UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

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1,031st COMMISSION MEETING

Thursday, October 20, 2016

Commission Meeting Room

Federal Energy Regulatory Commission

888 First Street, NE

Washington, DC 20426

The Commission met in open session at 10:01 a.m., when were present:

CHAIRMAN NORMAN BAY

COMMISSIONER CHERYL LaFLEUR

COMMISSIONER COLETTE HONORABLE

PRESENTERS:

G-1, DEREK ANDERSON, Office of General Counsel
ADRIANNE COOK, Office of Energy Market Regulation
JAMES SARIKAS, Office of Energy Market Regulation
MONIL PATEL, Office of Enforcement

A-4, PETER BRANDIEN, Vice President, System Operations, ISO-NE
WES YEOMANS, Vice President, Operations, NYISO
MICHAEL BRYSON, Vice President, Operations, PJM
TODD RAMEY, System Operations and Market Services, MISO
BRUCE REW, Vice President, Operations, SPP
NANCY TRAWEEK, Executive Director, System Operations, CAISO

A-3, ADAM BENNETT, Office of Enforcement
HILLARY HUFFER, Office of Enforcement
JOHN SILLIN, Office of Enforcement
RAMSES CABRALES, Office of Enforcement

P R O C E E D I N G S

SECRETARY BOSE: The purpose of the Federal Energy Regulatory Commission's open meeting is for the Commission to consider the matters that have been duly posted in accordance with the government and the Sunshine Act.

Members of the public are invited to observe, which includes attending, listening, and taking notes, but does not include participating in the meeting or addressing the Commission. Actions that purposely interfere or attempt to interfere with the commencement or conducting of the meeting or inhibit the audience's ability to observe or listen to the meeting, including attempts by audience members to address the Commission while the meeting is in progress, are not permitted.

Any persons engaging in such behavior will be asked to leave the building. Anyone who refuses to leave voluntarily will be escorted from the building.

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Thank you for your cooperation.

CHAIRMAN BAY: Good morning, everybody. This is the time and place that has been noticed for the open meeting of the Federal Energy Regulatory Commission to consider the matters that have been duly posted in accordance with the government and Sunshine Act.

Please join us in the Pledge of Allegiance.

(Pledge of Allegiance recited.)

CHAIRMAN BAY: I have one announcement to make at this time, and that is, I would like to recognize a member of Staff who is retiring at the end of this month who has been at FERC since 1978 and who has 41 years of public service. I'm referring to S. L. Higginbottom, who unfortunately is not here today, but who has served with great distinction here at FERC. He's been in the Office of General Counsel. He has become our Mr. QF, not only being intimately involved in every QF-related rulemaking and order, but serving as the Commission's chief point of contact with visitors and callers interested in exploring QF-related issues.

In this capacity, he has mentored any number of attorneys and other Staff members, helped guide the Commission through a thicket of difficult QF issues, and guided both utilities and QFs alike in compliance with the requirements of PURPA and the Commission's regulations implementing PURPA. So after 41 years of public service, S. L. will be retiring, and we are going to sorely miss his expertise.

Colleagues, any other announcements?

COMMISSIONER LA FLEUR: Thank you, Mr. Chairman.

I'd also like to congratulate S. L., who is not only a FERC lifer since it's begun, but has really shaped every stage of PURPA, from the initial regulations right up through today. And I consider him a friend and wish him and his family Godspeed.

A couple other things I just wanted to mention, I want to congratulate the Southwest Power Pool, because we're lucky to have them here today, and the persons are Paul Suskie and Bruce Rew, who are going to be in the winter preparation item. But later this month, SPP will celebrate their 75th anniversary.

If some of you don't know this, SPP was actually launched immediately after the Pearl Harbor invasion in 1941 so a bunch of electric companies could put their resources together to power up an aluminum factory for the war effort, which is a pretty interesting history. And obviously, they've evolved and grown a lot since that time, but still critical to their region, so congratulations to them.

Finally, I just wanted to mention that earlier this week I was honored to represent the Commission at it's trilateral meeting in Mexico City with the Mexican regulatory community and some of our Canadian colleagues. I've been trying to follow the tremendous growth and transformation of the Mexican energy system, and I was happy to have the opportunity to learn more.

Thank you.

CHAIRMAN BAY: Thank you, Cheryl.

Colette?

COMMISSIONER HONORABLE: Thank you, Mr. Chairman.

Good morning, everyone.

First, I'm wearing a very bright color today in recognition of Breast Cancer Awareness Month. And of course, it's all month long. We've seen our favorite or not so favorite NFL teams, for me that would be the Dallas Cowboys, wearing pink. I hope that you will take a moment to mention it to the special women in your lives to ensure that we continue to make this fight one of importance.

I, too, want to congratulate Mr. QF, Mr. Higginbottom, on an incredible tenure. And we've been honored to have him here with us, and we've certainly learned so much from him, and his legacy will continue on.

Thank you, Cheryl, for mentioning SPP, and my friends from Arkansas, Paul and Bruce, I've learned a lot from them and worked with Paul at the Arkansas Public Service Commission. And we worked well most of the time together. We had a few missteps about what the law meant and what it said and how it should be interpreted, but it was a pleasure to work with both of them.

I'm also honored to be able to join SPP at the 75th anniversary for the evening to review and to take time to acknowledge the tremendous work, not only that's occurring in the south SPP region but throughout regional transmission organizations and independent system operations around the country. So I look forward to it.

Thank you so much.

CHAIRMAN BAY: Thank you, Colette.

Madam Secretary, I think we're ready to proceed to the consent agenda.

SECRETARY BOSE: Good morning, Mr. Chairman. Good morning, Commissioners. Since the issuance of the Sunshine Act on October 13th, 2016, item E-1 has been struck from this morning's agenda.

Your consent agenda is as follows: Electric items: E-3, E-4, E-5, E-6, E-7, E-8, E-9, E-10, E-11, E-14, E-15, E-16, and E-17.

Gas items: G-2, G-3, and G-4.

Hydro items: H-1 and H-2.

Certificate items: C-1.

As to E-9, Commissioner Honorable is concurring with a separate statement. As to E-10, Commissioner Honorable is concurring with a separate statement. As to E-11, Commissioner Honorable is concurring with a separate statement. We are now ready to take a vote on this morning's consent agenda items.

The vote begins with Commissioner Honorable.

COMMISSIONER HONORABLE: Thank you, Madam Secretary. Noting my concurrence in items E-9, E-10, and E-11, I vote aye.

SECRETARY BOSE: Commissioner LaFleur?

COMMISSIONER LA FLEUR: I vote aye.

SECRETARY BOSE: Chairman Bay?

CHAIRMAN BAY: I vote aye.

SECRETARY BOSE: We are now ready to move on to our first presentation.

CHAIRMAN BAY: Madam Secretary, before we proceed to that, I would like to ask my colleagues if either one has any statements that she would like to make with respect to items on which we've just voted.

COMMISSIONER HONORABLE: Thank you, Mr. Chairman. I will yield first to Commissioner LaFleur.

COMMISSIONER LA FLEUR: No, I'm fine. Thank you.

COMMISSIONER HONORABLE: Thank you,

Mr. Chairman.

I'd like to quickly call attention to my concurrence statements in items E-9, E-10, and E-11. As you are aware, each of these orders deal with late-filed qualifying facilities certifications, and I'm concurring in these dockets separately because I do agree with the outcome in each, which is to require time-value refunds on revenues received by the QFs when they were out of compliance with Commission regulations. This is a long-standing policy, and I do not believe that we should depart from it at this time.

The time-value refund calculation, however, is only part of the picture, and something that became clear to me with the help of my staff in evaluating them is the other part of the picture that I wish to emphasize and attempted to do so through my concurring opinions.

The Commission allows for adjustments to time-value refund calculations to ensure resources are not forced to operate at a loss. And this refund floor is calculated in several ways, or has been over the time that we've conducted this work. For generation resources, we've looked at variable O&M costs. For transmission resources, we've looked at fixed O&M costs.

And the Commission has justified this different treatment based upon the cost structure for each resource type. For instance, generation resources typically incur more variable costs than fixed costs, and conversely, transmission resources typically incur more fixed costs than variable costs.

The generation resources at issue today in these three dockets, namely wind and solar, don't fit that mold. And so I'm writing separately to note that I stand willing to consider whether certain resources, based upon their cost structure, should calculate refund floors using fixed O&M costs.

And I'm taking this position and expressing an openness on this point to ensure that the refunds are calculated fairly for both generation and transmission resources. Finally, I hope that we will look closely at this and other long-standing policies to ensure that our approaches are evolving with the markets that we regulate.

Thank you, Mr. Chairman.

CHAIRMAN BAY: Thank you, Colette.

Madam Secretary?

SECRETARY BOSE: We will now move on to our first presentation and discussion item for this morning, which is G-1, a draft advanced NOPR of proposed rulemaking concerning revisions to indexing policies and Page 700 of FERC Form Number 6. The presentation --

(Audience interruption.)

SECRETARY BOSE: There will be a presentation by Derek Anderson from the Office of the General Counsel and Adrianne Cook from the Office of Energy --

(Audience interruption.)

SECRETARY BOSE: Accompanying Derek and Adrianne are James Sarikas and Monil Patel from the Office of Energy Market Regulation.

MR. ANDERSON: Thank you. Good morning, Mr. Chairman, and Commissioners. The draft advanced notice of proposed rulemaking in G-1 seeks comment on potential modifications to the Commission's policies for evaluating oil pipeline index rate changes and to the data reporting requirements on Page 700 of FERC Form Number 6. The purpose of these proposed changes is to improve the Commission's ability to ensure that oil pipeline rates are just and reasonable.

The Commission regulates the rates, terms, and conditions that oil pipelines charge under the Interstate Commerce Act. In the Energy Policy Act of 1992, Congress mandated that the Commission establish a simplified and generally applicable ratemaking methodology for oil pipelines, while maintaining the statutory requirement that all oil pipeline rates be just and reasonable.

The Commission's index ratemaking methodology has served as a predominant mechanism for adjusting oil pipeline rates for over two decades. The ability to ensure that index rate increases do not cause pipeline revenues to unreasonably depart from oil pipeline costs, as well as ensuring that the Commission and oil pipeline shippers have sufficient information to assess the relationship between oil pipeline rates and costs, is essential to the Commission's implementation of its statutory obligations under the ICA.

The proposals presented in the draft ANOPR are the result of the Commission's ongoing monitoring and evaluation of the relationship between oil pipeline costs and rates. In part, G-1 is an outgrowth of a petition for rulemaking filed by a consortium of shippers in April 2015 that urged the Commission to require pipelines to report additional information on Page 700.

Through the Commission's ongoing monitoring of the oil pipeline index and how it affects pipeline's rates, the draft NOPR notes that some pipelines continue to obtain additional index rate increases, despite reporting on Form Number 6, Page 700, that revenues significantly exceed costs.

Experience with index proceedings has also indicated that the standards for evaluating shipper objections to index filings could be strengthened and clarified to both protect against excessive rate increases and, consistent with the streamlined and simplified methodology required by Congress, minimize costly and time-consuming litigation regarding pipeline rates.

MS. COOK: Accordingly, G-1 proposes reforms to the Commission for the oil pipeline index rate filings in the reporting requirements for FERC Form 6 Page 700 to better fulfill the Commission's statutory obligations under the ICA.

First, G-1 seeks comment on whether the Commission should adopt a new policy that would deny proposed index increases if a pipeline's Form 6 Page 700 revenues exceed the Page 700 total cost of service by 15 percent for both of the two prior years or the proposed index increases exceed the annual cost changes reported on the pipeline's most recently filed Page 700 by 5 percent.

Second, G-1 seeks comment on whether the Commission should apply these new reforms to costs more closely associated with the proposed indexed rate than the total company-wide costs and revenues presently reported by oil pipelines on Page 700. In particular, G-1 proposes to require oil pipelines to file supplemental Page 700s for crude pipelines and product pipelines, noncontiguous systems, and major pipeline systems.

G-1 also seeks comments regarding a proposed requirement that pipelines report information regarding the allocations used to prepare these supplemental page 700s and separate revenues for cost-based rates, such as indexing, noncost-based rates, such as market-based rates or settlement rates, and other jurisdictional revenues, such as penalties.

In considering the revisions to Page 700, G-1 declines to adopt the April of 2015 proposal by the shipper consortium to require pipelines to file separate supplemental Page 700s for each rate design segment and to require pipelines to file workpapers. Among other things, G-1 notes that most pipelines have never made a filing with the Commission identifying their rate design segments, and rate design segmentation at Page 700 would likely insert into the Commission's simplified indexing methodology a complex, fact-specific dispute regarding the appropriate rate design segmentation.

Regarding workpapers, G-1 states that the proposal in the ANOPR should provide sufficient information to allow the Commissions and shippers to evaluate index findings and conduct a preliminary evaluation of a oil pipeline's rates prior to bringing a cost-of-service challenge. However, G-1 invites comments on the sufficiency of this additional information in evaluating index filings and conducting preliminary evaluations of a pipeline's rates.

Finally, G-1 seeks comment on the potential costs associated with the proposals being considered.

This concludes our presentation. We're happy to answer any questions you may have.

CHAIRMAN BAY: Thank you, Adrianne, Derek, Monil, and Jim for this presentation that reflects the significant work and consideration that has gone into this advanced notice of proposed rulemaking.

I believe that this ANOPR is a good example of the Commission's ongoing efforts to ensure that oil pipeline rates and practices remain just and reasonable. The proposed reforms introduce potential improvements to the Commission's indexing methodology and refinements to the data reporting requirements that will enhance the Commission's and shippers' abilities to evaluate the relationship between oil pipeline rates and costs. So I very much look forward to hearing the comments from stakeholders with respect to this ANOPR.

I just have one or two questions for the team. And one question is whether you could highlight how the proposed reforms to the indexing policies could reduce the likelihood that an oil pipeline's rates may substantially deviate from its costs.

MR. PATEL: Under the excessive rate test, if a pipeline's revenues exceed costs by 15 percent for two straight years, it will not be able to obtain index rate increases until the gap between its revenues and costs is reduced. Because these pipelines cannot receive an index increase, that cost and gap between revenues and costs to expand further, it constrains the differences that may emerge between rates and costs over time.

Also, by only permitting annual rate check rate increases that are within 5 percent of pipeline's costs changes, the Commission constrains the difference that can emerge in one year between pipeline's costs and its revenues.

CHAIRMAN BAY: Thank you. Thank you, Monil.

And one other question. Could the team provide an example of how the proposed changes to Page 700 reporting requirements will help ensure that rates better reflect costs.

MR. ANDERSON: One example involves our proposal to separate revenue reporting between cost-based and noncost-based sources. By separating revenue generated by cost-based vis-a-vis noncost-based rates, the Commission will be better able to compare cost and revenues associated with those rates that actually utilize the indexing methodology. This will allow the Commission to more easily identify any potential overrecoveries related to the use of the index itself.

CHAIRMAN BAY: So basically, it would allow for an apples-to-apples comparison as opposed to apples and oranges?

MR. ANDERSON: Correct.

CHAIRMAN BAY: Thank you, Derek.

Cheryl?

COMMISSIONER LA FLEUR: Thank you, Norman, and thank you Derek, Adrianne, James, and Monil and everyone else on the team who worked on this order in all the couple years of consideration that went up to it.

I also want to give a special shout out to Andy Knudsen, who has done a ton of work on this, but is unfortunately not able to be here today to be able to present it. I'm very happy to support this order. I think it's an important next step in the evolution of our oversight of oil pipeline rates.

While electricity, gas, and oil regulation all use the common term "just and reasonable," it's often correctly observed that the history and structure of oil regulation is very different than electricity and gas regulation.

Today's ANOPR certainly is an example of the different regulatory constructs that we use to ensure that rates are just and reasonable. We've obviously been deliberating for a while on the Page 700 petition, including the tech conference last year and many meetings with stakeholders on all sides of this issue, and I hope that the proposal on Page 700 is a workable framework that balances the Commission and shipper need for information with the regulatory burden on the pipelines.

Today, we're also proposing changes to clarify how we review index rate increases. As you noted, indexing has become the predominant mean for pipelines to adjust their -- means for pipelines to adjust their rates. For potential we have clear standards for how we will apply indexing to identify situations in which the pipeline revenues unreasonably exceed costs. I support the proposal to tighten and simplify our analysis of pipeline index filings using Page 700 data. I believe it'll help us satisfy our statutory obligation, while operating within the streamlined regime that Congress required.

This is the first -- to the best of my memory, which I think is still pretty good, this is the first ANOPR we've put out since I've been on the Commission in six years. It's not a format we use that often, but I think it's the right structure for this proposal because it's quite a change and something we don't change that often, and this extra round of commentary will allow us to shape a proposed rule in the next stage that will really allow focused comment.

So I hope it's thoroughly vetted, and I know I don't have to ask for robust comments on this one. I know we'll get them.

I did have one question. One of the big debates at the tech conference was how much additional information the pipeline owners had available to put in Page 700 and what the burden was. There was a lot of discussion of separating crude and products, which of course the ANOPR requires, but you also mentioned that the proposal requires separating noncontiguous systems and major pipeline systems, but not rate design segments. So could you explain the thinking that went into that and, you know, what new or additional data you think we're going to get from this.

MS. COOK: Sure. As you mentioned, we utilized both the shipper petition as well as our own internal analysis, just kind of looking at the program as a whole. And we felt that, you know, the shipper proposal, as you mentioned, was based on a rate design segment. It was a little bit unworkable for us and utilized the definition of segmentation that was actually more akin to an accounting definition, which didn't work particularly well for our purposes. So we did very carefully examine this proposal from all angles, but just determined that it was a burden question onto the pipelines to provide that type of -- that level of detail.

Because again, most pipelines have never filed a rate case at the Commission. We're talking about a limited universe. So it was just too large to try to ask folks to do that.

We appreciated the sentiment of segmentation and tried very hard to craft the ANOPR to kind of have a constrained definition of segmentation and something that's workable for everyone. And with that clear definition, shippers should be able to better estimate the specific cost of service that are important to them and have better information to determine whether or not a challenge to a pipeline rate is warranted, while not unduly burdening the pipelines for that.

So again, it was a limited universe of oil pipeline rate cases that we were able to review. But between that, the comments in response to the shipper proposal, and just the general analysis, the areas of segmentation, the crude product, noncontiguous, and major pipeline systems should reflect a definition of segmentation that will be useful in providing cost and revenue data while minimizing that burden.

We clearly expect significant comment on this particular proposed definition.

COMMISSIONER LA FLEUR: Thank you, Adrianne.

I know it sounds a little wonky, but there's been a lot of sound and fury on this one. And I hope we especially get comment on what is and is not doable and whether it'll meet the needs of the shippers. Thank you.

CHAIRMAN BAY: Thank you, Cheryl.

Colette?

COMMISSIONER HONORABLE: Thank you, Mr. Chairman.

Thank you to the team, those sitting here today and also those who worked hard at their desks as well. I also want to thank the stakeholders that submitted comments and the many, many stakeholders on all issues that have come in to visit with me and my team, I'm sure my colleagues, as well as Staff, about the issues attendant with this ANOPR. And I especially would like to thank those that participated in the July 2015 technical conferences and provided comments as well. They have been very helpful to me as I have considered these matters.

Today's ANOPR sets forth several potential reforms to our review of oil pipeline index rate filings and oil pipeline reporting requirements found in Form Number 6, Page 700. In my mind, these potential reforms should improve our ability to ensure that oil pipeline rates are just and reasonable, and that is our role here at the Commission, to further simplify and streamline our ratemaking process for oil pipelines, which is mandated by Congress, and also to enable oil pipeline shippers to better evaluate the index rate filings. And I think as Adrianne has mentioned, our attempt to in this ANOPR propose estimates will hopefully be a way to do that. I will certainly look forward to hearing from stakeholders, in particular shippers who I know will be very sensitive to that particular portion of the proposal.

I look forward to hearing from all stakeholders about the portions of the ANOPR and any other issues attendant thereto that you think need to be brought to our attention. I do appreciate the hard work of all of those involved, and I've been here, it will be two years in January, and I've learned a new acronym, the ANOPR.

And I think that Cheryl has succinctly and accurately referenced really the benefits of the use of this tool, but I wanted to ask you, other than an additional opportunity to allow for comment in recognition of how robust reengagement has been and potentially could be on this issue, what were the other reasons that led Staff to recommend an ANOPR in this matter?

MS. COOK: Of course. So as it's been recognized, the record in the RM15-19, which is where the technical conference came in last year, was very robust. But in the evolution of Staff's analysis, we just needed another round of input, because the scope had changed so dramatically in those cases. And it is very appropriate for an agency that's trying to gather that type of information, and we felt that was more appropriate than trying to go to a NOPR in which we needed -- we needed some more information to bolster a NOPR.

So hopefully that helps.

COMMISSIONER HONORABLE: Indeed. And I think another point that you mentioned was the fact that we don't have rate filings here with regard to oil pipelines as frequently, and I want to conclude by mentioning that I will be very interested in the comments from stakeholders on how we can ensure that shippers get the information they need to be able to respond to rate matters in a way that is balanced.

So I appreciate the ANOPR structure in recognizing the burden that would be placed on the pipeline, but I also want to make sure there's an even playing field.

Thank you.

CHAIRMAN BAY: Thank you, Colette.

Madam Secretary?

SECRETARY BOSE: We are now ready to take a vote on G-1. The vote begins with Commissioner Honorable.

COMMISSIONER HONORABLE: Aye.

SECRETARY BOSE: Commissioner LaFleur?

COMMISSIONER LA FLEUR: Aye.

SECRETARY BOSE: And Chairman Bay?

CHAIRMAN BAY: I vote aye.

SECRETARY BOSE: The next item?

CHAIRMAN BAY: At this point, Madam Secretary, I just noticed that three of our new administrative law judges are here this morning, and I'd like to acknowledge their presence. We have Judge Andrea McBarnette, if you'd please stand, Judge Suzanne Krolikowski, and Judge Jennifer Long. I thought Judge Long was in here, but perhaps, not.

(Applause.)

SECRETARY BOSE: The next item for presentation and discussion this morning is A-4, concerning the winter operations and market performance in RTOs and ISOs.

I will now introduce today's speakers in the order in which their presentations will be given. In the interest of time, discussion and questions will be held to the end of the final presentation.

Our first presentation will be given by Peter Brandien. He's the vice president of system operations at ISO New England. Next will be Wes Yeomans, vice president of operations at NYISO. Following Mr. Yeomans will be Michael Bryson. He's the vice president of operations at PJM. Next will be Todd Ramey, the vice president of system operations and market services at MISO. Following Mr. Ramey will be Bruce Rew. He's the vice president of operations at SPP, and the final presentation will be given by Nancy Traweek. She's the executive director of system operations at the California ISO.

CHAIRMAN BAY: Good morning, everyone, and welcome to our panel discussion on the regional transmission organizations and independent system operators' efforts to prepare for the upcoming winter. We're pleased to have all of you here to discuss this important topic.

As you know, the Commission asked each RTO and ISO to make a presentation at our September Commission meeting last year as part of its efforts to prepare for the upcoming winter. That request was, in part, a response to the operational challenges presented by the extreme weather events in the winter of 2013 to 2014, including what became known as the polar vortex.

And we wanted to hear from the ISOs and RTOs about how they were preparing for the possibility of a similar event in the future. We understand that since the polar vortex, the RTOs and ISOs have undertaken major efforts to improve winter preparedness.

In addition, the Commission has continued to facilitate gas and electric industry coordination to improve fuel availability. Specifically, in Order Number 809, the Commission revised its regulations to better coordinate the scheduling of wholesale natural gas and electricity markets in light of increased reliance on natural gas for electricity generation and to provide additional scheduling flexibility to all shippers on interstate natural gas pipelines, with the goal of improving generators' access to fuel during extreme weather events.

As of this June, the Commission has approved the compliance filings that all six RTOs and ISOs made to comply with Order Number 809. We have also heard through our monitoring efforts in the RTOs and ISOs that general operational preparedness and winter preparedness in particular continues to improve. With the passage of time since the polar vortex, we must not lose sight of the potential for future significant operational challenges to arise due to unusually severe and/or sustained winter weather events. We must continue to do all that is possible to be prepared to respond to them.

Moreover, the past year has seen new operational challenges as well, such as the Aliso Canyon natural gas storage facility leak in California. These new challenges further highlight the ongoing need for us to monitor our preparedness efforts.

With that in mind, I look forward to hearing from you about how each of your regions is preparing for this upcoming winter, as well as an opportunity for some dialogue and exchange of ideas. Please help us understand what you've done since last year's panel to prepare for this coming winter season and whether there are any further efforts or new initiatives that you will undertake to improve winter preparedness beyond this winter. Any thoughts as to how the Commission can assist your efforts are especially welcome.

With that, I look forward to what I'm sure will be an informative presentation.

Colleagues, if you have any other opening remarks.

COMMISSIONER LA FLEUR: I will save my time for questions.

COMMISSIONER HONORABLE: Same.

CHAIRMAN BAY: Please proceed.

MR. BRANDIEN: Good morning, Chairman Bay and Commissioner Honorable, Commissioner LaFleur. I provided written comments that were responsive, I believe, to all the questions that the Commission asked us to discuss here today. I think I'm in the minority, maybe the only one who will not make a PowerPoint presentation here this morning.

As you probably will hear from others as we go down through the panel, ISO New England does a number of activities to prepare for the winter. We're in the height of our transmission and generator maintenance in New England. We generally start that about the middle of September. We try to wrap up most of that by Thanksgiving, definitely by the beginning of December. And we have peaked in New England early December with cold weather. So we try to have all that wrapped up.

We also review and test all our operating procedures, particularly emergency procedures. We actually perform a voltage reduction test, which is one of the steps in our capacity deficiency, and we do that so that we have a good handle on what kind of load relief we get from a voltage reduction. And on a monthly basis, we will simulate our load-shedding procedures with our other transmission operators within New England.

We also, through the NPCC task force, have coordinated operations. We do a lot of discussion, share information with the other reliability coordinators in the Northeast, let them know where we stand, what our concerns are. We hear from them, and we are aware of what we would each need to do to assist each other if we get into tight winter conditions.

I believe either today or tomorrow NERC is doing a Webinar on winter preparedness. And we actually follow that up with our own generator winter preparedness readiness Webinar. And I believe that for us is next Thursday. What we will do with that Webinar is we will discuss the situation with all the generators in our footprint. We will share with them our emergency procedures, our outlook, what our expectations are of them. We will discuss the winter reliability program that the Commission approved last year for three winters until our pay for performance capacity rules go into place.

As a part of that program, there is an opportunity for them to commission dual fuel units. We actually test the ability of our dual fuel units to switch fuel, and we perform that test prior to December 1st.

That's an actual test where we learn a lot from the generators, what it takes for them to actually switch fuels. So do they have to come offline, switch fuels, how long do they have to be offline before they come back online, do they go back to minimum and come back up.

And the dual fuel units we're testing are not the old fossil steam units that historically are oil burners that have, through economics they ability to burn gas, but it's more the combined cycle turbine units that have the ability to switch fuel. So we want to make sure that those units have the ability and that we understand so that we can plan it into the operations if, for some reason, during the day the gas got tight and we had to coordinate the switching of fuels for generators. So we will have all that information at our fingertips.

Historically, cold weather has not been an issue from a equipment perspective. We have had units that maybe have been offline or coming online for the first time in cold weather, and maybe they have a cold weather problem, but they generally get online during that day.

As far as transmission equipment, maybe we will get some low gas pressure issues, but they charge the breaker. So cold weather equipment has not been an issue. It's really all about do we have the fuel to operate the generators.

And with that, we haven't put any new market rules in place for this year, but over the last number of years, we tightened our rules around shortage events. We did pricing of supplemental reserves, if we bring on additional reserves because we're concerned about it. We want to make sure we are not depressing the price, we actually price those supplemental commitments. We've increased our reserve pricing. We've moved our day-ahead closing. We've implemented intraday offers so that generators could actually update their offers into our market.

And last year, we implemented the coordinated transaction schedule with New York where we can actually change the interface on a 15-minute, and that was in place last year, and we believe that that will pay dividends if we get tight during the winter because of fuel prices spiking. And of course, we've got the pending pay for performance rules going in place.

New England, we're not seeing load growth. We're actually seeing flat, if not declining, peak load, and there's not a lot of difference between our 50/50 normal forecast and our 90/10 in New England. The issue is, as the temperature goes down, the fuels, the gases that's available to generators gets less and less, and actually, the gas LDC load takes off.

And that's where the LNG injections into the regions are very important. We actually follow those, and I've talked to the Commission about how extensive we are in monitoring LNG at both Canaport and at District Gas in Everett, Massachusetts. And also, the last two winters we had to ship at Bowie and the hub line around Boston that injected gas into the system. And we're hoping we see that happen again this year.

So LNG is critical to our operations.

The winter reliability program, October 1st was the date that the generators or people that wanted to participate in the demand response had to let us know that they were interested in participating. And we got pretty much the same volumes that we had a year ago, a little bit more oil, a little bit less LNG demand response, about the same place.

The other thing to benefit us this year is a pipeline expansion project is supposed to go into service at the very beginning of November. That's about 340,000 dekatherms a day. I use a thumb rule of about 100,000 for about 500 megawatts of generation. So you can see that's the equivalent of about 1,500 megawatts of generation. More than that, actually, because it's 340.

Now, that's not all available for us to use, but it probably will take a while for the LDCs to grow into that expansion. It's not going to go from nothing to full utilization. For the next couple years, we'll probably take advantage of that additional expansion and have more gas available at colder temperatures as we go forward.

We have some units that have indicated that they're retired. We have those units this year. So this is probably going my last best winter between I have those units this year. These are nongas units, and I have the pipeline expansion. As long as the LNG continues to come to those three locations, I think we will be in pretty good shape to get through this winter. But it's all going to really depend on how cold the temperatures get and how much

LNG is injected into the system.

With that, that concludes my comments.

MR. YEOMANS: Okay. Good morning, and thank you for inviting the New York ISO to this panel discussion.

As IT brings the PowerPoint slides up, I'll make an opening remark. We're on the heels of a very mild winter. If everyone remembers, last winter was a mild winter in the Northeast and for New York State, and I think for most of the country. We did want to communicate to the Commission that we're giving winter preparedness the same level of passion and enthusiasm and heightened awareness as we have the last three or four years. So we're certainly not asleep at the wheel on the heal of a mild winter. We have very good memory and we have long memories of how cold and tight conditions can get.

This doesn't mean just in the fall getting ready for the winter. It's really every month that we talk about market design, every month that we talk about procedures and criterias and rules. It's every month that we're talking about getting the signals right, that we're talking about winter preparedness in our designs, in our processes and procedures.

To talk about last winter a little bit, it was winter of 2016, which was last winter, was milder than the past two winters and milder than the 10-year and 30-year averages, again, specific to New York, but I believe for most of the country that's true. But we all have good memories. The winter before that was long and cold with February being especially very, very, very cold and snowy in New York State. And then the winter before that was the winter of polar vortex in January where not only was it very cold but it was cold for 7 to 10 days at the end of January and fuel inventories did become tight. For last winter, generation and transmission performance was good across the winter. Fuel inventories were maintained, and gas infrastructure performance was good. No need for out-of-merit generation commitments, very low number of generator derates last winter, which kind of makes sense in a mild winter, and no need to activate demand response resources.

I will point out that February 12th to the 15th, a three-day weekend, in 2016, so just last February, as mild as it was, was our second coldest weekend in New York in 45 years. So it does go to show, you can have 30 or 60 mild days, but you can have three brutally cold days sneak up on you. So you need to be alert and prepared at all time, and in that time period New York State did set an all-time gas throughput record of 6.6 billion cubic feet per day on February 13th. That includes, of course, the LDC retail load usage and the gas-fired generation that was able to get gas what they used. But we did set a gas throughput record on that weekend.

On the next slide is our projected baseline forecast for peak conditions and expected performance of transmission generation and pipeline. And by expected performance of transmission, we really do assume the transmission is going to be in all the in service. We're not going to go off and schedule maintenance during the month of January. Generally, the same assumptions for the gas pipeline infrastructure.

On the generation side, we do reflect on historical forced outage rates and then try to reflect that in our capacity numbers. But having said that, if you look at the table, in the top left would be our base case normal weather, so 50/50 peak conditions for an expected cold January day. And if we look at that load forecast against our capacity resources -- and we are a somewhat peaking entity. So we tend to be long on capacity in the wintertime. Our projected margins for a certain set of assumed forced outages would be about 9,430 megawatts. So we kind of start out on paper in pretty good shape.

The bottom two rows are our view of bottled transmission, whether it's the lower Hudson Valley or New York City area. And when we draw those circles and do that math reflecting on the transmission capability, we have surplus projected margin.

And as you move across the right on the first row, if we say what are 90 percent very brutal cold conditions. So 90 percent would be once-in-a-decade-type cold snap conditions. Really, the load doesn't move a lot. Our load is really a commercial industrial load, it's lighting load, but it doesn't move a lot with temperature. The availability of fuel can be more difficult with colder conditions.

But the actual electric peak only moves about 1600 megawatts, if you move from 50/50 conditions to once in a decade type cold snap conditions. And then as you move right, we do do a stress case where we say what if New York State can't get gas to the generators, and we subtract out the gas only fired units or dual fuel units where we know they don't have oil, and that's about 4,000 megawatts. But said differently, even though we have a large part of the portfolio that burns gas, a large subset of that does have dual fuel capability. We don't subtract it out here, and that's how we get by when we have trouble getting gas. We do have in the portfolio a large amount of dual fuel units.

The next slide, seasonal generator fuel surveys, we do do this, and that is indicated sufficient setting, winter stating oil inventories along with arrangements for replacement fuel oil for oil-burning units. The business strategy for most generators that burn oil is to not buy and hold a lot in starting inventory but to make replacement arrangements with railroad or barges on the Hudson River to be able to replace their oil.

But it's cost-effective to plan on just replacing it rather than purchasing a huge amount of inventory and just sitting on all that oil or, quite frankly, all that money. But that has seemed to work for the last three or four years. Three of the units do start out with a lot of oil, but most of the strategies are for replacement capability.

Our market mitigation analysis group has performed a on-site visit of generating stations to discuss past winter operations, preparedness for the winter. This is a review of maintenance records and a discussion of what forced outages did you have and what have you done to prepare to prevent those force outages with cold weather conditions going forward.

And then the last bullet, for New York State, we have a New York State Reliability Council that sets some of our rules above and beyond NPCC and NERC, and we have min oil burn procedures as a result of those rules for the generators in New York City and Long Island referred to as IR 3 and IR 5 and this established fuel switching at certain cold weather conditions to mitigate pipeline contingency.

So to be clear, these are not rules dictating a certain amount of dual fuel. These are rules saying for the dual fuel units that New York City and Long Island have, as the pipeline conditions become tighter and tighter and tighter and tighter, one of the gas pipeline contingencies that would result in a loss of generation that might turn into load shedding. And rather than crossing those thresholds, just switch to oil ahead of time on a proactive basis to be prepared for that large gas contingency.

Our next slide, for situational awareness, we do have a control room gas/electric support in our control room for winter conditions. This is some staff we've hired from the gas industry and from the gas marketing industry to help us understand the gas commercial dynamics. The Northeast interstate pipeline system is displayed on our large operating video board. So it is, I think some of you have seen in our gallery, we have a very large electric video board.

Off to the left, we have a large display of the gas system. And we enhance the lighting of those pipes when they are in OFOs to bring that awareness to our operators. And we have a Web-based fuel survey portal which provides generator fuel information to the operators.

Each week the generators update their gas nominations or their capacity releases. But more important is the fuel, what is their oil inventory, and if it's running low, when do they expect a replacement. But all of that information is being entered weekly to generators and provided to our operators. This is updated daily during cold winter conditions. This is a tremendous improvement from an operator awareness perspective for our operators.

The next slide, gas electric communications. I actually have three categories. One is a state communication with state government, communications protocols in place with New York State agencies, which include the New York PSC, which is really Department of Public Service, the New York DEC, and the New York SERDA agencies. This is to improve the speed and efficiency of generating requests to the state agencies for a mission waivers, if needed, for reliability.

And quite frankly, this is a weekly dashboard or a daily dashboard during cold weather conditions issued by the New York ISO indicating fuel and capacity margin status. It's actually very simple. If we have sufficient capacity for the week and sufficient fuel, the dashboard is green, and everybody just loves to see green. If we're either -- if we think we're projected to be short of capacity but there's plenty of fuel, we issue yellow. If we think we're short of fuel on one generator but we're long on capacity, well, then, we issue yellow to the states. But then if we're short of both, if we're projecting a shortage of operating capacity and fuel at one or more generators, then the dashboard is red, and we indicate that we provide that to the state agency to put them on awareness that they might receive a request from a generator to request an emissions waiver or they might not. And it doesn't mean they have to grant it, but it's just our way of communicating the height and awareness of the situation with generators, fuel, and our electric operating capacity.

Second is an emergency communication protocol put in place to communicate electric reliability concerns to pipelines and gas LDCs during, quite frankly, very tight electric operating conditions. This would be for significant load shedding. We have a process to go back to the pipelines to let them know to see if there's any way to come up with additional balancing or penalty service to help a generator that's otherwise trying to maintain their gas schedule. And all of that is within the gas tariffs, of course.

And then the last one, FERC Order 787, the ISO modified its code of conduct per the FERC Order 787 to accommodate pipeline requests for reliability information when they're short -- or when conditions are tight on the gas side.

On the subject of market enhancements, I was going to say nothing new and I was going to repeat last year, but Peter reminds me of the 15 minute scheduling with New England, so I will say that verbally. But to start with, in November of 2015, going into last winter -- and this was a significant enhancement. We really did enhance the shortage pricing to increase incentives for generators to secure sufficient fuel to meet day-ahead. Simply put we always had reserve shortage curves. We just heightened those to be at higher prices. So when we are short of reserve, we better value energy, and it makes it affordable for a generator to spend more money to purchase fuel to prevent this from happening.

Coincident with that but different is we increased the total amount of operating reserves procured in our markets from 1965 megawatts to 2620, and that's total operating reserves, in the day-ahead market and the realtime dispatch so that the NPCC operating requirements 1965, but we made the decision to purchase and secure and schedule and pay for up to 2620, and that just provides the money for generators to buy more fuel to provide reserves if we're short of reserves otherwise.

And then FERC Order 809, the ISO market has been closing at 5:00 a.m., posting from 9:30 to 10:00, and we made the decision that we didn't think we needed to advance that market timing, because, quite frankly, we're issuing generator schedules at 9:30 on a day-ahead basis, and they have fluff time to go procure natural gas by the 2:00 deadline in the gas industry.

And then June, we change enhanced scarcity pricing for the demand response to better reflect what the pricing is going into a demand response. And Peter reminds me, it's not on my slide. The 15 minute scheduling is very helpful. If either side loses a unit, rather than waiting an hour and a half for the market system to look at prices or reschedule energy to address either reserve shortage, by doing this every 15 minutes, you greatly advance the market's ability to solve the reserve shortage on either side. So that's a fantastic improvement.

And then the last slide are the issues, the continued issues are very real. If you think about gas fundamentals, there's so much gas and it's so inexpensive compared to our other generating fuel types that they're just going to be continued forces in the market for nongas units to exit and retire and not be profitable, and the fundamentals are going to continue to be more gas units coming online and likely more nongas units leaving the market. So the issues are very real and continuing.

From a gas availability perspective, it continues to be a fact, at least in New York, that gas LDC retail load has gas transportation priority over electric power generation during cold winter conditions.

Now, that's not the case on interstates. Firm is firm and interruptible is interruptible, and one firm customer is the same as another. But on the LDCs, a firm retail customer has priority over a generator, period, and that just remains a fact. There's nothing wrong with that. We don't want to be shutting off customers that heat their homes with gas. So there's nothing wrong with this, but we need to recognize this as a factor as we think about the future.

The next issue is always the extended cold weather condition. I always say if every cold snap was one day, that wouldn't be a big deal. But it's when they're seven days long, 10 days long, 13 days long. The burn rate of oil can be higher than the replacement rate, and you get your place where in day 10 to 13 you start to run out of oil.

NOx restrictions exist today and are becoming stronger. So for a generator switching from gas to oil, in some instances, resulting capacity limitations due to newer, tougher, more restrictive NOx limitations, we do try to track that. It's not really our expertise, but we're trying to learn that business, understand where they are. We're trying to proactively try to anticipate where we might get a capacity derate as a result of NOx restrictions. Having said that, the generators do an excellent job communicating their derates or projected derates to us so we can operate the electric system.

And then emissions to dual fuel burning oil may have further restricted by reduced NOx emission limits, less Northeast refinery capability or potential reduced carbon emissions. And certainly, the last one, new gas line pipeline siting, remains a challenge. It's always been a challenge, and it seems to be becoming more of a challenge in the Northeast than it ever was.

That concludes New York.

CHAIRMAN BAY: Thank you, Wes.

Michael?

MR. BRYSON: Good morning, Commissioner bay, Commissioner LaFleur, Commissioner Honorable. Thanks for inviting PJM. I will get right to it. So from a polar vortex, just to go back a little bit, we did a significant event analysis on the polar vortex a couple of years ago. A couple key recommendations, one was a capacity performance to improve generator availability. Another one was we implemented a testing for generation in advance of winter operations, recognized that improved natural gas, electricity market alignment, and implementing the market incentives for ensuring dual fuel capability, which was also really tied to capacity performance.

In terms of what we've done since then, we did implement capacity performance. That actually went live on June 1st. So it was in place for this past summer. While we had some pretty decent loads during the summer, we had no penalty hours this summer. In fact, we had no emergency procedures this summer, which I think, in some ways, is indicative of the attention that capacity performance got for our generation and resource fleet.

We also have some significant gas/electric coordination, and I will touch on that in a little bit. A lot of new generator requirements in addition to the capacity performance, the testing program, the winter preparation training that we do, and we also included a winter checklist a couple years ago that we continue to enhance with the generators. And then a number of tools that we actually put in place as well, and I will touch on them.

Capacity performance, as I said, implemented this past summer. Penalties essentially are assessed during emergency operations, if you don't perform to the level that you're committed to.

In preparing for that, particularly for the summer, a significant amount of operator or member training. We conducted drills with generators, and we're going to be refreshing those drills going into the winter season as well. In fact, in November will be our winter emergency procedures drill.

We implemented a unit-specific parameters as a part of that, and essentially what that means is if we go into our hot weather or cold weather periods -- and we had a number of them this past summer -- that we -- that the RTO basically can commit the units on the most flexible capabilities of those units.

And then a number of tool implementations that we put in place just to help with capacity performance, largely in the areas of just really enhancing communications to our generation resources and our regulators in terms of where we were in emergency hours. And we're currently just taking a look at the summer in terms of if we had had capacity performance hours implemented, where were generators in terms of performance and how it would look just to give them a bit of a feedback loop.

In terms of gas/electric coordination, we've done a number of things, and this is one of those things that we continue to improve upon. One of the things that we did is probably one of the more important things is we made a strategic hire, hiring somebody from the gas industry to come in, I mean, frankly, it's very helpful to us, because he speaks gas, and we don't. So it's amazing, while we knew he was going to be a good hire, he has provided a lot of insight into just the way the gas pipelines and the LDCs think, and I think it forces us to kind of rethink our approach in some things.

The PJM team, he's now in charge of the team, continues to improve our processes. We actually kick that off on November 1st where they meet every day, provide feedback directly to the dispatchers on where the pipelines are, where we are, you know, where the stress points are between the two.

We've done a lot of outreach, and I think we've been very successful with the interstate pipelines. We have the MOU. We've moved our electric day to align that a little bit our day-ahead market. We're still working on the LDCs. They tend to be a little bit harder to communicate with, but we're being very aggressive with them, and it's -- a lot of, I think, the challenge with them, number one, is there's so many, and the regulatory structure is a little bit different. Their confidentiality things are a little bit different. For us, it's 35 one-offs. Whereas, when we got the FERC interstate pipeline relationship, that was a lot easier, because it was one regulatory relationship. The day-ahead market we adjusted back on April 1st. So that timing has helped.

The next thing that we've been doing, and it's a week-to-week thing, is trying to reduce the amount of time to solve the day-ahead market, because our generators have told us that, frankly, gives them a lot more ability to look at what's available from a pipeline basis as well. We improved our reserve tools in the control room. So this is the ability for our dispatchers to go out and look at what's available from a fuel basis, from a reserve basis, on an hour-to-hour basis, and that's been a big help.

One of the things that I noted with interest was the Chairman's letter to NAESB to talk about gas/electric coordination because I think while we have made a lot of progress with gas/electric coordination, I think there's more we can do, both in terms of all of our individual relationships with the pipelines and just as two industries working together. We have an MOU with our pipelines. We continue to work on that. We will be meeting with all our pipelines here in November as well. But one of the things as we work with the pipelines, we've recognized that we have a lot of data available. And I think part of the success of that is the pipelines are now asking us for data. They're asking us for readiness and emergency procedures and a lot of those kind of things and what it means and what unit behaviors look like in different scenarios.

So one of the things we've set a goal is we're actually going to set up a gas page on a PJM where the pipelines can go and look at PJM's information, and it's designed just for them.

One of the things, as I look at this, our forecast for the winter 2016-2017. Our load forecast, again, we still look at a load forecast of just under 136,000 megawatts. And we know in 2015 we had a peak of 143,000 that was closer to 90/10, so we can still see that. That looks at us importing about 5,000 megawatts. Our installed capacity is still over 180,000 megawatts. So we're in pretty good shape there from a serve margin, and we're still studying generation outages.

One of the things that we did have happen going into this past summer is a Texas Eastern pipeline in Pennsylvania, up in the Pittsburgh/New Jersey area. I think that was a good -- while we didn't have any effects during any of our emergency hours this summer because that tends to be -- gas tends to be more of a winter critical thing for us, what we find in the summertime is that we're filling storage on the pipeline, so that's a priority for them. Sometimes that can cause some interruptions. But it tends to be more economic issues than really emergency issues.

But this -- if this had happened in the winter, we recognize that this would have caused some problems.

So one of the things we did here is we actually put some processes in place in our system planning and our operations to look at contingencies like this, set up contingencies that if you have a rupture. Those are not contingencies that we would normally run in day-ahead or realtime, because you really need to have some break out there like this to be able to do it. But I think it kind of inspired a process with us.

As we look at this particular issue, they are on track to finish their repairs and inspections by November 9th. So I think we're going to be in good -- the update we had this morning was instead of November 1st it will be November 9. So we will be in a good spot for this winter.

The last thing I just wanted to talk about, there's a number of projects across the system. In this particular case, we looked at what the options were going into the winter, and there's a lot of midstream pipeline projects all over the place that can help our generators, both in terms of capacity performance and winter reliability operations have more options, either dual fuel, oil, local natural gas, natural gas storage, or dual pipeline connections, and projects like this help.

That concludes my comments. Thanks.

CHAIRMAN BAY: Thank you, Michael.

Todd?

MR. RAMEY: Thank you.

Good morning, Chairman Bay, Commissioners Honorable and LaFleur. It's nice to be back with you here again. I do have some slides here.

Looking at a high-level overview looking toward the winter, we are currently projecting to have adequate reserves to meet the requirements this winter. But in addition to that, we think that the adequate readiness activities that we put in a few years ago that continue through our preparations for operations this winter, in addition to a sufficient set of control room operating processes and procedures, including coordination with our own members and our neighbors and gas pipeline operators position the footprint well for reliable operations this winter.

Just looking at some forecasts, our 50/50 load forecast for the winter is about 104 gigawatts. This compares to our actual peak during the polar vortex, January of 2014, and 109.3 gigawatts, and that kind of represents a 90/10 scenario in terms of peak load planning.

So even though our part of the interconnect, our part of the country is blessed with a very robust gas pipeline infrastructure system, gas electric coordination activities continues to be of importance for the MISO footprint.

A couple of reasons for that. The charts on the left show that we are becoming more and more dependent on gas as a generation fuel for MISO. In 2014, 18 percent of our requirement was supplied by gas-fired generation, and this year, that's ramped up to 28 percent. That's driven by a low fuel cost of gas, as well as coal plant retirements and some coal to gas switching. The footprint is becoming more dependent on gas. So we continue to work on those activities in coordination with the gas pipe operators in the footprint.

So in terms of the nature of those activities to drive those enhancements forward, it includes communication protocols and information sharing with pipe operators. It includes a -- produce significant dialogue with the gas-fired plant operators in our footprint so that MISO's control room operations team has as clear a picture as we can about fuel security around natural gas on those cold winter days on our part of the footprint.

I mentioned we had a pretty robust pipeline system, and that's good, but there are, in fact, some generation in our footprint that is connected to some pretty tight pipes, and both the polar vortex winter and the following winter we saw about 5,000, 6,000 megawatts of gas-fired generation that is susceptible to some level of curtailments on those coldest winter days.

So having complete information and awareness of the state of fuel supply, even for 5- or 6,000 megawatts of generation is important on those cold days.

So I wanted to share a little information about some interesting or unique operating challenges that cold weather operation presents. And I think I provided this chart last year. It compares a typical day load shape for a summer day shown there on the left compared to the load shape that we see on those coldest winter days.

If you look at the summer load curve -- and the blue line there going parallel with the load pickup that's about a 3- to 4,000 megawatt an hour pickup in the summertime. Generally speaking, compared to the winter that pickup happens later in the day.

In the summertime, we don't have the competition from space heating for natural gas. So we are pretty reliable in managing the unit commitment and the unit dispatch required to meet those ramp requirements in the summertime. Slower ramp pickup lasts a longer time, leads to higher overall peaks. But from a control room perspective, in coordination with the generation footprint, it's a reasonably straightforward process.

Compare that to the shape shown there on the right of the winter pattern, starting there at about 4:00 a.m., there is a more severe ramp load pickup that lasts for four to five hours. So the pickup from 4:00 a.m. to 8:00 to 9:00 a.m. is in the neighborhood of 4- to 5,000 megawatts per hour, again creates a pretty significant coordination challenge of coordinating and staging the unit commitments required to pick up that load, as well as the deployments.

So that's the period of time that we are most interested in the control room as we're preparing for operational readiness for a given day, really focused on the availability of the gas-fired fleet at 2:00, 3:00, 4:00 in the morning. Oftentimes, on those units that I mentioned that do have some tight pipe connections, they don't have good visibility often until that time frame early in the morning what their availability is. So us having awareness of what the status of those units and their ability to get gas helps us handicap, if you will, the availability of those units. To date, with the reserve margins we have in place, we've got other alternatives that we can go to and implement some more conservative operating procedures to make sure we can stay on top of those.

So a question about improvements that we put in place since last winter. One of the significant improvements we've had now that's very much related to this ramp issue is that we've integrated a ramp ancillary service product into our market design. And so the operational challenge I described just now also can lead to market challenges if the unit performance of commitment dispatch, which can be challenged during cold weather operations hits the control room, it can also manifest into some market disturbances, particularly when you get close or tight on required ramp to keep picking up that load every five or 10 minutes.

So in the past, we've seen a physical shortage of uncommitted online rampable capacity. You need to keep moving up. And that also translates into some market spikes. For our market design, with our five-minute dispatch, you can see ramp shortages translating into very high price spikes that may last only five or 10 minutes or so.

So as we analyze that, we thought for our market that it made sense to introduce this ramp product. Essentially, again, it's a new reserve product that is looking out at ramp requirements over the next 5 to 10-minute time frame. And as the unit dispatch optimized solution of deployment of capacity for energy and ancillary services is solving, it's also making a check to ensure there is sufficient ramp to meet both the forecasted ramp requirement, the load delta over a five or 10 minute period, as well as sufficient ramp to meet some uncertainties in that time frame. So we found that to be a significant enhancement, both in our market design, as well as supporting the control room's need to make sure we have availability of sufficient ramp as we're moving through those large pickup areas.

It's been fully integrated into all of our market and operations process, beginning with the day-ahead market, all the way through reliability commitment processes, and even into our very short-term look-ahead dispatch and the dispatch processes.

More detail on-ramp. I will let you study that so you can get back to me with any questions you have. Anyhow, essentially, it kind of graphically is showing what I described. It's integrating into the optimization to ensure that there's enough ramp on the system to meet future dispatch needs, both known and unknown, five to 10 minutes in the future.

And it is market products. So when ramp is short, it will bind, create a shadow price and a market price for reserves. It will have the effect of slightly raising prices in the current interval to get higher cost units that may have slower ramp rates moving in anticipation of needing to have sufficient ramp five or 10 minutes from now. So it's a market-based product that provides transparency and information to the market about the value of the ramp during those periods.

So at the conclusion of the polar vortex winter, we also went through a detailed event analysis, both internally with our stakeholders and we identified 17 discrete issues or areas for improvement as a result of that review, covering areas such as coordination with gas pipeline operators, enhanced coordination needs with our neighbors was important as well. We identified some market enhancement areas for improvement and also control room process procedure improvements.

17 discrete items were identified. Of those 17, I think 14 are fully in place now, but we continue to make enhancements and identify improvements. And here are four things that are available to us as we head into this winter that I didn't have at this time last year.

The first is the conclusion of our discussions with SPP about the utilization of the transfer corridor between our Midwest portion of our footprint and the southern portion of our footprint. Last winter, we were operating with transfer limits of 1,000 megawatts in each direction.

As a part of those agreements, we both enhanced our coordination protocols to make sure that there's good coordination, not just between SPP and MISO, but other transmission operators in that part of the country as well. And parties are comfortable that MISO can increase those transfers above that 1,000-megawatt limit to mean between 2,500 and 3,000 megawatts now. So that provides us a little bit more flexibility, but even with that additional transfer capability, the added coordination, and with Bruce's team and other transmission operators, it makes us comfortable that that's an increased transfer amount that can be well managed amongst all the parties.

I mentioned the ramp product. Emergency pricing. We also made some price performance enhancement improvements this year associated with pricing during next generation emergency conditions. There are steps that can occur during next generation events that release emergency-only capacity or the deployment of demand response that prior to this enhancement and price formation could have led to counterintuitive price reversals. So should we get into high-load conditions, tight generation conditions, we should expect better pricing performance this winter as compared to prior years.

And the last item there I wanted to mention was FERC Order 809. We are planning in November to implement changes to the schedule of our day-ahead market. We are moving back the closing of our day-ahead market a half hour compared to today, but concurrent with that, we're also reducing our day-ahead clearing window from four hours to three hours. So generators will receive their day-ahead commitment and energy schedules an hour and a half earlier starting next month than they have to this point. So that will enhance their ability to make sure they can schedule sufficient gas for operations the next day.

So I mentioned 17 items, areas for enhancement. This chart shows several of those that were put in place. So this kind of represents a timeline of readiness activities that occur through time to ensure that on any given winter day we're fully prepared to meet the requirements of that day, regardless of gas situation or loads and availability of generation. It starts in the planning time frame with our transmission planners for sure. Some of the areas that had been enhanced over recent years as a result of the polar vortex experience include items under the annual review there.

We've added a winter readiness workshop where we get together with pipe operators in the footprint and our stakeholders and certainly go over information activities, emergency operating procedures in advance of tight winter season operations. We've implemented an annual fuel survey where we engage our gas generation asset owners and giving MISO some information, a lot more information than we used to get about the details of their gas pipeline contracts and scheduling, again in support of overall situational awareness for my operators in MISO.

Winterization is a hot topic. Again, not taking our eye off the ball. As Wes said, given that it was a relatively mild winter last winter. We have both training awareness Webinars and discussions with stakeholders, and MISO certainly provides a lot of advocacy to our asset owners to make sure that they're moving forward with their responsibilities to get their plants and units ready for cold winter operations.

With that, I think I'll stop and wait for the discussion. Thank you.

CHAIRMAN BAY: Thank you, Todd.

Bruce?

MR. REW: Good morning, Chairman Bay, Commissioners LaFleur and Honorable. SPP appreciates the opportunity to come talk about our winter preparedness. I do thank you for mentioning the 75th anniversary. It's something SPP is very proud of.

And Commissioner Honorable, thank you for coming to Little Rock next week. We look forward to seeing you back home.

This slide just lists the items that I am going to cover. Let me start by talking about SPP's footprint.

Last October, we expanded our footprint, adding an integrated system, which is essentially everything north of Nebraska. From our previous footprint, we now go from Texas to Canada. And one of the things that we learned is that winter occurs sooner in North Dakota than it does in Texas. Last year, we had our winter preparedness workshop in December, and this year, we saw the need to move that up to September.

So let me talk about the things that we covered in our winter preparedness workshop. It was hosted on our campus September 13th, and it was attended by numerous stakeholders, both in person and via teleconference. We also had vendors and neighboring systems like MISO was present as well. We appreciate them attending.

So first off, if you look at the anticipated weather outlook for the next winter, we do expect it to be a little bit colder and a little bit higher load than we experienced last year. The forecasted peak is about 38,000 megawatts, which is above last year's peak of 37,400. So it will be a little bit colder, at least that's what we're planning for.

Overall, the system is expected to be ready to go for the winter. We do have significant outages in place now. Of course, it's our major outage season, but we expect anything major to be back in place by December in plenty of time for the peak winter months.

Maybe I will just mention a couple things. We have one small nuclear unit that will be shutting down January 1st, but we don't anticipate that causing us any problems.

I do want to mention one significant event from the 2015-2016 season that we learned and during the Thanksgiving weekend, we experienced a situation where the wind output was 3,000 megawatts less than forecast. It was a significantly lower end. What happened is an icing event occurred over our primary wind area. So the wind farms shut down for safety reasons because they had icing on them. So what we did immediately, we recognized we needed to have better enhancements of potential icing situations in our forecasting. So we were able to incorporate some of those tools immediately, and we are looking at an enhanced tool for our reliability studies that will go in place by November. So that will be our full inclusion of that potential icing and it did actually help us in January. We had a much smaller event occur in a different area of our footprint, and we were able to forecast the icing that did occur on wind farms. We had plenty of generation to prepare for that.

One thing I do want to mention, too, if you look at the polar vortex was several years ago. But the wind generation that we have now is about double what we had from back then. So we're up to almost 16,000 megawatts of wind in our system. In the April time frame, we hit a peak of 50 percent penetration. I'm anticipating us to hit that during the winter now, and probably next April we should be at 60 percent or greater wind penetration. So we have a significant amount of wind, and that is certainly a key for operations that we continue to look at and ensure that we're ready for anything that occurs with those units.

So a couple of specific things that I want to talk about for our ongoing challenges to the footprint. One is we do identify some must fund resources in North Dakota, in the Williston load pocket. But we do anticipate new transmission coming online that will help that, but just in case there's some delay in the transmission, we are prepared to operate through that if there is a delay.

We continue to increase our higher gas usage. Our coal right now is less than 50 percent of our resources where just a few years ago it was 60 percent. So we continue to move -- or trend down in our coal usage and increasing our usage in gas and, of course, the wind.

As I mentioned, we had a significant amount of wind increase in our footprint. So we continue to look at how we can manage that. Our forecasting continues to improve, and we are very dependent on that. But I think from a situational awareness, we're very confident in what our wind forecasting does and how we can manage that.

I do want to mention that we did change our gas timeline -- excuse me, our day-ahead market timeline to meet the gas order, and that occurred on October 1st. We went from our day-ahead market closing at 11:00 in the morning to 9:30 in the morning, and we also shortened up our day-ahead market calculation time by half an hour. This slide just shows you the before and the after timeline starting on October 1st.

So a couple of enhancements to recognize that we've put in place since last winter. The first one is our realtime must offer requirement allows us to ensure that we have fuel for the units that are participating. Secondly, in March of this year, we added what we call a short-term reliability unit commitment. And this allows us to do a very quick 15-minute study intervals in our reliability unit commitment process, and it really gives our operators another tool to be able to commit units in the short term to address any changes on the system that they might see.

We also extended our day-ahead reliability unit commitment window to include a broader study period, and this provides us what we think is a more accurate assessment and needs for the reliability of the system.

And we have improved the market clearing engine software time, and that increases our performance and ability to use that.

So one of the important procedures as well is what we do to train the operators to prepare them for a significant event like a polar vortex. And we enhanced our procedures to capture severe weather events, any fuel limitations, awareness. We have close coordination with the gas pipelines in our footprint. So we will communicate with them when we see issues and vice versa, if they see any concerns, they're communicating with us as soon as they see that. This allows both of us to prepare for anything that may occur within our footprint. We are similar to MISO in that we have a lot of gas wells in our area, a lot of gas pipelines. But that close coordination is still very important to us.

Should we get to a severe event, we also make sure that our operators are prepared to manage it, if it's as severe as a load-shedding event.

One one thing we're also proud of is that we've enhanced the operator training facilities. We've recently renovated our training room. This has improved the operators' training experience, and we feel like it's much more successful in providing and delivering that and using an advanced simulator above what we were doing, which gives them a greater situational awareness and preparation for things that might occur on the system.

The last thing I want to mention is just from an operations center perspective. We have enhanced our situational awareness and put in what's called a Macomber Map. And this is a map that provides detail with respect to the weather and the operating system so that we can closely monitor any weather systems that are coming in and overlay it right on top of the transmission grid.

So it allows the operators to see exactly where potential conditions are occurring, and they can have better visibility. They can also go in very quickly into the system and identify anything that might be in the area. For example, if a weather alert comes up, it can take them right to that area, and they can look at any potential problems in that area that's identified through the weather alert. So that situational awareness has helped the operators improve their ability to respond quickly and reliably.

And that completes my presentation. I look forward to questions.

CHAIRMAN BAY: Thank you, Bruce.

Nancy?

MS. TRAWEEK: Good morning, Chairman Bay, Commissioner LaFleur, and Commissioner Honorable. Thank you for inviting me and the ISO to FERC today to present our preparedness for winter. California is actually a summer peaking balancing authority. That doesn't mean we don't prepare for winter. We typically have mild temperatures. But I did want to share with you a couple NOAA maps that kind of show at least currently today where we think California is headed for the winter. The image on the left is showing the temperatures above normal or the prediction of temperature above normal. As you can see, the orange as it gets darker predicts that the temperatures will be above normal as we get closer into central Southern California and all the way down to the Arizona border.

The map on the left is showing precipitation, and "EC" means equal chances, which is equal chances of you're going to have more rain as you're going to have less rain. So we do anticipate that we will have a mild winter. We don't really know what our rain condition yet will be. We do know, though, we're still in severe drought in central California and drought conditions in Southern California. And fire threats are a consistent concern for us. They used to be only a summer concern, and they have now turned into just an all-around yearly concern. So we're always monitoring fire threats and preparing for the possibility of outages due to fires.

As far as winter preparedness, we actually do an annual winter assessment, and that's coordinated with our participating transmission owners, our neighboring balancing authorities, and our reliability coordinator. We identify if we meet acceptable pre- and postcontingency criteria. We look at our system operating limits, make sure we're meeting those needs, as well as we're looking at new and retired facilities. We're getting, many, many new solar facilities and a few new wind facilities. We're also seeing a lot of gas facilities wanting to retire. So we're always monitoring that, not just in our annual assessments but throughout those notifications.

We also continue to coordinate with our gas partners. We coordinate on a daily basis, sometimes hourly basis with them, as well as we coordinate our outages, and they're coordinating their pipeline outages with our gas and generation outages. We try to coordinate those as much as possible, as well as try to look at the impacts of those outages on both of our systems, electric and gas reliability.

Aliso Canyon, as you had mentioned earlier, is really uncertain as to whether it will be available this winter. So we participated in a joint technical assessment this summer for winter impacts of electric generation, based off of gas curtailments. Because winter is our lower-demand season that allows us more flexibility to move our resources out of the SoCalGas area into other parts of our system, so that does provide us flexibility, and in our assessment, what we did was we studied what the lowest level of gas burden we can have precontingency and postcontingency. It's a very low number. It's not certainly an economic number. And it's going to be something we want to maintain for a significant amount of time. But we do know we can get to a very low gas burn if required.

Even though electric generation does use less gas during the winter in California, it still remains at risk, because electric generation is the first generation to come off if core demand is not met, and core demand is the peak for the gas company. So the gas company peaks in the winter, and the electric system peaks in the summer.

You might have all seen this map many times, but I wanted to point out here that even though in the summer we were really concerned about the L.A. Basin -- and of course we're still concerned about the L.A. Basin. But in the winter, actually all generation within Southern California Edison or Southern California gas system and the San Diego system could be at risk due to pipeline outages or just core demand use. So through the coordination that we've established between us, the ISO, SoCalGas, our adjacent BAs that were impacted, like LADWP, and our generation -- generator community as well as the policies approved by the FERC and CPUC were really helpful to allow us to mitigate this summer. We coordinated daily and ensured that we were meeting both not only the gas needs but the electric needs.

So we are anticipating that we will still have that same coordination effort all winter long as well. So that will be a good thing.

We also have a joint agency action plan that is currently being worked on to help mitigate any gas concerns over the winter season.

As far as new market products, we are implementing our flexible ramping product actually in the next couple of days. It's really important functionality for operations in general, because it will help ensure that we will have the capability needed and the availability of ramping in the 15-minute interval for the next five-minute interval. For operators, this is a good feeling when you know you're going to have your ramping capability to meet those variable resources, as they can go up and down by thousands of megawatts within a few minutes.

This will give us both upward and downward capability, and that's really key, that downward capability that we've been lacking. So we're very excited about that new aspect of our market.

And then lastly on this slide, I wanted to talk about on October 1st, we welcomed two new partners to our EIM, Puget Sound energy and Arizona Public Service. We're very excited about that. We're seeing transfers right from the get-go. We saw transfers. But there's quite a bit of transfer capability now around the west between the EIM entities as well as the ISO and EIM entities. It's working out really well. It's helping us provide regional diversity amongst the west and helping both -- all the balancing authorities in EIM, as well as help us manage our renewables so we can transfer energy back and forth as needed. It's exciting for operations. A lot of us have been there a very long time, and it's exciting to see that now others in the west are benefiting from, you know, energy markets in realtime in consolidated dispatch. So we're very excited about that.

With that, I will conclude my presentation.

CHAIRMAN BAY: Yes, congratulations on the expansion.

MS. TRAWEEK: Thank you.

CHAIRMAN BAY: So I want to thank all the panelists for these very interesting and informative presentations. It's clear that you've been hard at work getting ready for this upcoming winter, and I appreciate what you've been doing. I think this is another example of the benefits to consumers of living in a region served by an RTO/ISO. Across the RTOs/ISOs, it's helpful to see the many different approaches that you've implemented to deal with the challenges of serving load in the wintertime. And the approaches include market enhancements and new products, better operational procedures, more planning, preparation, training, and situational awareness, and better gas/electric coordination. So this is all, I think, good to see. And again, I think consumers benefit from the work that you're doing.

So I just have one or two quick questions. I think the meeting is going a bit long.

How would you assess, then, your overall comfort level going into the winter on behalf of your RTO/ISO?

MR. BRANDIEN: For New England, it really comes down to fuel inventories. We first look at our winter reliability program and have a good understanding of what kind of fuel inventories we have going into the winter, and then we monitor closely the LNG facilities. Is Canaport going to come in, you know, topped off at 10 Bcf. Last December, a ship showed up at the Bowie. That gave us some level of comfort that they were going to be there. And we have very good relationship with District Gas, and they let us know exactly what their inventory is and let us know what their schedule is for ships coming.

So really, it's maintain that awareness of fuel inventory and close relationship with the gas pipelines and understanding if they're having any issues. We exchange information back and forth with them. We communicate with them two, three, four times a day. So it's that level of knowledge.

CHAIRMAN BAY: Thanks, Peter.

Wes?

MR. YEOMANS: Yeah, just quickly. The performance of the infrastructure is very important. But for expected performance, our view is that we are comfortable that we will be able to meet reliability criteria throughout the winter.

CHAIRMAN BAY: Thank you.

Michael?

MR. BRYSON: From PJM's perspective, very high comfort level with the procedures, the market enhancements we put in place, the resource infrastructures. My biggest stay awake at night thing is the unknown about the weather.

CHAIRMAN BAY: Thank you, Michael.

Todd?

MR. RAMEY: Once a month, I meet with a board committee, our markets committee, and I always start off by saying I'm happy to report another month of reliable, efficient operations. I do that for a couple of reasons. One is to remind the board that our processes and tools and procedures are designed to provide that outcome over a variety of weather configurations, load levels, asset availability.

So on one hand, that's one point I want to make, and the other point I try to make is that we need to be vigilant because the future is certainly fraught with unknowns, and you're always given the opportunity to learn, improve, and enhance.

So given that that's our normal process, procedure, I'm sure that's true for all of us. Looking forward, we do have a lot of confidence that we're prepared to meet the challenges for the region this winter reliably.

CHAIRMAN BAY: Thanks, Todd.

Bruce?

MR. REW: Well, I don't want to ever get too comfortable. But looking at SPP, we are a summer peaking. I am comfortable that we're preparing our operators to respond to anything unexpected, and that would probably be the only concern that we might have, is if there's some major storm that damages a lot of the systems. Outside of that, I'm confident that the operators can handle anything that comes up.

CHAIRMAN BAY: Thanks, Bruce.

Nancy?

MS. TRAWEEK: I think we're very comfortable with our assessment. We have plenty of capacity on our major transmission lines as well as we're not seeing any congestion through our studies. We will -- I feel very confident that our communications with the gas company will help us mitigate any issues that come up there, and our technical assessment is going to put us in place to know what possibly could happen and how to mitigate that. So I feel comfortable.

CHAIRMAN BAY: Thank you.

I think I will hold off on asking a second question, and I will yield my time to Cheryl.

COMMISSIONER LA FLEUR: Thank you very much, Norman.

Thank you all for being here and thank you for everything you and your teams do on the front lines to keep the lights on for customers.

What was going through my mind the whole time you were talking was how integrated a lot of the things we work on with you and with all the people around the table are, the reliability rules, market design and monitoring, transmission planning, and the ever-challenging gas pipeline certificate work.

In the interest of time, I'm going to bore in on the person who seemed the least comfortable, Pete, and ask just a little bit more about your fuel situation.

You mentioned the importance of the Algonquin incremental market project hopefully coming on by winter, and I hope you have a -- what your confidence is there.

And also, I wanted to ask about LNG. In an emergency, if you lost a pipeline or lost one of your nukes or something, how quickly can you get an LNG delivery? Is that something that's just there for you, or is there a lot of risk of LNG not being available? Is it just price, or is there an actual adequacy of supply issue?

MR. BRANDIEN: Well, first, we monitor tank levels. So there has to be fuel in the tanks. The last two winters, they have replenished on a somewhat frequent basis. So that gave us a comfort level.

I will start off with Canaport because that's the 10-Bcf facility, and that can inject about a Bcf. I think their max vaporization is about 1.2. That can't all come to New England. Some of that would have to go up into New Brunswick if they were vaporizing that amount.

That pipe is a higher-pressure pipe, like 1400-pound pipe, and it's dumping into the Algonquin and Tennessee pipe, which are lower pressures. So what we've been told -- I don't operate those pipes, but we have good communications with the pipeline operator, and that pipe, the maritime northeast pipe, which is where Algonquin goes into, is operated by Spectra Energy. And if they know that somebody has scheduled the gas and that Canaport is beginning to vaporize and send the gas, they generally will start to bleed the gas from the higher-pressure pipe into the lower-pressure pipe without a delay and then just catch up when they're vaporizing.

District Gas is generally vaporizing all the time, either supplying vista gate 8 and 9 or supplying their LDC contracts. So once again, that's pretty much always there. They -- as you know, they actually vaporize into the National Grid system and also into the Tennessee pipe, into the Algonquin pipe. So they can go in any direction, and they're generally right there.

The one that we're unsure of is the ship at the Bowie. They like to respond to price. And so they could sit there connected to the Bowie for days and not vaporize at all. Last December, they were sitting there December, January and vaporized later in the winter, but they were there. So I'm not sure how long they take, but they can generally get up and vaporize. It's a pretty simple system to take the LNG and vaporize. It's not very complex. So it's generally there relatively quickly.

COMMISSIONER LA FLEUR: Thank you.

I know we're talking about this winter. You ended your talk with somewhat of an ominous statement about the gas resource -- the nongas resources that you will be losing in the next year or so.

Are there things you're doing now to give yourself more margin for next winter or -- because these things take a long time.

MR. BRANDIEN: I wish I had a good answer that gave me comfort that as the nongas resources retire I had some sort of magic bullet. The region doesn't seem to be motivated to go down a path to expand the gas infrastructure. They want to invest in different things, you know, solar, offshore wind, onshore wind, energy efficiency. We have seen the benefit of energy efficiency. Our 90/10 peak for this winter is about 1100 megawatts less than our all-time winter peak. We actually see our peaks coming down through the years. But the generation retirements are going to outstrip those activities.

Solar, I look at some of that solar as I'm banking gas for later in the day. I was out in Denver at the National Renewable Energy Labs with Arnold Quinn, and I made the statement that, you know, everybody is talking about the role of gas in a renewable environment, and do we have to build flexibility into the gas system, and I think my reality is a lot of these renewables are going to give me the flexibility on the gas system to operate.

I think really what I see in the coming years is more and more reliance on LNG and ensuring the replenishment of that LNG.

Not the best picture when you look at 1500 megawatts retiring May 31st of nongas resources. That's about -- a thousand of that is coal, and that's about half the coal that's left in New England. And then we have a nuclear unit that's going to retire a year or two later, followed by who knows, the other older fossil oil resources.

So that's why, you know, I close it with this is probably my last best year, because I'm getting some expansion of a gas infrastructure, and I have those resources, which I won't have in the future.

COMMISSIONER LA FLEUR: Well, thank you. I know there's a lot more we could say, and it's a conversation we have to continue having. But thank you for thinking about all those things together, and we'll continue the effort.

Colette?

Mr. Chairman?

COMMISSIONER HONORABLE: Thank you.

Thank you for your presentations. Most of all, thank you for your work throughout the year. I really am quite fascinated by these presentations. I know it's getting toward lunchtime, but I'm very impressed with the level of work that you're carrying out, and each year, you are improving your work and looking inward and also looking outward. We've seen examples of work with neighbors and improvements. Thank you. My guilt factor is going down from your work on the contract path. And quite frankly, we are seeing the diversity, as the Chairman mentioned, of the ways in which you're tackling how dynamic and how radically changing the regions are. The CAISO example, what's happening in SPP. So thank you for what you're doing.

I was also very pleased with the compliance filings in response to Order 809.

In the interest of time, I want to -- I have lots of things I'd love to talk about, but I want to focus on gas/electric coordination, because I think your presentations demonstrate that while the winters will be mild, thank God, and have been, we can never take our eyes off of gas/electric coordination, and I think your presentations really highlight that.

From PJM, the fact that you've hired a gas expert, I think that's terrific. But I also heard you say that you are still challenged with how you coordinate with LDCs, which have a different regulatory construct. And so it speaks to me to work that we all have yet to do, because I know that you're not the only entity grappling with that issue.

And certainly, CAISO is a unique situation with Aliso Canyon and the heightened level of coordination, and really unprecedented, ranging from state and federal entities, to reflect upon what occurred and how to ensure that reliability is maintained. And quite frankly, the summer that you experienced, I think, demonstrated the best example of coordination and how well you have worked. And so I commend you and your colleagues for that.

I want to ask you all -- and I should mention SPP. Bruce, you mentioned your wind and gas numbers, which are growing by leaps and bounds. But that also speaks to me about the heightened need to coordinate to be able to manage the increased amounts of wind -- excuse me, gas, and the examples you gave regarding wind and some unexpected occurrences that you had. And then on the other end of the spectrum, very high inputs and increases expected soon.

So it also made me think about, what are the ways in which we could better support gas/electric coordination. If you have any thoughts about that now. If not, I know we will be meeting with you, and I really am interested in learning if there are tools that we can employ to support your greater work on gas/electric coordination, or are there barriers or problems. One actually from PJM, that's something I want to think more about, what we could do, maybe even if it's not a formal matter, how can we lend our help to aid in conversations.

So I wanted to extend myself in that way but also hear from you. Again, in the interest of time, if you can't think of anything now, that's fine. If you do have thoughts in mind, I would love to hear it. Thank you.

MR. BRYSON: If you had asked me a week ago, I would suggest we should send a letter to NAESB. Again, I think that was a great thing. I feel like there's something stalled, and there's a lot more -- there's just a lot more we can do on both sides, and I think it's going to require a change in the way we both -- approach our business to kind of look at that. So I appreciate that letter. Thanks.

COMMISSIONER HONORABLE: And thank you, Mr. Chairman.

Anyone else?

Thank you, Michael.

And I want to say very quickly, that I know a lot of folks work on the NAESB effort as they do on NERC matters. Both are equally important in my mind, and I think the work with NAESB can be more challenging.

But you're right, it's absolutely focused on business operations, absolutely focused on the work, for instance, that Richard Blain is carrying out and the work that happens in control rooms and such. And it's so important that all stakeholders continue to stay engaged to move past barriers and places where it may be difficult, but if we work a little harder, we may find an opportunity to reach some level of consensus or improve the standards by which we carry out this work.

So thank you for mentioning that.

CHAIRMAN BAY: Thank you, Colette.

Madam Secretary?

SECRETARY BOSE: Thank you, panel.

We're ready to move to our last item for discussion and presentation this morning, item A-3. This is concerning the 2016-2017 winter energy market assessment. There will be a presentation by Adam Bennett and Hillary Huffer from the Office of Enforcement. They are accompanied by John Sillin and Ramses Cabrales, also from the Office of Enforcement.

We will take a pause now until the Commissioners return.

CHAIRMAN BAY: Let me ask the team, in the interest of time, do you think it would be possible to summarize the presentation? I know the presentation in full will be posted online. But would it be possible, you know, as a result to present a more summary version of a full presentation. Let's wait until my colleagues return, and we will go ahead and proceed with essentially an overview of the presentation. Thank you.

MR. BENNETT: Yeah.

(Pause.)

SECRETARY BOSE: You may begin, Adam. Thank you.

MR. BENNETT: Good afternoon, Mr. Chairman and Commissioners. This presentation is the Office of Enforcement's 2016-2017 winter energy market assessment, staffer's opportunity to look ahead at the coming winter and share our thoughts and expectation on market preparedness, including an assessment of risks. I'm going to give a truncated version today in the interest of time.

So as we're looking ahead to winter, futures prices are looking modestly higher than they were last winter. Henry Hub over the summer increased from below $2 to more than $3 to what we're sitting at currently, and the future curves for both power and gas have mirrored that move upward, with the strongest gains in the Midwest and the West Coast markets.

In Southern California, we saw prices move up an average of 33 percent higher from early 2016 and power prices up over 20 percent.

Weather forecasts for this winter are greatly different than what they were last winter, which is warmer than normal. Since they're taken months in advance, it can only give you a broad explanation what the potential patterns are actually going to be, but we're looking for generally normal temperatures throughout the upper Midwest, New England, and Mid-Atlantic regions.

Given the more normal temperatures that we're likely to see are slightly colder than last year, we should see an appropriate increase in residential and commercial sector demand on the gas side, as well as a slight increase on the industrial sector.

As we've seen continuing through the summer and likely to continue through the winter, is an increase in exports, both on the LNG side and the exports on the Mexico side.

That should be somewhat contrasted by a drop in the level of gas demand for power generation.

As we talked about, larger response in the export side continuing to go forward into 2017, which is really the larger year. We should see a slightly higher demand on the export side this upcoming winter, but far more beyond this winter that it should be an impact.

That's actually countered by a plateauing or a small decline in natural gas production that we've seen over the summer and continuing up to this point in mid-fall. As of right now, we've seen a 0.2-Bcf-a-day decline in U.S. natural gas production through the first nine months of this year. That compares with a 4-Bcf-a-day increase over the same period in 2015. So that's a risk that we flag going forward.

Strong storage inventories, as we sit today, should keep the market well-supplied. However, we exited last year with very full supply, and we're entering this winter with still above five-year-average supplies.

And if it is needed over the winter, Canadian imports, as well as imports of LNG, should be able to help fill in those supply gaps. There's a high level of pipeline conductivity between Canada and the U.S., and global LNG prices are significantly lower than they have been in the past years. So that should incentivize cargos to come into the U.S. should prices allow.

And as we look to the market areas, some new pipeline additions over the past year or so helped to ease some of the market area prices. There has been about 6 Bcf a day of new transport capacity added within the Appalachian region alone since 2015, and there's set to be about another 2 Bcf a day of new transport capacity from that region before the start of 2017. And that should help to really mitigate some of these price spikes that we've seen in previous years. One of the core additions upcoming, as was talked about earlier, is Spectra's Algonquin incremental market power project, which will add about 350 MMcf per day into the greater Boston/New England market.

We are on slide 11. I apologize for that. Futures markets are actually signaling that New York City prices will be the highest this winter, peaking at around $9 per MMBtu in January. They're higher than the prices in Boston and other surrounding demand hubs. And one of the challenges that we flagged going into this winter is in Aliso Canyon and in Southern California. After the leak and subsequent closure this year, there has been ongoing operational issues that have continued through over the summer.

As of right now, where we sit at the beginning of October, state regulators have approved 27 of the storage wells to come back into service, while taking 78 out of operation. And it's limited injection and withdrawal capability. So total inventory in the Southern California area sits at 61, almost 62 Bcf, versus the roughly 120 that was there at this time last year.

State regulators have actually said that the region should be stable without additional capacity from Aliso Canyon but may face a small shortage if the most extreme winter weather happens.

And I will turn it over to Hillary.

MS. HUFFER: Thank you, Adam.

Electricity demand in winter months differs from other seasons, not only in the amount of demand but also in the pattern during the day. This graph shows how CAISO's duck curve has changed between January 2011 and January 2016. The duck curve is widening, indicating that renewable generation serves more load during the middle of the day, but natural gas-fired generation is increasingly called upon to ramp up output in the afternoon and evening as solar generation declines and load increases. CAISO's widening duck curve is, in part, due to increased solar generation. Looking ahead on the power generation side, we continue to see a shift away from large centralized power plants. The majority of new entrants expected to come online between now and February 2017 are primarily small to midsized generators, which are less than 400 megawatts, and renewable products. This map shows various regions by number of proposed new transmission projects. In the darkest shaded region, you would see there are more than 20 high-voltage transmission line projects expected to be completed in MISO between February 2017 and now. Many of these projects will serve areas that have been identified by Staff as having persistent price divergences.

In terms of upcoming generator retirements, the Fort Calhoun nuclear power plant in Nebraska is the only major announced nuclear plant retirement this winter. However, significant price impacts are not anticipated from its closure.

This chart shows the annual change in electric generation capacity since 2010 for ISO New England, New York ISO, and PJM. It illustrates a decrease in overall generation capacity of nearly 7500 megawatts from 2014 to 2015. The chart also highlights the decrease in coal-fired generating capacity and the increasing importance of natural gas for electricity generation. This change in the resource mix can pose challenges for winter operations, especially in ISO New England where approximately 44 percent of generation capacity is now gas-fired and disruptions in gas supply and pipeline capability can occur due to the configuration of the system.

Historically, ISO New England has been able to rely on coal- and oil-fired power plants in the winter when residential and commercial demand peaks. To help maintain reliability with its changing resource mix, ISO New England has implemented a winter reliability program that is designed to prevent overreliance on natural-gas-fired generators, as well as to implement other proactive measures during the winter months.

In New York ISO, nearly 50 percent of capacity is natural-gas-fired. And New York's ISO demand response programs, which reduced energy use at peak times, can be activated to help support regional reliability and manage demand during the winter months. In PJM, natural gas accounts for more than 30 percent of generating capacity. PJM continues to build on the gas/electric coordination efforts established after the 2014 polar vortex. Also, this winter will be the first year that PJM's new capacity performance market design will be in effect.

In summation, the outlook for the winter is cautiously optimistic, with markets well supplied for the coming season. Normal to above average temperatures are expected and should lessen possible gas delivery constraints. New infrastructure in terms of pipelines and transmission lines will transport gas and electricity to alleviate price differences and mitigate spikes. Staff will continue to monitor developments within the electric and natural gas markets, with particular attention paid to the issues at Aliso Canyon and the Northeast.

This concludes the 2016-2017 winter energy market assessment. We are happy to answer any questions you may have.

CHAIRMAN BAY: Thank you, Hillary, Adam, John, and Omar. I must tell you that I always look forward to this presentation each year. It's very helpful to me. I think it's informative. I think it's helpful to the stakeholders and the public as well. This year, I think it was particularly helpful because it came right after the regional presentations from the RTOs and ISOs. So it was very nice to get the comparison between their perspective at a regional level and then your perspective at a national level. So thank you very much. I appreciate the good work.

COMMISSIONER LA FLEUR: Thank you. I will just add that the whole presentation, I believe, is going to be put online. There's just a tremendous amount of information packed into these charts. So I commend it to the viewing public, out on video, for their reading.

Thank you very much for your work on it.

COMMISSIONER HONORABLE: Thank you.

And thank you to the team for your presentations and most of all for the work you also do throughout the year to stay on top of what is happening across the country and how our work needs to respond to that or get ahead of it.

I have one question, if you don't mind, and I'll be quick. It's on slide 7. Because I think we should pause to really take stock of what this slide means, this is the graphic depicting production and the first decline in shale gas since the evolution, revolution, whatever you want to call it, over the past 10 years or so. And it looks like from 2015 to '14 and 2016 to '15 there was such a large decrease. And so I want to think about what should we anticipate in terms of capacity, what should we anticipate in terms of impacts to price, in your opinion?

MR. BENNETT: Yes, that's a very good question. Thank you for the question. The impacts of price going forward of the lower production are really going to be regionalized, I think. You are seeing actually some of the lowest prices that we've seen in a really long time in the Appalachian basin. Some of that's due to pipeline constraints and some of that's just due to seasonal constraints because we're at the very tail end of the injection season and we're nearing full storage.

A lot of analysts, myself included, see that we might see a bump-up over the winter months as they get some slightly better pricing, and you can sell into nearby demand markets at a higher price than $1 or $2.

COMMISSIONER HONORABLE: Thank you so much, and thank you in advance for the work you will continue to do.

CHAIRMAN BAY: Thank you, Colette.

Thank you, panel. I appreciate your work.

So last but not least, I have one final announcement to make. I'm very sad to say that my chief of Staff, Larry Gasteiger, will be leaving FERC this Friday. I've asked Jamie Simler, who is currently the director of the Office of Energy Market Regulation, to become my next chief of Staff, and she has graciously agreed.

And I've also asked Anna Cochran to become the acting director of OEMR, and she has graciously agreed as well. Anna and Jamie are both outstanding members of the senior executive service here at FERC, and I know that they will serve with great distinction in their new roles.

But I would like to return to Larry Gasteiger. Where is Larry right now? He's hiding behind Mark. And I really need to thank Larry for his 27 years of public service, the last 19 of which have been spent here at FERC. Larry has served in the Office of General Counsel, in OEMR, in the Office of Enforcement, in the Chairman's office, and in each position he has excelled.

In particular, I personally am grateful to Larry for the help he has given me over the years. He was my deputy in the Office of Enforcement, clearly one of the most important picks that I had to make when I came in as the director of OE when I was new to FERC and when I was in a great need of having a Sherpa. And Larry filled that role.

Back in 2009 when I started here at FERC and when Larry started working with me, I don't think he had a touch of gray hair. So I'm not sure what that says about working with me. On the other hand, back in 2009, I had a full head of hair. So I'm not sure what it says about working with Larry.

But as my chief of Staff, I have really enjoyed working with Larry. I valued his experience, judgment, and ability to get things done. He has truly been an outstanding public servant, and FERC is a better agency for his dedication and his commitment to its mission.

I will now let my colleagues make some remarks, and I will return to make a presentation to Larry.

Cheryl?

COMMISSIONER LA FLEUR: I don't know what's wrong with all you men, because I'm the oldest person around here, and my hair never changes color.

I want to thank Jamie and Anna. If anyone doesn't know that these two ladies make things go around here, they haven't been hanging around FERC very well. I will also save most of my time for Mr. Gasteiger.

I just want to comment. The Chairman outlined some of the jobs he's had, but he's really, in each of those jobs, I think, made defining contributions and lasting contributions to the Commission. When he was in the solicitor's office, he defended Order 888 in court. That seems in retrospect a rather important case to get that upheld. He led OEMR East at a time when the three RTOs we just heard from were just congealing their remarks and starting the capacity markets, and all of that that is now so critical to what we just heard.

When EPAct 2005 was passed and the new

adjudicate came from New Mexico to run enforcement, he helped shape that enforcement and the penalty guidelines and getting that started. And then of course, his time as chief of staff.

So we're going to miss you. And we'll think about you whenever the Nationals or the Capitals are doing well, and I wish you and Eileen every happiness in your next chapter.

COMMISSIONER HONORABLE: I, too -- this is bittersweet really because I guess I came along in the Gasteiger era when he was in enforcement, and that was very new for a state regulator to grapple with. I greatly appreciate Larry and Larry and team helping a newer commissioner and Staff get acquainted with this work, and yes, in particular, the critical work that underpins this very controversial area, quite frankly. So I've greatly appreciated your patience and your instruction. And then he got a little closer to the fire, I would say a lot closer to the fire.

So while we may seem even-keeled and mild-mannered from afar, Larry became chief of staff and learned what we were really like. And what I appreciated most about Larry's work as chief of staff is that he was always willing to help smooth and develop a path for consensus, for the best result in the interest of our work here at the Commission, most of all in the public interest.

So I've greatly appreciated the opportunity to get to know you, Larry, and I wish you well in your new journey.

I also want to congratulate Jamie and ask Jamie to visit with Larry to learn how crazy it is working with all of us, but most of all, I think how wonderful it's going to be. I, too, have learned a lot from Jamie and her team, and I did previously congratulate Anna. And I think I was smiling maybe a little bit more than Anna was. It's going to be okay. We're going to be just fine. I look forward to working more closely with Jamie and with Anna at the helm and OEMR. So congrats to you all, and we will miss you, Larry.

CHAIRMAN BAY: Not surprisingly, it is hard to find an award that Larry has not won at some point while here at the FERC. And after OER did a lot of research, and OED did a lot of research, I think we finally found an award he has not achieved, and that is the Chairman's Medal. So it gives me great pleasure to present the Chairman's Medal to Larry Gasteiger.

(Applause.)

CHAIRMAN BAY: And with that, this meeting is adjourned.

(Whereupon, at 12:19 p.m., the hearing was concluded.)

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:

CONSENT MARKETS, TARIFFS AND RATES - ELECTRIC
CONSENT MISCELLANEOUS ITEMS
CONSENT MARKETS, TARIFFS AND RATES - GAS
CONSENT ENERGY PROJECTS - HYDRO
CONSENT ENERGY PROJECTS - CERTIFICATES
DISCUSSION ITEMS
STRUCK ITEMS

1,031st COMMISSION MEETING

Place: Washington, DC

Date: Thursday, October 20, 2016

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.

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Official Reporter