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FEDERAL ENERGY REGULATORY COMMISSION

Winter 2018-2019 Operations and
Market Performance in Regional
Transmission Organizations and Independent Systems Operators

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TECHNICAL CONFERENCE

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SPEAKER LIST

Christopher Ellsworth - Moderator

Commissioner Cheryl LaFleur

Commissioner Richard Glick

Peter Brandien - ISO, NE Vice President, System Operations

Emilie Nelson - NYISO Vice President of Market Operations

Dave Souder - PJM, Director Operations Planning

Rob Benbox - MISO, Executive Director of Energy Operations

Bruce Rew - SPP, Vice President of Operations

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P R O C E E D I N G S

MR. ELLWORTH: Good afternoon, and welcome to this staff-led Technical Conference of the Regional Transmission Organizations and Independent System Operators at this to prepare for the upcoming winter.

For the past several years the Commission has asked each ITO and ISO to make a presentation on its preparations for winter. I am pleased to continue that conversation today and thank each of the RTOs and ISOs for taking the time to join us.

In the recent past, the RTOs and ISOs have faced winter operational challenges for about events that stressed electric and gas operations including last winter's bomb cyclone and the polar vortex of 2013 to 2014.

Similarly a continuation of limited operations at the Aliso Canyon natural gas storage facility in California, and local pipeline outages there, illustrate how unanticipated events can challenge operations in both the gas and electric industries.

With that background in mind, I look forward to your discussion about how each of your regions is preparing for this coming winter and new initiatives you have implemented or may be undertaking to improve winter preparedness.

Any thoughts about how the Commission can assist

your efforts are greatly welcome. Before we start a few logistical details -- please turn off your mobile devices or place them in airplane mode to avoid interference with the audio visual equipment. Be sure to turn on your microphone to speak directly into it so the audience can hear you and also for the webcast. When you're not speaking please turn off the microphone. This Technical Conference is being transcribed so please introduce yourself before you begin.

And as a reminder the Conference is due to end at 3:30 so I ask each speaker to keep their opening remarks to about 10 minutes or so. We will hold all questions until after all the presentations have been made. For those wanting to ask a question or make a remark, please place your tent card up.

So before proceeding with the presentations, I would like to ask the Commissioners whether they have any opening remarks.

COMMISSONER LAFLEUR: Well thank you very much Chris. I just wanted to welcome the speakers. This is an event I look forward to every year I think it's an important event on our calendar to look forward to winter.

I don't watch Game of Thrones, but I know they say "Winter is coming," so -- and that is true in the real world too and with the -- all the changes that we're seeing in the electric grid, especially the increased dependence on

natural gas, we see certain challenges in cold weather that we've experienced over the last several years that it's wise to be mindful of.

So I'll save the rest of my time for questions -- if I even have any time, but thank you very much.

COMMISSONER GLICK: And thank you too, I don't really have a prepared opening statement but obviously this is a very important issue of coming up on winter again. We had an interesting presentation this morning by staff and I think hopefully we'll continue that conversation this afternoon and I'll too have a couple of questions as well.

MR. BRANDIEN: Good afternoon, I'm Peter Brandien, Vice President Systems Operations for ISO New England and I think as everybody realizes the winter is a concern for us in ISO New England. If we could get my presentation up -- slide 2.

Just I'll start with a little background. We really do not have an installed capacity requirement in New England. The concern that we have is when it gets cold. It's not that the electric load increases, it's that the fuel kind of disappears and that's the concern we have and that's what I'm -- the bullets on the first slide is trying to communicate.

The next slide -- really our concern is extended cold weather. It's not whether or not the winter is above

average or below average. Last winter December, January and February were all above average temperatures in weather, but we experienced extreme cold weather from December 26th through January 8th and it's those kinds of spells that have us concerned.

So it's not when you look out at a long-term forecast, is it above average or below average. It's what kind of cold spells are we going to have as the winter goes on? Next slide -- our contributing factors -- I think everybody realizes that New England we're very reliant on gas-fired generation. There's plenty of gas in the off-season but when it gets cold that gas is used by the local gas distribution companies and we do not get a significant amount of gas left available for electric generation and we have to rely on other resources to provide that energy in the reserves for us.

And what we experienced last year and what we knew is the fuel logistics is extremely important. Is the fuel there at the beginning of the winter? Can they replenish during these cold spells? And that is replenishment of the LNG facilities as well.

They have cargos coming in off-loading so that they could inject into the regional pipe in those LNG facilities in New England the District Gas Facility in Canaport, they counter the constraint flows coming from say

through New York into New England.

So those injections will become available to -- whether it's LDC or generators if they're injected, so we watch that quite a bit. We continue to see non-gas units retiring. This is our last unit with the Pilgrim Nuclear Power Plant at 680 megawatts.

We have a coal unit that will be retired. We don't have much coal left but we're going to see a coal unit retire and oil units continue to retire. These resources are all resources that have stored fuel and that help us get through those cold spells. The other area that we watch closely is the dual fuel units and we have been watching those units closely -- how they replenish, the size of their tanks, and more importantly is the limitation on their ability to burn fuel.

We have some units where we have to declare an emergency before they could actually burn the oil. Some we could declare a capacity deficiency and they can burn, others we have to declare an energy emergency before they could actually burn it.

So that's a concern and with other units they may not -- in Massachusetts they may not have the CO2 requirements to burn them or they'll use them up very rapidly and convey -- get more CO2 credits to continue to run.

We ran into some of that last year, hopefully with the changes that the state of Massachusetts is making where they can trade some of these credits will alleviate some of those concerns because it runs on a calendar year and of course the winter is the beginning of the year.

The next slide -- we had a winter reliability program that helped us out the last four or five years. That program incented people to have oil in their tanks by December 1st. It incented people to go out and make arrangements for LNG and also any demand response that wasn't already in our market to bring forward additional demand response and this allowed us to have stored fuels or additional energy available for us during those cold weather.

That worked well for us. I think the first year we put it in it was extremely cold and we looked like heroes. A couple other winters it wasn't much of a winter and it looked like we acquired too much oil. Last year in that period from December 26th through January 8th we burned more oil in that period of time than we burned in two previous years so you could see those stored fuels can go very rapidly.

That Winter Reliability Program -- that is gone, I can't seem to forward it. Oh, there I am, okay with the paid for performance the incentives that we have in our

capacity market we no longer have the Winter Reliability Program. The paid for performance incentives went into the capacity market June 1st of this year.

It provides incentives for units to be there when the system gets tight. This is our first winter with paid for performance. I just looked at the fuel inventories -- we do monthly oil inventories. Last year the oil was about 68% of the tankage by December 1st. Looking at where the oil levels are October 1st, so I'll see if much replenishment happens between October 1st and December 1st.

We've got less oil inventory in New England than we had under the Winter Reliability Program. It looks like, you know, a short duration cold spell -- five, six, seven days were about the same level. I feel fairly comfortable that we're at the same place with the Winter Reliability Program. But for extended cold or if we have a series of cold spells that doesn't give the people time to replenish their fuels, that's where I get concerned based on what I'm seeing in fuel inventories right now, next slide.

You know I already spoke about what we saw last year. Replenishment of those fuel inventories are going to be very important to us and I've got a slide on what we're going to attempt to do and see whether or not we can provide more information to the marketplace to get people to kick in their logistical arrangements to replenish those fuel.

One of the things that we saw last year is once it gets cold in New England, gas goes way up and we start burning oil and we don't know how much gas may be available off the pipe but the economics say burn the oil and basically burn it until it's all gone and then go back to gas.

We're going to -- one of the other slides that I have hopefully will address that and help people try to manage their oil inventories. Where are the concerns with the fuel logistics? I can't seem to advance -- there. Oh, the presentation disappeared but the logistics -- the concern we have is, you know, the heating customers tend to get priority, so we saw trucking fuel oils around to heating customers versus to power plants.

We saw storms where it either delayed trucking and barges and even LNG tankers from being able to off-load -- of course the restrictions on truck drivers to be able to truck that oil around.

My slide 9 for people that are following along that can't seem to get the right slide up there -- okay. So what are we doing based on what we saw? One of the things that we're going to attempt to do is to do a 21-day forecast based on actual fuel inventories that we have in New England and we are going to tie the triggers in that forecast to the EOP, the EEA -- the Emergency Energy Alerts and so we've got

EEA 1, 2 and 3 and if we see the fuels being depleted, we'll forecast EEA alerts and if we see an EEA level 2 or 3 in the day 1 to day 5, we will actually declare an energy emergency.

And when we declare an energy emergency, that's when we fill out the DOE form 417 and you'll see that form, it comes down to D.C. here to FERC. I believe you guys get that form. Our intention is to provide information to all our participants that the fuel inventories are getting tight and by forecasting out 21-days that should allow them to kick in any logistical arrangements that they would have, get the barges -- make arrangements for the barges, get those barges filled, get those barges transported from either Philly or some other oil import terminal to the power plants and avoid that energy emergency.

So we're hoping that in day 6 through 21 people are making the arrangements so that we don't have to declare an energy emergency in day 1 through 5. We will start that 21-day forecast the end of November for the first week of December and that is something that we will be posting on our website for people to see.

The other thing that we're going to attempt to do or that we will do, is allow generators to put an opportunity cost into their offer into the market. What we saw last year is when they offered in on oil, we just burned

through their oil and we would burn oil right until their tanks were empty.

This will allow them to put an opportunity cost to reflect the scarcity of the oils that they have in their tank -- hopefully they'll be making arrangements to replenish those oils while they're using that opportunity cost and not using their opportunity cost to avoid being dispatched and not replenishing.

So we'll see how that works. By that opportunity cost, that will allow maybe some gas that may be available in the market to be run for electric generation because we saw last year when we actually stepped in and postured some of the units that were getting low and called for some of the gas only units, they were able to go out and get gas.

So we're going to try to get that same thing to happen through price through this opportunity cost. So where does that stand? We've got pay for performance that's in -- that's an incentive, we've got the opportunity cost and we've got this 21-day forecast. We think that with this additional information, these additional incentives and pricing mechanisms that we should be able to manage the cold weather.

The fuel logistics is a concern and we'll keep an eye on that. We do monthly surveys -- once we start burning the oil we'll do a weekly. When we really burn the oil

we'll do daily surveys so when we do this 21-day forecast, we're actually going to be using the actual oil levels at the generators right down to the daily surveys that we have.

I spoke about LNG shipments. We closely monitor LNG shipments and we will continue to do so and the non-gas resources are vital. The last slide -- okay, our biggest challenge as I already spoke about is any extended cold weather that we would have and whether or not people are making the arrangements to replenish those fuels and also if we had an large contingency during the day where we had to go and start burning more gas.

If we lose a nuclear unit, if we lose the tide, to quote back, those sort of things where we have to dispatch our gas units up will we have enough gas to make up for those resources, those non-gas resources that we lost?

So you know in closing we have adequate capacity. We expect to be able to get through the winter with these -- let's call it market enhancements and operational enhancements that we have in place and we do have the emergency procedures that we have available to the operators and we test on a frequent basis so we're somewhat cautiously optimistic again that we'll get through the winter with the better information that we're providing in the marketplace, so thank you.

MR. ELLSWORTH: Thank you very much, Miss Nelson.

MS. NELSON: Good afternoon. My name is Emilie Nelson. I'm the Vice President of Market Operations at the New York ISO. It is my pleasure to be here with you all today and I will just wait for the presentation to come up.

Some of the presentation logistics makes power operations seem easy. Okay, so my prepared comments are intended to address many of the topics outlined in the Conference agenda and I will be happy to answer any additional questions you may have.

Looking toward winter 2018-19 preparedness, in advance of the winter season NYISO completes several actions in advance. We have conducted a seasonal fuel survey to assess oil inventories and also understand arrangements for replenishment capability.

Many New York generators have access to barge deliveries to replenish oil supplies via the New York harbor and the Hudson River so that is something we understand carefully. By the end of October we will have visited generators that provide just under 14,000 megawatts of capacity across the state.

We look to the minimum oil burn procedures that are established by the New York State Reliability Council and help to manage pipeline contingencies in both New York City and Long Island and we coordinate with transmission and generator owners to align any maintenance work that needs to

be done with the reliability needs on the system.

Next, looking at our projected capacity margins -- let me first provide a reminder that in New York we are a summer peaking region. Our record summer peak occurred in July of 2013 at 33,956 megawatts. In comparison -- depending on which particular load forecast you are looking at, our winter load forecast for this coming winter is 8,000 to 10,000 megawatts lower than that record peak.

Taking a deeper dive into the numbers on the slide in front of you we have healthy capacity margins. The winter capacity assessment that cedes these numbers uses a deterministic approach to approximate capacity margins.

What we do is we look at the supply side taking into account projected supply additions and deactivations. We look at net capacity sales with external areas, we look to our demand response programs and we make an assumption on the level of forced outages that we've historically seen combined with any planned or approved maintenance outages.

And then we couple that with the requirements. We reflect our 2,620 megawatt reserve requirement across the state and we consider two different forecast levels. At a 50/50 load forecast which is 24,260 megawatt load for this year, you'll see the number at the top of the slide. We have a margin of 11,436 megawatts -- moving that to a more extreme load forecast -- a 9010 load forecast, the margin

reduces to 9,821 megawatts, still again a very healthy margin.

And then we look at more extreme scenarios -- toward the bottom of the slide you'll see gas limitation scenarios all built off of that 9010 peak winter condition case. And if we subtract out all of our units that are gas only i.e. not dual fuel, we have a margin of 3,290 megawatts and then we add back those resources that have firm contracts and the margin is roughly 5,000 megawatts.

So one other additional piece of good news for New York is that looking into this winter we continue to have a generation fleet with quite a bit of diversity -- statewide, if you consider the dual fuel capability that we have on a capacity basis, 48% of our generated capacity can burn oil and gas.

We have 14% of nuclear as indicated by the yellow bar on the left-hand side on the slide in front of you and we have 15% of hydro state-wide.

Looking to the down state region -- and that's the lower graphic on the right-hand side, only 9% of our capacity down state is gas only with a portion of that being backed by firm contracts.

Gas electric coordination -- there are two communication protocols that I'd like to point out for you. The first is with New York state agencies to address any

generator requests that come up regarding emission waivers that are needed for reliability. This protocol proved helpful last January during some of the extreme cold that we experienced. It helps facilitate communications across all parties.

The second communications protocol is to allow for effective outreach regarding electric reliability concerns to pipelines and gas LVC's as needed to avoid the loss of firm electric load and that is a procedure and requirements that we have incorporated into our open access tariff.

We are always mindful of making sure we have the appropriate level of situational awareness for our control room operators. We have staff that is committed and dedicated to support gas electric coordination with the control room. We have invested in regional displays to show the northeast pipeline system and any operational flow order impacts, many of these techniques we've learned with partnership with ISO New England and others.

And then let me spend a moment on our fuel surveys. These are updated weekly by generators throughout the winter and they're updated daily upon request which we typically do as we move into more cold extreme conditions. The cooperation with our generation fleet is excellent in this regard.

I'm going to pivot momentarily on what we experienced during last winter for 2017 to 2018. I've included several interesting statistics on the slide in front of you, but in the interest of time I will offer it was very, very cold. We had a 13-day extended cold weather event which spanned December 26th through January 7th and during that time we experienced our winter peak for last year, it occurred on January 5th at 25,081 megawatts.

In comparison on all peak time, peak in New York in the winter occurred during the polar vortex back in January of 2014 at 25,738 megawatts so it's a bit shy of that prior record.

Throughout this event NYSO operations participated in conference calls with the Northeast Power Coordinating Council and our neighbors to the south, PJM, also participates in that NPCC calls, so the coordination across the area is very strong.

This is definitely an eye chart but I wanted to provide a view of the fuel prices. This graph actually spans quite a long duration from November 2013 through September 2018 and the most recent experience from the last winter is on the right-hand side of the graphic.

As you can see in the solid black line, you had many days of gas prices which were escalated and exceeded oil prices which are indicated in the bottom of the graph

with the solid gray line. The natural gas prices as indicated -- as indexed to Transco zone 6 for the New York City area averaged during the 13-day cold snap, $47.34 per MMBtu.

In comparison earlier in December of 2017 that average was $3.45 per MMBtu, so a significant increase. Not all of the increases in the fuel cost translate into energy prices because of course we have the ability to select alternate fuel types -- oil, et cetera and that often sets our marginal price during this time. During the same period -- again 2013 spanning to September of 2018, you can see the line graph on the slide in front of you but honing in on the 13-day cold snap the average weighted LBMP was $135.96 per megawatt hour.

Some of the formatting on the display is a little bit off but I just wanted to spend a moment talking about some of the market enhancements that we've invested in in New York over the past several years. We are focused on aligning our market signals with reliability needs and much of that focus in New York has been specifically with regard to our energy market.

So we have enhanced our shortage pricing to deal with reserve shortages as well as regulation. We have adjusted the amount of operating reserves that we secure in the market and also have focused on the locations of those

reserves and added specific requirements where needed.

We've also incorporate scarcity pricing to the extent demand response is activated and we've insured that our day ahead market timing is aligned well with the gas day. This by no means is a comprehensive list -- it's something that we're continually evaluating.

One of our focuses now is how do we evolve our market design to incorporate additional resources that add value to the system. So we are of course very focused on complying with FERC Order 841 and incorporating storage.

Going forward I'd like to spend a moment talking about our view on the efforts necessary in New York for resilience. New York and the NYSO does not currently face imminent resilience concerns, however, the power grid is going through a transformation and we must be well positioned across both the planning and operations horizons to manage the grid going forward.

The approach that we're taking in New York is we are working with our stakeholders to consider market operations and planning enhancements that will be needed into the future. Earlier this year, I believe it was in June, we released a master plan and that outlined several of the market initiatives that we think will be important to make sure we have the flexibility and resiliency we need on the grid going forward -- it aligns with our strategic

vision for our organization over the next five years.

We're also kicking off a fuel security study. In 2019 we have a project effort to assess fuel and energy security, we, in particular, want to evaluate stress system conditions. Thus far, we have focused on developing our scope of work which we intend to share and get input from our stakeholders in the next few weeks on and of course the objective of this study is to evaluate if further enhancements are needed to support grid resilience into the future.

Although many of my comments today describe a system position to meet the winter ahead, there is a lot of hard work required to manage the challenges before us, especially over the long-term. As a result we will keep our eye on these challenges and our upcoming fuel and energy security study should further inform what is needed to meet reliability needs going into the future.

And with that I'd like to thank you all for the opportunity to discuss these very important topics today.

MR. ELLSWORTH: Thank you very much.

MR. SOUDER: Hello my name is Dave Souder. I'm Senior Director of Operations Planning at PJM. I'd like to thank the Commission for allowing me to speak on behalf of PJM to summarize our winter operations.

There are three areas I will be covering today.

I'll be talking a bit about our coordination and our winter operation projections. I'll talk a bit about resilience and our efforts and fuel security, our fuel security analysis as well as recent changes to markets.

So from a coordination-prospective in preparation there's a lot of preparation in advance of winter operations focused on three areas. One is the studies -- the data requests and drills that we perform -- a lot of coordination with our neighbors, our neighboring reliability coordinators and our regional reliability organizations as well as coordination in the gas electric area.

I'll talk a bit about our seasonal assessment coming up here in the next couple of slides but we performed resource winter testing prior to winter where we bring generation on at minimum and then swap to the alternate fuel so we test these resources in advance of the winter to make sure that we work out any bugs for when we really do need the generation.

We perform emergency procedure drills and basically we test all of our communications, our tools and our procedures in advance of the winter operations. We perform a fuel inventory survey where we collect information on generators with respect to on-site fuel capabilities, deliver-abilities and environmental restrictions.

We do that seasonally but we also have the

ability to do that periodic surveys just like my neighbors here -- we talked, they talked about doing it weekly or even daily. And the other thing is we go through a generation cold weather preparedness checklist -- that's actually contained within a common tool that the asset owners also interact with that way we can track actually conforming to with the actual winter checklist and they provide a C-PAC and they can actually then acknowledge that they performed that checks.

Again with respect to our outreach to our neighbors and regional reliability organizations we really focus at changes to our systems in advance. We communicate that, communicate changes in our procedures -- really look for if there are any issues out there that we may need to work on together as far as coordination and advanced procedures in place for our operators.

So those meetings that we have with our neighbors are very productive. Another area that we focus on is gas electric coordination. In November we had a Web-X conference call scheduled with INGA as well as the major interstate pipelines where we'll talk about where we are with the electric system, any challenges to the gas system. It's a good opportunity to work together and communicate.

In addition we do -- have face to face meetings with the interstate pipelines down in Houston where we can

really sit down and talk through what we're seeing with respect to our winter operations, you know, what the interstate pipelines are seeing with respect to their winter operations and then areas that we can work on from a coordination perspective.

We have a gas electric coordination team that really focuses on the daily, weekly and monthly communications and providing that input down to our operators as well as we have sharing agreements with our interstate pipelines, our LCD's and we're always focused on tools for our operators.

One of the latest areas where we're focused on is gaining -- collecting the electronic information we need from the asset owners so that we can automate some of the gas pipeline contingency analysis that we do within system operations to make it easier for the operators.

This is just a highlight of our peak loads. We are a summer peaking PJM market with summer peaking. The all-time peak occurred back in 2006 at almost 167,000 megawatts. That compared to our all-time winter peak of 142,729 which was back in 2015.

Now we don't expect to see the 167,000 megawatts anymore from the summer peak with the energy efficiency and distributed energy resources, so typically we'll see between 150 to 155,000 megawatts for the summer peak. And as you

can see last year the winter peak was 137,000 so it's just typically our summers are about 10 to 15,000 higher than our winter peaks.

As I mentioned we do perform seasonal assessments. We look at our normal winter load as part of our base case -- 135,000 megawatts or sole capacity is about 160 - 186,000 megawatts that we have significant reserves. In performing that analysis we saw no real issues on the system, everything -- plenty of reserves with reliabilities maintained.

I do want to say I did have a conversation with our meteorologist before we came here -- she's projecting slightly colder than normal temperatures. She's projecting dryer than normal. We will have a couple Arctic cold spells to contend with and also potentially some coastal storms, but nothing out of the ordinary as compared to previous winters.

And I will also mention that our seasonal assessment actually work with the combination of our transmission owners so there's a lot of input and vetting of the seasonal assessments.

With respect to the seasonal assessments we perform many contingencies and sensitivities. We look at the impact of external contingencies on the PJM system. We look at relay trips and the potential impact of over trips.

We look at gas pipeline contingency analysis. We analyze more than 90 gas contingencies and the impact on the electric system.

We look at maximum credible contingencies or typically the power or loss of substations. We look at 1,700 different contingencies and analyze them on the cases as well. We look at transfer interface limits, which is your interconnection reliability operating limits and the ability to transfer energy across a system to serve load, limits into the Baltimore Pepco area.

We also do sensitivities with respect to the loads that we're analyzing so we scale the loads up to a 90/10 where we look back at some of the extreme weather we had at polar vortex to see what the impact would be on the system if we modeled that.

Again, from our studies and the sensitivities we've performed so far, we're not seeing any reliability issues. We're seeing some local congestion, possibly some switching and putting on capacitors to control the voltage.

Gas electric coordination is a very large effort within PJM. We have a cross-divisional team that we really switch members out each year so we can develop bench strength across the organization, and the goal is to really develop that knowledge so that as we increase the amount of gas on our system we can coordinate more effectively with

the gas pipelines.

One thing I'd like to note is that we've actually participated in a 2018 drill in Pennsylvania where we modeled the loss -- it was a tabletop, where we lost a major interstate pipeline during January cold weather. It included PJM, Interstate Pipeline, impacted local LDC's as well as the Pennsylvania State Government.

And we really focused on to evaluate the planning, operational coordination and real-time information sharing between the government and the private sector. We're looking to enhance those drills into 2019 and looking to reach out to Interstate Pipeline and have them as part of the drills that we have on the PJM system.

We've worked well with the gas pipelines and actually leveraged their hydraulic models to analyze some of the contingencies on our system to determine how long it would take before the generation would be lost and that's good impact into how we plan for our system and respond to those gas pipeline contingencies.

And again we continue to focus on enhanced operated operator communication because that's really where we'd like to see the communication go.

Next let me just step back and talk a little bit about some of the resilience efforts at PJM. There are some new technologies that we introduced recently. We have a

voltage defects tool which it helps us in identifying effective load shed for low voltage scenarios -- that's an operated tool that's been recently put into operations.

Also we have a cascading tree tool which will help us evaluate basically RTEP upgrades and not only looking at reliability but if we select one over another how does it help with resiliency and potentially limit the amount of post-contingency load shed and that's part of our discussion into our planning process and resiliency within the planning committee at PJM.

We recently modified our operating procedures or are in the process of modifying our operating procedures. Specifically our concern of operations procedures with a focus towards resilience and looking a bit more in coordination with our members on cyber and physical threats and how we would jointly respond to them.

And probably one of the biggest initiatives we had in 2018 was the Fuel Security Initiative. This is a process we started back in May. We've engaged our members and really we're looking at to identify fuel security risks.

We're looking at the supply risks, delivery risks of the fuel and we're looking to analyze that over an extended period of time really focused on a weather event -- 14 days and we're looking at what the impact would be to

generation.

As I mentioned we are in the analysis stage and we have a special MRC session scheduled for November 1st which we'll start reporting out on those results. Stage 2 would be to then work with the stakeholders to determine what a fuel security -- how we would model the fuel security risk within a market construct.

Again, in parallel we're working with DOD and DOE on more of a DOE-informed cyber and physical threat and how that would impact fuel security and that would be something we'll continue to work on through 2019.

Last I'd just like to cover some of the changes to markets, again consistent with FERC Order 825, PJM implemented 5 minute settlements April 1st of 2018. We work with our PJM, our stakeholders as part of the PJM operating committee to define a methodology to calculate 30 minute reserve requirement on the PJM system and that would be input into the Energy Price Formation Initiative which is going on right now and will be going on through 2019.

As far as initiatives into 2019 again we are actively working within the stakeholder process on energy transformation -- that's the senior task force and will continue through 2019 for focusing a couple of areas. One is synchronizing their performance and compensation -- a 30 minute reserve market product, Fast Start energy pricing, a

more holistic energy pricing which will value the inflexible -- the benefits of inflexible generation.

We're also looking to make enhancements to the day ahead market timing through the use of advanced hardware and market changes. We're looking to shrink the overall time to run the day ahead market from 3 hours to 2 hours -- that would allow us to allow increased bidding time from 10:30 to 11 o'clock so the bids would have to be in by 11 a.m. and we've still basically posting results by 1:30, so again that provides more value to our stakeholders. Thank concludes my presentation.

MR. ELLSWORTH: Thank you.

MR. BENBOW: Good afternoon, my name is Robert Benbow, Executive Director of real time operations at MISO. I'll start off by saying that MISO is prepared for this upcoming winter. We have adequate resources to meet our load and operating reserve requirements and also to manage congestion.

Also our analysis of the transmission system looks good -- we don't have any identified issues of significant concerns for this upcoming winter. Lessons learned from the last 2017-2018 winter that we experienced here earlier this year had been reviewed and we have some of those lessons learned in place for future events and some of those lessons learned have already been applied in recent

operational events and proved to be a value-add.

We also continue to focus on emergency preparedness efforts and also working with the team on cost effective and innovative solutions to help increase preparedness and situational awareness with MISO, our members and our neighbors.

Just a little bit on MISO -- we are a large geographical area spanning 15 states and part of Manitoba and Canada. We are a summer peaking ISO as well and our peak is 127 gigawatts for the summer. Typically I would say we're in the low 120's over the last couple of years.

Our winter peak has been back in the polar vortex of 109 gigawatts -- this last winter we were at 106 under the conditions that we saw this last winter. Winter was extremely cold like our neighbors were saying from Christmas all the way up and through the first of the year.

It actually extended for MISO all the way up into the middle of the month where we experienced some of our coldest conditions and that was largely in the southern part of our footprint. Back during the polar vortex I would say it was colder in the north central part of our footprint, driving us to get to the 109 this last winter we actually -- the south region actually peaked almost where they actually peak in the summer.

Okay, alright for resources this upcoming winter

we target a 17% planning reserve margin. Forecasts at operating reserves are 36%. We have following all the outages that we expect to see -- 6 to 20% to manage a range of scenarios of higher than normal loads and above normal forced outages.

Forecasted peak for this upcoming winter is 103 gigawatts. The forecast for the upcoming winter is slightly warmer than normal. We do expect to have more precipitation in the southern part of our footprint that would probably lead to icing conditions during this time period -- again, it's a forecast.

I think similar forecasts we expected last year but that was different as we all experienced. For MISO last year -- here we go, we did go into our emergency procedures in the middle of January for the 17th and 18th it was the furthest that we went into our emergency procedures all the way up to where MISO actually had to purchase emergency power from our neighbors to meet our obligations.

Our peak in the south was 32.1 gigawatts. The all-time peak down there during the summer was 32.7. For the 17th we had 1.2 gigawatts of emergency power from our neighbors and then on the 18th we had almost a gigawatt worth of load management in place to replace that emergency power that we purchased.

It was really driven by forced outages going from

the 16th to the 17th and we lost about 4.7 gigawatts worth of generation which is about 15% of our resources in that area to meet our obligations. Typically we try to go into an operating day with 10% reserve margin to handle those uncertainties and during that day we ate right through that and we went even further into that.

So we implemented all of our emergency procedures up to an EEA level to an energy emergency alert and everything up to buying emergency power from our neighbors leaving us basically with the only thing left would be load shed in order to manage reliability in that area if called on.

Lessons learned from January -- and this is a number of lessons learned here, we're working with our neighbors as well during the recent months. Part of our procedures we updated to put out a capacity advisory. What we've noticed is if the more communication and the more transparent you are about upcoming scenarios with your markets and with your operators, it gives you a better chance of being successful.

So we've now used capacity advisories when we get below a certain reliability margin to notify our members, our neighbors of our position as we go into that operating day. That increases the situational awareness for them that hey, we are getting concerned about capacity and then

basically we also work -- the last bullet there is we work with our generation, generator operators, transmission operators to recall transmission outages but also reschedule generation outages if possible so that we can have as much capacity as available to meet our requirements during that time period.

We have focused on improved collaboration, communication within our footprint but also with our neighbors in the south region to make sure they understand what our position is. We also exchange more information with them on our forecasted conditions. So an example would be how much we're transferring from the north central part of our footprint to the south.

We provide that information looking out 7 days so they have an understanding of what we're seeing as we move into the operating day. Forecasts -- we provide greater awareness and communications around the regional dispatch transfer so just making sure we forecast that information and then share it with our neighbors and then we also focused on internal and external training on drills, on emergency purchases.

On that day there were opportunities to improve on how we execute on getting emergency power so each neighbor does it a little bit different. We have protocols in place. That's something that we train on but we'd really

never executed in real time and so there are some execution issues there that we observed and so what we've done is taken those lessons away that we actually did more training with our operators but we're also doing training with our neighbors on how we execute that in a timely manner.

All this here has been helpful. Recently here on September 15th we again actually went into the same level of our emergency procedures but things went much better. Coordination, communication was better, the execution of our procedures went much better and we actually came out of that with a good outcome but that was just with the training, with the drills and the improvements from the lessons learned back in January.

Other things that we focus on to be prepared for winter -- we talk about gas electric coordination. Again here, this was probably back during the polar vortex was the first time MISO really experienced a lot of generation within our footprint that could not get fuel for the gas generators.

And so we put protocols in place to make the situational awareness of those units not being able to get fuel with our operators much more aware for them. So that includes coordination on a monthly basis and during emergencies. We can actually talk with those pipelines and understand what their position is and what our position is

and share information.

We do have a small group that focuses on gas electric coordination on a monthly basis and we work with our neighbors with that group as well but it also supports the control room as well during the winter months.

Emergency preparedness -- MISO continues to hold emergency operating procedures and winter and summer readiness workshops. We'll have a workshop coming up here for this winter but we put those workshops in place to work with our members on capacity, emergencies, conservative operations, communication protocols and we do a lot of operator to operator training. We also share projections in our positions for the upcoming months.

Typically that has always been focused on summer but I would say summer we can manage that fine, it's the shoulder months and the wintertime that we've experienced more issues when we look over the past two years.

Emergency response and power system restoration drills -- we do that on an annual basis as well. We're doing that with our members currently here this quarter. Emergency procedures -- we made several updates to that based on recent events and that will be in place for this upcoming winter.

Generation portfolio -- a lot of planning and collaboration with our members to maximize the use of

generation so we've communicated with them that we're going to put out capacity advisories to give them a heads up when we see tight conditions and we've also worked with them from an outage coordination perspective on moving generation where we can when we're in an emergency, so it's just letting them know where we're at, being transparent and then working with them to shift generation.

I think one thing you have to be careful is in the shoulder months, you have to shift generation, you could just be shifting the problem to the next time period that you need that generation by moving an outage.

We did have some of those issues in the past but it's something to be aware of. Operational readiness -- communication, coordination, planning and training -- our operators go through a ton of training as far as getting ready for winter and summer and we do that with our members every spring and then for the winter we do a workshop.

We also will do a fuel survey -- that's underway right now and we'll review the results of that and provide that at our winter readiness workshop here coming up at the end of the month. We will focus on winterization guidelines again for this upcoming winter and we'll have a special speaker coming in to talk about that as that was part of some of the issues that we saw this last winter.

A little bit on our workshop. It will be on

October 29th, we will talk about the winter lessons learned from 2017-18. We'll go over our assessment for 2018-2019, we'll review the preparation for the weather conditions and we'll also talk about winterization guidelines for this workshop.

Enhancements to tools and processes for extreme conditions -- so out of the lessons learned from this last winter on the transfer from our north central to our south we're putting in a product or we're using a product called reserve procurement. Basically what it does is allow for us to insure the deliverability of operating reserves to the south and price it accordingly.

In the past that was a manual operations, where now we operationalize it within our day ahead in real time markets. Operating guides -- we've worked with the south region on some operating guides. With recent events that will also help us manage some of the load pockets in the southern part of our footprint.

Our resource availability and need program -- it's ongoing. This is work to ensure there are sufficient resources to be available for real time and all times and that's kind of some of the near term things that we're focused on is outage coordination and then also how do we use load modifying resources in a planning horizon and how that follows through into real time.

Again, gas electric coordination tools and processes there, it's ongoing but it still improves the situational awareness both on the gas side and on the electric side for our footprint.

So just to conclude we have adequate resources to meet our obligations for this upcoming winter. The transmission system looks good, we've taken the lessons learned from last winter and they will be in place for this upcoming winter and we continuously train and improve our processes and tools for improved operations. Thank you for your time.

MR. ELLSWORTH: Thank you very much, SPP.

MR. REW: My name is Bruce Rew, I'm VP of Operations for Southwest Power Pool. Today I'd just like to give you a brief overview of SPP and then touch on a few things from last winter that we've experienced and give you our preparations for the upcoming winter.

So SPP's footprint extends from Canada down to Texas and we are a summer peaking system with just over 50,000 megawatts. Our winter peaking is just about 85% of that. We reach about 44,000. There is a very diverse weather pattern with a large geographic area -- it can be cold in the north and relatively warm in the south.

And we do have sufficient reserve margin -- a reserve margin based on summer peaking is 28% and that goes

up for the winter value. So a few things to highlight for the 2017, excuse me 2017-2018 winter -- we did set three new peaks starting on January 2nd culminating with our peak on January 17th. This is the cold event that Rob was talking about, it also significantly impacted us in the southern part of our system.

One thing that was interesting for us too is we recognize we had total energy consumption has increased by about 5% and I'll show you some more details about that in the next slide. One of the big challenges for us is the wind variation that we see and I've provided you some numbers here in terms of our peak record and then our wind penetration record.

The wind penetration record there at 56% that is during the winter months. Actually we see higher than that in the spring time. And wind is our second largest energy resource. In the wintertime it provided 27% of our energy second only to coal in our footprint.

And I've showed you this from the variability there you can see we go all the way from almost 16,000 megawatts down to less than 500 megawatts and the correlation of that wind output is not directly related to the load either. You know we can have high wind, high load, we could have low wind and high load so we have to manage that on a regular basis.

And now I'm going to touch briefly a little bit more on the extreme weather event. So looking at the energy consumption -- so this is the four winter months, December through March from 2016 to 2018. As you can see, especially in January, February and March we had significantly more energy in 2018 than we had in the previous two years and while we think some of that is due to weather, I think we're also seeing some more load growth due to primarily key pumps for winter heating in our footprint.

So the January 17th event on the next slide, we call it the big chill and we had significantly cold weather in the southern part of our system where it resulted in a record winter peak for SPP.

One of the good news for us during this event is that we did have high wind throughout the period of time and the wind is on forecast, so that's very important to us as well is that the wind is forecast -- is consistent with its output and it was at this point.

But during this event we experienced significant transmission system loading as well as heavy transfer across our system helping to support MISO south and the situation they're in.

But overall SPP did not have an energy shortage during this event. We had sufficient generation in our footprint, just significant loading. I think Rob has

touched on a lot of those things that we've done for the coordination. It really helped us in terms of learning how we can do better for operational in those tight situations and as he mentioned last month, we saw that in coordination where we had significant loading on September 15th.

So what does 2018-2019 look like for Southwest Power Pool? So we're seeing a chance of an El Nino and what that would do for us is potentially a warmer loading, the warmer temperatures in the northern part of the system with the potential for wetter in the southern part.

Overall we see a slightly above average temperatures for the SPP footprint is what's in our forecast. One of the things that we do for winter preparedness is we host a winter preparedness workshop and we did that a couple weeks ago on October 2nd, so we have a very diverse group of attendees covering multiple things related to winter operations.

We reviewed the previous winter, some of the congestion that we saw. We talked about how we're going to be able to improve that in next winter. We also go through the assessment methodology looking at you know, what we're seeing for potential loading in the system, you know, any concerns that we have.

And then we meet with market participants and review the specific conservative operations, the weather

alert process to make sure that they're not only up to date on that but they're also current and ready to go with anything that potentially comes up.

The next slide and slide 10 just shows you some additional things that we do for winter preparedness so we -- for the winterization we contact the generation operators to make sure that they've taken all their necessary precautions to prepare for the winter. Obviously the ones in the northern part of the system that's a normal process for them, it's also about insuring the entities in the southern part are also prepared as much as possible.

And we also look at any potential outages during the season in terms of are there big outages, are there concerns that we see with those outages in our studies that we do for ahead of time.

We do have a few units that can do fuel switching so we'll look to those generators to make sure that they have proper communication at any time that they do change those units. If there's a change in rating with the units that it gets properly reflected so we've reviewed those processes with them to make sure that they'll do that promptly any time there's fuel switching that occurs.

One of the things I want to highlight to you is that in operations we've developed what we call high risk and uncertainty reports and these give us a 7-day look ahead

on things that we would see as leading indicators. And on the next slide I'll show you an example of that.

On the left-hand side of the column is just several of the things that we look at and then we project that out 7 days so this gives our engineers plenty of lead time and to spot something as soon as possible and flag it in terms of a potential concern for us in operations.

So this gives us as much notice as possible and we do this, you know, every day we're continuously updating it. So like on the January event, we could see a couple days in advance that we had the potential for high loading and we could track that and see how that materializes.

One of the things I've talked about over the last couple of years is the transmission expansion of our footprint and over the last couple of years we've had a lot of energization of 345 transmission lines completing out some of the expansion projects that we've had.

During the past year we've really not had any major transmission expansion like we've had in the past so overall we see just a few transmission additions to affect us but overall we feel like the transmission systems additions that we've made in the last several years have been -- are very adequate to provide us a robust transmission system to manage.

So overall for our SPP winter assessment, we

think our forecast will be slightly lower than what we had last year with our all-time peak last year of 43,500. We should be just a thousand or two megawatts below that. Generation reserves continue to be high for our region and we also -- the reliability coordinator has confirmed winter preparations with a transmission operator and generation operators at our October 2nd meeting and then a one-on-one as necessary as well.

So overall I'd say SPP indicates that we're prepared for our 2018 and '19 winter season and I look forward to any questions that you might have, thank you.

MR. ELLSWORTH: Thank you.

MS. TRAWEEK: Good morning my name is Nancy Traweek, I'm the Executive Director of Systems Operations at the California ISO. I wanted to give you a little bit of background of California ISO very briefly and then we'll go into some of the winter assessment.

Our resource mix is changing as California, as everybody knows, it's pretty diverse at the moment. We have thermal hydro, some battery, bio-gas, however the majority is now becoming wind and solar.

Currently today we're seeing a transition of our thermal fleets from baseload or high minimum load resource to a very flexible resource where they can come on and off within a 10 minute period and we're looking for those types

of flexible resources.

Our renewable resources currently between the wind and the solar we have about 20,000 megawatts installed utility grade capacity there and we've seen just about 16,000 megawatt of a peak output in one instantaneously.

We also have to content now with rooftop solar. We have about 6,000 megawatts that we can tell of rooftop solar as well including all the other type of solar utility grade solar. So on May 26th, 2018 we actually served 74% of our load instantaneously at 2:49 p.m. with just solar and some wind, our renewable resources.

So in order to manage those resources we have a multi-dimensional strategy that includes storage, demand response, some of the bigger things that we're also looking at are the flexible resources that I just told you about -- the transition of those base load resources and the flexible resources are really helpful as well as our energy and balanced market being able to send out energy or receive energy through the energy transfers on that market.

So our energy and balanced market has grown. We now have in real time -- so we have 9 active entities and 3 more that will be coming in by 2020 and 2021 and that's helped us support the reliability with the renewable fleet that we currently have as well as it's helping the participants in the west with their reliability because

they're not only just transferring the energy back and forth with us, they're transferring energy back and forth with each other and that's helped the reliability in the west.

So if we get to the winter as always, I think every year I come here and tell you this. We're looking at higher, above normal temperatures for the winter in the California region and this year we're looking at normal precipitation in California. Right now we're still considered in summer -- it's very warm and dry in California and really the biggest risk we have right now is a risk of wildfire.

With the winds coming up in this time of the year and it being still warm and dry we can see tremendous wildfires as we do now pretty much every year and it's becoming a year 'round issue. It used to be October would be our big wildfire season and now we can see it anytime of the year.

So we also did some additional analysis and there is a chance of us having what we call an El Nino year where the waters are warmer and that could cause more precipitation in southern California. Also we had last year several -- what we call atmospheric rivers, and that's where we can get 2 to 10 inches of rain within a 24-hour period.

So we watch those closely. They can hit anywhere

in this state which helps us from a reservoir level perspective but it also can be bad when we have a burn scar area like we saw in the Santa Barbara area last year, those kind of atmospheric rivers that hit burn scars can cause landslides and trouble like that.

A couple of years ago we had a really great wet winter and we had a lot of rain so all of our reservoir levels have come up. Last year it wasn't quite as good so they're starting to drop back however this year we think we'll be at least at normal, average or below.

In Northern California we typically stay at normal when we have decent years. We think there will be a normal or above in our reservoirs. Central California will normally average and then in Southern California we think will be below average based off the forecast today.

This is important because these are the resources that we're using to help manage the system during the summer and we like to have our reservoirs as full as possible. So my favorite friend, Aliso Canyon -- we were still there, we do a winter assessment every year and outside of just our normal winter assessment to see if we're ready for winter which we are again this year.

We also look to see how low we can go with the gas in the Southern California region because of Aliso Canyon, so we'll do a very stressed case, not only for

ourselves, we jointly do this assessment with LADWP as well as our adjacent balancing authorities. We're all included in this assessment to see how low we can actually run the generation.

The conditions haven't changed at all since last year. We still have two major pipelines still out of service and not expected back until sometime in the spring possibly, that's the earliest timeframe that we understand.

Storage levels however in Aliso Canyon have increased. The CPUC has increased the storage levels from 24 BCF to 34 BCF. That said, Aliso Canyon is still considered last resort resource. So that means we have to do what we can to re-dispatch generation in the south and then if we can't do any more than Aliso Canyon can be used.

SoCalGas has indicated again this year that they will not be able to meet a 1 in 10 winter peak for their customers who are residential gas customers. So to the extent that that doesn't happen the electric customers, electric utility or thermal generation is the first to go -- it's the first up to 60% is the first to get cut. So we work very closely with SoCalGas as well as the rest of our gas partners to make sure we understand what's headed our way and what's coming up and how we can help support that.

Last year or actually it was this year, I want to call it last year, end of February into early March for a

two-week period we did have a cold spell in the San Diego, Los Angeles area and we were asked to curtain for two full weeks. We did what we could but as others have said, when you have a lot of outages in the wintertime it is challenging to continue to keep backing down the gas generation fleet.

They did use Aliso Canyon first for a period of time during that two-week period and we were able to maintain and get through that working with the gas company and like I said doing what we could and also supporting our partners, our other balancing authorities.

Even though winter's not a peaking season for us, what we do have is a very steep peak ramp to our evening peak. With all the solar during the daytime when that goes off our ramps can be you know 13,000 megawatt ramps. That can put -- and we use that mainly, we do that mainly with thermal resources -- that puts a strain obviously on the gas system. Pipelines are not really meant to draw that much gas, solely on their own so we do work closely with the gas company as well when we do think we're going to have these higher ramps and try to give them a heads up that we're going in that direction.

We have procedures in place and we have had them for a few years now for gas coordination with all of our gas companies and so we've managed that in that way. We are

adding a few new resources, we do have a new 230 KV transmission line going into the San Diego area that will help support load there.

We also have a new energy center, 500 megawatts simple cycle resource. This is a fast start resource just like I was talking about, it can come on and off in 10 minutes so that helps us a lot with the renewables. And we're also adding about 1,000 megawatts of additional capacity this winter -- predominantly that is solar and wind resources, there's a few small gas, small battery and some bio-mass resources.

We're also anticipating a couple of our larger resources that have high minimum loads are going to transition to those flexible-type gas resources as well as we go through the next several months.

Okay so I touched on this a little bit but we do have daily calls with the gas company to make sure that we're all on the same page as far as what the gas concerns might be. Anytime we see weather coming out you know in the 7-day, 10-day forecast, depending on what that is we will coordinate that with our participating transmission owners, the adjacent balancing authorities, pipeline owners as well as our reliability coordinator and then our state regulators as well.

So we're continually coordinating as we move

through not only summer events but winter events and making sure that everybody's on the same page as to what we're seeing and how we're going to manage that. So with that, that concludes my portion.

MR. ELLSWORTH: Thank you everybody for those presentations. I'd like to just turn to the Commissioners to see whether they have any questions or comments first.

COMMISSIONER LAFLEUR: Well thank you very much, that was excellent. I could ask a ton of questions but I'll limit myself to two and I have to start with New England not just because of my shirt, but Pete I feel like we're playing a -- we're like in a long running production of "Same Time Next Year" where every fall you come and say we have plenty of capacity but we might not have enough gas.

I'm cautiously optimistic we can make it through -- I'm curious your thought if there are -- assuming hypothetically, that there are no new major pipeline additions coming into New England from out of the region and that not saying that's what I want, I'm just making that as an assumption, when do you think it will break and you will see relief either from the Massachusetts procurement of Canadian Hydro, all the other things that are going on to bring in non-fossil resources to the region?

Is that four years out? I mean how many more winters will we be in this show?

MR. BRANDIEN: It's my belief that we're always going to be managing pretty much right on the edge. I think the states have done a very good job of energy efficiency and, you know, behind the meter stuff and we see that with our energy forecasts being negative and our peaks each year going down.

So you alluded to you know Massachusetts and reaching out for another 1,000 megawatts from --

COMMISSIONER LAFLEUR: Not just Mass, they're the biggest one but others have to.

MR. BRANDIEN: Reaching out, another 1,000 megawatt tie with Quebec off-shore wind, continue with energy efficiency in other non-carbon emitting resources but we're going to continue to see retirements. We've got a lot of old oil units.

I mean a new oil unit was put in in 1975 so how long are they going to be around? So I think we're always going to be managing this and at some point in time if you want to continue decarbonizing, you're going to see investments in transportation and getting off of gas burning in homes and going to heat pumps which is going to drive the electric use up.

I think as the operator of the system we're going to continue in this balancing in making sure that we're providing the right information to replenish the small dual

fuel tanks and sending out the right information to get LNG tankers to those facilities. I don't see us -- energy efficiency and renewable way out of this.

COMMISSONER LAFLEUR: Well I really appreciate how closely you and your colleagues watch it because -- and I read the Globe every morning and I know there's just so much emotion on all sides of energy debates up there and there always have been but it certainly seems that way now and if we're going to operate it tight, then that real time and look ahead information is really critical.

MR. BRANDIEN: Yeah and from a resilience perspective it doesn't do much for resilience. I mean if we have one major pipe interruption you know, we're going to have to reduce the load and then figure out where we are and then pick up what load we can. We're not very resilient from a fuel supply or energy supply perspective.

COMMISSIONER LAFLEUR: I could ask a lot more but I was going to ask both you and Dave would the -- you mentioned Pete, your look at what generators had done for the winter so far in terms of oil inventory but looking beyond just that one number, asking you and Dave with the advent of paper performance and capacity performance, have you seen generators and other resources that have capacity obligations take different steps in getting ready for winter?

Are you seeing that in how you see the system being run, maintained, fuel contracts or anything else?

MR. BRANDIEN: I can't say I've seen anything from the fuel perspective yet, but we did have one event where we triggered our pay for performance incentives or penalties and we did see resources try to get on quicker than what they're offered into the market for. So we are seeing people respond when the system gets tight, but we're in a wait and see to see what happens from a fuel perspective.

COMMISSONER LAFLEUR: Obviously that's what we're paying them for, Dave?

MR. SOUDER: Yes, and we are seeing with the advent of CP more natural gas generators that have firm fuel and we're also seeing some higher inventories with respect to onsite fuel.

COMMISSIONER LAFLEUR: Thank you very much.

COMMISSIONER GLICK: In the interest of time I'll just limit to one question. I recently saw a report from the Brattle Group talking about demand response in the gas sector and I know and I know that you all obviously the RTOs and you can't really operate demand response programs on the gas side, but the report suggested there was significant opportunities there especially during times in New England for instance, when you know, it's cold weather and there's

not a lot of gas supply for electricity.

I was wondering if each of you and maybe Mr. Brandien if you could start with what you thought of the possible potential for that and what you think the Commission might be able to do to promote demand response on the gas side?

MR. BRANDIEN: I think it's something that should be pursued. We've in our discussions with some of the states you know, they asked us whether or not that would benefit and I think it would because the fuel disappears. Our low doesn't jump up, the fuel disappears.

And if we get to the point where we have to reduce load, it doesn't make sense for them to be sending fuel to people that don't have electricity, so I think there is potential there and I think it should be pursued.

MS. NELSON: Certainly there's a lot of competing interest for the gas supply between residential industry use so if there is some way to manage sort of voluntary users to make the gas available for critical electric needs, certainly residential needs takes priority then that may be beneficial.

Oftentimes in New York what we manage through is seeing is gas truly unavailable or is it available but at an extreme price? We have seen quite a lot of steps taken to try to take advantage of gas that may be there and at times

it's -- the market has really been more liquid than one would anticipate but certainly trying to manage demand is something that we often look to to solve these types of problems.

MR. SOUDER: Yeah I don't have anything addition to add on that but I do believe that the main response is important with respect to its asset resource so.

MR. REW: I'd just add that with SPP we see gas as very important for the flexibility that we have in order to start and you know if there's an opportunity for us to insure that it's there by you know, putting in something like that then we see a benefit in doing it.

MS. TRAWEEK: As part of the Aliso Canyon measures the gas company has implemented a demand response, small at first -- I think 9,000 customers originally and I think that they're going to go up to 50,000 this year. So we have seen that. I do think it's really important we have something -- our flex alert kind of program in the summer.

They're looking at that as a way to give people a head's up that you know, it would be a good time to try to conserve from the gas side as well.

COMMISSIONER GLICK: Thank you.

MR. ELLSWORTH: If folks around the table have any other questions please do raise your tents. If not, I'll ask if there's anything further the Commission can do

to help, particularly in the realm of gas electric coordination. Are you getting all the information that you would like to get from market participants and is there anything the Commission can to do facilitate that exchange information?

MS. TRAWEEK: I'll just start and say I appreciate what you've done for us for the Alisa Canyon piece already. We're getting closer and closer communication with the gas companies and so thank you for what you've already done for us.

MR. REW: For SPP we have two major gas line providers in our footprint and you know, some smaller ones but we are really pleased with the coordination that we have with them and the data sharing and information sharing has been really good and I am pleased with that process.

MR. BENBOW: For MISO the coordination that we have on the gas side we're pleased with the response that we had with the pipelines that we work with, we feel like we're in a good spot in the Midwest with a lot of diversity as far as gas pipelines.

We've seen some issues since the polar vortex and we put processes in place with the gas side and that continues to serve us well at this time.

MR. SOUDER: I believe PJM continues to make progress with the coordination with the gas electric. I'd

like to see some of the communications go down on to the operator floor. I think there are tariffs in place that require the communication with the customers before they'll be reached out to PJM so I'd like to see some movement in that area.

And again, I think the gas industry has been very cooperative of we've leveraged their tools from a hydraulic analysis perspective but possibly moving them more towards real time would be beneficial.

MS. NELSON: Within New York we are satisfied with the coordination that's in place at this point. We've seen improvements over the past several years and at this point we think that the coordination across all parties is very strong.

MR. BRANDIEN: Ditto from New England and we actually do have communications right down in the Florida control room to the gas control in Houston and that works out very well to us, it's two-way. If we see something where we lose a nuclear unit and we're going to start pulling on the gas we make a call to them.

If they see something they call us and we have daily calls with them. The big question mark for us is how the LNG is going to play into market and of course the big dog is up in New Brunswick because they've got the 10 BCF and you know, that we're kind of, you know, mining as much

information as we can but I'm not sure what you could do about that but you know, from our operational fuel security study you could see the injection of LNG is significant in the availability of electric generation in the wintertime.

MR. ELLSWORTH: Again, thank you for your presentations and answers and if there are no more questions I think we're adjourned, thank you.

(Whereupon at 3:31 p.m., the meeting was adjouned.)

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: Winter 2018-2019 Operations Market Performance in Regional Transmission Organizations and Independent Systems Operators

Docket No.: AD16-24-000

Place: Washington, D.C.

Date: Thursday, October 18, 2018

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