BEFORE THE
ILLINOIS COMMERCE COMMISSION

IN THE MATTER OF:)
)
GAS AND ELECTRIC POLICY SESSION)
)
Coordination between the Natural)
Gas and Electricity Industries.)

Chicago, Illinois
July 9, 2014

Met pursuant to notice at 1:00 p.m.

BEFORE:

MR. DOUG SCOTT, Chairman
MR. JOHN T. COLGAN, Commissioner
MS. ANN McCABE, Commissioner
MR. MIGUEL del VALLE, Commissioner
MS. SHERINA E. MAYE, Commissioner

SULLIVAN REPORTING COMPANY, by
Tracy L. Overocker, CSR

I N D E X

CHAIRMAN SCOTT: Pursuant to the provisions of the Open Meetings Act, I now convene this policy session of the Illinois Commerce Commission to address the coordination between natural gas and electricity industries and the impact of that coordination on reliability in Illinois.

Thank you all very much for coming today. As you know, we've started doing more of these policy meetings to try to get a little bit more in-depth look at some major issues that are facing the Commission and facing Illinois and we do it outside of the normal rate case setting, in a normal docketed setting so we can go into a little bit more additional things that may not have relevance to a particular case, but may be very, very important to the issues as a whole.

So we've all been taking turns at teeing these issues up and for this one, I really want to thank Commissioner Colgan and Linda Wagner for really assembling not only a really great topic and a great way to address the topic, but also a tremendous group of speakers that we're going to have today. So I really appreciate all the work. I know it takes a lot to put one of these together, so I really appreciate all of the work that you have done. I appreciate everyone for being here and I'll turn it over to Commissioner Colgan.

COMMISSIONER COLGAN: Thank you, Chairman. As we explored in our 2014 summer preparedness policy session back on May 14th, the recent trend to rely more heavily on natural gas and electricity generation is expected to continue. In fact, this trend appears likely to accelerate as coal-powered generation is retired, renewable energy resources require more backup by natural gas plants, nuclear power plants are faced with some risk of closure, and low natural gas prices encourage more use of gas.

Accordingly, the interdependency of these industries merits careful attention. As a result, we've designed this gas and electric policy session to explore the very complicated issues surrounding the coordination between the natural gas and electricity industries and the impact of that coordination on reliability in Illinois and the region.

We are privileged today to have a group of national experts on this topic who will share their thoughts and experiences with us. Included are representatives of FERC, NRG Energy, MISO/PJM, the Illinois local distribution companies, Kinder Morgan and RBN Energy.

The Commission has asked these panelists to address questions such as, What are the issues of common concern regarding infrastructure adequacy and reliability? What are the changes that should be made to current natural gas and electric market business practices to improve interoperability? What are the problems that could occur because of the uncertainty surrounding the life cycle, Shale formation and possible shifts in Shale production due to environmental and other factors? And, What are the lessons learned from the polar vortex and other recent experiences? And I'm sure we are all looking forward today to hearing our expert panelists address these issues.

So today we're going to have three

panels. The first panel will explain the issues and initiatives regarding pipeline infrastructure and gas-electric harmonization; the second panel will tackle various aspects of the potential solutions to those issues; and the third panel will be an informal dialogue about the emerging issues in gas-fired generation.

Each panel member is -- made prepared comments and after they make those comments, I'll ask my fellow Commissioners if you have questions of clarification. Then you can ask those after the individual makes their presentation. Other than that, for general discussion and general questions, we'll wait until the three panelists are each concluded.

The first panel is Ed Murrell of FERC, Tia Elliott of NRG Energy and Joe Gardner from MISO.

If the three of you would like to come up and take a seat.

I'd first like to introduce Mr. Murrell. Mr. Murrell is an economist by training graduating from the University of Virginia in 1977.

His FERC career began in 1979 with natural gas pipeline certificate regulation. He was involved in the formulation and implementation of open access policies which have transformed the natural gas industry, beginning with Order No. 436 and continuing with Order Nos. 636, 637, 712 and others.

Mr. Murrell was a technical advisor to Commissioner Don LaSanta (phonetic) from 1993 to 1996. The Commission signature achievement during this period included the implementation of natural gas pipeline, restructuring Order No. 636, oil pipeline market-based rates and the Commission's first electric transmission open access policies culminating in Order Nos. 888 and 889.

From '96 to the present, Mr. Murrell worked in different capacities for FERC: in the Office of Pipeline Regulation, the Office of Markets, Tariffs and Rates, the Office of Energy Market Regulation and currently works in the Office of Energy Policy and Innovation.

Since 2000, Mr. Murrell has increasingly focused on electricity industry issues, including work on RTO formation, RTO market design, demand response and energy storage, renewable energy and natural electric -- natural gas-electric integration issues.

You've been a busy man.

The Office of Energy Policy and Innovation provides leadership in the development, formation of the Commission's policies and regulations to address emerging issues affecting wholesale and interstate energy markets.

The floor is yours, Mr. Murrell.

MR. ED MURRELL: Thank you.

PRESENTATION

BY

MR. ED MURRELL:

Thank you for your invitation to speak with you today. I'm going to try to keep my remarks short so that I leave more time for you to ask questions and have a dialogue towards the end of this session, and I want to try to keep my remarks a little bit at a high level today. I think there's really a lot of territory to be covered today, you've got some good speakers ON this panel with me and later on this afternoon that are going to cover a lot of this.

From a FERC perspective, we've been looking at gas-electric issues, you know, pretty seriously over the last couple of years starting in early 2012 with Commissioner Phil Noyes' (phonetic) request for industry input and following that with a series of regional conferences. The Commission has been attempting to really get its hands around the scope and scale of these issues.

We have two industries that have been operating independently and barely even talking with each other for many, many decades. In fact, on a global level, they're competitors for the retail markets. They really kind of don't want to have anything to do with each other in the historic past. Today it's different.

Electric generation is the single biggest growth opportunity for the natural gas industry. Natural gas for our generation, at least in the near term, seems to be the most promising opportunity to build new capacity and fill gaps as they come up in the generating fleet all over the country. Many regions have spent tremendously more on gas generation.

Coordination is now becoming more important. They need to start understanding each other, they need to reach out, they need to learn the vocabulary and the practices and business perspectives of each other and that's relatively new.

From a FERC perspective, we've divided these issues into just a handful of key categories. That's driven more by what we think we can influence than by any limit in terms of the nature of what has to happen out there in the field.

Communications is a very important area. We've already issued a rulemaking and taken some steps to remove barriers from some of the other Commissions' regulatory imperatives. We've seen the RTOs make changes and focus more on keeping up with what's going on in the pipelines in their community and that's helped them over the last couple of winters in keeping their gas-fired resources on-line in the wintertime.

Scheduling practices has been a little more recent. In March, the Commission issued a Notice of Proposed Rulemaking. We've asked NAESB to attempt to forge a collaborative consensus solution. They've made some progress, but have not completely solved the problem. There is still remaining issues both between electric and gas industry components and from regional stakeholders from the West and the East.

Operating practices of wholesale electric markets and the way that those markets function have a way of dealing with generation. So basically it's a day ahead or an hour-to-hour type of business framework. The operator of the market basically commits resources as needed and those commitments change from hour to hour.

Natural gas, it doesn't work that way and in order to get natural gas in the wintertime when demand for gas is high and infrastructure is operating at capacity, there will be a need in the future for firm contractual commitments to meet those needs.

Pipelines are reaching capacity. Historically, gas-fired generators were only serving peak demands during the summertime. At that time, pipelines were not full. They weren't needed to serve their other customers and it wasn't difficult for electric gas-fired generators to get that capacity.

Today, that's not necessarily the case. Generators are competing with each other. They are now putting demands on pipelines that have risen to a level of filling those pipelines up during the summertime and even during the off-peak months.

As we saw during last winter, winter demands can also be very high and coincide with high gas-fired -- gas consumption from all the other uses in gas system.

So I'm going to speed this up a little bit. The connections between gas and electric really have just a handful of different dimensions. Service offerings don't align very well. Pipelines basically sell daily service; generators sell hourly service.

Communications and coordination are not well aligned. Pipelines have a set of nationwide practices and schedule for nominating and scheduling pipeline service. RTOs have a schedule for receiving bids from generators making market commitments, making reliability commitments and moving the operational framework towards real time. The gas day starts at 9:00 a.m. The electric day in the East starts at midnight. Contractually, that's not a very good fit.

Different commercial approaches are going to have to be looked at in the future to try to bridge these gaps. In order for a generator to commit to a firmer gas pipeline or a gas supply arrangement, there's going to be a need to deal with, you know, basically some cost. Pipeline charges for firm service are fixed monthly fees, uses charges are very small and vary only a small amount from month to month. The guts of the fees the pipelines charge are monthly reservation fees. Generators are going to have to either find a cash flow that is going to support that or they're going to have to find ways to find alternative paths to get their gas supply.

And then low gas prices have had impacts on both industries. It's increased demand, which is part of what fills up the pipelines; it also has some pretty dramatic effects on the hemodynamics in the electric industry; it lowers market clearing prices and affects the cash flow that generators rely on to keep firm supplies full.

So I've touched on communications and scheduling practices. Operating practices, I just want to say that each of the RTOs has some form of active stakeholder process. They're all looking at slightly different things. Problems here in the Midwest are completely different than problems in the East and that is reflected in the focus stakeholders and RTO managements are bringing to the table.

I'm very encouraged to see that effort, look for regional solutions, consensus and collaboration among the market participants. That's the best first step before things come to regulators for a decision, at least on a federal level.

In terms of pipelines reaching capacity, we've got market mechanisms in place to allow as much liquidity as the market can provide. Capacity release allows for, in a secondary market pipeline capacity, customers who have firm commitments, can let that capacity go to others when they don't need it and that has formed a pretty solid foundation for a fairly competitive market for gas and helps keep the gas-fired generators running.

So in terms of infrastructure, we do have a -- kind of finite set of pipeline capacity. It takes several years to build new pipeline. It takes a fairly significant amount of time to go through both the contractual commitments the pipelines have to negotiate with their customers, the regulatory process which, for pipelines, includes the federal citing and environmental reviews that on the electric happens and it takes time to construct. We have market mechanisms that allow that capacity to be used as well as it can be and to let the market help make that happen.

New capacity firm contractural commitments in terms of current policies, current approaches and the current reality in the financial world seem to be where that's going to go. There's room for innovation and new business models; but until they arise and until people have commitments that they're willing to go move forward on, we'll just have to wait and see what kind of innovation comes from that direction and access to storage, which I haven't talked about yet which also is vitally important.

Here in the Midwest, you are amply blessed with quite a bit of storage capacity. Some of it's commercially available in the wholesale market. Some of it's held by local distribution companies that helps support their winter needs. All of that can be made available in the market under the current federal regulatory regime.

So I'm really gratified that the Illinois Commission is looking at these issues. I think it's important that Commissioners increase their awareness, engage with their utilities and their stakeholders and really try to get a better understanding of what the challenges are and be prepared for the steps that industry stakeholders and the regulating entities take to solve some of these problems.

I think there's a lot of room for the market to provide assistance. I think people have some flexibility to look for market-driven solutions. Some of that is just entering into contracts that makes sense; some of it is making the kinds of changes or improvements in both the electric and gas markets to make the two industries work better together; and some it is simpler things. Aligning maintenance schedules and communicating and coordinating that across the industries has been very helpful.

So I wrap it up there and pass it on to the next panel. Thank you.

COMMISSIONER COLGAN: Thank you, sir.

Any clarifying questions from either of the Commissioners.

(No response.)

COMMISSIONER COLGAN: Okay. Our next speaker is Tia Elliott. Tia Elliott is director of Regulatory Affairs of NRG Energy, an independent power producer headquartered in Princeton, New Jersey, and Houston, Texas. In her role, Miss Elliott represents NRG's interest at Midcont- -- MISO and she's the current vice chair of the MISO Electric and Natural Gas Coordination Task Force. Additionally, she represents the IPP sector on the MISO Advisory Committee and MISO Finance Subcommittee.

Prior to NRG, Miss Elliott acted as the chief technical advisor at the Indiana Utility Regulatory Commission for two years, from 2011 to 2013, where she interfaced with MISO and PJM stakeholders as a liaison for the Indiana Commission.

She also represents the State of -- represented the State of Indiana during meetings of the organization of MISO states and the organization of PJM states coordinating regulatory oversight of policy formation among the states.

While at the Indiana Commission, she served as the cochair of the OMS State Seams Working Group and chaired OMS Ad Hoc Working Groups on credit practices, Order No. 741, and electric and national natural gas coordination.

From 2004 to 2010, she worked for ACES Power Marketing as manager of energy scheduling where she managed physical and financial transactions in and outside the RTO for multiple portfolios across the country.

She made the transition from electric to natural gas in 2004 working for GridAmerica in real-time operations and real-time operations at MISO.

Tia began her career in the industry in 2000 holding positions with natural gas marketers in the East and West performing trading analysis, scheduling functions and monitoring well production. She earned a Bachelor of Arts degree in Political Science from Indiana University in Bloomington in 1999.

Miss Elliott?

PRESENTATION

BY

MS. TIA ELLIOTT:

Good afternoon and thank you for the invitation to be here and present to you today. Today I'm going to touch upon infrastructure adequacy and the impact on prices. Before I really get into my presentation, I just want to provide a brief illustration up there.

I'm not going to ask you to close your eyes or picture anything; but this illustration is just about a cold January that drives down storage availability followed by an extended cold snap in February. Pipeline capacity struggles to meet demand. During the morning peak hours, you know, you have a combustion turbine, which is a gas-fired generator or CT, that needs to come on in the power market; but at the same time is also when, you know, residentials -- people are waking up, turning up their thermostats, using gas and a pull from both of those could cause fluctuations on the pipe that generator takes the gas and reduces the pressure that's needed there on the pipe.

Now, that illustration was provided to me back in April of 2013 when I was coordinating a similar panel. It almost sounds like it could have predicted a little bit of what we saw in January of

2014, which is concerning. This illustration, though, was reality back in February of 1996. So considering that this happened and this was occurring in this region around Chicago, Northern Indiana, Michigan where these concerns arose, no storage and a severe cold snap.

So moving forward into the presentation, what this illustration highlights is the impact on reliability which then could result in an impact on prices. During extreme conditions, often only firm contracts are going to be deliverable. Now that's not an absolute statement. I said "often" because it's not always; but typically a gas-fired generator is going to be used, for instance, in the summer when the pipelines are at capacity and in peak situations also. So gas-fired generators typically will procure generational contracts. It's more economic and the cost is less and when you're only running it for a few hours as needed, it's not a base-load product based on the resource, there's no need for the firm contract.

Even if gas is deliverable in extreme

conditions as we saw with the polar vortex, what could occur, the gas-fired generator may be called upon in our market for two or three hours depending on the peak time, morning, evening, afternoon, whatever it may be. There still may be a need to schedule that gas for the full 24-hour gas day and that, again, is to reduce the fluctuations on the pipe whereby dropping the pressure or pulling storage that may already be low.

So then you kind of run into a little bit of a situation, which we've heard from market participants through the MISO Coordination Task Force, that during the polar vortex, gas was available, the generator -- a gas-fired generator needed it for two or three hours, but they were going to be required to schedule gas for 24 hours. So then they're paying for this gas that they're taking for 24 hours, but may not need the generator.

What this also highlights is another issue with regards to costs and that these costs need to be recoverable and at least in the power markets, in the RTOs, there are not mechanisms or market rules that provide that ability to recover costs associated with the gas or with the services that have been procured to make that generator reliable, to make sure that the gas is delivered to that generator and those services could be, you know, a firm contract, they could be storage services and that's something that we need to be looking at within the markets and the RTOs.

In the power world, we use a lot of acronyms and I'm going to try to stay away from most of them, you know, for the regulators who are not familiar with the power markets; but I am going to throw one acronym out there for you today and that acronym is ICE, I-C-E. And what this is -- I'm terming ICE as three key drivers that are significant to electric and natural gas coordination. So "I" is for investment, "C," coordination and "E," environmental impact.

So moving on to the first letter or acronym "I" for investment, we need to begin looking at investment in infrastructure. Natural gas infrastructure is funded through long-term commitments with customers and in the Midwest region around this area in Indiana, Illinois, Michigan, we are fortunate that there is quite a bit of storage, especially compared to the rest of the country, as well as many of the interstate pipelines do interconnect and cross through this area.

So to that point, you know, we're in a better position probably than the East Coast, for example; but it doesn't negate that there are potential local reliability issues that need to be looked at and considered.

For example, a customer and a -- who would be the generator -- needs to be talking to and have discussions with their supplier, which may be a pipeline, if they need a direct connect to a pipeline or like some sort of lateral developed to identify if that is an infrastructure need or it could be just as much as talking with a supplier or the local distribution company, the local utility to find out what services are offered that may be able to help assure reliability for that generator, you know, services that they may not be aware of that could be underutilized.

Now to that point though, I would just note that there are not standard services, it's not one size fits all and most tariffs, you know, buy pipe and buyer local distribution companies are going to vary. So that's why you can't just across the board say, This service is this. We need you to use that. So that's why the communication and coordination to identify the local infrastructure needs are going to be necessary.

Moving on to "C," coordination, the coordination movement, I just touched upon which is the discussions, the communications that need to be happening at the local level between the customers to identify if there are local reliability issues, if infrastructure upgrades are going to be needed. The other piece of coordination -- and this is not with stating the coordination just between the industries themselves, especially with regards to scheduling and the gas and electric days -- but I think we're going to need to see moving forward an increased coordination between the states and the RTOs. This may become more imperative going forward with, you know, new proposed environmental rules that could impact the availability that a generator may be dispatched. So that coordination there is going to have to begin taking place between the states and the RTOs as well.

Moving on to our last letter of our acronym, "E," environmental impact, during the polar vortex, there were quite a bit of forced outages for different reasons and one of those reasons was due to frozen coal piles. However, much of the generation that was on-line and supporting reliability on the system was from coal-fired units. The concern here is that, you know, looking two years down the road, a number of these coal resources could potentially be retired.

So putting that into perspective, you know, if this happened, you know, two years from now, our discussions might be a little bit different.

So to that point, you know, it's good that we are beginning to address that now. I hated all that snow in my yard for three months, but it has gotten us to these discussions that are necessary.

The bulk of the unscrubbed coal units remain in the Midwest here in this region and the further proposed environmental rules that could be incentive enough for the plant owners to go ahead and shut the plants down and retire these resources rather than installing expensive scrubbers to make them compliant.

So it's reasonable to anticipate while we already thought we were going to see more dependancy on gas for a number of reasons, coal retirements, the cost of gas, with newer proposed rules, the dependency upon gas could be even greater than what we had initially thought; and it wouldn't be dependency on the gas, you know, this could be clean energy we're talking about and renewables, which brings me to -- my slide here is what we really need to be talking about in addition to the coordination and considering is -- a diverse fuel mix.

You know, the polar vortex proved, again, that fuel diversity is key to maintaining a long-term system reliability. Coal or even oil units are suitable for repowering and for conversions and this is going to be a key when transitioning to reliability units.

Along that line and specific to the Midwest region, especially at costs in the Illinois and Indiana area, I think we'll continue to see wind and solar increase and enter the market even more. That's also going to require the right technology mix, which would be another consideration as we move forward.

Responsive and flexible technologies are going to be important to balancing the growing renewables that we see and along the line of flexibility that brings us to another resource which is nuclear resources, and we do have that around this region and this area. And nuclear does provide necessary fuel diversity similar to coal-based resources, but the nuclear resources don't rely on flexibility that may be sometimes needed during peak conditions. So that's another consideration when talking about the need for diversifying the fuel mix.

With that, I am going to conclude my presentation and turn it over to you for any questions.

COMMISSIONER COLGAN: Thank you for you comments.

Anybody have any clarifying questions for Miss Elliott?

(No response.)

COMMISSIONER COLGAN: Okay. Our next speaker is Joseph Gardner from MISO. Mr. Gardner is responsible for MISO's forward markets and operational processes overseeing the administration of MISO's financial transmission rights market, the Day-Ahead Energy and Ancillary Services Market, transmission and market settlement, outage coordination, Seams administration and tariff administration and scheduling.

In addition, his responsibilities include leadership of MISO's market engineering and modeling services. Previously, Mr. Gardner played a key role in the development and launch of MISO's market and reliability functions.

Mr. Gardner joined MISO in 2000. Prior to joining MISO, Mr. Gardner spent 16 years at Central and Southwest Services in Dallas, Texas, where he earned positions of increasing responsibility including director of Systems Operations.

Mr. Gardner earned a Bachelor's of Science degree in Electrical Engineering from the University of Texas at Arlington.

Mr. Gardner.

MR. JOSEPH GARDNER: Good afternoon.

COMMISSIONER COLGAN: Good afternoon.

PRESENTATION

BY

MR. JOSEPH GARDNER:

So I'm going to talk a little bit about some of the things that we see coming in the near future as well as the activities that we've had in place for the last couple of years just to deal with some of those things and changes we see that may be necessary to deal with the changing environment and then I'll give you a little bit of a flavor for what we saw during the polar vortex.

The first slide, basically, just shows our footprint. It is a very geographically diverse footprint. It's typically not cold everywhere at the same time. It's typically not hot everywhere at the same time. There is a lot of geographic diversity as well as time zone diversity.

This winter was a little bit of an exception to that. Actually, it was cold at the same time -- and I talk a little bit about this later -- but in the peak load there it says it's about 126 gigawatts. That doesn't include -- you know, the whole footprint included in the Southeast Region that we picked up in December and this past -- typically, our winter peak is about 30 percent lower than our summer peak -- maybe 25 percent.

So it was like 100 gigawatts prior to this year in our winter peak. We broke that winter peak by 10 gigawatts, which is like 10 percent and that's just a very unusual thing to have happen, to actually beat a peak load by that much of a percentage -- an all-time peak load by that much of a percentage, that -- I've been in the industry a long time. I haven't really seen that kind of record being broken. So it was a -- I don't know if it was a 1 in 20 year event, but it was definitely a 1 in many year event that we saw this past winter.

The next slide. So we've been seeing this coming for a while, the EPA activities associated with coal units in particular. We're going to see about 10 gigawatts of coal-fired capacity actually retire by 2016. That's largely going to be either -- eat into our reserve margins historically for the last 15 or so years, at least, that we've operated at a level of reserve margin much in excess of the actual minimum planning reserve margin, that would give us a 1 in 10 year reliability. That's going to be eaten away by the gig- -- the coal-fired retirements and so we're going to be operating much closer to our planning reserve margin.

The other thing that will happen is we're going to be -- we're going to see more and more renewables come on-line and we'll also see more gas generation go on-line and our generation queue reflects that as well.

The next slide. So about two years ago, we put in place a Natural Gas-Electric Coordination Task Force and we've been working with the gas industry for a while trying to work closer together on key things such as this situation awareness. We want to -- historically, we have not needed at our control center level to know the details associated with what's happening on the gas pipelines. We haven't even needed to know exactly which pipelines are connected to which plant and how many pipelines were connected to which plant. And so we saw the need to start having more visibility into that.

In addition to that, we don't have a requirement right now for firm fuel and that typically has not been a problem historically because we mostly needed it during the summer, not so much during the winter. Like I just talked about a minute ago, our peak load in the winter is significantly less than in the summer, so there was always a lot of extra capacity that we could rely on from the winter. That's changing because we're going to be operating closer to the margin and we're going to need to have more visibility into what fuel is available and then also have more fuel obligation.

Now, one of the things -- firm fuel obligation. One of the things that we're looking to do is going to a seasonable model, at least from a resource adequacy point of view. So today, we only have a resource adequacy on an annual basis and since our winter peak was 25 percent less than our summer peak, we didn't really need to require firm fuel and if we did require it, it would be requiring the utilities and the generators to spend a lot of extra money that wouldn't necessarily be needed for the winter and so we haven't had that requirement.

So what we're looking to do is have a seasonal -- one of the things, is to have a seasonal model where we actually plan -- and have planning for the winter separate from planning for the summer and then perhaps making a firm fuel requirement makes sense. There will be a discussion about that going forward.

The other thing that we need to make sure we're doing more of -- and that Mr. Murrell talked about -- is alignment of gas-electric scheduling and I'll talk more about that in a couple of minutes.

We had a lot of experience with the polar vortex. We weren't fortunate in that we did have some loss of generation due to gas, but not an amount that would cause us to initiate emergency procedures. And we are looking forward to what's going to happen in the future as new gas generation comes on-line, what kind of time line is going to be needed for the natural gas construction build-out, so we're doing an analysis associated with that.

So some of the remaining challenges is just identified in modeling pipeline contingency. So as we see a pipeline go out of service, what kind of challenges may cause that among multiple plans or an area of our footprint, we want to make sure we capture the fuel risk in planning and mark the contracts like I just talked about, perhaps, going to a seasonal resource adequacy model.

We put a pilot in place this past winter associated with a gas pipeline where we were in close coordination with them and we're looking to expand that. In addition to that, we want to make sure that our operators in the control room actually know, first of all, the state of all the pipelines and what's -- what type of operation condition they might be in as well as have visibility into which pipeline -- which plants that pipeline serves; and then, finally, scheduling misalignment and I'll talk about that in a minute.

I think maybe I talked about all of these. Let's go to the next slide. So in March, FERC actually issued a proposed rulemaking that wanted NAESB to do essentially two things. One of them is to look at moving back during the day when timely nominations are going. So instead of making timely nominations at 11:30 in the morning, perhaps doing it later in the afternoon. And then the other thing that they wanted to look at was changing what gas day is. Currently, it's 4:00 a.m. to 4:00 a.m.

and look at changing that to 9:00 a.m. to 9:00 a.m.

Okay. The reason those things are important is that -- go to the next slide and we may come back, okay -- so that the current day ahead market for MISO runs between 11:00 a.m. and 3:00 p.m. All right. So at 11:00 p.m., we need to know what all the generators are planning to do and what their offers are for tomorrow and then we run for 4 hours and we let everybody know at 3:00 o'clock in the afternoon what their clearing results were. Well, right in the middle of all of that, at 11:30 in the morning, the gas pipelines require nomination from all those generators, but they haven't got the clearing results yet from us and so it presents a little bit of a challenge for getting that right.

And so what we're looking to do and what FERC was looking to get out of this was move that gas nomination period back into the afternoon and then have us move our day ahead market up earlier so that our clearing results are available prior to the nomination process. And so that discussion is still ongoing.

NAESB will be making a filing with FERC, if they haven't already, pretty soon that talks about moving that nomination back and then we have an obligation to file with FERC at the beginning of next year indicating what we're going to do in response to that or show why we shouldn't. So these are basically two choices, so I will be working on that activity.

There was also a lot of activity associated with moving the gas day from 4:00 a.m. to 4:00 a.m. to, say, 9:00 a.m. to 9:00 a.m. The reason why that's important is because today, in places like New England and New York -- we haven't had this issue in the Midwest yet -- and I actually said that backwards -- from 9:00 a.m. to 9:00 a.m. back to 4:00 a.m. to 4:00 a.m. -- today, the gas nomination -- the gas day ends at 9:00 a.m. The morning peak in the winter is also around that same time, around 9:00 a.m. So there are times when generators are actually running out of fuel at the same time as the morning peak is occurring and so that causes some generators -- but we typically want one to come off-line prior to the morning peak because they're running on what they nominated the day before and that creates operational changes for us. And so the idea is to move it to 4:00 a.m. to 4:00 a.m. so that it does not coincide with the peak.

The next slide. So I'm going to transition now into some of the experiences that we had last winter. So it was cold and we're just showing on some days in January and February and March of the average loads in our footprint. And, remember, even though 2 degrees might not seem cold, it is pretty cold when you average in temperatures in Louisiana and Northwest Mississippi. They don't get anywhere near that cold. So the average temperatures were a lot colder this year and they were the coldest experienced in about 20 years.

The next slide. This one is a little bit busy and it has a lot of information on it. The important thing is that loads were high and that we only had to go into a max gen event, which is the shading on March the 4th, bottom right, one time going into the period. We were in cold weather alerts a lot. We were concerned of operations to make sure everybody was on their toes and paying attention, there wasn't unnecessary maintenance going on, so we had a lot of that activity; but we only actually had to go into an emergency event one day and it was only the very first step in the emergency process, which was to ask some units that were available only during emergencies to make themselves available. So that's really all we had to do from an emergency procedure point of view.

I already mentioned the fact that our peak load was up almost 90 percent higher than all time, which is a very unusual event.

And the next slide. And this slide, the colors aren't coming out very good; but basically, what we're trying to show is total forced outage due to gas issues which is kind of the middle bar in all of that, and on some days, we had as much as like 6 gigawatts of generation unavailable. We had some gas issues. Which is -- it's a large amount; but because we -- because we have a reserve margin for summer peak and our summer peak is so much higher than the winter peak, it causes us to not have to go into emergency procedures like I talked about before.

Next slide. And we were able to manage things through adequate staffing. We had conference calls with local market participants, with our local balancing authorities, as well as our adjoining RTOs, internal meetings, just good situational awareness making sure we have alerts, notifications, declarations and staying on top of everything from a situation awareness point of view.

And with that I'll be happy to take any questions.

COMMISSIONER COLGAN: All right. I think we have about 10 minutes for our questions.

Does any of you have -- Chairman?

CHAIRMAN SCOTT: Thank you, Commissioner. And thanks for the presentations. They are all very good and I appreciate you being here. I actually have one hopefully short question for each of you.

Mr. Murrell, you talked about the differences a little bit between the Midwest and the

East and we've heard this before, but I don't know if anybody ever very succinctly explained why we're not in the same situation that's true in the Northeast. So maybe if you can take a couple minutes to do that for me.

MR. ED MURRELL: Well, I think I can sum it up fairly quickly. The Midwest and Chicago, in particular, is kind of a crossroads for natural gas. There's pipeline capacity coming in from almost every part of the country. There's a lot of development in place to move even Marcellus Shale back towards the Midwest. If you look at prices, for the most part, except for these very extreme days, Chicago prices sometimes even beat Henry Hub prices because you have the diversity of supply and the diversity of storage and resources. That, except on the most high-demand periods, is ample for most needs. You just have more tools to work with on the gas supply front.

New England, by contrast, is at the end of just a couple of pipelines so whatever they have to do is going to take a little more effort and it's going to be a little more concentrated. So that's number one.

In terms of capacity, New York PJM and New England all have some form of a -- kind of a wholesale market capacity/market construct that determines, you know, in the region, what adequate capacity commitments have been made. Everything is in the market. There are a lot of bilateral agreements underneath that, but it's still -- everything is in the market.

In the Midwest MISO market, you have a little more -- kind of voluntary capacity market. It's a little more of an opportunity to trade available capabilities and people tend to rely more on their own bilateral commitments or cell phone generation so that market construct is significant.

Obviously you've got PJM and MISO serving Illinois, so you've got a little bit of both flavors of that, but those -- aspects of those things make things distinct. You have, probably, a slightly bigger nuclear fleet relative to some of the other regions. When you look at the division of fuel sources for the capacity that's available to Illinois and available to MISO, it's kind of evenly divided. Coal tends to be first; gas second; nuclear third. But when you look at the actual generation, coal is almost the majority of the electricity generated in Illinois and it's a very high percentage in the MISO market.

So that function is really just the ability to have that relatively cheap marginal resource coming into the market and it provides, you know, a bigger amount of load.

You do have a fair amount of wind now. Wind is like the fifth largest capacity for electric generation in the Midwest. I haven't done any comparisons, so I'm not sure if you are ahead of all the other Eastern Regions or just kind of setting the pace for the Eastern Regions; but I was actually surprised when I did my recent research to get ready for this panel to see how much wind had picked up in the last few years. And I think the need to have flexibility with the rest of the generating fleet to deal with the variability of wind is going to put important stresses on the system that have to be managed. And Joe and his guys have done a great job putting wind resources in the market in a dispatchable way in managing those resources, but that's going to be a continuing challenge going forward; and that's probably not distinguishing you from the rest, but that's kind of how I look at it.

CHAIRMAN SCOTT: I appreciate that. Thanks.

And quickly, Miss Elliott, then, so part of the 11D is the ramping up of gas to the 70 percent capacity. That's one of the building blocks that's in there. It's not as big an issue for us because we don't have that much gas to ramp up. Is the infrastructure ready in other place to handle that?

I mean, that's an issue we're all going to be dealing with, but I'm just curious from your point of view -- not necessarily Illinois specifically, but in other places.

MS. TIA ELLIOTT: Honestly, I'm not really in a very good position to say because I think, again, once we talk about infrastructure, we have to look at the other local levels.

Now, one thing I would add to that, though, while we do have the supply here -- and Shale was mentioned earlier and we are seeing some backhaul in the Midwest Region, we do receive a lot of supply from the Gulf; but what's happening is there's quite a bit of load growth happening in the Southern Region, and MISO specifically, the portion of Texas across Louisiana and into Alabama.

So what that means is those -- that new load, largely industrial, will begin to rely upon a lot of the gas that we -- the Midwest region is getting from the Gulf. Take that away and then I think that also creates another caveat. We may still have supply, but where is it coming from and is the infrastructure adequate to support that in addition to the increase on the gas-fired generators?

Unfortunately, it doesn't answer your question very well, but I do think that we have to also look at that locally, again, to determine where the needs are. And while the Midwest is in a good position, probably better than other areas of the country, it doesn't, again, negate that locally we potentially have issues with infrastructure.

CHAIRMAN SCOTT: And my other question -- the next panel too, so I'll hold on. Thank you.

COMMISSIONER McCABE: Mr. Murrell, wouldn't a fifth attribute of Midwest versus the East also be our storage capacity?

MR. ED MURRELL: We certainly have a lot of storage. I think that, you know, New England is clearly storage-deficient. New York and PJM probably have, you know, almost comparable assets to storage. There is a lot in New York and Pennsylvania. So they're not necessarily in the same footing, but they're not that far behind; but, yeah, I think storage -- at least it's an important ingredient for you to have in your mind as you consider what the options are going forward.

COMMISSIONER McCABE: And you mentioned room for innovation and new business models. I wonder whether you just want to talk about what are the possibilities you see in the future.

MR. ED MURRELL: I'm going to try to sum this up. It's hard to do that briefly. I think part of what happens in the real world -- I mean, we just expressed this last winter. We saw unprecedented prices. We saw pressure on both electric and gas industries for high prices. We had market rules that had to be changed on an emergency basis at wholesale and high prices have a very strong attractive force. People out there have things they see that I don't see where they think they can make money and fill gaps that they believe were exposed by these recent experiences, I think innovation is going to be coming to follow the money.

So I think in terms of marketers who stand in the middle and kind of meet the gaps between the gas industry and the electric industry in serving individual generators on a day-to-day basis, you have people that are contemplating a different way of contracting for FERC capacity instead of individual customers. You would have customers pool together and contract for pipeline capacity recognizing they're not all going to be using their full needs at the same time.

So there will be some ability to kind

of balance the financial commitment of more pipeline firm commitments and the overall kind of aggregate needs in the region and that's going to be important. If you build all the pipeline capacity you need to serve every single gas-fired generator, what is that going to do for prices in the electric industry? What is that going to do for the demand for gas?

And at the end of the day, those generators are still only going to be operating as needed. It could be a 12 percent load factor in a particularly moderate weather year. So if you overbill, there's a lot of prices and costs that have to be carried with that. There's probably service innovation at pipelines and storage providers that other service providers can also provide.

COMMISSIONER COLGAN: All right. I think that with that, we probably need to move on to our next panel, but I think a theme that I heard -- it's something that you brought up, Mr. Gardner -- is this issue of resource adequacy planning on a seasonal basis and the balance between interruptible services and firm service and how is that going to play itself out in the long run? I think that's probably a really good point on that. I'm not asking you to respond to that. I took note of that.

So let's thank our first panel.

(Applause.)

COMMISSIONER COLGAN: Our second panel this afternoon is titled Business Practices and it also has three panelists: Andy Ott from PJM; Gene Nowak from Kinder Morgan; Tim Sherwood who works at Nicor who is going to be speaking for the Illinois LDCs.

If you three would like to come forward.

Andy Ott is executive vice president of markets for the PJM Interconnection. He also serves as a board member for the Association of Power Exchanges, PJM Technologies and PJM Environmental Information Services.

Mr. Ott has been with PJM for more than 15 years and is responsible for executive oversight of PJM's market operations, market strategy, member training, state relations, Customer Relations and Performance Compliance divisions. He was responsible for designing and implementation of PJM's wholesale electricity markets including the PJM locational marginal pricing, financial transmission rights, day ahead energy market and capacity market systems.

Welcome, Mr. Ott. We'll be interested in your comments.

PRESENTATION

BY

MR. ANDY OTT:

Great. Well, thank you for having me today. I appreciate being invited here to speak.

If we go to the first slide, this item -- the first two coordination issues might be repetitive of what Mr. Gardner was referring to, but I just highlighted PJM's perspective on this. I think the issue of coordination between the gas and electric systems, what we've seen, I think, and what FERC has highlighted is that the nominations for gas and the awards for power just don't line up and we really need to deal with those.

And there are two different issues.

One is the power plants that burn gas need to come into the power market not knowing whether -- with the gas offer not knowing if they're going to need to procure the gas or not because of the system. The coordination issue, of course, on the back end of that is the power market awards the schedules -- the gas generators to run and at that point, the gas generators go out and they've missed a timely nomination for the gas sites. So it makes it difficult for them and that's a timely issue that we face. Obviously, there are solutions that we'll talk about.

If we go to the next slide, this item is -- again, was alluded to by Mr. Gardner, too. I think probably look at it a little bit deeper from two points of view and this is the time between the gas day and the electric day. Again, in the winter which is when gas matters the most to the power system, we have the load shape as you see on the -- on the slide for power unit, an extremely steep load ramp, right before the gas day is ending. So the gas day is started at 10:00 a.m. for us -- 10:00 a.m.

eastern the day before and it's ending at 10:00 a.m. in the morning.

So our peak -- our two peaks in the power system -- in the power industry, two peak demand periods are two different gas days. So there's two problems with that. First is the morning ramp, so we have our peak usage right as the gas day is ending and have to switch over to a new day. The second issue is intraday nominations for gas don't really line up with the power peaks. So what FERC had pointed out in their -- rulemaking were those two issues.

If I go to the next slide, what I do -- I would be remiss if we didn't point out -- if I didn't go into observations from the January 2014 operations. We had an incredibly successful implementation of reliability coordination between the power industry and the gas industry, especially with PJM; but I think everywhere we had gotten some orders from FERC that allow us, on the power side, to share information with the gas side and vice versa. And I tell you we -- in the control room during that

January, we had unprecedented information on what the -- what our cash units were capable of running, what the gas acquisition -- like from a reliability perspective from them, so we knew what was going on. Situation awareness was vastly improved, so that was a success story.

Now we go to the challenge. The challenge is on the commercial side. What we saw this winter was fairly significant issues with the market timings and, really, scheduling issues between the gas and the electric systems and, really -- probably mostly creative costs -- and I'll explain that as we go through -- but also created some scheduling challenges. It did not create reliability challenges because, as I said before that, that it was very successful.

What we saw, though, was pricing impacts -- fairly significant pricing impacts. We also saw impacts on the power side to the cost of reserves. And let me explain a little more finer point on that. In the power industry, the way we schedule to run on peak load days is we schedule, of course, the base load equipment, the mid-merit equipment and the stuff that's very flexible; the very high cost, we scheduled just at the peaks.

What we found -- the phenomenon we saw this winter was unprecedented -- we hadn't seen it before -- we saw it in New England last year, so we should have saw it coming -- was our most expensive units became gas-powered combined cycle units that had to take gas 24 hours a day. So they were sitting up at the very top of our cost curve; but they were not flexible, so we had to run them as mid-merit units even though they were the most costly and we held in reserve our very flexible resources for reserve at the 500 to $700 energy price range. So we're running $1,000 stuff and leaving stuff off that was cheaper so we could have flexibility and completely inverted how the power system normally would operate commercially.

So what we found is we were holding the bag with a fairly significant cost increase for reserves. This number was not small. In January, it was $500 million to the PJM footprint. Now the PJM footprint is pretty big, but can you imagine a price tag of $500 million? That exceeded the entire cost of our reserves for the entire year of 2013. So it was a fairly significant hit for us.

If we flip to the next slide, I'll put a little finer point on that. These costs of reserves, these blue bars are -- I have it here on my slide and hopefully you have it on paper in front of you -- the blue bars match up with the dollars that you see on this -- on the side of the slide. So it's in millions of dollars on the left side of the slide. So you can see there are some days where we were actually paying $90 million a day for reserves. A typical day would be half a million, so it's a significant increase in costs to us.

You can see in -- the green line lines are the price of gas for those days. Again, it was not the price of gas that caused the problem, it was the combination of price of gas and we had to take those resources that were high priced for 24 hours because the gas units had to run with the cost of flow of gas. So the issue of the combination of high price, the gas pipeline run, the operational flow orders, we had to have gradable take on the gas units. So that was the issue we faced. So the lesson learned there is we have to get much more attention on that issue because from a cost perspective, it was fairly astounding.

The next slide, the other issue we had was a scheduling issue. I entitled this slide Holiday Considerations because it so happened one of the days where it was very cold -- we were expecting cold weather was over the Martin Luther King holiday as we're looking forward from Friday into Tuesday to try to schedule equipment to manage peak load conditions that were expected on Monday and Tuesday of that next week.

The issue was the gas units had to know Friday morning whether we need them or not because it's very difficult -- from what I understand -- I'm not a gas trader, but from what I understand, it's difficult to get weekend -- get Monday gas over a weekend generally because of the liquidity of that product. It's -- again, it's not a pipeline issue, it's really a trading issue that we see there.

To make sure we're clear, this is really an acquisition of the gas commodity, it's not a pipeline schedule; but the issue was we were trying to forecast ahead of time -- three days ahead of time what kind of gas units we needed to schedule. It became extremely expensive to carry those things through the weekend. One of the lessons learned there is we really needed to work with the folks to get much more flexibility on how those units were scheduled in the future.

So now I'm going to turn to proposed solutions. So I told you the problems. And, again, those were the problems we saw this winter and some of the commercial problems. Of course, Joe Gardner from MISO already talked about the reliability. I did not want to be repetitive there.

The first is we really need on the power side to really create a mechanism to improve generator availability during winter. One of the challenges we faced in the winter -- even though the gas units were able to get gas mostly, we had very few unavailability of gas units due to fuel from a relative perspective, we saw a fairly significant downturn in the availability of resources during the cold weather and that, of course, also increased costs.

So we need to create a mechanism to deal with that on the power side. That will help us then to deal with the issues on the gas flexibility, more resources to work with. Obviously, from PJM's perspective, adopting the changes to gas nomination timings in the FERC NOPR I think is something that obviously we'll be advocating for.

The FERC NOPR also added two additional intraday nominations which also helped with gas day fluctuations and to power. It also was already mentioned, advocated -- or put out in their NOPR the gas timing, moving the gas day timing from 9:00 a.m. Central to 4:00 a.m. Central. And, again, from the power side, that would be optimal because then we'll have the same gas day for both of our peaks. And we realize there is a larger debate there because there's a national issue, but that doesn't change our opinion on the power side. My colleagues from California have actually agreed with that.

Then we go into, obviously, the power market needs to change. We need to change our timing and the way that we deal with the gas market. Certainly on the power side, we were ready, willing and able to make some changes.

If we go to the next side, my last set, we are working actively with generation owners and gas industry folks to create more flexible products to support power operations. Again, power plants, people have asked me, should we just require firm transmission and firm commodity for power plants?

And here's my point: It's not really going to be sufficient to do that because what the power industry needs is the power plants to be able to have a flexibility in how they burn the gas. Power plants just can't -- we can't run all the power plants flat out and have them take a constant amount of gas and still run the power grid. If we're going to have upwards of 70 percent of the power generation -- of the gas, it's not going to happen. There's got to be a mechanism that provides for flexibility because on the power side, we have very changing conditions during the day.

So we need to deal with that issue. It could be a combination of storage and other types of mechanisms to do that. It could be -- if we have to do fuel on-site storage, on-site energy, whatever it is, we have to deal with that issue though because it's too expensive not to.

As I said, the issue of inverting that supply curve and us paying units to run at those levels is really not sustainable. We need to make sure that the power market rules reflect the gas commodity prices, the actual cost of transport, the cost of commodity and the cost of storage.

So we need to make sure on our side that we adequately articulate what we need there to make sure it gets priced in; we need to update our scheduling protocols -- based on what we saw this winter -- the issue that was alluded to -- and last, but not least -- I think this is probably going to be extremely important -- is for us to revise a product definition for what we are purchasing as far as capacity.

We really need to have fuel assurance, fuel security reflected in that and also resource performance because if you have units that have high fuel security and they have high performance, they should get a premium payment. Today we don't necessarily have that in our markets and we've heard, obviously, some criticisms, some coming from this area of the country where resources aren't necessarily valued based on that and we actually hear that and think that is probably something we need to deal with rather quickly.

And I thank you for your time and I look forward to your questions.

COMMISSIONER COLGAN: Very good. Thank you.

Any questions.

(No response.)

COMMISSIONER COLGAN: Okay. The next speaker is Gene Nowak. He's vice president of transportation and Storage Services, Interstate Pipelines for Kinder Morgan. Mr. Nowak is currently responsible for the management of commercial business operations of all the regulated entities regarding their transportation and storage transactions. His responsibilities includes nomination, scheduling confirmation, allocation and contract administration functions.

Gene is a pipeline segment representative, on the NAESB board of directors since 2012. Most recently, he has actively participated in the NAESB gas-electric harmonization forums regarding the scheduling NOPR being discussed in the industry. And, lastly, Gene was on a -- panelist on the FERC Scheduling Technical Conference held in 2013.

Previous positions held at Kinder Morgan during his 27 years with the company have provided Gene with a broad range of experience in the gas pipeline industry including marketing, operations, scheduling, contract administration, accounting and IT.

Gene started in the gas business as an accountant for Mitchell Energy for seven years responsible for several pipeline and plant assets. Gene is a graduate of Grove City College in Pennsylvania with a Bachelor's of Arts degree with a major in accounting.

He earned his MBA at the University of Houston majoring in Finance and Management Information Systems. Gene also achieved his CPA certificate from the State of Texas.

The floor is yours, sir.

PRESENTATION

BY

MR. GENE NOWAK:

Thank you for letting me have the opportunity to present what's going on with the scheduling NOPR and the NAESB process. Just to -- for those who might not know Kinder Morgan and the pipelines, we do own -- we do have about 70,000 miles of pipelines across North America. We do hit a lot of the major Shale plays that are very active now. Our key pipeline assets I've listed there, both NGPL being the one of most interest to this group and I've been -- along with NGPL for all those years before

Kinder Morgan actually bought that pipeline.

March 20th is when FERC issued three of these companion orders that were alluded to in the earlier presentations as well. I'm primarily going to go through the scheduling NOPR and some of the NAESB process and where we stand with that process.

The second order on the -- that came out that day was related to the Shale cause order for companies to be able to post offers to purchase capacity on the pipeline systems. That's a regulation that is currently in existence and I believe all pipelines have been applying those type of rules. It has not been very -- demand has not been there a lot for that type of service, so there's not been a lot of big system enhancements. NAESB has taken that up and is going to put out some more standards relating to that regulation.

And the last one, of course, is the one that's related to electrics to move up to day ahead market clearing to be in conjunction with the gas day changes that we are working on.

So the scheduling NOPR was to -- and

as we've stated in other presentations, to coordinate the gas and electric. I've listed four main components of it. One is moving the gas day start from 4:00 a.m. to the current 9:00, moving the timely cycle back an hour and a half from 11:30 to 1:00, increase the number of intraday scheduling cycles from two to four cycles and also to require interstate pipelines to allow multiple service agreements -- multiple party service agreements. I'll go through each one of those later with, I guess, Kinder Morgan's position on those items.

The time line was set to give NAESB a chance to obtain energy consensus and any changes to the NOPR and have those changes filed with standards by September 29th. The NOPR itself, the comments period is closing November 28th and final order would be issued sometime after that -- assuming early next year -- and then NAESB will then have to go back and update any standards that were modified by the final order.

So the NAESB process to date -- and just to make sure everyone is aware, this -- the way this is coming out is a different process than FERC has dealt with NAESB in the past. Typically in the past, the industry gets together, they get -- they have consensus on standards, they then file those with FERC, FERC then issues a NOPR of which comments can be presented and then a final order comes out. This one was kind of backwards. FERC came out and directed NAESB, Here's the NOPR. Write the standards.

So it was a different process for the NAESB folks, but I think we all that were involved kind of stepped up to make this work.

So to make it -- to really get through a consensus to any changes to the NOPR, NAESB did a lot of meetings -- four two day meetings in a short time period very heavily participated by both industries, probably by some in this room as well. It started off with 13 different presentations of people's views of where things are. They range from no change of anything to let's schedule every hour on the hour. There were many voting opportunities to try to narrow down and whittle down if there were any consensus positions on the changes and, as expected, the gas day was the main issue that couldn't get consensus on. We did talk about other gas days, but it really came down to 4:00 a.m. versus 9:00 a.m.

The scheduling cycles, however, there was a wide agreement on changes to that over what the NOPR did propose. They did propose four cycles. This group came up with three-cycle proposal and it fixed a lot of the issues that were embedded in the NOPR time lines. And I'll address and highlight a couple of those in a minute.

So after these seven meetings, the NAESB Board of Directors directed the folks in NAESB to write the standards to proceed with making the standards with three-intraday cycles, not the four-intraday cycles as the NOPR laid out; but remained neutral on gas day start and also to make any corresponding standards that made sense, mainly around the capacity release time lines. NAESB did file a report to FERC which has blow-by-blow details of all these meetings that we had, so it's out there for the public's view.

So what's come up in the NAESB process is currently right now, there's a group writing the standards that need to be ratified by the wholesale gas quadrant because that's the only area that the standards were being changed and file that with FERC by September 29th; and then NAESB is going to sit back and wait for a final order to come out. I threw some days on here just to kind of, you know, think through when is the earliest it could possibly happen.

So we could see FERC could order something in the first quarter of next year with probably a direct move onto 4:00 a.m. versus a 9:00 a.m. directive which then NAESB would have to go back and readjust any standards to have that specific time laid out in there.

After that, it's -- we're not quite sure what's going to happen because of -- there's certain variables. One -- the one -- this is a new process with NOPR coming first, so we're not sure if FERC is going to issue another NOPR. It hadn't -- passed NAESB filings or condition to work off of the

NOPR they're working on now.

There's also a pending Version 2.1 set of standards that has not been ruled on by FERC and there is also work happening in NAESB for 2.2 standards. So there's a lot of things happening in the NAESB world and we're not quite sure how it's going to all come into play; but based on -- that is very complex -- I think the implementation, at the earliest, would be the fourth quarter of '15.

I'm not going to go through this in detail, but this is just a side-by-side layout of the different cycles that are on the table. The first column is the current cycles, which is, you know, two day ahead cycles and two intradays; the second column is FERC NOPR, which is two day ahead and four intradays; and the last one is what NAESB is working on proposing. It doesn't have the gas day reference in there. I must have left that blank.

And I did speak earlier that there were some issues with the FERC NOPR the way it's laid out. The primary one is they're basically overlapping intradays. Intraday 2 nondeadline is one half-hour before the results of Intraday 1 is finished. So it's almost defeating the purpose of having four cycles if you're not even knowing what the results are of one cycle before you have to make adjustments for the next cycle. So that was something that we did fix in the NAESB gas-electric process.

And the last thing -- the other thing that we considered a problem with the NOPR is on the Intraday 3 and 4 cycles, they shortened the processing time from 4 hours to 2 hours for the pipelines to process all the activity which is a very short time frame. And so we did have some agreement on that -- agreed to process in time which was about an hour reduction of what we are having to do right now.

Just to go through some of the bullets, what Kinder Morgan's position on it is we prefer no change to the gas day just from a pure pipeline perspective; but if we did have a change, no earlier than 4:00 a.m. The main preference for not changing is this is going to be a huge implementation effort across this whole gas grid that has been working well for 15, you know, 20 years on the current cycles. Every meter that comes in and out of our system has to be reprogrammed, readjusted to make these gas days happen. It's going to be a big effort on Day 1.

Now, once we figure out how to do all that, that's -- you know, it's set, it's not going to be a big deal; but that first stage in coordination is going to be very difficult, and I would expect a lot of comments that we're going to talk about that will come through in the NOPR, a long implementation period.

There is an advantage -- I'll skip my second bullet for a second. There is an advantage for having an earlier start. Which was alluded to earlier in the presentation, it does get the peaks all in one gas day, so that is a good thing. We'll make it a little -- it should make things better for the coordination effort, I would think.

We have automation at most of our significant locations, so whether the gas changed --

one gas to the next happens at 9:00 or at 4:00, if the automation is working, it's probably not a big deal. We also have some locations where it's manual maybe by our counterparts. They have to be onboard with the 4:00 o'clock day change because they can't just rely on pipelines to take a swing until they get around to making the proper changes.

But to the extent that automation does fail for, you know, whatever reason, it will probably cause increased nighttime call-outs and, you know, sending guys out, it could be more of a safety concern that we don't have to deal with right now. Right now, at 9:00 o'clock if something fails, it's daylight, you can go send someone out to fix it. 4:00 o'clock, we have to make a decision, if it's significant to go send someone out and risk the safety concerns or just wait to fix them when that day comes. And that's really the main reason why we're saying the 4:00 o'clock would be the earliest we'd want to have it because that's, you know, 2 to 3 hours before normal daylight that you could probably -- if there is something that did happen, you could probably handle a swing. That has been raised, a concern, especially for the West Coast folks because 4:00 a.m. Central is 2:00 a.m. West Coast. That's 2 more hours further away from daylight, more risk and more call-outs going to folks to go into the field, more safety concerns.

Moving on to the timely cycle. We have -- you know, we're all on board with moving it back an hour and a half to 1:00 o'clock. I think that's right in line with the intention of the orders that came out that day. We'll allow time for the electric markets to make adjustments and make sure that they are planning their day ahead market in plenty of time.

One that wasn't directly addressed in the NOPR, but it's going -- but NAESB is working on is the capacity release time lines should all be adjusted as well and there is one specific one that is a release with an open season for the timely cycle, which is the most critical cycle to get your nomination in. We'll be able to do that earlier and still have time to nominate for that next day.

Right now, it closes with -- it closes after the timely cycle closes, so you can't nom timely until two days out, so that's going to be a big improvement for folks who are releasing capacity to be able to participate in that timely cycle on the next day.

Increasing the number of cycles two to four, again, I've spoke to this earlier, three cycles should be sufficient. This will cause, probably, a longer gas day for our gas scheduling office folks and we wanted to make sure in the time lines that we didn't have any overlaps that we were working on one day at the same time we were working for any -- on another day because that also causes a lot of confusion in the industry that -- folks can focus on one gas day at a time.

And the last point was the multiservice party agreements. The way it was written in the NOPR, we are okay with it, we have three pipelines that have those provisions in them right now at Kinder Morgan. It is kind of limited in whose pipeline is -- or each party in the -- that holds that contract is jointly reliable for the activity of that contract and there's going to be -- one of the parties is the administrator of the contract. This is really just a -- in our view, kind of a shortcut of having to do capacity release.

So in conclusion, gas industry is moving and making changes with what's happening, this NAESB effort adding additional cycle, shortening the processing times by an hour, having a later timing cycle, having a quicker potential release for timely cycle, so the only thing that really is at issue is the gas day itself and I think there are a lot of folks -- that is kind of a sticking point. The benefit of moving it is not really seen across the whole gas industry and they view it more of a cost than a benefit to the entire industry.

And with that, that's -- I'm open to any questions.

COMMISSIONER COLGAN: All right. Thank you.

Any clarifying questions.

(No response.)

COMMISSIONER COLGAN: I have one. You

mentioned the safety issues and I think I'm hearing you say that the big safety issue is the difference of doing things at night rather than in the daylight?

MR. GENE NOWAK: Yes.

COMMISSIONER COLGAN: That's the big issue.

Are there other safety issues that kind of pivot off of that or are there individual other issues.

MR. GENE NOWAK: No, I think it's mainly the nighttime effort. You know, we send -- some of these locations are very remote -- remotely located and sending guys out in bad weather, in the middle of the night, we try not to do that in a work-forced business.

Now, if it was an emergency, that's one thing; but just to adjust the gas in a commercial transaction that was supposed to change and someone didn't change it, you know...

COMMISSIONER COLGAN: Can some of those issues be dealt with remotely?

MR. GENE NOWAK: Well, that's what we have -- the automation, when I say "we have automation," that is all remote. That is the remote aspect of it, but you're remoting equipment that can fail, it can freeze off. You know, there could be times where you need to send the actual body out there to make things flow.

COMMISSIONER COLGAN: Okay.

COMMISSIONER DEL VALLE: I had the same question about the automation. You say that the automation is remote to more significant locations. Are we moving towards automation at most locations or all? I'm assuming there is a cost issue.

MR. GENE NOWAK: It comes down to a cost issue, I think is what it comes down to. It's -- a lot of these connections that are coming from wellheads, the producers are just setting it to flow and the gas just flows. So there is no real flow automation needed unless you wanted to go and override it and actually shut them off.

So there's not a whole lot of benefit to actually having remote control at a location like that; but if there was an issue -- like gas quality is one we have to monitor -- if the producer is giving us gas that's not pipeline quality, you might have automation on there to send someone out there to go check it out and intentionally stop the flow.

COMMISSIONER COLGAN: Thank you. Our next speaker is Tim Sherwood, vice president Gas Supply Operations for AGL Resources, and Tim is going to speak to us about -- on behalf of the LDCs here in the state of Illinois.

Tim was named vice president of gas supply operations for AGL Resources in December of 2011. He's responsible for interstate capacity planning, gas supply acquisition, gas control operations and forecasting as well as customer transportation program management for AGL Resources Utilities, including Nicor Gas.

Sherwood joined AGL Resources in 2005 as managing director of gas supply and capacity planning. In that position, he oversaw all aspects of capacity management for companies -- retail nature gas customers in Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia.

With more than 25 years of experience

in the utility industry, Mr. Sherwood was director of energy acquisition for Washington Gas Light Company prior to joining AGL Resources. He also held various management positions with Ameren Illinois, including administrator of federal regulatory matters, supervisor of gas supply and manager of electric arrangements. He earned his undergraduate degree in Economics from Illinois State University and continued professional development at Columbia Southern University.

Mr. Sherwood, the floor is yours.

PRESENTATION

BY

MR. TIM SHERWOOD:

Thank you. I appreciate the opportunity to speak on behalf of the LDCs. Hopefully I will do a good job or I've got a group of people who are going to meet me in an alley here, so pretend like you like it even if you really don't.

The first slide is one -- it's just another format of a lot of presentations you've seen before. This is the gas day and scheduling cycles, kind of current as -- and proposed. I think generally speaking, the LDCs in Illinois feel that this is a dialogue at least that we need to be involved in and having so that both industries can understand each other better, if there are ways to make adjustments to the nomination cycles like Gene spoke about that really just add more transparency to understanding how much capacity is really available to the market.

I don't know why we wouldn't want to do that, but there are concerns like the things that we've talked about 4:00 a.m.s, for example, is problematic from our perspective. And to some extent, we feel like it's change that not clearly results in a solution to a problem. Our concern is that predominantly the issue is a lack of capacity, an hourly capability of the marketplace and simply changing the nomination cycle time and beginning of the gas day doesn't really change that. It's kind of like showing up at the airline gate earlier with a standby ticket. You're still only as likely to get on if all the people that bought confirmed tickets don't use it. You'll just find out earlier you're not getting on.

So -- but we do think this is an important thing. You know, back in Order 436, 636, I think we all thought a lot of this stuff wouldn't work and obviously we were able to find ways to make those things work, so it's worth a joint effort to look at them.

The next slide please. But I think this is what -- and this is to my point: I think, you know, we need to continue to work on communications. We've found as we've had discussions with folks from MISO and from PJM that a lot of times we just talk a different language and they don't really appreciate the restrictions and constraints we're under and they don't appreciate the restrictions and constraints that they're under and understanding those better are helpful; but time line adjustments and those things don't create pipeline capacity and at the end of the day it's -- and while we oftentimes talk about buying capacity on a daily basis and having to take it for the day, the reality of it is, we all operate under hourly constraints.

All of our LDC's loads, if you look at them throughout the day, peak for certain hours and drop off at certain hours and we buy capacity capable of serving that peak hour and admittedly our holding capacity in those off-peak periods that arguably wouldn't have but the pipe doesn't shrink and swell with the load throughout the day, you have to put the pipe in place to serve it.

So even if you have more nomination cycles, if you're under a pipeline OFO, for example, you want to take 24,000 and it's 1,000 an hour, you would normally take that; if you want to take it over 8 hours at 3,000 an hour and the local piping and pressure system won't carry 3,000 an hour, it doesn't matter that you could change your nomination and that's what, for example, OFOs are.

OFOs say don't take more than 1,000 an hour because the pipe capacity, the compression and storage in the area can't deliver more than that amount; and if you take more than that, you'll actually be taking someone else's gas. That's what, effectively, the restrictions are that are in place. So we think infrastructure is the answer to most of these issues at the core of it while these other discussions are certainly important ones to have.

The next slide, please. This is based on our understanding of the marketplace and from having conversations with folks; but we do have -- several LDCs in Illinois are combination utilities and those that are combination utilities have communicated to us that they haven't typically seen extreme problems with this because in their market structure, they have the ability to contract for and acquire firm capacity consistent with what their needs are at their plant, they have a way of recovering those costs so they incur those costs, and generally they are able to operate under the current mechanism the way it works right now.

Having to nominate far in advance of what you know your usage is going to be, that's -- that is an occurrence in the industry. The Wednesday before Thanksgiving, every year for the last 20 years, we've had to nominate gas for the Monday after the holiday at that point in time. The weather forecast can change a lot. Our demand could change a lot. We contract for storage services and balancing services and FT to say what that need might be so that we can adjust our demand or adjust our deliveries to meet what that demand is knowing that it's less predictable when you are forecasting it four or five days ahead of when you need it.

But we do understand and we've heard and that's why this conversation has been helpful because we do hear a lot of folks operating out there say, Well, I don't have a way to recover costs of holding capacity and I've got a bid into a market not even knowing if I want to schedule gas, if I'm going to be able to acquire it and get it and it's creating a problem and even sometimes I've heard anecdotally where it's bidding up the marketplace because everybody is going out there to try to buy delivered gas anticipating that they might be dispatched, but not necessarily knowing that they're going to be dispatched.

I can understand that problem and I

can appreciate the fact that that is an issue as both industries we need to address because it results in mixed market signals that there maybe is more demand out there than really even exists and can drive up prices for those that are trying to operate the way they need to. So it's certainly something that we have to get our arms around because the growth in gas demand for power generation is only going to grow and further impact the grid.

So going on to the next slide, I think that from our perspective, we see that -- as you see these greater needs as generation goes more and more to gas, you are going to see greater reliance on no notice storage-type services, for example, the kind that we contract for that -- and has been mentioned by others, that we may -- need to be contracted for by -- by generators are going to effectively increase their costs. It could increase the costs of the entire gas grid and trying to manage line path, the difference between the maximum pressure that can be held on a pipe and the pressure at which downstream takers of gas can utilize it.

That's the way -- a lot of times when a power plant or other -- or an LDC ramps up their usage and takes more for an hour -- an hourly basis, it comes on line back, plant power -- plant ramps up -- or an LDC ramps up and you have 900 pounds in an 1100-pound MAOP system, well, it may pull that pressure down in that system down to 500 pounds and that's where that gas comes from because gas nomination cycles -- you put gas in Texas, it travels at 20 or 30 miles an hour.

So changing an out bed line doesn't get gas to where you are burning it right away, it's localized facilities, it's diameter of pipe locally, it's compression facilities locally, it's storage locally that gets that need ultimately satisfied and the system was denied for a historic level of peak hourly demand versus daily demand and it looks like the dynamics of the market are going to change as we get more of this high-peak hourly demand coming on the system.

And the only answer to that that we see is infrastructure will be built; but it could wind up driving costs. These are costs that LDCs, for example, traditionally flow through things like our purchase gas adjustment and you can see in the future as these demands on the systems go up and it drives the cost of providing gas up, you may see higher PGA costs from LDCs than you would have seen otherwise, not necessarily -- well, not a good thing, but not necessarily an inappropriate thing because it may be allocating costs the way they need to be allocated for the services that are needed.

And then the last part -- this is touching on a little bit of what Gene had talked about -- is that changing -- depending upon what comes out of the gas day change -- and I don't really know what will come out of the NOPR -- as with most things like this, we'll probably wind up with a group of people who are all equally dissatisfied, so that might be the best solution that will come out.

But to the extent that it's going to change -- you know, we don't normally have people, for example, coming in at 4:00 a.m. to do nominations and scheduling. They come in and they work a normal cycle. We may need more personnel to manage the functions around scheduling and nominating. We may need more people to do safety and security-related things, like you said, changing flow rates out in the field such as for things that aren't automated or if they are automated, if the automation fails, you have to have somebody go out there and physically adjust those things.

We -- most of our transport customers have built their business around serving the transport customers behind our system based on the way the pipeline system operates and there may have to be changes in our system for how transport marketers interface with us to be able to accommodate the changes here; just like the pipelines will have to make changes to their systems to address whatever comes out of that, and those are all costs that we would potentially incur at LDCs that are normally recovered through a base rate type of recovery mechanism.

So you may see that, depending upon what comes out of it, there could be changes in base rate costs associated with just operating under this kind of newer environment as we move forward; but I do believe there is certainly adequate gas supply to meet these markets. I think it's a matter of just rightsizing the local facilities, predominantly interstate pipeline facilities, but also storage, marketer storage. Illinois is blessed with a great deal of it, great geology for it and has the potential to potentially expand storage to help meet some of this without having to build yet more capacity all the way back to the production areas to meet these hourly fluctuations. You might be able to much better meet it with storage capability that the State is -- has a great deal of.

And that's my prepared notes. If you have any questions, I'll be happy to answer them.

COMMISSIONER COLGAN: Thank you. We're a little bit off schedule; but I think if we had questions that people have, we'll take a couple of those.

COMMISSIONER MAYE: I have one question.

COMMISSIONER COLGAN: Commissioner?

COMMISSIONER MAYE: Definitely.

Mr. Shorewood, I wanted to take advantage of you -- the LDCs, this afternoon -- or perhaps it was this morning in the Chicago Trib, there was an article on the storage and refilling the storage and basically I'll just quote, "Natural gas is being injected into storage facilities at a clip unseen in more than a decade. Still, however, inventories remain 27 percent below the five-year average, according to the American Gas Association, and analysts say they're unlikely to rebound fully before winter."

Additionally, there is another statement on behalf of Integrys that says, "If we have a year like last year, which we really don't really expect, it could be a challenge." So I know that you're stating -- obviously in Illinois -- and as a matter of fact last week, myself and Commissioner McCabe went out to Nicor's facilities in Kona and were -- you know, were told basically that the storage, you know, is adequate; they are prepared for a winter even if it is like last winter across the board.

I'm curious now and obviously concerned based on this article. I'm curious to know if the AGA is speaking as a whole or any of our particular utilities are included in that concern.

MR. TIM SHOREWOOD: Well, you know, from -- I can't speak for -- you know, in detail for all the LDCs in Illinois, of course, but just -- but obviously we talk and they all operate generally under the same operating principles that we do at Nicor which is storage will be full before winter, that's an unequivocal statement.

There will -- there is not a chance that our source is not going to be full for winter unless there is some kind of cataclysmic event that -- because we, again, we contract for capacity even in the summer to make sure that we can transport enough gas from the production areas to inject into storage and the other LDCs do as well and we -- we plan as if every winter was going to be like last winter. That's that -- because the risks of not being prepared for that are so high when we provide a safety-sensitive product to customers that they use to heat their homes, you can't risk being without it.

So we really -- I'm really indifferent to whatever the future weather forecast is because our storage was full before last winter, it was full before the winter five winters ago and it will be full for the winter five years from now because that's -- we use that to meet the critical needs of our customers.

Nationally, yes, I think storage is below; but we also have to keep in mind that the amount of storage inventory available in the United States now compared to even five years ago is substantially higher than it was because a lot of storage has been developed in the nation. A great deal of that storage is salt dome storage which looks much more like a thermos bottle of gas, which doesn't have some of the same characteristics like a lot of the storage here and you can fill that. Many of those storages could be completely depleted in 10 days and completely filled in 20. So I'm -- I'm not sure we'll get back up to the pre-winter of last year's levels, but I'm not particularly concerned that nationally we're going to have a storage issue. I think right now a lot of that salt dome storage is held by folks who trade in gas and the economic signal right now doesn't tell them to fill it. It says fill it later because there's a better economic time to fill it, but they can fill it pretty quickly if they need to.

COMMISSIONER MAYE: Thank you.

CHAIRMAN SCOTT: Mr. Sherwood, in listening to a lot of conversations here and other places, the changing of the times has been -- I mean, almost everybody brings that up, that's part of the discussion that's going to happen through the NOPR, but -- and I understand you're acknowledging it -- Commissioner Maye and I appreciate it -- but, again, it's not necessarily going to help at all unless people know earlier that they're not, you know -- is there some significant downside to doing that? I mean, are there other unintended consequences from that that would be difficult? I'm trying to figure out, is it just a matter of, I just don't know if it will help that much, why is there that kind of debate on that?

MR. TIM SHOREWOOD: Well, I think a lot of it is because as an industry, people have spent a lot of time on -- and spent a lot of money on systems built around the time frame that we have now and are unsu- -- and it's -- I think it is predominantly a cost issue. I'd say from our perspective -- and I think from the LDCs in general when we spoke about this prior to this -- our biggest concern was -- is that folks would walk away with, we go to 4:00 a.m. to 4:00 a.m. and get three nom cycles, the problem is solved and we're all sitting back in front of you guys two or three years from now when the electric generators didn't get the gas that they needed to operate and the legitimate question would be, I thought you guys told us this was going to fix it.

And I strongly -- and I think the other LDCs strongly come to the opinion of this doesn't fix it and we don't want to give anybody the illusion that a paint job makes a new car. It just doesn't change fundamental problems that just need to be addressed and these aren't problems that are caused by bad behavior by power generators, it's the nature of how they have to use gas and the gas grid wasn't designed to satisfy that particular need. It's not that they're doing something wrong. It doesn't have anything to do with wrong and right, it's just different in the way that the pipeline grid was originally designed.

It was originally designed predominantly designed to serve LDC load and then opportunistically serve combustion turbine gas load in the summertime when all of our customers were not using gas for space heat and it worked really well for that. You start bringing a lot more generation on and it creates circumstances where they need to use capacity at the same time that traditional users of capacity need to use it and just -- it does require these kind of discussions in understanding how do we adjust the overall industry and marketplace to best meet both needs and adequately and appropriately allocate costs.

I mean, I'll be honest with you, we're

not interested in having Nicor customers pay for flexibility services that they're not necessarily benefitting from because that's our responsibility to our customers and we will advocate those positions and I know that I spoke for the other LDCs when I say that as well.

COMMISSIONER COLGAN: Okay. Thank you. We're a little bit behind schedule, so we're going to have a little bit of a convenience break here and I'm going to ask people to be back here by no later than 10 minutes after 3:00. We'll reconvene at 10 after 3:00.

(Recess taken.)

COMMISSIONER COLGAN: Very good discussion so far. Very stimulating. And so we have a final panel and we have just two people on this panel and one of them has already been introduced to you, Ed Murrell from FERC, but another person is on the panel who has a history of working on a lot of these kinds of issues and been really active in the NAESB process. His name is Rick Smead and he's the managing director for RBN Energy, LLC.

Rick is the managing director for RBN Energy, an analytics and consulting firm based in the fundamentals of natural gas oil and natural gas liquids industries. He specializes primarily in the natural gas sector offering expert policy analysis and advice, litigation support and strategic advice with respect to gas pipelines, potential supplies and market initiatives.

His background includes over nine years as the director with Navigant Consulting and over three decades in the natural gas industry. That experience included over 20 years in senior management of major interstate pipeline systems. His consulting practice has spent -- has spanned the domestic natural gas industry, all aspects of the Shale gas boom, liquidified natural gas trade and consumption opportunities. He was a pioneer in the understanding of the Shale boom managing and coauthoring the first major quantification of the U.S. Shale Potential in 2008, the pivotal North American natural gas supply assessment.

Most recently, he's been deeply

involved in the opportunities for the use of the nation's natural gas abundance, including power generation, LNG exports and gas to liquids technology.

He holds a Bachelor's of Science in Mechanical Engineering from the University of Maryland and a law degree from George Washington University.

I'd like to invite Mr. Smead to give us some comments. The goal of this session is going to be to get us into a discussion. We're going to hear from Mr. Smead. We're going to hear from -- again, from Mr. Murrell in response to his comments and then we'll go to questions and answers and just hopefully a good open discussion with the Commissioners.

Mr. Smead, the floor is yours.

PRESENTATION

BY

MR. RICK SMEAD:

Thanks, Commissioner.

Yeah, listening to the earlier

discussion, it was great. First off, I'm very proud of Tim Sherwood because he worked for my former company, Washington Gas Light, and now works for my former boss, John Somerhalder, so overall I'm glad he sounded intelligent.

(Laughter.)

You know, this issue, it's a huge issue for Illinois because you don't have much high capacity factor gas-fired generation and so on an annual basis, you use very little. With the pressure on coal, pressure on growth, everything else, it's very likely you will have a lot, so I'm -- it's a great effort to understand what that means.

As Ed pointed out earlier, I think it is important to note -- and as Commissioner McCabe noted, between pipe and storage, Illinois has a marvelous situation in terms of gas reliability and gas flexibility compared to most of the country. Having spent many years competing in Chicago and around Chicago, I can tell you this is the toughest market in the United States to deal with for commercial side because there are so many options.

This winter, with the severity of everything that hit everybody, prices went way up in Chicago for the first time that I can remember; but you'll note that they went way up at the Canadian border, and the reason -- a lot of the reason for that is that the northeast got so constrained and the north pipelines couldn't get there that the northeast was pulling enormously hard on Canada and pulled all the prices up here as well. So it means -- nobody is an island, but meanwhile in terms of reliability, you're better off than pretty much anybody in the country.

The -- I guess elements that I would like to highlight, number one, is that with all of the changes that are happening, the evolution toward gas-fired generation has been going on for 25 years. It's representative of about 71 percent of the capacity added in the United States since 1990. It's still -- natural gas combined cycle plants are still less capacity than coal; but the total gas-fired generation is quite a bit more than coal, and now we've gotten to the point where it's very likely it has run in the winter.

We are fortunate that in 2012, because of very low prices with gas running a lot, we had a laboratory and running at very high capacity factors for long periods of time. We know we can do it. We know that combined cycles can do it at high efficiency. This winter, we had a great experiment in, Oh, my goodness, oh, my goodness, what are you going to do? But everything worked. Reliability was sustained around the country. Prices went crazy in some instances.

In New York City, gas hit 120 bucks an MCF I think on January 7th and -- maybe that was Martin Luther King's birthday holiday -- anyway, it happened -- very high prices a couple of times. That applied to very little gas; but because of the way power prices worked in competitive markets, it applied to an enormous amount of power, so it had a big consumer impact.

So understanding that, understanding the interaction is very important, the NAESB effort -- to have the two industries understand each other is very important; but basically we've learned an awful lot in the last two years, and it's great that the regulators in the industry are picking it all apart to see what it does mean for the future.

MISO, in particular, has gone through a three-phrase effort to understand the capacity implications of having to run in the winter and has gotten very sophisticated by the third level and would commend that. I do a lot of work for America's Natural Gas Alliance and in that role was working with them a bit on it and just very impressed for what they were able to learn.

In terms of storage, I wanted to address Commissioner Maye's question. The national level of storage injection that's going on this year probably will come up short with most of the shortfall being in the northeastern storage, in Pennsylvania and West Virginia and New York in that area, and that really shouldn't matter because the deliverability from production in the Marcellus and Utica Shales is ramping up faster than it ever has in the past and so additional deliverability out of just producing wells will probably make up for any missing storage delivery this winter and it's all located in the same place geographically, which is very fortunate.

The overall effort that's going on, the overall interaction in the industry, it's been going on for over 10 years. When I worked for John Somerhalder -- it was one of my first jobs -- you know, on behalf of pipelines negotiating this stuff in 2001, in charge of a couple of the efforts of NAESB, I really think that what's going on in terms of both industries understanding each other and trying to fix each other's problems, is better faith and more productive than anything I've ever seen in the past.

So with that -- an awful lot of the credit for that goes to a regulator who is willing to understand both industries and who has brought them together and every so often said, If you guys don't fix it, I will, so I really commend Ed's efforts at the FERC. Thank you.

COMMISSIONER COLGAN: Mr. Murrell?

MR. ED MURRELL: There are just a couple of comments I'd like to add before we start actually having dialogue.

FURTHER PRESENTATION

BY

MR. ED MURRELL:

This past winter was a real eye-opening experience I think for a lot of people in the industry. I think everybody in both the electric and the gas industries -- events from the polar vortex has caught everyone's attention. I don't think there is anyone left who really doesn't believe that there's an issue that needs to be resolved in terms of improving how gas and electric are working with each other. So I think that's a very important point. I think people are motivated to not be as scared this winter as they were last January.

The second point I want to make is that I think it really is remarkable that despite all of the challenges both industries faced over the first quarter of this year, that everybody kept the lights on in terms of gas delivery despite a couple of, you know, somewhat significant failures of pipelines serving the Midwest between NGPL and TransCanada. There was still enough gas to meet the necessary requirements. The residential, commercial and industrial customers were served. The electric generators got the gas they needed to operate and both industries were able to keep things working reliably. I think that's pretty important.

We've heard a number of comments earlier today about a number of different aspects of the events from the past few months. We've heard a discussion about the NAESB process and the debate that's going on about changing the schedules and widening the schedules and I think that's very important. I think we're going to see a commercial response to high prices.

As an economist, I have a very strong bias. I like markets. Even though I don't want to pull out my checkbook and pay the bill when those $120 prices are flowing through the PJM electricity rates, I'm going to. That's where I am. So -- unfortunately, I think Andy left, but I'll have words with him later -- but the truth of the matter is is that high prices are important for other reasons than just creating revenues. High prices tell us clearly in an ambiguous way, Hey, look, there's an issue here and when there is an issue and everybody knows about the issue, everybody has the ability to take what they know and the individual details of the different aspects of where they are in both of these industries and come forward with better ideas and improvements and ways to make things work better.

I think we've already seen a lot of small changes and some not so small changes. Ice in New England dramatically changed the timing of its market schedules because they realized after the winter before last things weren't working well for them. They needed to get their market commitments earlier so they could reduce the issues their gas-fired generators faced in procuring gas supply.

As long as we continue to have these mismatches, there is a risk and there is a cost associated with that risk. I'm afraid I still have my economist hat on. I hope I'm not being too mysterious about that; but generators are paying a risk premium today because of these timing gaps and those risk premiums are flowing to the ratepayers in the electric industry because at the end of the day, some of these generators are putting bids into the markets that might be higher than what they would be able to put forward if the two industries were better aligned.

Those things represent efficiencies that I think we can achieve. I don't think it is going to matter at the end of the day if we pick a 4:00 a.m. start for the gas day or a 2:00 a.m. start for the gas day or a midnight start for the gas day. I think we're going to see some kind of decision made to try to align those schedules a little bit better. It will help.

So those are the comments I wanted to leave you with. The only other comment comes from, you know, my world as somebody who advises regulators like yourselves. Federal regulators have a different set of puzzles that they're sorting out; but, really, it's the same kind of thing. We are trying to ensure that we have fair and just and reasonable services and rates. We're trying to make sure that we can keep things working well and reliably. We're trying to make sure that everyone is treated fairly. That's the same basic regulatory portfolio that you have.

Over the years, one of the most important lessons I've learned is I can't fix every problem. Some of these problems have to be fixed by the electric utility, some of them have to be fixed by the natural gas pipeline company, some of these problems have to be fixed by the financial market; some of these problems can actually be fixed by almost anyone. There are certain things that really -- there's space for people from all different sectors to come in and put improvements or innovations or market solutions on the table to fix it.

The same thing is going to be true for you as you think about what are the important problems that you have to identify and deal with. You are going to have to decide what are the problems within our control, what are the problems that we need to leave to the marketplace, what are the problems that require collaboration between diverse interests and how do you move forward?

It's going to take concerted action and individual action from the federal regulators to the state regulators, the market participants, the pipelines and the utilities and I think that what encourages me about the experience of the polar vortex, I think everyone is kind of energized and focused on these problems.

Any questions?

COMMISSIONER COLGAN: Thank you. You know, I've heard a lot here today, some of it I was already somewhat familiar with and some of it I could see a little bit of light in terms of -- it sounds like -- different parties agreeing and working together to solve a very complex issue. There is vested interest coming from all sides.

I guess I see that, you know, part of this will probably be solved by the fact that there is an enormous supply of the product and there's a real interest in giving that product to the marketplace and there is -- on the consumer side, there is probably going to be some pushback in terms of some of the costs that are associated with that and all of that works in harmony with itself so that you end up with, hopefully, reliable products, supply and demand and affordable rates.

And I guess I'm just asking that general question, is that -- that's kind of like a really high altitude look at what I think I'm hearing people say -- is that a reasonable perspective?

MR. RICK SMEAD: Yes, it is, Commissioner. I think the extent of the U.S. natural gas abundance now is still staggering. The industry is still wrapping its mind around it, honestly. It's only come forward in the last six years really and we've gone in -- energy administration projections, six years ago we were going to be importing about 7.8 billion cubic feet a day of LNG by 2030. Now we're expecting to be exporting 9.2 BCF a day. The swing between those two numbers is almost two guitars and so it is just a staggering change and what's happened so far is that more gas than expected keeps coming into the market, especially in the Northeast, so that is what put these enormous pressures of pipelines and on the pipeline relationships with all users including the producers and including the generators.

One of the challenges in generation -- and what we're seeing now, it's really the same challenge LDCs have been facing since they've existed which is they call it the load duration curve; but, you know, you serve part of your load with pipe, part of your load with underground storage, part of it with peak shaving, part of it with interruption to some customers. The generators are facing something similar except that it's not because their load is peaking, it's because of the rest of the market may be pulling capacity back from them at the wrong time; but it still comes down to how long is your congestion problem going to last and does pipe make the most sense in the way to solve that or some other answer?

So in a lot of markets, they're looking at alternate fuel capability or even on-site LNG storage, different ways of style dealing with the periods when you need to run and the system is congested; but the learning curve is steep, the fuel is abundant. It is just an issue of getting it where it's needed, when it's needed is different. For the power industry, a lot of power operators are used to looking out at the window at the big pile of coal and creating the equivalent of a big pile of coal in a gas pipeline is the challenge.

COMMISSIONER COLGAN: Questions?

Commissioner McCabe.

COMMISSIONER McCABE: In the next few years we'll see a lot more coal retirements and environmental regulations being implemented. How do you see that affecting all the gas issues?

MR. RICK SMEAD: The -- actually -- well, actually, Chairman Scott and I got to listen to Gina McCarthy for 3 hours on Friday and the EPA is committed to being flexible, working with the States and sorting things out in a way that doesn't cause a lot of dislocation, she says.

And so still, you know, most of the projections of coal retirements have been in the

60,000 megawatt kind of level, which is about 20 percent of the fleet, and that -- an awful lot of that was going to happen with or without carbon regulation because of with other pollutants and economics. Add a 60,000 megawatt retirement and filling in that energy with the existing gas combined cycle fleet, it put -- nationwide, it puts both coal and gas combined cycles in about a 60 to 62 percent capacity factor just balancing out the same energy; then under the analysis of 111D, they're trying to push gas up to about 70 percent capacity factor.

But I guess the point -- the intelligence I draw out of that is that at least on a nationwide average basis, everything is somewhere within a range of stuff that's already been done and it can be done. It will vary a lot regionally and a state like Illinois, if it has to retire major coal, you can't do it with the existing gas plants without a huge loss of efficiency -- you've got to build new stuff or something -- and so that's going to be the cycle we'll be going through.

MR. ED MURRELL: And I think a couple of things

I would add to that is that there's a pretty active discussion going on, at least in a couple of the regions, about what a generator's obligation is to the capacity market as a capacity resource and does the capacity market structure in PJM, in New England, you know, potentially in some of the other regions -- is it sufficient to support where a coal-fired generator has to make decisions about what it's going to do going forward. It's going to be faced with whatever aspect of the state implementation plan is going to affect them directly; they're going to have some potential capital decisions to make.

It's not clear to me -- I don't know enough how that's going to affect the decisions of the individual owners of these coal-fired plants. I mean, we've seen plenty of the previous years. We've seen the rate point experience. New England is another example.

So I think to some extent I have a little bit of a wait-and-see attitude from my point of view, but these capacity market changes may play a role separately whenever a generator retirement threatens reliability. Typically, the RTOs have a review process they go through. There are times when the RTO steps in and says, We can't really afford for you to retire.

Now, I can't talk about a lot in detail. There's still plenty of contested issues at FERC about individual cases, but I know most of the RTOs have some kind of process in place to enter into must run agreements or SSR agreements or some other kind of externally contractural commitment to preserve reliability. It's probably no one's best outcome because ratepayers are going to be paying. The fact that that generator is there and available, at least as a capacity item, may also have a detrimental effect on capacity prices or may have effects on other resources in the marketplace.

Presumably, RMR Agreements are only there until an adequate replacement to preserve reliability has gone; but those two features may have a role to play as regions like the Midwest evaluate where are we going to be in a few more years as we implement these environmental relations? But as Rick pointed out, I mean, a lot of these coal plants are extremely old. Most of the early retirement announcements were the smaller older coal plants that, frankly, they may not be economic under any circumstances that anyone can envision. It's not driven -- it may be an excuse that they have to do environmental investments; but, you know, they're not in the market, not in the money.

Gas resources as an alternative may play a role, but that's kind of how we expect markets to work.

CHAIRMAN SCOTT: Can I follow up with you guys for just a second and kind of play a "what if." So we know that the 70 percent capacity ramp up in gas is done -- whether we argue whether or not done based on EPA saying that that's something that can be doable, we've looked at the issue about availability and the pipeline and other things; but it could get a lot broader than that, especially in the Midwest.

And so I'm wondering about a scenario where -- in addition to that -- states, you know, not necessarily in Illinois, but states in the Midwest that might have a lot of coal retirement, might look to refuel switching or building new natural gas and now you've got something very different than just the 70 percent or something in addition to that.

If we get to a scenario like that, are we talking about substantial build-out then or other infrastructure that's going to be -- that's going to be necessary? What are the kind of the implications of that if we have to go much beyond the 70 percent, which is really possible in a place like the Midwest.

MR. RICK SMEAD: I think you have to add a lot of new generation to make up for the coal retirement initiatives in the market, Mr. Chairman. The obvious question is, Do you have the pipeline infrastructure in place to be able to serve that reliably? In many instances you will. But it's going to come down to this question, what time -- what times during the year are you running and how are you running?

One of the important aspects of gas-fired generation that I think gets lost in the dialogue a lot is that when you're operating a gas-fired combined cycle, the way you would operate a coal plant or a nuclear plant and if that's what it's replacing at a high capacity factor, you can afford firm transportation, you're not changing your nomination every day.

And it was one of the messages we heard in the summer conferences of the FERC in 2012, that utilities with gas-fired generation was saying, you know, things were a lot quieter now because I'm just running the things all the time and so it's only when gas is doing what only gas can do which is ramping rapidly up and down, filling gaps at intermittent renewables, whatever, that all of these nomination issues and business practice issues and interaction with the infrastructure really get kind of dicey.

And so assuming those are sorted out, applying them to new generation and having the right answer made for new generation shouldn't be a big deal and the economics of the pipe to serve higher capacity factor, generation should be a no-brainer.

CHAIRMAN SCOTT: Thanks.

MR. ED MURRELL: I would just like to add that where it's clear that that new generation is going to be run somewhat significantly in the wintertime, it's more likely going to require more pipeline to be built. If it's really more of a three-season type of situation and it's really primarily covering some repeats, it's going to put less pressure on the pipeline infrastructure.

My guess is it's going to be a little bit of a combination of both and it's going to depend on the specific plant that's being repowered or replaced.

CHAIRMAN SCOTT: Thank you.

COMMISSIONER DEL VALLE: I see we are nearing the end here, so as I listen to all of this, I think what would ratepayers be thinking right now if they had sat through this entire presentation -- Illinois ratepayers.

My guess is that many of them would be scratching their heads in trying to understand how -- as we've heard here today, we're in great shape in terms of storage, we're in good shape in terms of pipeline, we have an abundance of natural gas, we're exporting and yet we have these high prices, high prices that were due to the polar vortex and we've learned some lessons.

But as you've indicated, Mr. Murrell, high prices tell us there is an issue. Can you in a nutshell -- I know we've gone through this -- tell me what you would say to a ratepayer -- an Illinois ratepayer that ended up seeing those huge increases, explain to them how it is -- why that happened given all those other things you've just mentioned and what steps need to be taken to prevent that from happening to the extent that it happened this winter.

MR. ED MURRELL: I think I can answer the first part of your question. I'm not sure I have a really fabulous answer for the second part, but I'll give it a stab.

This past winter, it was really cold in the Eastern United States -- across the entire Eastern United States. That cold weather increased demand across literally the entire Eastern U.S. The Southeast was cold and increasing their demands on natural gas at the same time that New England was at the same time that the Midwest was. When you have that kind of unusual extreme weather, it's going to tax the system, it's going to increase demand for the resources that the system relies on to operate reliably and it's going to increase prices.

That is, unfortunately, part of how markets work. That increase in prices is the signal that you need all the resources you have to take care of these problems and, unfortunately, for this past winter, we're all going to pay a little bit more. We've already incurred those costs. They will eventually flow through. We will be seeing higher bills as a result of that.

The second part of your question is, Can we enumerate what steps we're taking to help protect against that happening in the future? And I can give you a little bit of an answer to that, but I don't think it's complete yet because I don't think we've fully identified all the steps. I think we're still working on that. I think we're looking to make improvements in the coordination and the cooperation across the two industries. We're looking to improve the day-to-day communications between the gas industry and the electric industry so that they minimize the kinds of problems that can lead to higher prices.

One example of that is scheduled maintenance. Pipelines routinely -- the summer is the slow period for a pipeline. So believe it or not, you know, that's when pipelines schedule maintenance. As a matter of coincidence, if they have a misfortunate scheduled maintenance the same day that that hot weather comes in and creates peak demands, you've got a problem.

The utilities and pipelines are communicating and coordinating that kind of information today and largely avoiding those problems, where two or three years ago they were tripping over each other on a regular basis and we have -- you know, unfortunately, there is several regions of the country that have some mild horror stories associated with that. So, you know, those kinds of things have already been improved.

The organized wholesale electric

markets are very complicated. There are a lot of moving parts. There is a lot of interrelationships between those moving parts. Each region of the country -- including MISO, including PJM -- is taking a hard look at those market rules and looking at where they can improve those market rules to make them more better, to make sure that generators have the appropriate level of fuel security, to make sure that the system is getting what it paid for and hopefully to make sure that the relationship between reliability and improvements in these operations and the cost of delivering reliable electric to ratepayers is balanced off so you don't have excessive costs flowing through the system.

That's as far as I can go in terms of --

COMMISSIONER DEL VALLE: We blame the Northeast, we're going to see -- we need more coordination and the markets are going to have to make some changes? That's it?

MR. ED MURRELL: For now, I think.

MR. RICK SMEAD: There's more, Commissioner. I think the most important message for ratepayers is that nobody in the industry liked the high prices either and that everyone is focused on which things are inefficiencies, like timing and communication; which things are infrastructure issues, the one that we really didn't have an issue is the supply. You know, on the day the gas hit 120 bucks in New York City, 275 miles away in Pennsylvania, it was $4.30.

So, it was a pure matter of pipeline constraint and so we're getting those sorted out one issue at a time as we go and I think the -- from the producer's perspective, who I represent, that is our biggest growth market and if it's busted, we don't get to sell to it, it's that simple. So it's going to be fixed.

COMMISSIONER DEL VALLE: Thank you.

COMMISSIONER COLGAN: Recently I went to the Harvard -- Commissioner McCabe and I both went to the Harvard Electric Policy and we had a whole session on the downside of uplift. I think that's what we're talking about here is the downside of the uplift and -- but just maybe one final question. I think --

Commissioner Maye, did you have a question?

COMMISSIONER MAYE: No.

COMMISSIONER COLGAN: I think we talked about -- you know, a lot of this has been brought to light because, you know, the necessity being the mother of invention, we had a polar vortex and it brought all of this discussion that was going on in the background really out into the forefront and we had to come to grips with the fact that we're living in a time where the unexpected can start to be expected and I'm not sure that the polar vortex is as much of an anomaly as we hoped that it was.

But there are other events that are happening like Sandra and we had Sandy and we had -- some of the events that we have had in Illinois that straight-lined events, kind of unheard of things happening on a regular basis so -- and I think what happened last winter is -- and I hear all the planning that we had in place ended up to be sufficient to and navigate through what was right on the verge of a crisis.

But I think we saw on the horizon --

we saw the edge and it's kind of a scary edge and I'm glad to hear that a lot is happening and I think it brings people to come to grips with the fact that, you know, we have this issue and that we need to work with all too urgency to make sure that question avoid these things from getting any more out of hand than -- and I'm not sure it did get out of hand, but it seemed like it was on the verge of it.

With that, I'd like -- any of the Commissioners, would you like to make any final comments? No?

Well, I thank everybody for being here today. I know a lot of people traveled long distances to be here. I'm sure it wasn't convenient to do that; but I appreciate your response, all the presenters, excellent job and I'd like to give you all a big thank you.

(Applause.)

With that, Mr. Chairman, I'll turn the meeting back to you.

CHAIRMAN SCOTT: I just want to thank Commissioner Colgan and Linda one more time for putting together a really excellent discussion and I appreciate all the witnesses as well and your input and your willingness to come out and talk to us.

COMMISSIONER COLGAN: And I do want to thank Linda Wagner. She did the yeoman's work on this project and did an excellent job.

CHAIRMAN SCOTT: Thanks again. Meeting is adjourned.