like we sell pole
attachments, we lease right of ways, there's another
opportunity for us to earn something on that, we would
simply go back to then offset the existing rates of the
transmission customer.

MR. ENAYATI: So, I would totally agree with what Michael just said. In terms that if the storage is the cost-effective solution for a transmission reliability issue, it should be considered as a transmission asset. But let's just -- I just need one more minute on actually explaining where storage can be a solution.

Storage is not a solution for every single reliability problem, and I hope that during you know, other questions about the specifics, I can talk about where storage can be a potential solution and where it cannot. I'll leave it until later, but comparing storage with traditional upgrades, like reconductoring a line, storage can provide additional support, and that's basically one of the biggest supports is power quality.

We're talking about renewable energy, integration to the grid, we have like off-shore wind integration. Our service territory, we have, you know, and I'm sure, you know, a transmission level, renewable integration in general, like solar power plants, also being developed and connected to the grid, and due to intermittent nature of these resources, of course you may experience some power quality issues, but storage can mitigate those challenges for like a typical line as just the line, you're just adding more capacity to it.
So, I think just reliability is the base, but we need to look at other grid support functionalities as well.

MR. ABHULIMEN: I would support, you know, most of what has been said so far. You know, it depends, every storage resource, you know, has different characteristics. So, it depends how it is being deployed.

If it is being deployed to serve or to solve a transmission issue, then I think it should be classified and treated that way. But then again, if it's used for generation, then it should be treated in that fashion. So, I think it depends how it is being deployed in the system and what is the intended use of that resource. So, I think that a definition should be very clear, and I think that the planning authorities like, you know, ISO, you know, should clearly indicate how that resource is being deployed.

And I think then once that definition is clear, and the usage is clear, then I think it should be treated in that fashion.

MR. PEIROVI: Thank you. Let me turn it to my fellow staff members here at the table to see if they have any questions.

MR. CORBETT: Yes, thank you, I have a question. I'll turn it on. Not only in the earlier panel, but also in this panel, I hear a lot of cost-effectiveness, costs of
reliability, and that's something that we struggle with.

However, I know that, especially in the planning environment, when you make a decision to apply a grid-enhancing technology to your project, you're not just saying grabbing these things out of thin air, you've researched them, you're making an intentional purpose to apply them, to maybe measure the results and try to capture the benefits that you're receiving for your investment.

But when you make that ultimate decision going forward to apply these technologies, through your -- shall we say, your transmission planning standard, or a standard fix for a particular type of problem, how do you weigh this cost? How do you measure this cost to reliability that you take into the consideration to justify that grid-enhancing technology as part of your project -- maybe conventional or unconventional, and local area versus wide area?

MR. KORMOS: I'll take a stab at it. First, to be honest with you, I think that's the big question. And I think even internally, just looking at a utility, is a very tough decision because in some cases, you're accepting some kind of risk where the solution is potentially not as robust, it's more narrowly defined as to how it solves the problem.

And so, you're accepting some greater risk and then potentially accepting some greater cost associated
with. And that's not always the case, and that's why I'm mentioning you know, in some cases for us, we were able to look at some aluminum clad composite core conductors where they are more expensive, but in the grand scheme of things, it was a more cost-effective solution, because we didn't have to increase our right of ways, we didn't have to rebuild our towers to do that.

In some of the ones we're talking about in the non-traditional, I think it becomes at issue is it doesn't solve the problem the same way, and so how do you decide how much risk you're willing to take, potentially at something that's more cost-effective, and still being prudent to your customers, that you're still coming up with the most prudence?

So, there is a learning factor and you want to gain that learning factor. So, I think it's a very difficult discussion we all have internally. I think one of the things that's a problem is it compounds when you are then going to an Order 1000, open window competitive process.

I honestly don't know how an RTO will make that decision. I think it becomes very difficult for them to basically tell somebody take more risk, and spend more money, or even take more risk at a lower cost, still accepting the risk and how they ultimately make those
decisions.

Because I think, again, at least in PJM, but I think in most others, it's become very litigated in this day and age as to how those projects are picked, and who gets the right to build the project and such. So, I will say that is an increased challenge. So, I think your question is -- it's always been a difficult one with new technologies as to where that breakpoint is as to whatever increased risk you're having, either because it's new, or solving it differently, is worth the risk you are accepting.

That's difficult enough for a utility to take when we have the accountability and the responsibility and the liability to maintain our system. It's even harder when you're now asking a third party to make those kind of decisions, and I think it's going to be difficult until we gain more knowledge.

And for us, it's probably why we focused on trying to look at doing things sort of, at a smaller scale, in the pilot projects where they are probably less controversial in the nature of those things.

MR. ENAYATI: So, one of the -- some of our pilots we haven't really monetized some of the benefits here, so like for example in terms of DTR, you know, reduced maintenance time and we're still working on it, right.

But in terms of energy storage, I'll just tell
you what we're doing at this point. So, we are utilizing a tool that can predict the costs of the battery for the next 5 years, 10 years, we are looking at you know, the installation cost, so this tool gives us the total costs of this battery storage facility, depending on the size and megawatt hours.

And then we're also -- we know how long the line is. We know the approximate costs for line upgrade per mile, so we have an idea of how much it's going to cost us to upgrade the line, so it's easier for us to compare it to, but we also look at you know, are there benefits that stores can provide.

I mentioned, like the power quality benefits. In terms of like the substation automation, and again, it's not just the cost it's more like the benefits that you know, reduce time to build a substation, we can have smaller footprints for the substations with like the digitized substations and all benefiting customers, you know, as the grid changes we'll be able to respond rapidly, for even like outage restorations and so on.

Some costs are easy to capture. Some are still we're in the process of, you know, monetizing some of the benefits.

MR. ABHULIMEN: Joseph Abhulimen, I just want to add that, you know, in response to your question that I
think that some of this technology should be evaluated through the planning phase. It should be evaluated as part of the alternatives that are being considered.

So, once you identify a particular transmission need, at least in California, we always ask these questions. What alternatives have you evaluated? What is the ability of the relationship to your identified project? Have you evaluated alternatives? And if so, what are the benefits -- what are the costs related to the particular technology?

So, I think that all of this question should be answered through the planning phase, alright. So, once you have identified what these benefits are, then you have to look at the costs. From my perspective, in California, we always ask those questions in terms of is the alternative chosen able to meet a particular objection? And to be able to deliver what you intend or to solve the transmission issue, and if so, what are those costs.

So, I think in terms of the cost benefit trade-off, those are some of the questions that should be answered at that phase, because once you get into the you know, as I said, into the bidding phase, it's almost too late. So, before you actually choose a particular project, you should have already done all the homework in terms of the alternatives that you have evaluated on what those costs are.
MR. CLARKE: I'll agree with some of what's already been said. I think we're certainly still working through what the appropriate metrics are to value. I think it's further complicated by differences in lifecycles, and we need to recognize those and make sure we take those into account.

And then I think really it breaks down into two questions, number one is what is the need and number two is what benefits does the solution provide? And there are potentially two different answers there. You may have a need and the solution may provide that, plus more, but I think really there's two things that we have to work through with that.

MR. PEIROVI: Before I turn to my other fellow staff members, oh, sorry Jeff, go ahead.

MR. WEBB: Well, just very briefly, piggybacking on some of these comments and what you heard earlier, I think Mr. Kormos was talking any risk. To me, I think risk involving GETS is the maturity question, right? You don't want to -- once you have, once we establish the viability of these technologies, they should become part of the planning tool set that you would evaluate as you do any other transmission facility against another.

We evaluate -- it's not always crystal clear either, because you have things like special protection
schemes, for example, which are always a matter of comparing
the risk of implementing some kind of a scheme that could --
is not 100% secure, like a transmission line, but it may
obviate the need for something that's a low-risk situation
that's very expensive to fix.

So, I think the key here is what we heard
earlier, that once these are proven technologies -- and what
does it take to be proven? Is it 1, 2, 3, commercial
applications of these? Is it, you know, it's not just a
pilot, but it has to be a routine piece of equipment like
NSVC.

MR. PEIROVI: Thank you, can I just piggyback on
that before I turn it to my colleagues here? What I'm
hearing is, especially from Jeff, is you're not seeing a lot
of these technologies coming through the planning process
yet, and so, I'd like to ask, well, you know, grid-enhancing
technologies, as you've heard before, are inclusive of many
different technologies.

What technologies are farther along that you
would expect to see pretty soon within your planning
process? And also, you know, what regulatory approaches, or
if there were some regulatory approaches implemented by the
Commission, how would that change your outlook on the
planning process?

MR. WEBB: Well on the last piece, I don't think
that it doesn't -- I don't think that the best approach
would be to provide incentives for one type of transmission
solution over the other because you're just going to get
into situations where maybe you're providing incentive for
small scale upgrades, when maybe larger scale upgrades are
the ones that are needed.

MR. PEIROVI: Benefits.

MR. WEBB: Repeat the other part of your
question?

MR. PEIROVI: How about regulatory approaches
geared towards the benefits of certain technologies, or any
technology?

MR. WEBB: You know, our planning process is as
long as you establish -- what's important is to establish
what the benefit metrics are perhaps, because if we have
clear read on what the benefit metrics are and then how
projects, investments are allocated, in terms of cost, then
I think you only need to rely on the planning process to
measure the impact on benefits.

But you would do that to compare each different
-- everything should be compared the same on their benefits.

I don't think you need special incentives for one type of
project over another because you're going to get some
perverse outcome I think at the end of the day.

MR. PEIROVI: Thank you, Babak?
MR. ENAYATI: Just to follow-up on that. I think where the Commission can help is having ISOs consider these, you know, grid-enhancing technologies as a potential solution for some of the planning issues and reliability issues, plus the you know, in terms of storage, we talked about, I mentioned in my opening remarks about ownership also, you know, having utilities and allowing them to own energy storage as an example, is also another opportunity that the Commission can help.

MR. ABHULIMEN: In response to your question, I think that you know, FERC can also help a good deal when you make a final decision how studies should be treated. And I think, by and large, in California, you know, I will say storage, you know, has been a resource that is being evaluated to solve a transmission or a load need. That is not to say that most of them are being treated as a transmission asset. So, once a decision is made, you know, on that particular issue, then I think that will go a long way in terms of using that resource to address a specific transmission need.

But I think in California, storage is being used you know, you've got to serve generation, or to serve, you know, address some transmission issues.

MR. KORMOS: So, I think probably the short answer is I wish I knew because I'd go invest in that
company if I knew what the next SCC was. But I think one of
the issues that I would personally say I weigh in my mind
is, a lot of these technologies would actually benefit in
shifting in how we operate to going from the pre-contingency
where we're working today where we're fairly conservative,
into how we operate the transmission system, recognizing
that you know, the flows will have to stay under normal
ratings.

Upon a contingency, we want to make sure they
stay under typically a four hour rating, and that gives us
enough time to back those flows down. Four hours is
typically what a lot of people are comfortable with saying.
We could go, we'll use that four hour rating.

Because again, if you go beyond that, then you
risk some kind of cascade where again, the 2003 blackout,
you simply just start overloading everything. So, when we
look at some of the technologies, particularly storage,
which has a limited ability as far as duration to respond,
or some of the ability to shift the flows.

I think one of the things is how much -- how
willing are you to go to a post-contingency world and
operate closer to the edge? And one of the things I would
say is with a battery, and I think Jeff brought this up, is
right now, it's a pre-contingency. So, we don't know if the
transmission constraints are going to last three hours, or
six hours or ten hours, so I don't know how the RTO sizes
the battery because they don't know how long it's going to
last.

Now, if what we said is well, what we'll do
instead is operate to a 30 minute rating, knowing we just
have to get it back to the four hour rating within 30
minutes. Now you might be very comfortable with a one hour
or two hour battery, but you're accepting the fact that
you're going to let that flow jump to the 30 minute rating,
and there's some increased risk in operating closer to the
sort of edge, knowing though, that you believe batteries are
able to quickly, and almost instantaneously respond to bring
that flow down.

Some of the same things with Smart Wires and
other powerful control, it's the same concept. We're going
to push more flow out. We're basically going to absorb the
head room that the system has -- there's risk here. I mean
we just don't have as much ability to take in the unexpected
consequence when you didn't think 4,500 megawatts of
generation could trip, but it can, and it has, and those
flows are very different.

So, I think part of it is looking at the
operating and now, somebody mentioned, this has NERC
implications, FERC implications, as to as we start adopting,
are we comfortable operating closer to the edge and really
looking at some of these technologies?

And you know, my first opinion is I do think we need to get there. I'm not sure what the pathway there is, and how to gain that confidence in getting there.

MR. PEIROVI: Jeff?

MR. WEBB: I would just add to what's been said.

I think some of the tools, some of the solutions might be tools in the toolbox and that toolbox is continuing to evolve as we work through some of the new technologies, how to evaluate them. I think there's certainly a recognized need to maintain flexibility there.

And as was mentioned, really tailor, if there are any incentives, tailor them to specific use cases rather than over-arching that would take away some of the flexibility.

MR. TOBENKIN: Hi Jeff, I hate to pick on you, but I actually was wondering for a couple, it seems like one of the strong points of these technologies is flexibility. And I guess one question I was wondering, would, you know, for example in the competitive solicitation process of MISO right now, I don't think one of the evaluation points specifically, is flexibility.

And I was wondering is that a competitively neutral way that could allow some of these technologies to have a sort of, a window to demonstrate their ability? And
do you think they're far enough that they would be, you
know, possibly able to do that, or to compete effectively on
that basis?

MR. WEBB: Well, that's a good question. I guess
I would say that we you know, considering flexibility is not
something that's new to transmission planning when you're
weighing, you know, some people have said planning is an
art, right?

And so, when you try to sharpen the pencil too
much and make everything a checked box of criteria, that can
be dangerous because maybe you'll overlook things, or maybe
you don't check the right boxes and it excludes some better
solutions. So, there is a qualitative consideration that
goes into comparing alternatives that considers its
flexibility.

For example, one type of flexibility is your
ability to withstand a certain condition on the grid and
have some optionality around how you could switch the grid,
and a battery could provide that kind of flexibility.

So, I think it's already a part of the planning
process in a qualitative way. Whether we could -- when we
do competitive selection, we consider qualitative elements,
and compare one against the other which incorporates
flexibility, but it's on a sort of, comparing one against
the other judgment.
We haven't, I don't think, articulated those very crisply as to what passes and what's better than another. So, it's a part of the existing process I think we could make that more prescriptive. I'm not sure that that gets us to the right place, but it could be an element.

MR. TOBENKIN: And I guess on the same line, kind of a different approach to the same issue, is just looking you have category projects, multi-value projects, look at different benefit streams of projects, like reliability, economic, public policy and I guess a question there is you know, and that also tries to balance the, you know, benefits and costs throughout the region.

And I was wondering, did consideration of these types of technologies through that you know, portfolio approach, yield more opportunities or more ways to allow them to participate as kind of add-ons to other projects?

MR. WEBB: Well I think we -- you know, you can look at the effect on the entire region of any one of these technologies that might be incorporated on a line by line basis. I mean just as we evaluate the production cost benefit per se of a single new transmission line.

So, you know, you can get a regional benefit, or more than a localized benefit out of any particular technology. Whether or not you would need a portfolio, I think do you mean that you would install Smart Wires in a
MR. TOBENKIN: In part, to respond to Doctor Bose's comment in the preceding panel that you know, we just haven't had the systemic deployment to really drive, you know, the potential of some of these and that might be one way of approaching it.

MR. WEBB: Well, yeah, I think that cuts the other way too, because one of the most -- what increases the complexity of the ability to implement these is having hundreds of them as was suggested, you know, on a one by one basis. It's not hard to evaluate these in the planning realm.

You know, you can -- a Smart Wire is a series inductor basically, and we know how to plan for those on a case by case basis, but if we had a hundred of these across a system and they were operating independently of each other, the last panel talked about that, there would be -- you would need some optimization software that tells you both in the planning, but even more so in the operational realm, as to how these things would coordinate with each other.

So, that's the big challenge I think, with these things, is that on a line by line basis. One thing, somebody asked what was the difference between these things
and any other kind of transmission upgrade. I mean we sort of know how transmission lines coordinate with each other.

They just kind of sit there and you know, they take flows, and you know, when one's out, they just flow as it should be, then that's pretty easy to -- you know, programs have been figuring out how to evaluate that for a hundred decades.

But these things, if they're constantly shifting the dynamic in nature, and you have many of them, you can imagine the optimization problem that you have. And, it's one thing in planning, but the only thing about planning is that you're taking a snapshot of what you think what state they should be in in the optimal mode, and you know, one thing you know about planning is that you're always going to be in a different situation than what you plan for when you get to real time, and will these things be operating in the modes that you saw that they could optimally operate together, so it's a huge problem.

MR. PEIROVI: I'm glad you touched on that last point, Jeff. I know Michael Kormos, you mentioned also that you know, when you install a reconductor line, then you know exactly what you're getting out of that, whereas if you install a particular technology like a grid-enhancing technology, you're not always going to know.

That kind of highlights the point that the grid
is evolving in nature. It's becoming more dynamic. How do you see your transmission planning processes changing in the future to account for you know, future changes in the grid? And that's a very kind of pie in the sky question, but I'd appreciate any comments on that.

MR. KORMOS: I think, I mean I'll give you a very pie in the sky answer. I mean I think it is, I think in that last conversation it also highlighted, you know, these one-off planning processes that we have today. I would actually argue some of these are less flexible, when it's just one of them it's less flexible, it's not more flexible. But I agree if there's a hundred of them. So, if you could only control flow on one line, you're very limited as to what you can do with it. If you have a hundred of them, and you can control flow on every line, it's a very different answer. But I think you're radically changing the planning process to be much more holistic at that point where you really are looking at more holistically, looking at the larger picture, and are willing to make these types of investments with the associated risk of what those investments bring.

That would not be a very inexpensive proposition, to either have a massive deployment of storage devices, massive deployment of Smart Wires, or any of the others. But you're accepting a lot of risk as to the benefits you
expect, will they actually materialize? And who is wearing
that risk? And then throwing it into the market and you
know, market says to the FTR holders, where are the risks,
because they're the ones who hedged and paid to get to
mitigate some of this congestion, now you've removed it and
their investment is worthwhile.

The generator who located, because he thought
LNPs were going to look a certain way are no longer looking
that way and what about them? So, I think the answer is
yeah, we can look at more holistic and look at how to solve
some of these problems. It's probably easier in some areas
of the country than others, and particularly in areas that
have very competitive markets.

You're not just looking at the impact on the
planning process in the transmission system itself. There
are a lot of players in there and there will be winners and
losers in every decision that is made, in my opinion you're
putting the RTOs in a very difficult spot at that point.

Mr. Patton may disagree.

MR. ENAYATI: So, in terms of our planning
processes, the technologies that are based on like dynamic
operation, like DLR, DTR, these are mainly targeting
operations, than long-term planning because there are many
variables included like wind, temperature, like you can't
predict what the wind speed is going to be six months from
now, right?

So, it's kind of more like real time operation usage. But we are looking at, like, you know, how we can consider storage as a solution for reliability issues, from a planning perspective. So, there's one basic rule -- well not one, there's more, but this is just one of them and transmission planning, and contingencies can happen any time, it can last for a long time, right?

So, we looked at our New England and New York network, studied thoroughly, but different, like under contingencies, and there are some typical just you know, in our forecast models, there are some thermal overloads that need to be mitigated, and this overload can last for I don't know, months, like the contingency.

One line can be down for many reasons like maintenance or whatever, so I need a storage that can charge for months just to bring the power below the rating of the line. So, it's really not practical. Size is going to be huge because there is no time for storage to actually discharge.

But some overload conditions are not like fixed, in terms of you know, always being above the static rating of the line. For example, some of our overloads are caused by PV generation. So, you don't have PV at nighttime, right? Or, I'm sorry, solar at nighttime, so during the
daytime when you have the overload, storage is charging.

At nighttime, it has time to discharge and get ready for the next cycle, the next day. So, we have to -- in our planning processes, we're looking at you know, what opportunities are out there, what problems storage can solve, but definitely as I said, just you know, typical contingency analysis when the contingency can last for months we see that storage is not going to be the solution, so I'll leave it at that.

MR. PEIROVI: Let's turn to Drew, and then I see some folks on our side tables have their tents up, so we'll go to them after Drew, oh, and after Joseph, sorry, so first Drew.

MR. CLARKE: So, in terms of how the planning process changed in the future. Some of the things we're looking at are more detailed models, things that time savings analysis what I'm trying to classify, not only the magnitude but also, things like duration of needs, get some more bounds on that.

Also, flexibility was mentioned in terms of the operating construct, but one of the things that's recognized as well is we need flexibility in terms of different future scenarios. So, if we're looking at solutions as we look forward, one of the things that at least begs more consideration is, is the solution only good if future pans
out exactly one way, or does it maintain flexibility that
the solution still maintains reliability, future pans out
multiple different ways given that we're looking,
potentially quite a ways out in the future.

MR. ABHULIMEN: I just want to quickly add that,
you know, as Professor Anjan mentioned this morning, I feel
that forecasting is very important. You know, it's very
hard to predict, you know, your load behavior. For example,
in California, we do have the dark issue where you know, we
have excess renewables during the day, but at nighttime when
the sun goes down and we have the lacking issue in the
evenings.

You know you can't really predict that, you know,
behavior. So, I think once you are able to accurately
predict, you know, your load profile, then you can plan for
this in an effective way and come out with you know, some
efficient solutions, effective solutions to address, you
know, some of those lapping issues.

So, I think once you are able to come up with the
model that can help you predict accurately, you know, your
load behavior, I think that might help a good deal in terms
of being able to plan effectively on how to address some of
these issues.

MR. PEIROVI: Thank you, good points. Let's move
down the line of our side table panelists here. Oh, --
Babak?

MR. ENAYATI: I'll add just one more point about Smart Wires, we talked about that a lot in previous panels too. I just want to like highlight that sometimes a line upgrade is the only solution, okay? We're talking about the grid-enhanced technologies, but they work in some cases and they do not work in some cases. And for example, if I have a line of line, I predict it to be like 200 percent overloaded during contingency, and I want to use Smart Wires to push that 100 percent away from that line, where does that go?

I can have a case where just pushing power away from that line can cause other overloads on the adjacent lines, so it may work or may not work in some cases, I just wanted to you know, put that on the table, so.

MR. PEIROVI: Thanks, Jeff?

MR. DAGLE: Jeff Dagle, Pacific Northwest National Laboratory. Something is screwy with this microphone, so, I'll just talk loud and hold this far away for people remotely. So, I'm going to focus in on the transmission planning process itself. On this panel I heard, I think Babak, you made the comment about standard storage models.

MR. ENAYATI: Yes.

MR. DAGLE: On the previous panel I heard
something about let's not have black box models, let's have better visibility in the models. So, I'm going to pull the thread a little bit on data and data availability, data for models, data for your planning processes. Do you all feel like you have the data that you need, either from your partners, your neighbors, your suppliers?

You know, it seems like as we evolve into much more complicated analysis that you know, we might be making a lot of assumptions that could be maybe enhanced with better data. So, I'll comment on that and then I'm also concerned a little bit about exchanging best practices for these more complex planning scenarios, right?

I think that what you all do in terms of the plans for these things are more complicated than what we've had before. You know, I think we're looking at the leaders here at this time across, you know, we think of the thousands of entities, collectively, around our North American grid, you know, you guys are the leaders.

So, there's just a lot of need to take the insights that you've gained and share it with your colleagues from other utilities, because after all it is an interconnected system, are the forums and the ways that your planning engineers exchange information and insights and knowledge -- are those suitable, or are we well-equipped for the future there as well? So, data and planning practices.
MR. ENAYATI: Okay, I'll just go first. So, very quickly in terms of storage models, yes, there's -- we do have models, PSSE models that are in black box, right, so we really don't know the exact details of how that storage will function like during different grid conditions and how we can change the settings, and be comfortable with that model.

So, and I want to bring in distribution a little bit to this whole conversation. I know it's more like transmission-focused, but we're moving away from you know, having that line of demarcation between T and D and whatever we do in distribution now, in terms of you know, DER integration, storage integration is impacting transmission.

So, I want to highlight that we're in a much better shape on transmission than distribution. Also, we do have some models, I think some black boxes that can help not fully, but in distribution we're really struggling and the models that are provided are too generic and does not give us any information on how these devices are going to respond to like, you know, during like fault conditions, you know, are they addressing protecting issues properly?

So, it's a big gap. We've been doing more like asking for test data from manufacturers, so we can kind of build the model that would represent, you know, kind of diverse engineering, to represent that generator or the inverter, and that takes time and you know, we have the
tools that utilities use are also limited in terms of you
know, that capability to build models and modify it.

So, there's a big gap there and exchanging best
practices, so and you know we've been actively participating
in ISO New England and NYISO meetings and reliability
meetings, you know, sharing lessons learned from these
devices that we have put on the system. Every time there's
like a new asset coming on, we do the study, present it to
the reliability committee, that has been you know, it's more
like the local venue we use to exchange best practices.

MR. ABHULIMEN: At least in California, I cannot
speak, you know, for the CAISO specifically, in terms of the
amount of data that they get in their planning processes,
but it is a stakeholder process. The California Energy
Commission, generally, we predict, you know, outage for the
next year, the load that the State of California needs, you
know, to serve California's population.

Then the CPUC, California Public Utility
Commission, they take that information and go to what we
call the integrated resource planning. So, once, so that is
the process where you actually identify you know, the ROPS
requirement, you know, research options policy and local
policy requirement to identify where that total load, where
the sources that it's going to come from.

This is the information that the CAISO then takes
on planned transmission around that. So, CAISO does engage
in the stakeholder process where they get the utilities
involved, they get all the, you know, balancing authorities
that are interconnected to the California grid to you know,
find out what the transmission processes are in terms of
their load, you know, how much are they going to get from
California, how much California is going to get from them to
the EIM as the energy in balanced markets.

You know, some of the day ahead market issues to
come up with a you know, what we call the comprehensive
study plan, you know. So, once we go through that, then we
ger get engagement now in the stakeholder process, you know,
that everybody's involved, including the PUC, to do that
technical study.

So, through this process they are able to come up
with, you know, a reasonable transmission plan in terms of
how to bring that estimated total load into the system. So,
in terms of the accuracy of that data, you know, as I
mentioned before, it's not really the quantity of the data
that you have, it's how accurate is the data for it to do an
accurate forecasting in terms of the you know, in terms of
the load that you need, and in terms of your transmission
planning.

So, no matter how much data that you have, I
think that the most important thing for you to do an
accurate forecasting, is the you know, is the accuracy of that data that is most important because the system can get out of whack very quickly if your data is not reliable.

MR. KORMOS: I think I would just add on to the previous three speakers. I think the two areas I would agree that we would focus on, you know, I would have said load modeling, which I think is the distribution issue.

I think, you know, our load models right now in the industry are just not good period. Our ability to predict how load will react, particularly now with DER integration, is very poor from a visibility and from understanding it. And I think it becomes more important as we start to look at technology to basically accept the fact, we will push the system harder.

We will lose some of the head room. We're willing to take that risk, and this also I think, goes to load forecasting accuracy. The better tools for us to get more comfortable as to what those future possible scenarios could be, and are we covered in all of those? And I think that's the two areas where I feel right now we probably need a lot more work, and how do we get comfortable with that forecasting accuracy that the -- you know, even today, you know, you go into a rate case, you know, most times or into a study case.

The judge doesn't want to hear well, I've got 150
different scenarios, and this works in 90 of them and the other 50, not so much. They want to know this one, this is it, we have to do it, kind of thing. And we have to get more comfortable into how we look at that.

And again, I think a big part also then gets into the interaction with how does the load respond in some of these kinds of critical cases where we're pushing the system harder and if there is a problem on the system, how will it react to this process.

MR. WEBB: Yeah, just to round out that discussion. I think on the question of data, it kind of falls into different buckets. I think we have good information on the data related to the existing transmission system. We're in constant communication with the asset owners, you know, in planning on a daily basis.

And if we don't have -- if we feel that we don't have something, you know, we drill down with them to make sure that we understand, you know, something, the data that we might not have. The other piece of that is for the new technologies and data, you know, the dynamic performance of devices for the newer ones is also going to be something we're going to have to understand how these things react, including batteries.

Right now, I think we're looking and we rely somewhat on the vendor of the battery that's generally
worked in collaboration with the entity proposing the
temperature to help explain how the -- you know, to help with
the detailed technical analysis of how is the device
performing, what is it capable of, what is it not capable
of.

So, but I think it's like the other technologies
that we talked about, you know, using VC as an example.
But, once upon a time it was a strange new device, and we
didn't know how to model it in PSSE and power flow models
and that sort of thing and now we do quite well, you know,
there's models for these kinds of things.

So, I think it's just an evolution, same thing
with the transmission planning process. I think that will
just evolve over time. We'll get more sophisticated. I
think we could today sort of do an optimization on Smart
Wires. We could run copper sheet production cost models,
and sort of back into what would be the best, what would be
the impedance on all the lines, that would you know, make
that work properly. We could do root force methods like
that.

But, so there's ways to look at these things in
planning today and we'll just get better at it over time as
long as once, you know, they get more mature.

MR. PEIROVI: Thanks. David, I noticed you had
your tent to the side, but you put it down.
MR. PATTON: I figured you registered me -- you know, I don't know, I find myself very confused listening to all this because it just -- there's so much about it that doesn't make sense to me. We rely on markets to solve transmission problems all the time.

Most of the markets that we monitor have local capacity requirements or local reserve requirements that are reflections of transmission security issues that haven't been resolved by transmission investment, and so we spend price signals to either through local shortage pricing and energy markets, or through capacity markets to motivate people to build generation that solves the same problem.

And we seem you know, maybe people are being nice to me, but we seem to have a lot of faith in markets to motivate investment in that, but we have virtually no faith in markets to motivate investment in transmission. And I can't figure out why. Like if someone wandered in the door with an investment to New York and said, "I want to spend 10 million dollars of my own money to upgrade transmission capability in New York City by 100 megawatts, and I want the right to sell 100 megawatts of local capacity and 100 megawatts of transmission rights into New York City and I want to avoid all the risks of it."

That you guys talk about to like customers of you know, because what you're talking about is guaranteeing cost
recovery for these things and so yeah, once you decide that
something's beneficial, then customers are at risk. Because
who knows, 20 years from now, it may be worth nothing.

I can't see why that doesn't work. I can't see
why New York, when it's a great, you know, I'll be happy to
take your 10 million dollars and -- assuming we're talking
about technologies that are proven that we know how to
operate. I'm not talking about you know, speculative new
technologies.

But and yet it doesn't even seem to come up as an
option. And it would seem -- I actually agreed with almost
everything you've said in that about how difficult this is
to quantify benefits and all the risk associated with it.
It seems like all -- if all I was asking you to do was
quantify the incremental transfer capabilities, so that I
could give somebody property rights, it seems like it would
make your life way easier.

MR. KORMOS: So, I'll take a shot at that. This
is much from my previous experience. And I think you're
right and I think it's one of the issues with an LNP based
market is the fact that you know, the reason merchant
transmission hasn't taken off is the fact that you have a
network system of free-flowing ties, the very nature of when
you fix the problem, you lose the congestion.

And the congestion doesn't exist and therefore
people have been very reluctant. I've often wondered why
doesn't merchant transmission take off more. You know,
we've had very few uses of it, most of those in between
systems and it's decent, right?

So, most of the HTP or Neptune, or some of those
projects that went pure merchant, and they weren't even pure
merchant in that they didn't actually take the risk, they
sold the risk off to somebody else through bilateral
contracts, but they were willing to make that investment was
because they could, in fact, control the flow and who was
actually using it and extract the congestion rents.

Where I think when you start to look at the
overall larger markets with the network transmission system
as it is, it becomes much more difficult. You know, we've
had some success with people doing incremental ARR requests
for very small -- for parts where you can make a request,
you don't remove all of the congestion, some of the
congestion, but it becomes very difficult.

It becomes very risky, quite frankly, because as
you probably, you're aware as good as anybody else, the
congestion can radically change than based on other things
that are happening in the power system, whether it's new
generation retirements, or whatever, or changes in load
patterns.

And so, asking somebody to make a 10 million
dollar, 30 year investment, I think has become much more of a challenge. So, I think in theory, you ask yourself why doesn't it work, but I think in practice, we haven't seen it work, and so I think you're right.

We fall back because we can't just take the gamut that particularly reliability. Now, I would say we have not relied on markets solely to solve reliability problems. We deal in real time, in problems that were not foreseen in the planning process, but all of us have still relied on sort of the classic and true planning process of putting in transmission upgrades for expected future problems, not standing back and saying well, we'll send price signals and hope generators build in that case.

So, I don't think we've actually moved there, but I agree. I think it's one of the more fascinating aspects of it is how do you ever get to that comfort where people can get those property rights and they still have value in the free-flowing AC network tie-lines. It seems to have been much more effective in a more of a DC model kind of thing.

MR. PATTON: Can I violate the rules and respond? Yeah, quickly, I don't think generally it's true you wipe out the congestion, that's sort of the, you know, the common wisdom. I think it's true if you're building an AC or DC line, you wipe it out, but in most cases what happens is you
eliminate one limiting element and the reason that I said
increase the tie capability by a hundred and not a thousand
is that you pop the congestion from one line and then you
hit, you use up the head room and you hit congestion
somewhere else.

And so, the right from Hudson Valley to New York
City doesn't just -- congestion's not going to go away, it's
just going to -- you're just going to eliminate the limiting
elements one at a time which seems like pretty much exactly
the Smart Wires would do if they installed some of these.

So, there's simply a lot of value in the rights,
but the other two things is A -- almost none of us give
capacity rights to people building. I mean in a case like
that, there's more in New York City capacity payments than
there is in congestion.

And B -- I'm not sure that an TO has an
obligation to actually take the money and build the thing.
I mean Order 1,000 gets added through competitive
procurement, but I think if you obligate it, the TO's, to
actually, you know, participate in building the thing, you'd
overcome some of the reasons why I think we haven't seen it
happen.

MR. KORMOS: I won't respond, we could go on
forever, so.

MR. WEBB: Yeah, I would just say we're not
opposed to market -- we refer to those as market participant
funded upgrades, and we have seen some of those. But I
think to Mike's comments, if transmission is built solely on
a competitive market basis, we don't think that it will --
we're not confident that you will actually get what you need
because there is a lot of assumptions built into an
efficient market that goes into the planning to make sure
that that is there, and that's capable, and that's
foundations, as sort of the base planning, and then we let
congestion deal with real time issues that deviate from that
sort of core planning average situation.

But we have had market participant funded
upgrades, but you could probably count them on both sets of
fingers. And we give them FTRs for those kinds of upgrades,
if they're willing to fund them.

MR. PEIROVI: Thank you, we could go on for
hours, that's for sure, Mike, thank you and thank you David
and thank you. Let's turn to Steve, who has had his name
tent up for a while.

MR. HERLING: I just want to get back to the
issue of the impact to the planning process. You know,
you're aware we use a sponsorship approach to our
competitive solicitations. If you think back to the example
that Bob Bradish gave this morning, if we had a criteria
violation radial serving load to go into a competitive
solicitation, we would have to put out a power flow model
and identify the contingency elements and that would be
pretty much it.

Anybody could try to figure out how to solve that
problem with transmission. If you expect one of the
solutions to be storage, now you can't just give out a model
for the peak loads, you have to -- based on the megawatt
hours that somebody might design into the solution, you may
have to put out a bunch of time slices so that they can
accurately design their solution to actually satisfy that
need every day over the peak.

MR. PEIROVI: And you do that, PJM does that
currently.

MR. HERLING: Well, we've only just gotten our
first few storage projects in our solicitations, but if you
had, and we often do, if you had a dozen different criteria
violations in a given area, deriving a need, now you would
have to really look at each and every one of them and think
about what data, what models need to be put out there for
the proposing entities, so they can think about what
solution to develop.

If some of those are summer and some of those are
winter, or light load violations, you could have a
tremendous amount of information that we would have to
prepare before we even take proposals, so that when we start
evaluating proposals, that it's all done on the up and up.

Everybody had a fair shot at developing a workable solution. That's based on our understanding today of how storage would behave. If new devices come along that approach the solution in a completely different way, we have to anticipate the kinds of modeling needs that that solution would require and make it available at the front end of a window, so that that developer has a fair shot at developing a workable proposal.

So, it changes radically the kinds of information that we have to put out, assuming we're sticking with a sponsorship approach. It changes radically the kinds of information we have to put out there so that -- because we have to take all comers. We have to take every conceivable proposal that someone might make, and they have to be able to be evaluated fairly.

So, it could significantly change our workload in anticipating the kinds of solutions that might be presented to us.

MR. PEIROVI: I understand that there's an Ameren project incorporating Smart Wire solutions, currently?

MR. HERLING: Yes, yeah and we've had that one. We've had a couple others, I believe. We've had a small handful of storage solutions, so each window that we open we're, you know, potentially getting things that we've never
MR. PEIROVI: Thank you. Yachi?

MS. LIN: This is Yachi Lin, from New York ISO.

Mike, thank you for your comments for two things. You helped me answer David's question about TCC. It's a New York specific question, thank you. And I'm completely in line with you.

The second one is that you mentioned how ISO RTOs could be put in a very difficult situation. So, for New York ISO, taking our competitive transmission planning process, as Steve mentioned, we are also using a sponsorship model. After every single conclusion of the competitive transmission process, we conduct a lesson's learned process.

We ask the competing developers, stakeholders, and certainly all Board members, what are some of the things we can do better. The repeated comment that we got from developer, is the more-clear we can identify the goals to be, the better it is for them to compete. So, to expand on what Steve was saying, is what are the load conditions? What are the policy goals? What are the locations? The more specific they are, the better the project will come out to be.

But they seem to be at odds with the flexibility that we are discussing throughout today. So, I was wondering if the panels have any suggestions on how to
incorporate flexibility in this kind of sponsorship

competitive transmission planning process, thank you.

MR. KORMOS: To be honest with you, I wish I did. I don't. And I mean I think that's the problem with those
are very difficult decisions as to how do you weigh those
risks that the flexibility that provides or doesn't provide,
and accept that risk on behalf of a transmission owner, or
the customers of the transmission owner, you know, at what
price?

And then -- and that's a very difficult decision
for you to just make in general. Then to say how do you
make it clear to the developers, and those who are going to
bid in, how you're going to evaluate that? I don't have an
answer. I think, as I said, I think these are very
difficult decisions if we were just making them individually
as transmission owners.

I think when you throw them into a competitive
environment like this and ask an independent entity to
assess that and make that risk and do it in a very
transparent manner, I think we're tying ourselves a little
bit in knots right now, unfortunately.

Not to say that we won't come up with the answer,
but I think it's going to take a lot more work and a lot
more time to understand how we would basically be able to
quantify some of those kinds of risks that you're willing to
accept for a different technology than another technology
would give you.

Because in many cases they bring a different set
of risk and reward to the table.

MR. WEBB: Well, I can't really offer any help to
this sponsorship model because we never chose to use that
kind of a model, so. You know, what we do -- we identify
the opportunities to provide for a more efficient grid,
using various metrics production costs primarily. We work
with stakeholders within the planning process to in a way,
solicit ideas for how to best address those, but then we use
standard -- let's say, simplified standard planning
comparative analysis on which one works more effectively,
you know, most cost-effectively, and then we decide what the
plan is and that would go on for -- we solicit bids for
those, it's a little bit simpler, I think.

MR. PEIROVI: Yeah, no, but Jeff you said you
currently use flexibility as a defining characteristic, did
you know, earlier? Or, did I miss something?

MR. WEBB: I'd have to go back and look at the,
you know, as a qualitative.

MR. PEIROVI: You consider flexibility, but it's
not a defining characteristic or anything?

MR. KHELOUSSI: This is Dan, and thanks for the
panel and I guess you can consider these other things in the
stakeholder process and how to quantify them. What latitude
would an applicant have to bring their own estimation of
benefits of a non-congestion or production costs savings?

Getting back to the morning session when we were
talking about quantifying resilience and some of what we
said here with flexibility and maybe state policy goals. If
an applicant demonstrated with a reasonable study that they
tried to quantify these benefits and they go beyond the
standard application, what openness I guess, does the RTO
provide to considering those?

And perhaps what can FERC do to encourage any of
that sort of openness?

MR. WEBB: So, I think interestingly a slightly
different -- yeah, a slightly different answer maybe for
reliability than for -- it's still not on, maybe it's dead.
That's better, can't trust these batteries. You know,
interestingly for reliability, the metrics are qualitative,
right, lights on, lights out. You know, you go into a state
proceeding to talk about need and for a project and many of
those kinds of qualitative attributes can be brought to the
table to -- as justification for the value of the project.

We'll get to more, you know, non-reliability,
economic market efficiency type projects. We've ended up in
a regime where we have very specific metrics and it has to
check X, Y, Z and if it doesn't, it doesn't fit the defined
threshold criteria. And I think that this is an excellent point because, you know, there are more reasons than just incentives, or lack thereof, for having the right type of transmission built.

I think some of those are not having enough guidance perhaps, from FERC, on what should be a legitimate realm of benefits that can be considered in transmission planning decisions. So, certainly we are receptive in the stakeholder process, to benefit demonstrations, particularly in the reliability realm, where you can compare one to the other, and then we would have a robust stakeholder discussion about whether that makes sense to most of us and we could validate those to the extent that they're -- you know, you can model them and that sort of thing.

But really, again, in the non-reliability, we have a defined set of benefits that strays outside of that. We haven't been able to push the projects.

MR. HERLING: Just to add two seconds to that, and I agree with the last bit that Jeff said. People disagree all the time with our assessment of benefits, especially of their proposals and we have to take all the information and we have to go back and often it delays our making a decision by months and months and months. But at the end of the day, we have to make a decision.

So, sometimes they convince us and sometimes they
don't. But to Jeff's point, we have to be open to taking all the input.

MR. PEIROVI: Thanks so much. One more question from our staff here, yeah.

MR. KHELOUSSSI: Just to be a quick question. So, grid-enhancing technologies, I think a compensation 30 years ago was a new technology. It was a grid-enhancing technology and took 30 years to evolve. If the transmission planners are comfortable to use the models and study, it.

So, I guess the question I just have for you is that what can we do in the planning process to make this evolution process faster, so the transmission planner gets a little bit more comfortable with using some of this storage today? Do they need training? Do they need to get familiar with the models? To shorten this timeframe, you don't want to go 20-30 years, you know, the way static has been through, and I remember statcom was just new and so on.

So, what do you think we could do to shorten this process and the planning timeframe to start planners becoming more comfortable using these models to study and evaluate, as is compared to building a new line or upgrading, you know, a line or transfer. What can we do? What, in terms of the planners becoming comfortable with that?

MR. KORMOS: You know, unfortunately, I don't
think it was the planners versus the actual experience with
those devices. So, I think, you know, you had two things
with SVCs. There's was one -- they were extremely expensive
in the early days and so, to basically put that technology,
and you had to be willing to accept it wasn't the most
cost-effective.

And that was a decision a utility had to
ultimately make and then it was gaining experiences that
they would operate as designed. It was no -- we weren't
exactly sure they were going to operate. They weren't going
to just go in the wrong direction on us, kind of thing.

So, I think to move some of this up, it is more a
pilot project. I don't necessarily think it's a planning
and those getting comfortable versus are we just comfortable
with the technology that it will perform as we expect, and
that we will drive the costs down, you know, to some higher
level of commercialization.

I think again, a lot of these technologies in the
early days, are just very expensive because they're one-off,
they're -- you know, it's new. So, I think if you look at
the SVC model, who other than planners, other than they
didn't have the experience that it was worth the investment
that they were going to work.

Over time, we got that experience, but it was
more through pilot projects. And I'll be honest with you,
in the current environment of Order 1,000, power projects are difficult to do, in any scale.

MR. KHELOUSSI: The pilot projects that we need to have more of those.

MR. KORMOS: I think that gets us experience as to how we will actually use these in operation and get comfortable that they do work. But that's a lot more difficult in the current environment where we're all competing. And nobody really wants to hear about a pilot project. If I could have done that instead of you, kind of thing, so.

MR. PEIROVI: So, just before -- sorry, Babak, just note that we're running a little low on time, so go ahead.

MR. ENAYATI: Yes, definitely, I'll keep it short. Some technologies we've learned enough from some pilots that we've done in the past. So, yes, some technologies are new. We still need to, you know, be in the pilot phase for a while, but I'll give you storage as an example, so what needs to be done. First thing is like fill that modeling gap. Our planners need to be able to model the storage facilities properly and understand the full dynamics of the storage facilities. So, right now as I've said, they're provided in like black box, we don't have good visibility.
So, in terms of us relying on assets that would resolve us, meaning utilities, resolve our reliability issue on our system, utility owners should be on the table as an option, so that we can have that, you know, opportunity to maintain it and make sure it's there when we need them.

And finally, the incentives that we've discussed is also the best way to encourage, you know, us in terms of utilizing the asset and expediting the adoption process.

MR. ABHULIMEN: Oh, I just wanted to add also that as Michael mentioned, many of these services of grid technology enhancement elements have become very competitive. So, I think that a question that you can actually ask is one -- are these technologies able to meet the identified project objective?

And two, you know, how quickly can they be deployed? And three, you know, what are the costs? Because like I said, this, you know, services compete among themselves, I think that a question that a planner should ask again be open to allow, you know, many people to provide the alternatives, and then evaluate those three criteria in terms of the ability to mitigate objective, you know, how quickly can they be deployed and also what are the costs because I think these are the three elements, you know, that we accelerate, if you will, to determine the grid-enhancing services.
MR. CLARKE: I'll just add to what's already been said and that I think a big part of it is comfort around that the solution will adequately meet the need and as mentioned earlier, somewhat of a chicken and an egg-type problem. But I think there is going to have to be comfort there. And then, following on to that, working through the evaluation of these technologies to see if they become another tool in the toolbox, when do they make sense to deploy and in what situations.

So, I think the big thing will be somewhat of a flexibility still on a case by case basis for needs of are we comfortable that these solutions can meet that need? And then, if so, be able to appropriately evaluate.

MR. PEIROVI: Thank you very much. First, before I close this let me ask Commissioner Glick to see if he has any other questions? Thank you. That's a very difficult set of issues under this panel. I want to thank you all for participating and thank the audience for tuning in. That concludes day one of the workshop.

Let me add one quick note that we will be opening up a post-workshop comment period after this workshop and so, our hours and hours of conversation can be written down on pages on you know, the pages of your filings.

Day two will begin tomorrow at 9 a.m. Thank you.
(Whereupon, the Conference concluded at 3:53 p.m.)
CERTIFICATE OF OFFICIAL REPORTER

This is to certify that the attached proceeding before the FEDERAL ENERGY REGULATORY COMMISSION in the Matter of:

Name of Proceeding: Grid-Enhancing Technologies

Docket No.: AD19-19-000
Place: Washington, DC
Date: Tuesday, November 5, 2019

were held as herein appears, and that this is the original transcript thereof for the file of the Federal Energy Regulatory Commission, and is a full correct transcription of the proceedings.

Larry Flowers
Official Reporter